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EASTERN INTERCONNECTION STATES' PLANNING COUNCIL

Market Structures and Transmission Planning Processes In the Eastern Interconnection

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MARKET STRUCTURES AND TRANSMISSION PLANNING PROCESSES IN THE EASTERN INTERCONNECTION

prepared for
Eastern Interconnection States' Planning Council
and
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MARKET STRUCTURES AND TRANSMISSION PLANNING PROCESSES IN THE EASTERN INTERCONNECTION

EXECUTIVE SUMMARY

This report identifies and assembles information pertinent to the assessment of market structures and planning in the U.S. portion of the Eastern Interconnection. It is not intended to critique wholesale market structures, transmission planning processes, or state laws and regulations, but is limited to the orderly compilation of information, a comparison of market structures, and an explanation of how differences in those market structures are likely to affect private investment and states' approaches to planning and resource development.

Overview of the Eastern Interconnection

The Eastern Interconnection covers the eastern U.S. and Canada, from the Atlantic seaboard to the Great Plains. In the U.S., it encompasses all or part of thirty-nine states, plus the District of Columbia and New Orleans.

Generation and transmission in the U.S. portion of the Eastern Interconnection are partly regulated by the Federal Energy Regulatory Commission (FERC) and partly by regulators in each of the thirty-nine states (plus the District of Columbia and New Orleans). In general, FERC regulates electricity services that are sold in interstate commerce, particularly wholesale generation services and transmission services; while the states regulate intra-state electricity services, particularly retail transactions.

The Eastern Interconnection has two fundamentally different market structures for the supply of electricity. With some simplification, these structures are:

- *The traditional structure*, which is built around vertically integrated utilities that offer generation, transmission, distribution, and system operation services as part of a single package.
- *The RTO structure* in which Regional Transmission Organizations (RTOs) coordinate generation commitment and dispatch as well as transmission planning.

The two market structures both ensure reliable service, offer similar transmission services, and allow competition in generation supply. But these two structures allocate scarce transmission capacity differently, generally plan transmission over geographic areas of different scope, and have different bases for power system cost recovery.

Market Structures

All power systems require energy, regulation, operating reserve, voltage control, black start, and system coordination services. Of these, energy service of one type or another is universally traded in all markets in the Eastern Interconnection, while regulation and operating reserve services are traded in some but not all markets. There do not appear to be any places in the

Eastern Interconnection wherein voltage control, black start, and system coordination services are subject to market pricing or trading.

Energy costs, prices, and trades are determined by the way that power systems commit and dispatch their generation assets. Under the traditional market structure, individual utilities minimize their own generation costs; and bilateral trades among utilities serve the purpose of helping minimize regional generation costs because parties with relatively low generation costs sell to parties with relatively high generation costs, thus allowing cheaper generation to replace more expensive generation. Under the RTO structure, the RTOs minimize regional as-bid generation costs; and the RTOs operate markets for the trades among market participants that are consistent with the cost-minimizing regional dispatch.

Operating reserves are provided by resources that can respond, within a specified short timeframe (like ten minutes), to sudden large losses of power supply. They come in two forms: spinning reserves that are already synchronized with the power system and so can respond to imbalances within a few minutes; and non-spinning reserves that are not synchronized with the system but can become synchronized within specified timeframes. Balancing Authorities are required to meet the spinning and non-spinning reserve requirements specified by the North American Electric Reliability Corporation (NERC). Under the traditional structure, individual utilities meet their own reserve requirements, perhaps through reserve-sharing arrangements with other utilities. Under the RTO structure, generators provide reserves in response to reserve prices.[1]

Regulation service addresses very short-term, second-to-second imbalances between generation and load by adjusting the output of selected resources up and down via an automatic generation control signal, with the goal of maintaining interconnection frequency very close to sixty cycles per second. Balancing Authorities are responsible for procuring quantities of regulation resources sufficient to meet NERC reliability standards. Under the traditional structure, individual utilities meet their own regulation requirements, while under the RTO structure, generators provide regulation service in response to regulation prices.

Many or most jurisdictions in the Eastern Interconnection also have markets for derivatives of energy or operating reserve services, as well as markets for services that have been created in response to regulatory or legal mandates. These markets include capacity markets, transmission rights markets, and environmental rights markets.

Capacity markets are distinctly different for the RTO and the non-RTO regions. Although “capacity” generically refers to the productive capabilities of generators, the word is used for trading purposes in two radically different ways. In the RTO regions, “capacity” generally refers to installed physical generating capability and its demand-side analog. In non-RTO regions, by contrast, “capacity” refers to an option (i.e., a right) to obtain energy and operating reserve services under contractually specified conditions (e.g., when particular generating units are available).[2]

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[1] When market prices fail to bring forth sufficient operating reserves or regulation capability, RTOs make out-of-market payments to generators to induce them to provide sufficient amounts of these ancillary services.

[2] In the non-RTO regions, “capacity” does refer to physical generating capability as in the RTO regions; but it is only the options on generation services that are *traded* in the non-RTO regions.

Transmission rights confer the ability to transfer a specific quantity of power from one or more source (generation) locations to one or more sink (load) locations under terms and conditions (including price) that are known with a fair degree of certainty in advance.

- In non-RTO regions, transmission rights are "physical" in the sense that transmission customers taking firm service have the right to use the underlying physical transmission capacity. Transmission service priorities resolve congestion (i.e., potential transmission line overloads) through curtailment of power transactions that significantly contribute to line overloading: transmission service is curtailed by priority level, beginning with non-firm service and then continuing with increasingly higher-priority firm service.
- In RTO regions, transmission rights are "financial" in the sense that the transmission rights owner will be financially compensated for uncertain transmission prices. In RTO regions, transmission price uncertainty arises from the fact that the RTOs basically allocate transmission capacity, a day ahead, to the highest bidder. This has the virtue of allocating transmission capacity to its highest-valued uses, but the drawback of creating price uncertainty. Financial transmission rights offset this uncertainty by paying, on behalf of the rights owner, whatever the market price of transmission happens to be.

Power system coordination is highly centralized in the RTO regions, and is de-centralized in the non-RTO regions, though some non-RTO regions have large utilities comparable in size to some RTOs. The RTOs offer centralized trading of energy, regulation, operating reserves, capacity, and transmission rights, all of which may also be traded bilaterally. Outside of the RTOs, all of these services, to the extent that they are traded, are traded bilaterally only, though there are some reserve-sharing arrangements that involve coordination among utilities.

Retail competition has been growing over the past two decades. Although electricity consumers have traditionally been the captive customers of the distribution utility that serves their local areas, several states now permit consumers to choose their suppliers of electricity services. Competitive suppliers put together packages of the generation and delivery services that comprise delivered electricity service; and they do so under a variety of service plans that give consumers flexibility in their energy purchases. Retail competition tends to be limited to RTO regions. In the non-RTO regions, electric utilities generally continue to have monopoly franchise service areas with an obligation to serve all existing and future customers within those areas.

Transmission Planning Processes

Throughout the Eastern Interconnection, transmission owners are responsible for assuring that their systems meet NERC planning criteria and FERC planning requirements. Nonetheless, there are a variety of arrangements under which groups of transmission owners share in the responsibility to maintain reliable power systems. Furthermore, various FERC orders require that transmission providers must coordinate their plans with their customers and neighboring transmission providers.

Participants in planning processes in RTO regions are: transmission-owning utilities, who may prepare initial plans for transmission enhancements; transmission-dependent utilities, who must purchase transmission services from other utilities in order to serve their own loads; wholesale and retail customers; generators; power marketers; demand response providers; state regulatory commissions; and RTO personnel. Some RTOs' governance processes also include participation by consumer representatives and environmental organizations.

In non-RTO regions, planning occurs in Integrated Resource Planning (IRP) processes and as a result of requests for transmission service under the Open Access Transmission Tariffs (OATTs) of transmission providers in those regions. Participants in individual IRP processes adjudicated at state commissions tend to be those parties directly affected by the rate changes caused by such IRP plans, namely retail customers, retail customer groups, environmental groups, and state consumer representatives. Wholesale customers may also participate. For regional and sub-regional transmission planning, stakeholders include transmission providers and owners, wholesale customers, federal utilities, rural electric cooperatives, municipal electric system groups or power authorities, and large retail customers. State regulatory and FERC staff often participate as observers.

Planning processes for RTOs distinguish between "reliability upgrades" that assure reliable power system operation and "economic upgrades" that reduce power system costs (such as transmission congestion costs). Some of these processes also consider projects that would advance public policy (such as encouraging renewable energy). Reliability upgrades are treated as necessities, while economic upgrades are treated as desirable but not mandatory.

In non-RTO areas, transmission planning is primarily driven by resource and load requirements as identified in state-regulated IRP and RFP processes, as well as by long-term firm transmission service commitments made by the utility's customers under the FERC-regulated OATTs. The IRP process identifies the most cost-effective and reliable transmission solutions for meeting future load and resource needs. The long-term firm transmission service commitments made under a utility's FERC-regulated OATT represent additional transmission needs. The transmission planning process then identifies a comprehensive, least-cost transmission plan to satisfy all of these requirements, which are then coordinated and combined to develop a transmission expansion plan for that utility's transmission planning region.

Alternatives to transmission investment, in both RTO and non-RTO areas, generally include large central-station generation, renewable energy (local and remote), distributed generation, storage, demand response, and energy efficiency.

Transmission investors are primarily incumbent vertically integrated utilities, in all regions. Some transmission has been built by cooperative or municipal joint action agencies and by public-private partnerships. There are a few transmission-only firms that are in the business of building significant transmission infrastructure in the Eastern Interconnection; and there are some firms that have built (or have proposed to build) transmission in certain opportunistic situations.

Mandated transmission investment occurs only in certain situations. To the extent that authority is granted to the RTO by their transmission owner members, the RTOs can mandate investment in transmission facilities that are needed to assure reliability. On the other hand, RTOs tend to have only limited authority to mandate investment in transmission facilities that improve or relieve congestion and thereby improve market efficiency, though transmission owners may have an obligation to make good faith efforts to build projects approved in their RTO's regional plan, including economic projects.

State regulatory commissions have authority to mandate transmission investment, although the extent of that authority varies from state to state. State commissions can usually enforce laws that require utilities to reliably serve all existing and future customers within defined service boundaries, and that may require the construction of transmission in certain instances.

FERC jurisdictional transmitting utilities have an obligation to make "best efforts" to build new transmission to satisfy requests for firm transmission service.

Individual transmission utilities may have obligations to build transmission for others under bilateral or multilateral contracts.

Transmission cost allocation rules are set by several FERC orders that, among other things, specify that transmission providers must offer transmission service on a non-discriminatory basis, giving similar treatment to similarly situated customers. The general rule is that the costs of Network Integration Transmission Service are allocated among network customers in proportion to their relative loads, while the costs of Point-to-Point Service are allocated among point-to-point customers based upon their MW reservations.

Future Research Questions

This report's examination of the market structures and planning processes in the Eastern Interconnection raises questions that should be investigated thoroughly by the EISPC as it continues in its role to help inform and guide the states in their policy decision making. These questions include:

- What planning rules and market structures actually induce investment in generation resources and participation by demand-side resources?
- What are the incentive effects on transmission investment of different planning rules and market structures?
- How and to what extent is resource development affected by the differences among states and regions in their planning processes and market structures?
- What will be the likely effect of the EPA's environmental regulations on state Renewable Portfolio Standard (RPS) and energy efficiency resource standard (EERS) policies and on state implementation of integrated resource plans?
- What will be the likely impacts of Order No. 1000 on state RPS and EERS policies, state authority over transmission projects, and state authority over integrated resource plans?
- How can state integrated resource and long-term planning processes benefit from taking a broader view of resource development in the Eastern Interconnection?

MARKET STRUCTURES AND TRANSMISSION PLANNING PROCESSES IN THE EASTERN INTERCONNECTION

1. INTRODUCTION

In response to the Request for Proposals issued by the National Association of Regulatory Utility Commissioners (NARUC) and Eastern Interconnection States' Planning Council (EISPC) on July 11, 2011,[3] this report provides information that will serve as a foundation for EISPC's further understanding of how market structures and transmission planning vary across regions and states and how those different structures impact generation, resource, and transmission development and planning in the Eastern United States. This report thus identifies and assembles information pertinent to the assessment of market structures and planning processes in the U.S. Eastern Interconnection. This report is not intended to critique wholesale market structures, transmission planning processes, or state laws and regulations. Rather, its purpose is limited to the orderly compilation of information, a comparison of market structures, and an explanation of how differences in those market structures are likely to affect private investment and states' approaches to planning and resource development.

Regardless of the form of its retail regulation, every state's retail electricity market is dependent, to varying degrees, on wholesale electricity markets. The efficiency of the wholesale markets can affect policies and choices that drive retail rate levels and retail rate structures. This connection between wholesale and retail markets is strongest where states have developed markets that are organized by Regional Transmission Organizations (RTOs), but is also influential in traditionally regulated areas without RTOs. Different market structures engender different approaches to planning the physical infrastructure necessary for providing reliable electric service, differing degrees of dependence on competitive wholesale markets and independent generation, differing ways in which transmission is utilized, different forms of pricing for both generation and transmission, and different jurisdictional boundaries between state and federal regulation. The effects of wholesale markets on retail markets and final consumers give the states a strong interest in how the wholesale markets work.

This report is organized as follows. Section 2 provides a broad overview of the physical and institutional characteristics of the Eastern Interconnection. Section 3 describes the electricity services that are traded and the terms under which they are traded, the extents of vertical integration and centralized power market coordination, conditions imposed upon generators and customers for participation in markets, state regulatory requirements, and environmental requirements. Section 4 identifies who is responsible for transmission planning, the scopes of that responsibility, the forums in which planning occurs, and the parties who participate in those forums. It then describes some of the details of planning studies, the processes for adding projects to a transmission plan, if and how alternatives to transmission investments are considered, who transmission investors are, and how transmission costs are allocated to and

[3] Eastern Interconnection States' Planning Council and National Association of Regulatory Utility Commissioners, *Request for Proposals to assist the Eastern Interconnection States' Planning Council (EISPC) Members with preparing an analysis of Market Structures: identification of relevant market structures that will effect resource development*, July 11, 2011.

recovered from customers. The section concludes with a discussion of environmental and siting requirements. Section 5 considers how the market structures of the Eastern Interconnection are likely to affect generation and transmission resource development, particularly because of the incentive and financial effects of those market structures. It also explains how the planning processes of the Eastern Interconnection depend upon and interact with market structures and state regulatory processes. The report compares and contrasts the structures and explains how the differences might affect private investment, states' approaches to planning and resource development, and planning over the whole Eastern Interconnection. Section 6 raises several research questions that should be investigated thoroughly by the EISPC as it continues in its role to help inform and guide the states in their policy decision making.

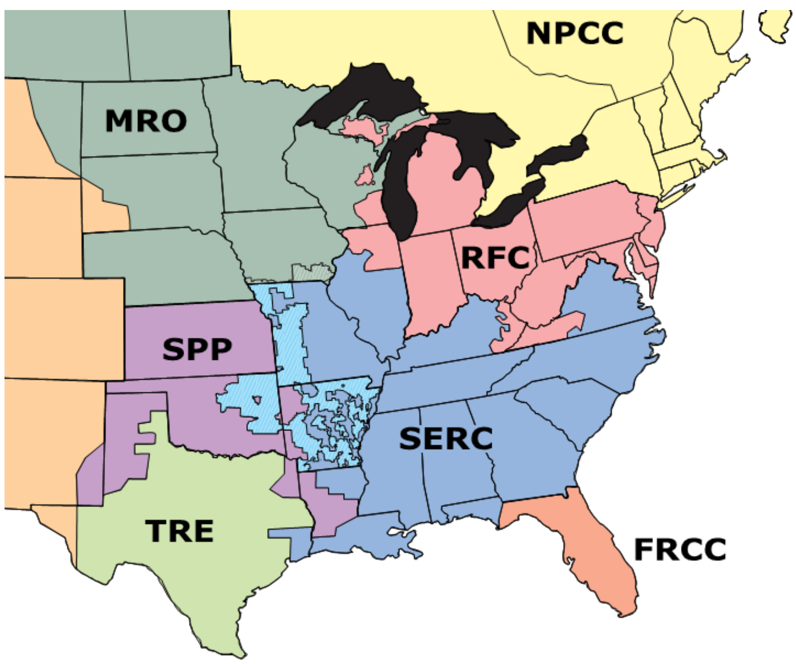
2. OVERVIEW OF THE EASTERN INTERCONNECTION

This section provides a broad overview of the physical and institutional characteristics of the Eastern Interconnection.

2.1. Physical Characteristics

The Eastern Interconnection covers the eastern portions of the U.S. and Canada, from the Atlantic seaboard to the Great Plains. In the U.S., it encompasses all or part of thirty-nine states, plus the District of Columbia.

Figure 1
Reliability Regions in the Eastern Interconnection[4]



[4] North American Electric Reliability Corporation, http://www.nerc.com/page.php?cid=1%7C9%7C119.

As shown in Figure 1, the Eastern Interconnection in the U.S. is divided among six Regional Reliability Organizations (RROs): Florida Reliability Coordinating Council (FRCC), Midwest Reliability Organization (MRO), Northeast Power Coordinating Council (NPCC), ReliabilityFirst Corporation (RFC), SERC Reliability Corporation (SERC), and Southwest Power Pool (SPP).[5] Each of these RROs is responsible for helping assure compliance, in their respective regions, with the reliability rules of the North American Electric Reliability Corporation (NERC).

For each of the reliability regions of the Eastern Interconnection, Table 1 presents estimated demand, resources, and reserve margins for the summer peak period of 2011 and the winter peak period of 2011-2012.[6]

Table 1
Estimated Demand, Resources, and Reserve Margins by NERC Region[7]

		Summer 2011			Winter 2011-2012		
NERC Regional Entity	**NERC Assessment Area**	**Total Internal Peak Demand (MW)**	**Anticipated Capacity Resources (MW)**	**Anticipated Reserve Margin (%)**	**Total Internal Peak Demand (MW)**	**Anticipated Capacity Resources (MW)**	**Anticipated Reserve Margin (%)**
FRCC	FRCC	46,091	61,116	32.60%	47,613	59,203	24.3%
MRO, RFC, SERC	MISO	99,572	120,882	21.40%	79,994	110,767	38.5%
MRO	MAPP	5,087	6,484	27.46%	5,036	6,727	33.6%
NPCC	NPCC-ISO-NE	27,550	32,761	18.91%	22,255	32,299	45.1%
NPCC	NPCC-NYISO	32,712	38,975	19.15%	24,533	37,176	51.5%
RFC, SERC	PJM	148,941	193,266	29.76%	130,711	194,458	48.8%
SERC	SERC-W	25,101	36,896	46.99%	19,931	36,836	84.8%
SERC	SERC-E	43,249	53,683	24.13%	42,459	54,109	27.4%
SERC	SERC-SE	49,314	61,598	24.91%	44,259	65,962	49.0%
SERC	SERC-N	46,846	59,961	28.00%	47,123	57,401	21.8%
SPP	SPP	53,512	64,851	21.19%	41,089	65,372	59.1%

[5] Texas Reliability Entity (TRE) is entirely outside the Eastern Interconnection.

[6] The Reliability Assessment Subcommittee (RAS) of the NERC Planning Committee (PC) prepares the Reliability Assessment report for Summer and Winter seasons based on data submitted by eight NERC Regional Entities, NERC Assessment Areas, and other stakeholder participants. Table 1 represents the values submitted by these entities as organized by NERC as of April 30, 2011. The mismatch between the NERC Regional Entities shown in Figure 1 and the regions presented in Table 1 arises from some Regional Entities having sub-regions (i.e., Assessment Areas) that are responsible for conducting the assessments and submitting those reports to the RAS.

[7] North American Electric Reliability Corporation, *2011 Summer Reliability Assessment*, May 2011, Table 1, p. 27. *Winter Reliability Assessment 2011-2012*, November 30, 2011, pp. 28-29.

Table 2 summarizes the generation capacity across the NERC Regional Entities and Assessment Areas by fuel type.

Table 2
Generation Capacity by NERC Region and Fuel Type[8]

NERC Regional Entity	NERC Assessment Area	Gen Capacity (MW)	Gas/Oil, Gas, & Oil	Coal	Nuclear	Hydro	Pumped Storage	Wind, Solar	Other
FRCC	FRCC[9]	52,157	74%	16%	8%				2%
MRO, RFC, SERC	MISO[10]	141,970	9%	75%	13%	1%		2%	1%
NPCC	ISO-NE[11]	30,380	66%	8%	13%	4%	5%	3%	
NPCC	NYISO[12]	38,285	64%	6%	14%	11%	4%	1%	1%
RFC, SERC	PJM[13]	166,512	12%	49%	35%	2%		1%	1%
SERC	SERC-W, E, SE, N[14]	247,943	37%	39%	14%	5%	4%		1%
SPP	SPP[15] (2010)	66,175	46%	40%	3%	4%	1%	4%	1%

2.2. Institutional Characteristics

Generation and transmission in the Eastern Interconnection are partly regulated by the Federal Energy Regulatory Commission (FERC) and partly by regulators in each of the thirty-nine states (plus the District of Columbia and New Orleans). In general, FERC regulates electricity services that are sold in interstate commerce, particularly wholesale generation services and transmission services (excluding bundled retail transmission service); while the states regulate intra-state electricity services, particularly retail transactions (including bundled retail transmission service).

2.2.1. Market Structures

The market structures in the Eastern Interconnection have evolved, in part, from decades of legislative and regulatory milestones. Among these is the Public Utility Regulatory Policies Act of 1978 (PURPA) which, for the purpose of fostering investment in renewable energy resources,

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[8] Because of rounding, percentages do not always sum to 100%.

[9] FRCC, *Florida Public Service Commission: 2011 10-Year Site Plan Workshop*, presentation, September 7, 2011, p. 13.

[10] Midwest Independent Transmission System Operator, *Midwest ISO 2010 Summer Assessment Report*, October 20, 2010, p. 12.

[11] ISO New England, *ISO New England 2010 Annual Markets Report*, June 3, 2011, p. 77.

[12] New York Independent System Operator, *Power Trends 2011*, undated, pp. 16 and 22.

[13] PJM Interconnection, *2010 State of the Market Report*, Vol. 1, March 10, 2011, p. 33.

[14] SERC Reliability Corporation, *Information Summary*, July 2011, p. 5.

[15] Southwest Power Pool, Untitled Power Point presentation, January 28, 2011, p. 6.

required vertically integrated utilities to purchase electric power from certain independent power producers (IPPs) at the utilities' "avoided cost." The Energy Policy Act of 1992 (EPAct 1992) went further by requiring transmission-owning utilities to offer unbundled transmission service to certain IPPs. In 1996, FERC specified the terms of this unbundled transmission service requirement through its Order No. 888.[16] This order required transmission owners to provide non-discriminatory "open access" to their transmission systems, defined the ancillary services that transmission owners must provide to transmission customers, and introduced the concept of "Independent System Operators" (ISOs). In 1999, for the purpose of fostering unbundled transmission service and competition in the provision of generation services, FERC's Order No. 2000 further encouraged the formation of RTOs that are similar to ISOs.[17] An intentional effect of this evolution has been a partial divorce of the provision of generation services from the provision of the transmission, distribution, and system operation services.

In some regions of the Eastern Interconnection, IPPs became a major component of the power supply, which sometimes burdened incumbent utilities with significant liabilities for above-market payments for IPP power and/or for "stranded" generation investments with above-market book values. At the same time, some states introduced retail competition or customer choice that contributed to these liabilities. Bargains were struck by state legislatures in these regions to allow their utilities to recover their costs in exchange for opening up markets to further wholesale and retail competition.

In 1996, about the same time that some states were opening retail markets to competition, FERC supported the development of competitive wholesale markets by adopting new requirements by which transmission-owning utilities must offer non-discriminatory transmission service (Order No. 888) and provide information about the availability and price of transmission service on their networks (Order No. 889). In late 1999, FERC embraced a more aggressive restructuring and wholesale market institutional change agenda in its RTO rule (Order No. 2000). Under Order Nos. 888, 889, and 2000, utilities in most of the states promoting retail competition agreed to form or join RTOs. In some parts of the Eastern Interconnection, the RTOs evolved from existing tight power pools.

Meanwhile, other areas of the Eastern Interconnection – particularly the Southeast – continued to regulate retail service as they always had, through monopoly franchise areas and cost-of-service regulation. Wholesale markets in these areas nonetheless evolved to encompass greater competition, including the increasing presence of IPPs, as a result of changes in federal regulation.

Thus, the Eastern Interconnection has two fundamentally different market structures for the supply of electricity, both of which share the common goal of providing reliable service at least-cost while nonetheless using different approaches to planning and resource development. With some simplification, these structures may be characterized as follows:

- *The traditional structure*, in place for roughly a hundred years, is built around vertically integrated utilities that offer generation, transmission, distribution, and system operation

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[16] Federal Energy Regulatory Commission, Order No. 888, *Promoting Wholesale Competition Through Open Non-discriminatory Services by Public Utilities*, 75 FERC ¶ 61,080, Docket No. RM95-8-000, April 24, 1996.

[17] From the standpoint of functional and operational responsibilities, there is no distinction between an ISO and an RTO.

services as part of a single package. Other utilities that are not vertically integrated, including load-serving entities (LSEs) such as public and cooperative utilities, have also long been a part of this structure. While the retail rates for the vertically integrated utilities in these markets are set by state-regulated cost-based regulation, wholesale rates are largely based upon competition among power providers who sell electricity at market-based rates pursuant to negotiated, bilateral arrangements. These competitive wholesale markets have been evolving for many decades as neighboring power systems have found it mutually beneficial to coordinate planning and operations, including emergency relief, seasonal exchanges of power, and economic interchange of power.

- *The RTO structure* is built RTOs' centralized commitment and dispatch of generation and transmission resources according to generators' offers for supply of energy and ancillary services. Of the five RTOs in the Eastern Interconnection, three evolved from tight power pools, one evolved from a loose power pool, and one was created from scratch – all four of the power pools were in existence for decades before they became RTOs. Generators, as long as they are found not to possess market power by the FERC or the RTOs' market monitors, sell at unregulated prices (generally subject to caps). While many states in these markets provide retail choice for customers, retail choice is not a required (or universal) feature of this market structure.

There are important similarities between the two market structures. They both ensure reliability consistent with the NERC Reliability Standards, conduct open and transparent regional planning activities consistent with FERC requirements, offer network and point-to-point transmission services on firm and non-firm bases, perform security-constrained economic dispatch, allow bilateral transactions, and allow competition in generation supply.

There are also significant differences between the two market structures. Scarce transmission capacity is allocated differently, with the traditional structure tending to allocate capacity according to long-term firm commitments for native load and for OATT service users while the RTO structure tends to allocate capacity to the highest bidders. Transmission rights are *physical* in traditional markets (conveying the right to transfer physical power among locations) and *financial* in RTO markets (conveying the right to financial compensation for transmission charges among locations). Transmission planning and transmission cost recovery have tended to cover far wider geographic areas under the RTO structure than under the traditional structure.

Generation costs are recovered on the basis of costs under the traditional structure[18] and on the basis of market prices under the RTO structure.[19] Consequently, generation investments in traditional markets are often made according to the results of state-regulated IRP and RFP processes that determine incremental needs and the least-cost means of serving those needs, with the RFP processes testing the wholesale markets for competitive opportunities. In RTO markets, generation investment decisions are generally made according to forecasts of future market conditions under the RTO structure. Finally, the traditional structure tends to allow state commissions to retain their traditional jurisdiction over retail ratemaking, including the transmission component of bundled retail service; while the RTO structure, by unbundling the

[18] The costs are those of the utility's own generation and of any bilateral power purchase arrangements.

[19] When market prices fail to bring forth sufficient supplies of generation services, RTOs make out-of-market payments to generators to induce them to provide sufficient amounts of such services.

generation, transmission, and distribution functions, generally shifts some regulatory responsibility from the states to FERC.

RTOs (including ISOs)[20] were initially intended to serve primarily as independent operators of power systems, assuring non-discriminatory commitment and dispatch of generation resources and non-discriminatory access to transmission systems. Because prices are driven by commitment, dispatch, and transmission use, however, RTOs also run centralized wholesale electric markets that determine day-ahead (commitment) and real-time (dispatch) prices.[21]

2.2.2. Geographic Boundaries

Figure 2 presents a map showing the approximate boundaries of the five RTOs in the U.S. portion of the Eastern Interconnection. The map shows that much of the Eastern Interconnection is served by RTOs, with the exception being a region of the Southeast generally coincident with the FRCC and SERC reliability regions.

ISO New England (ISO-NE), the New York Independent System Operator (NYISO), and the PJM Interconnection (PJM) originated as tight power pools in the late 1960s and early 1970s.[22] In response to Order No. 888, these three northeastern power pools became ISOs in the late 1990s; and in response to Order No. 2000, ISO-NE and PJM became RTOs a few years later.[23] While ISO-NE and NYISO have served the same states for decades, PJM has grown from its original footprint in the Mid-Atlantic Region (Delaware, the District of Columbia, Maryland, New Jersey, and Pennsylvania). Since 2002, PJM's footprint has added all of Virginia and West Virginia and parts of Illinois, Indiana, North Carolina, and Ohio.

The Southwest Power Pool began, in 1941, as a loose power pool, and became an RTO in 2004. The Midwest Independent Transmission System Operator (MISO), by contrast, was created from scratch and became an RTO in 2001. Over the past ten years, its geographic scope has varied as it has gained and lost members. If Entergy succeeds in its present effort to join MISO, this RTO will stretch from Canada to the Gulf of Mexico.

[20] For simplicity, this report utilizes the term "RTO" to refer to both ISOs and RTOs.

[21] See Section 3.1 for descriptions of the several services to which these prices apply.

[22] In a tight power pool, member utilities maintain a continuously operating central dispatch authority to optimize generation capacity utilization. Such pools do not have the range of functional responsibilities assumed by RTOs.

[23] There is presently no practical distinction between an ISO and an RTO. When the tight power pools became ISOs in the late 1990s, it was under the institutional definition established in Order Nos. 888 and 889. Later, these ISOs took on additional responsibilities as defined by Order No. 2000 and subsequent orders. The RTOs of the Eastern Interconnection have all evolved over time in response to FERC orders to encompass the same set of functional and operational responsibilities. SPP is moving to an RTO model that encompasses the full set of RTO responsibilities.

Figure 2
RTOs in the Eastern Interconnection

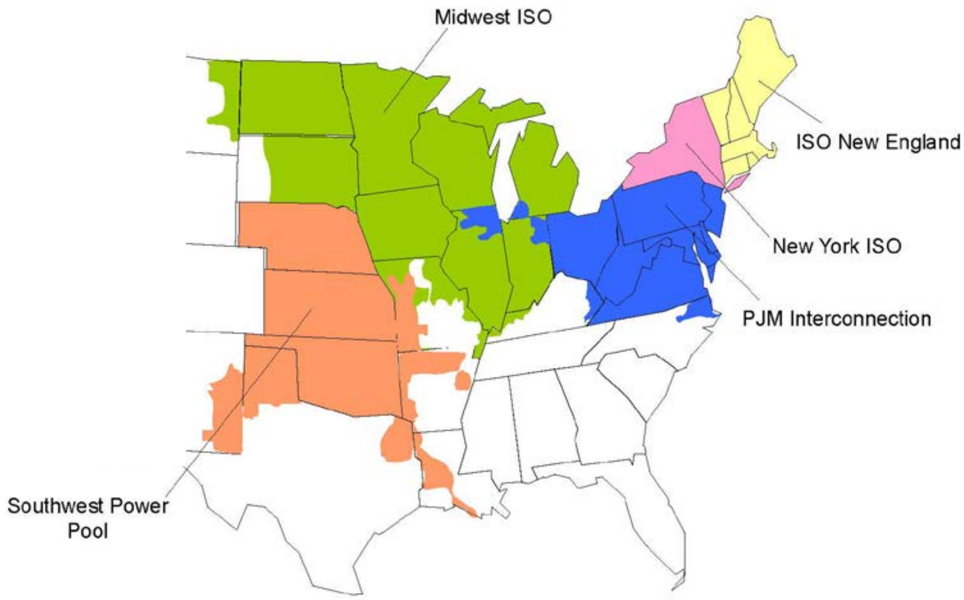

Table 3 summarizes the miles of transmission lines, installed generation, and population in each RTO region in the Eastern Interconnection.

Table 3
Statistics of the Five Eastern RTOs[24]

ISO/RTO	Headquarters	Energy Load (MWh, millions)	Peak Load (MW)	Installed Generation (MW)	Transmission Lines (miles)	Population Served (millions)
ISO-NE	Holyoke, MA	137	27,707	33,700	8,130	14
MISO	Carmel, IN		103,975	131,010	46,941	39
NYISO	Rensselaer, NY	164	33,452	40,685	11,009	19
PJM	Valley Forge, PA		136,465	164,895	56,499	51
SPP	Little Rock, AR	223	54,949	66,175	50,575	15

[24] ISO/RTO Council, *2010 ISO/RTO Metrics Report*, p. 11; ISO New England, "Net Energy and Peak Load Report," Excel spreadsheet, http://www.iso-ne.com/markets/hstdata/rpts/net_energy/index.html, December 7, 2011; Midwest Independent Transmission System Operator, *Midwest ISO 2010 Summer Assessment Report*, October 20, 2010, p. 3; New York Independent System Operator, *Power Trends 2011*, p. 3, undated; Monitoring Analytics LLC, *PJM State of the Market Report*, Volume 1, p. 11; Southwest Power Pool, *2010 State of the Market Report*, May 10, 2011, p. 9; and Southwest Power Pool, "Region Hits All-Time Record For Electricity Use {8/3/2011}," announcement accessed at http://www.spp.org.

Consistent with the map, Table 4 indicates whether each state is wholly or partly in an RTO. Considering only the portions of states within the Eastern Interconnection, eight states have no RTO participation, twenty-one states (plus the District of Columbia) are entirely within a single RTO, three states are entirely covered by a combination of two RTOs, four states are partly covered by one RTO and are partly not served by any RTO, and two states are partly covered by two RTOs and are partly not served by any RTO. Note that, in some of the states entirely covered by RTOs, not all utilities are RTO members.

Table 4
RTO Memberships of the States

	RTO					
State / District	**ISO-NE**	**MISO**[25]	**NYISO**	**PJM**	**SPP**	**non-RTO**
Alabama						X
Arkansas					X	X
Connecticut	X					
Delaware				X		
District of Columbia				X		
Florida						X
Georgia						X
Illinois		X		X		
Indiana		X		X		
Iowa		X				
Kansas					X	
Kentucky		X		X		X
Louisiana[26]						X
Maine	X					X
Maryland				X		
Massachusetts	X					
Michigan		X		X		
Minnesota		X				
Mississippi						X
Missouri		X			X	X
Montana		X				
Nebraska					X	
New Hampshire	X					
New Jersey				X		
New Mexico					X	

[25] Manitoba is in MISO; but because this study is limited to the U.S., Manitoba is excluded from the table and the discussion of this report.

[26] SWEPCO, Cleco, and LUS are in Louisiana and are SPP members. However, Cleco and LUS are not SPP market members and are therefore not subject to SPP's OATT. Like the rest of the state, the City of New Orleans is not presently part of an RTO.

RTO Memberships of the States (continued)

State / District	RTO					non-RTO
	ISO-NE	MISO[27]	NYISO	PJM	SPP	
New York			X			
North Carolina				X		X
North Dakota		X				
Ohio				X		
Oklahoma						X
Pennsylvania				X		
Rhode Island	X					
South Carolina						X
South Dakota		X				X
Tennessee[28]						X
Texas[29]					X	
Vermont	X					
Virginia				X		
West Virginia				X		
Wisconsin		X				

3. MARKET STRUCTURES

This section describes the electricity services that are traded and the terms under which they are traded, the extent of vertical integration versus centralized power market coordination through RTOs, conditions imposed upon generators and customers for participation in markets, state regulatory requirements, and environmental requirements.

3.1. Services Traded and Terms of Trade

As a matter of physics, all power systems require energy, regulation, operating reserve, voltage control, black start, and system coordination services. Of these, energy service of one type or another is universally traded in all markets in the Eastern Interconnection, while regulation and operating reserve services are traded in some but not all regions. There do not appear to be any places in the Eastern Interconnection wherein voltage control, black start, and system coordination services are subject to market pricing or trading.

As a matter of institutional arrangements, many or most jurisdictions in the Eastern Interconnection also have markets for derivatives of energy or operating reserve services or for services that have been created in response to regulatory or legal mandates. These markets include the following:

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[27] Manitoba is in MISO; but because this study is limited to the U.S., Manitoba is excluded from the table and the discussion of this report.

[28] A very small portion of Tennessee (including Kingsport) is served by American Electric Power, which is in the PJM RTO.

[29] Most of Texas is in ERCOT.

- *capacity markets*, which were traditionally markets for options on energy or operating reserve services, but have more recently become tools for encouraging generation capacity investment;
- *transmission rights markets*, which are based on physical rights in traditional markets and provide options on locational differentials in energy service prices in centralized markets; and
- *environmental rights markets*, which help meet emissions and other government requirements.

For ease of exposition, the discussions of the non-environmental markets begin with explanations of the workings of the RTO markets.

3.1.1. Energy

Electrical energy is the main service – in terms of performing useful work and economic value – that electricity consumers want. Certain other services – particularly covering transmission and distribution losses and providing Energy Imbalance Service as required by FERC's Order No. 888 – are merely different forms of energy service which, regardless of their pricing, have the same costs and economic values as energy. U.S. markets have thus evolved to generally recognize that energy has the same value in all its forms, so that energy imbalances, losses, and energy tend to all have the same prices at each particular time and place.

Energy costs, prices, and trades are determined by the way that power systems commit and dispatch their generation assets. Both the commitment process and security-constrained economic dispatch (SCED) seek to minimize generation costs by seeking to dispatch the lowest-cost generating units first, to the extent that transmission and reliability constraints will allow. SCED finds the cost-minimizing dispatch, the generation costs associated with that dispatch, and the prices that are consistent with that dispatch. In non-RTO regions, individual utilities use SCED to minimize their own generation costs; and bilateral trades among utilities serve the purpose of helping minimize regional generation costs because parties with relatively low generation costs sell to parties with relatively high generation costs, thus allowing cheaper generation to replace more expensive generation. In RTO regions, the RTOs use SCED to directly minimize regional as-bid generation costs (which may differ from incremental generation costs); and the RTOs provide the centralized markets that arrange trades among market participants that are consistent with the cost-minimizing regional dispatch.

"Bilateral trades" refer to direct trades between willing buyers and sellers, outside of a centralized market. Bilateral trades can be hourly, daily, weekly, monthly, or multi-year. Bilateral agreements can be the result of arms-length market negotiations, formal requests for proposals, and informal or unsolicited bids for sale or purchase. Bilateral trades can be tailored to fit the unique circumstances of buyers and sellers, including the particular characteristics of their loads and generators.

The RTO Regions[30]

RTO energy markets include bilateral transactions as well as centralized markets operated by the RTOs. The centralized markets are day-ahead and same-day hourly markets, while the bilateral transactions are generally for longer-term forward trades that occur outside of the RTO's centralized market but are nonetheless scheduled by the RTO. Centralized market trades are implicitly multilateral trades, and serve the purpose of covering differences between a party's resources (including any self-supplied resources such as owned generation and energy acquired through bilateral markets) and that party's obligations (including loads and resources sold through bilateral markets).

The day-ahead markets allow market participants to buy or sell energy one day before the operating day in order to resolve (i.e., hedge) any differences between their available resources and their load obligations. Market participants can also trade "virtual" supply and demand with the intention of speculating on differences between day-ahead and real-time energy prices. The real-time markets find the prices that exactly match generation with load and delivery losses[31] in real time. Market participants must buy or sell in the real-time market any differences between their available resources and their load obligations, where such resources and obligations include whatever energy that they bought or sold, respectively, in the day-ahead market.

In both day-ahead and real-time energy markets, the "locational marginal prices" (LMPs) of energy vary by both time and location.

- LMPs vary over time because of changes over time in both loads and the availability of power system facilities (such as generators and transmission equipment). Day-ahead LMPs change hourly, while real-time LMPs change every five minutes or less.
- LMPs vary by location because of transmission losses and constraints. At each location, LMP equals the marginal cost of providing electrical energy to that location, as determined by resources' offer prices and by losses and constraints. Generators face prices that are the LMPs specific to the pricing nodes at which they are located, while loads face prices that are load-weighted averages of the LMPs within the zones in which they are located.[32] Prices tend to be relatively low at "export-constrained" locations where supply is abundant relative to demand, and tend to be relatively high at "import-constrained" locations where supply is scarce relative to demand.

The supply of electrical energy is determined by sellers' offers. Day-ahead offers based upon physical generation resources can be three-part offers reflecting start-up costs (for synchronizing a non-synchronized unit with the grid), no-load costs[33] (reflecting hourly operating costs that do not depend upon output level), and incremental energy costs (reflecting the extra costs of

[30] Because all five RTOs in the U.S. portion of the Eastern Interconnection will have so-called "Day Two markets" by 2014, the discussion of RTOs focuses on Day Two markets. ISO-NE, MISO, NYISO, and PJM presently have Day Two markets, while SPP plans to inaugurate its Day Two market in April 2014.

[31] "Delivery losses" refers to electrical energy lost in the form of heat as electricity passes through transmission and distribution facilities.

[32] Note that, to facilitate trading and market liquidity, the RTOs also have some trading "hubs" that aggregate the prices of specified sets of nodes.

[33] "No-load costs" are also known as "minimum generation costs."

increasing output). Offers for the latter component may change with a resource's output level. Because all auction winners are paid the same "uniform" market clearing price, competitive resources maximize profits by setting their offers close to their true marginal costs, thus providing financial incentives that seek to assure efficient least-cost provision of electric power services.[34] While physical resources may make offers in both the day-ahead and real-time markets, speculative "virtual" offers may only be made in the day-ahead market. Sellers make such speculative offers when they hope to buy the energy back in the real-time market at a lower price than they receive in the day-ahead market.

The demand for electrical energy is determined by purchasers' bids. These bids may depend upon price, so that (for example) the quantities purchased fall as price rises; or they may be fixed, so that the buyer pays whatever the market price happens to be. The bids may be for the real loads that the buyer expects to actually serve; or the bids also may be speculative purchases in the day-ahead market that the buyer hopes to sell back in the real-time market at a higher price.

The RTOs simultaneously determine the prices of energy, operating reserves, and regulation services. This simultaneous determination is necessary and appropriate because generators can simultaneously provide these services from different portions of their capacity. To find the efficient least-cost provision of these services, the RTOs must determine the quantities of these services that should be provided by each of the available resources, and they must also identify the prices that give resources incentives to provide the efficient quantities of these services.

Although efficient market prices should theoretically fall right out of the mathematics of the RTOs' dispatch algorithms, practical problems require the RTOs to develop rules and exercise judgment in setting prices in some recurring situations. The basic problem is that efficient prices depend upon bids that are based on marginal costs, but there are several reasons that the marginal costs that underlie the RTOs' LMPs may be poorly defined:

- Accurate marginal cost information may not be available, even to resource owners.
- Resource owners may offer services at prices that differ significantly from marginal costs, perhaps for the purpose of manipulating market prices. RTOs use market monitoring processes to minimize the opportunities for and impacts of such manipulation. FERC and other governmental agencies also provide enforcement against the exercise of anti-competitive practices.
- There may be no mathematical solution to the simultaneous optimization problem. This can occur, for example, if the available generation resources are not sufficient to permit full respect for all operating constraints (such as formal transmission limits). In such cases, the RTOs impose penalty factors on constraint violations, utilize demand curves that attribute increasing costs to violations of increasing severity, or relax constraints so that mathematical solutions can be calculated.

[34] "Competitive resources" are those that lack market power. Setting offers close to marginal cost is profit-maximizing because: a) bidding below marginal cost can result in a loss if the resource wins a bid wherein the market-clearing price is lower than its marginal cost; and b) bidding above marginal cost can result in the resource losing a profitable sale if the market-clearing price is above its marginal cost but below its bid. By contrast, an offer that is close to marginal cost will always make money when the market-clearing price exceeds the resource's marginal cost.

- Inflexible generating units[35] create cost discontinuities that are often not amenable to a mathematical solution. To deal with this problem, the RTOs calculate prices by artificially smoothing the discontinuities (by ignoring the inflexibilities) and/or by making out-of-market side payments to generators that they want to provide services in spite of inconsistencies between market prices and the generators' operating and cost characteristics.

- Generators may fail to precisely follow dispatch instructions. This can occur because the RTOs or their dispatch models are unaware of generators' operating constraints or conditions, because generators encounter sudden operating problems, or for other reasons. Many RTOs impose penalties for failure to follow dispatch instructions beyond a defined bandwidth.

- RTOs may be compelled to operate some generators out-of-merit order for reliability purposes. The effect of out-of-merit order dispatch is to increase supply through out-of-market compensation and thereby reduce the market-clearing prices of energy and operating reserves. The price impacts, as well as the ultimate consequences for generation investment, can be significant. For reasons of both efficiency and equity, the RTOs attempt to minimize their use of out-of-merit order dispatch.

The Non-RTO Regions

In the non-RTO areas of the Eastern Interconnection, prices for retail customers are generally set according to costs that are determined through state regulatory processes for public utilities and through internal processes for government-owned and cooperative utilities. Thus, retail customers in non-RTO regions generally bear the actual costs of generation that its local load-serving utility either owns or has contracted for via power purchase agreements, optimized through security-constrained economic dispatch and short-term energy purchases and sales when opportunities arise.

In non-RTO regions, energy is traded bilaterally on an hourly, daily, weekly, monthly, or multi-year basis. Many utilities and IPPs in these regions have received FERC approval to sell energy at freely negotiated market-based rates, particularly outside of their own service territories. Utilities without market-based rate authority must sell energy at cost-based rates under FERC-approved tariffs. While most savings and profits from bilateral transactions go to utility customers in the form of lower prices, utility shareholders are sometimes allowed to share in the savings as an incentive to aggressively seek such deals. Utilities purchase power bilaterally for short-term cost reduction (e.g., when a purchase is available below the utility's marginal cost), for short-term reliability (e.g., to replace a generator on forced outage), or for long-term capacity (e.g., when capacity can be purchased more cheaply than built).

The southeastern portion of the Eastern Interconnection is characterized, in significant part, by large utilities and by holding companies that own utilities in multiple states. Several of these utilities are of a scale comparable to the RTOs. To the extent feasible, these holding companies operate as integrated systems, minimizing costs by dispatching power without regard to state

[35] Inflexible units include, for example, generators that can produce discrete quantities of power (e.g., 30 MW and 60 MW) but cannot produce intermediate quantities of power.

boundaries. In a typical holding company pooling agreement, each operating company makes its generating resources exclusively available for economic dispatch by the pool, with short-term wholesale transactions arranged on an economic opportunity basis.

3.1.2. Operating Reserves

NERC reliability standards establish requirements for Balancing Authority Area operators to maintain system balance. These standards require Balancing Authority Area operators to deploy generator ancillary services to operate the grid reliably. Operating reserves are among the required ancillary services.

Operating reserves are provided by resources that can respond, within a specified short timeframe (e.g., ten minutes), to sudden large losses of power supply. They come in two forms: spinning reserves that are already synchronized with the power system; and non-spinning reserves that are not synchronized with the system but can become synchronized within a specified timeframe. Balancing Authorities are required to meet the spinning and non-spinning reserve requirements specified by NERC.

FERC's Order No. 888 requires all transmission providers to offer these two services to their customers as Spinning Reserve Service and Supplemental Reserve Service that are both available within ten minutes.[36] Spinning Reserves respond to disturbances within a few minutes, while Supplemental Reserves respond within ten minutes. Both types of reserves maintain their responses for at least ninety minutes, by which time NERC standards require that deployed Spinning and Supplemental Reserves be restored by replacing the resource lost by the disturbance with another resource or a purchase. Per Order No. 888, transmission providers must offer Spinning and Supplemental Reserves to transmission customers at their cost for acquiring those services from the generators in the Balancing Authority Area that may be providing those services. Within the Balancing Authority Area, generators capable of providing these services must do so on a cost basis unless they have FERC approval for market-based pricing. Network Service customers are required to take Spinning and Supplemental Reserve Services from their transmission providers unless they are able to meet their operating reserve requirements from their own generating resources or from third-party sources that satisfy applicable reliability criteria. Other transmission customers may take this service on an as-needed basis.

A major purpose of reserve markets is to induce more generators to commit themselves or agree to be committed (i.e., start up) in response to market prices than would occur if there were only energy markets. Reserve markets can thus provide price incentives for generators to commit themselves in a manner consistent with reliable system operation.

[36] Spinning reserves are also called "synchronous reserves," "10-minute spinning reserves," and "10-minute synchronous reserves." Supplemental reserves are also called "non-spinning reserves," "non-synchronous reserves," "10-minute non-spinning reserves," and "10-minute non-synchronous reserves." The terms "contingency reserves" and "operating reserves" are often used to refer to the sum of spinning reserves plus supplemental reserves.

The RTO Regions

The "Day Two markets" of the RTOs are characterized (among other things) by separate markets for energy, reserve services, and regulation services. In some Day Two markets (e.g., New York), resources do not make separate offers for reserve services, but instead make three-part day-ahead supply offers as described in Section 3.1.1. Through simultaneous optimization of energy and reserve services, the RTOs overseeing such markets determine both the cost-minimizing dispatch of resources for supplying reserve services and the prices of these services. The prices implicitly reflect the marginal opportunity costs of these services, which generally reflect the marginal profits that generators lose when they provide reserves instead of energy. In other Day Two markets (e.g., MISO), resources do make separate Regulation, Spinning, and Supplemental Reserve offers.

The RTOs provide extra compensation ("make-whole payments") to generators that are needed for reliability purposes but that would lose money if they were paid only the market prices of energy, regulation, and reserves. The need for such out-of-market compensation can be exacerbated by the ceilings that are imposed on energy and ancillary services prices in some markets.

The costs of reserve services are borne by LSEs (and then ultimately by their customers) who must either supply or pay for quantities of reserve services that are roughly proportional to their loads. They can satisfy these requirements from their own generation and load resources or through reserve services purchased bilaterally or through the RTOs' markets.

Table 5 summarizes some of the differences in reserve practices among the four eastern RTOs that presently have Day Two markets. All four have markets for, and market-based pricing of, 10-minute spinning reserves. Although they all have supplemental reserve requirements, ISO-NE, MISO, and NYISO price these reserves on a market basis while PJM prices them on a cost basis. Furthermore, NYISO's explicit requirement is for total ten-minute reserves, so that its implicit supplemental reserve requirement is the amount by which actual spinning reserves fall short of meeting the total ten-minute reserve requirement. Only ISO-NE and NYISO have thirty-minute non-spinning reserve requirements.

Table 5 also shows that the RTOs all divide their reserve markets into zones that are defined by transmission constraints. For all RTOs, the market price of each service in each zone reflects the offer price of the marginal supplier of that service in that zone. ISO-NE has a reserve demand curve that is defined by the Reserve Constraint Penalty Factor associated with each reserve product, with the consequence that reserve demand varies with reserve price. NYISO has demand curves for each reserve product that set price when a reserve requirement is not being met. MISO utilizes a fixed demand curve for Regulating Reserve, and a multi-step (sloping) curve for Operating Reserves to establish scarcity prices. PJM also has sloping demand curves for reserve services.

The determination of reserve requirements is similar across the four RTOs. ISO-NE requires that ten-minute reserves be sufficient to cover the largest single system contingency, that between one-fourth and one-half of the ten-minute reserves be spinning, and the additional thirty-minute reserves be sufficient to cover half of the second-largest system contingency. ISO-NE also administers a forward reserve market to acquire forward commitments to ten-minute non-spinning reserve and thirty-minute operating reserve for delivery in real time. For each reserve zone, the forward reserve market includes an auction two months in advance of the procurement period.

In PJM, the total synchronized reserve requirement for each zone is determined for each hour of the operating day. In the ReliabilityFirst Corporation (RFC) Zone, the Synchronized Reserve Requirement is defined as the greater of the RFC's minimum requirement or the largest contingency on the system. In the Southern Zone, the Synchronized Reserve Requirement is defined as the Dominion load ratio share of the largest system contingency within Virginia-Carolinas Region (VACAR), minus the available fifteen-minute quick start capability within the Southern Zone.

Table 5
Characteristics of Eastern RTO Reserve Markets[37]

RTO	ISO-NE	MISO	NYISO	PJM
Required Reserves:				
10-Minute Spinning	market	market	market	market
10-Minute Non-Spinning	market	market	market[38]	cost
30-Minute Spinning			market[39]	
30-Minute Non-Spinning	market		market	cost
Number of Zones:[40]				
Spinning	2	6	3	9
Supplemental or Total 10-Min	2	6	3	9
Sloping Demand Curve	no	yes	yes	yes

In MISO, the minimum zonal operating reserve requirements are identified through studies performed on a daily basis prior to each operating day. For each zone, the studies determine the hourly zonal regulating reserve requirements, contingency reserve requirements, and spinning reserve requirements. Each zone's minimum reserve requirements are based upon (among other factors) the zone's import capability and the size of its largest resource contingency.

For the NYISO, total operating reserves must equal at least one and one-half times the largest single contingency. Total 10-minute reserves must be greater than or equal to the largest single

[37] SPP is excluded from this table because its Day Two reserve markets will not start until 2014.

[38] The NYISO's contingency reserve requirement is for Total 10-Minute reserves, which is the sum of 10-Minute Spinning and 10-Minute Non-Spinning reserves. The supplemental reserve requirement is for Total 30-Minute reserves, which is the sum of 30-Minute Spinning and 30-Minute Non-Spinning reserves.

[39] The NYISO defines 30-minute spinning reserves as "[o]perating [r]eserves provided by qualified Generators and qualified Demand Side Resources located within the NYCA [New York Control Area] that are already synchronized to the NYS Power System and can respond to instructions from the NYISO to change output level within 30 minutes." New York Independent System Operator, *NYISO Auxiliary Market Operations*, Version 3.21, October 27, 2011, p. 6-1.

[40] In addition to the two zones shown in the table, ISO-NE has local reserve requirements for meeting second contingencies in import-constrained areas.

contingency and 10-minute spinning reserve must be greater than or equal to one-half of the largest single contingency.

Like the four RTOs with Day Two reserve markets, SPP, which is presently developing a Day Two market, also bases its operating reserve requirements on its largest contingencies. Specifically, SPP sets its operating reserve requirements (for 10-minute spinning and supplemental reserves) equal to the capacity of the largest on-line generator plus half of the capacity of the next largest on-line generator. Each member of the SPP Reserve Sharing Group is required to carry an amount of operating reserves based upon relative load shares.[41]

The Non-RTO Regions

Vertically-integrated utilities in non-RTO regions provide operating reserves as part of their normal unit commitment and dispatch function. This involves day-ahead commitment of generation sufficient to provide operating reserves, as well as real-time operation to ensure that reserve requirements are met. In these regions, reserve requirements are usually met by the utilities' own resources, including the generation they own and obtain through power purchase agreements. Accordingly, while there are no specific "markets" for operating reserves in non-RTO regions, the utilities in those regions buy and sell capacity that can often be used by the purchasing utility to provide operating reserves. In addition, utilities can and do meet some of their reserve requirements through reserve-sharing arrangements or through purchases from demand-side resources within their Balancing Authority area.

3.1.3. Regulation

Regulation service (or regulating reserves) is another ancillary service that NERC requires for reliable grid operation. Regulation service addresses very short-term, second-to-second imbalances between generation and load by adjusting the output of selected resources up and down via an automatic generation control (AGC) signal, with the goal of maintaining interconnection frequency very close to sixty cycles per second (60 Hz). This frequency control assures that the balance between supply and demand is maintained in a manner consistent with reliable power system operation. Power systems require quantities of regulating reserves sufficient to meet NERC reliability standards.

Balancing Authorities, including RTOs and utilities outside of RTOs, are responsible for assuring sufficient regulating reserves to keep electric energy supply and demand in balance at all times. They achieve this by scheduling resources that offer sufficient downward and upward ramping capability, by continually monitoring the power balance within their respective Balancing Authority Areas, and by adjusting the output of resources with automatic generation control. Generators have traditionally been the resources that provide regulating reserves , and they still provide the vast majority of such reserves; but new technologies, such as battery storage, promise to also provide this service.

FERC's Order No. 888 requires all transmission providers to offer unbundled regulation service to their customers as Regulation and Frequency Response Service. According to Order No. 888, this service must be offered at the transmission provider's cost to acquire such service.

[41] Southwest Power Pool, *Southwest Power Pool Criteria*, p. 6-5.

Generators capable of providing this service must do so on a cost basis unless they have FERC approval for market-based pricing. Transmission providers must identify the regulation requirements for transmission customers serving loads in their Balancing Authority Areas and must develop procedures by which customers can avoid or reduce such requirements. Transmission customers are required to take this service – in quantities that are roughly proportional to their loads – unless they are able to meet their obligation from their own generating resources or from third-party sources.

The RTO Regions

In a market setting, regulation service pricing would be most efficient if it had two components: an availability price that reflects generators' costs of being able to provide regulation service, even when no service is actually provided; and a usage price that reflects the cost of actually providing the service. More or less consistent with this efficiency principle, FERC's recent Order No. 755 requires RTOs to offer two-part, market-based compensation for regulation service. This order:

> …requires RTOs and ISOs to compensate frequency regulation resources based on the actual service provided, including a capacity payment that includes the marginal unit's opportunity costs and a payment for performance that reflects the quantity of frequency regulation service provided by a resource when the resource is accurately following the dispatch signal.[42]

This order will soon cause substantial reform of the RTOs' existing regulation service procurement and pricing practices; so only a few observations about existing practices will be made here. The RTO regulation markets operate in day-ahead and real-time timeframes. Some RTOs have regulation zones. PJM's regulation market is market-based when the market is deemed competitive, and is cost-based otherwise; and PJM sometimes requires dominant suppliers to make cost-based offers, even though such suppliers are paid the market price when their offers clear auctions. NYISO has had a sloped demand curve for regulation service, so that the regulation requirement falls when the price gets high.

The Non-RTO Regions

In non-RTO areas, Balancing Authorities may rely upon any resource in its area to provide regulation service, including resources owned by load-serving utilities or third parties. Bilateral contracts may need to be in place in order for a Balancing Authority to call upon such resources, however. Because FERC Order No. 755 applies only to RTO markets, Balancing Authorities in non-RTO regions will continue to procure such service from their own resources and from resources procured on a bilateral negotiated basis.

3.1.4. Capacity

The RTO capacity markets are distinctly different from the non-RTO capacity markets. Indeed, although "capacity" generically refers to the productive capabilities of generators, the word is

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[42] Federal Energy Regulatory Commission, *Frequency Regulation Compensation in the Organized Wholesale Power Markets*, Order No. 755, 137 FERC ¶ 61,064, October 20, 2011, p. 2.

used for trading purposes in two radically different ways. In the RTO regions, "capacity" generally refers to installed physical generating capability and its demand-side analog. In non-RTO regions, by contrast, "capacity" refers to an option (i.e., a right) to obtain energy and operating reserve services under contractually specified conditions (e.g., when particular generating units are available).[43]

The RTO Regions

ISO-NE, NYISO, and PJM have centralized capacity markets that were created to ensure resource adequacy by providing a steady stream of income for generators, with the idea that this would encourage generation investment and delay generation retirements. In principle, the same level of income (albeit unsteady) could be provided by energy and reserve service prices that were allowed to rise extremely high levels (i.e., thousands of dollars per MWh) during electricity shortage conditions; but because of an aversion to price volatility by both generators and consumers and because of the concern that high prices might be due to the exercise of market power, extremely high energy and reserve prices are not an acceptable mechanism for investment cost recovery. There is the reasonable concern that energy and reserve prices, when subject to price or offer caps, will not be sufficient to induce enough generation investment to maintain reliable electric power systems.

There is some controversy, however, about whether the capacity markets do in fact encourage generation investment. The concerns arise because the investment incentives provided by capacity markets are limited by the high volatility of prices in these markets and by the short timeframes of these markets (i.e., no more than five years into the future) relative to the long lives of generation assets (e.g., fifty years). Furthermore, although capacity markets balance supply and demand like other electricity markets, they are unlike other electricity markets in how demand is created. Consumers demand real-time electrical energy for all their uses of electricity; and system operators demand real-time regulating and operating reserves so that they can respond to changing power system conditions; and the forward markets for energy and reserves, whether a day-ahead or a year-ahead, serve the purpose of mitigating price uncertainty for services that people really want.

By contrast, capacity is a derivative product: it is not desired for the capacity itself, but for the energy, reserves, and other ancillary services (e.g., voltage control) that the capacity can provide. Although the demand for capacity could, in principle, be determined by the demand for energy, reserves, and other ancillary services, it is in practice determined by administrative rules that meet resource adequacy criteria that are generally mandated by the states. To create markets for this product, the RTOs translate the resource adequacy criteria into capacity "demand curves" or other measures of capacity "requirements." Furthermore, because capacity is often needed in specific locations, the RTOs create these demand curves or requirements for each of several capacity market zones that are defined by transmission constraints. The demand curves basically specify a high capacity price (in dollars per MW-year) based upon the cost of new peaking capacity (also known as the "cost of new entry," CONE) when planning reserve margins are low; and (in NYISO and PJM) these curves have successively lower capacity prices as planning

[43] In the non-RTO regions, "capacity" does refer to physical generating capability as in the RTO regions; but it is only the options on generation services that are *traded* in the non-RTO regions.

reserve margins increase above a minimum reliable capacity level. The horizontal placement of the demand curves (in MW) is determined by the RTOs' estimates of the quantities of capacity needed to assure reliable power system operation and is based on the mandated resource adequacy criteria. The demand for capacity is made effective by requiring LSEs to procure rights to capacity resources proportional to their forecasted peak loads. Such procurement can be through ownership, bilateral purchase, or acquisition in the RTO capacity markets.

Table 6 provides a summary of some of the main characteristics of the northeastern RTOs' capacity markets.

Table 6
Characteristics of the Northeastern RTO's Capacity Markets

Design Features	ISO-NE	NYISO	PJM
Name of Market	Forward Capacity Market	Installed Capacity Market	Reliability Pricing Model
Frequency	Annual; Monthly	Semi-Annual; Seasonal; Monthly	Annual
Term[44]	3 years forward; 1 month forward during commitment period	6 months forward of each commitment period; monthly forward for remainder of the months in the commitment period; immediately before each month	3 years forward; 1 month forward during commitment period; daily auctions during commitment period
Commitment Period Length	One year; new capacity can lock in for up to 5 years	6 months; 1 month	One year
Reconfiguration Auctions	2 years, 1 year, and immediately prior	None	20, 10, and 3 months prior
Price Determination Mechanism	Descending Clock Auction	Offer curve intersection with Capacity Demand Curve	Offer curve intersection with Capacity Demand Curve
Price Limits	Max: 1.4 x Net CONE[45] Min: 0.6 x Net CONE	Max: 1.5 x Net CONE Min: zero	Max: 1.5 x Net CONE Min: zero
Zone Definition	Transmission constraints	Three zones[46]	Transmission constraints
Demand Side Participation	Yes	Yes	Yes
Intermittent Resource Participation	Yes	Yes	Yes
LSE Capacity Obligations Satisfied	Self-supply, bilateral contract, or auction	Self-supply, bilateral contract, or auction	Self-supply, bilateral contract, or auction
Net Energy and Ancillary Services Revenue Offset	Yes	Yes	Yes

To implement their capacity markets, the RTOs hold capacity auctions for specific future time periods, and they hold these auctions at specific intervals. The auctions may have several rounds

[44] In view of the timing of the auction, the actual forward terms for ISO-NE and PJM are 40 months prior to the commitment period.

[45] These maximum and minimum values apply only until three consecutive successful auctions have been conducted, after which no limits are imposed.

[46] NYISO is in the process of determining the process and criteria for determining new capacity zones.

to allow the market to find equilibrium or to allow market participants to adjust their positions. The early rounds tend to involve all available resources, while the later rounds tend to involve only those market participants who need to adjust their capacity positions because they have too much or too little capacity.

NYISO has three types of capacity auctions: forward strip auctions in which capacity is traded in six-month blocks for the upcoming capability period; monthly forward auctions in which capacity is traded for the remaining months of the capability period; and monthly spot auctions. The two forward markets are voluntary for LSEs, who must in any event procure sufficient capacity to meet their respective capacity obligations at the conclusion of the spot market immediately prior to each month. LSEs that have purchased more than their obligation prior to the spot auction may sell the excess into the spot auction.

NYISO's capacity market design differs from those of ISO-NE and PJM in two important respects. First, New York has a short-term forward market (half a year or less) compared to ISO-NE and PJM's longer-term forward markets – three-year ahead auctions. Second, aside from the monthly spot auction, its forward auctions are voluntary, in contrast to the other two RTOs.

PJM's capacity market has an annual auction to contract capacity for three years into the future. Capacity payments are differentiated by location to encourage the efficient siting of generation resources, with higher payments to capacity in those areas that are constrained by a lack of available import capacity or internal generation resources. The capacity price in a zone is set at the market clearing level, at which the total amount that the winning bidders are willing to supply is equal to the total amount required in the zone. PJM's capacity market is structured as a series of auctions. The Base Residual Auction is held in May for each delivery year three years in the future. Incremental auctions are conducted after the Base Residual Auction to allow LSEs to adjust their resource commitments to account for changes in load or other factors.

MISO does not presently have a capacity market, but it does have a process by which it ensures that Resource Adequacy Requirements are fulfilled one month in advance. MISO calculates resource adequacy requirements according to the monthly demand forecasts provided by market participants plus the planning reserve margin. Market participants can satisfy their monthly capacity obligations with qualified planning resources acquired through bilateral transactions, the voluntary capacity auction, or owned or contracted generation. If a market participant does not have sufficient planning resources to satisfy its monthly resource adequacy requirement, MISO assesses a deficiency charge based on CONE.

MISO plans to create a capacity market. Its July 20, 2011 filing with FERC seeks to create an annual capacity market that is differentiated by zone. Market participants will continue to be able to satisfy their capacity obligations with qualified planning resources that are either owned or contracted.[47]

SPP has no present plans to create a centralized capacity market. In the absence of such a market, the capacity requirements in the SPP footprint are similar to those of non-RTO regions.

[47] Midwest Independent Transmission System Operator, Inc., *Filing to Enhance RAR By Incorporating Locational Capacity Market Mechanisms*, before the Federal Energy Regulatory Commission, Docket Nos. ER08-394-004, ER08-394-005, ER08-394-021, ER08-394-022, ER08-394-028, ER08-394-029, and ER11- ___ -000, July 20, 2011.

Determination of Capacity Requirements

Capacity requirements generally depend upon some combination of peak loads and generation availability characteristics, though these variables may be hidden within the other variables that the RTOs use directly in their capacity requirement equations.

- ISO-NE quantifies the reliability of its system with its existing capacity (including both supply- and demand-side resources) and then sets its capacity requirement to achieve a reliability goal of a one-in-ten-year loss-of-load expectation. The calculation of the capacity requirement depends upon the "Additional Load Carrying Capability" (ALCC) that, if served by existing capacity, would exactly meet the foregoing reliability goal. The capacity requirement is then set equal to Hydro-Québec Interconnection Capability Credits plus the product of: a) existing capacity within ISO-NE net of certain load and import capacity relief obtainable from implementing Emergency Operating Procedures; times b) one plus the ratio of ALCC divided by summer peak load. This latter ratio indicates what capacity would ideally be relative to what capacity actually is.[48]
- MISO does not set capacity requirements within its territory. Instead, MISO relies on stakeholders, state commissions, and FERC to set and satisfy resource adequacy standards. Consequently, capacity requirements throughout the MISO region vary by state.
- NYISO sets its capacity requirement equal to the product of: a) forecast peak load; times b) one plus the Installed Reserve Margin (IRM) requirement.[49] The IRM requirement is set by the New York State (NYS) Reliability Council to achieve a reliability goal of a one-in-ten-year loss-of-load expectation, and is based upon "demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring control areas, NYS Transmission System emergency transfer capability, and capacity and/or load relief from available operating procedures."[50]
- PJM sets its installed capacity requirement equal to the product of: a) forecast peak load; times b) one plus the Installed Reserve Margin. The Installed Reserve Margin is set to achieve an "acceptable level of reliability," and is based upon forecast loads, generators' forced outage rates, and generators' scheduled maintenance.[51]

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[48] ISO New England, *ISO New England Installed Capacity Requirement, Local Sourcing Requirements, and Maximum Capacity Limit for the 2014/15 Capability Year*, April 2011, p. 11 and p. 25.

[49] New York Independent System Operator, *Installed Capacity Manual*, August 2011, p. 2-3.

[50] New York State Reliability Council, LLC, *New York Control Area Installed Capacity Requirements for the Period May 2012 - April 2013*, December 2, 2011, p. 3.

[51] PJM Interconnection, *PJM Capacity Market*, Manual 18, November 11, 2011, p. 7 and p. 9; and PJM Interconnection, *PJM Resource Adequacy Analysis*, Manual 20, June 1, 2011, pp. 21-34.

- SPP requires LSEs to have capacity at least equal to 112% of their "system peak responsibility,"[52] except that the percentage is 109% for LSE's that have hydro-based generation comprising at least 75% of their resources.[53]

The methods by which the RTOs forecast peak loads are critical to the determination of capacity requirements.

- ISO-NE forecasts loads based upon historical loads, real income, real price of electricity, weather, and a time trend.[54]
- MISO relies on its member utilities to forecast the peak load statistics that are used in the determination of capacity requirements as set by state commissions.
- NYISO forecasts peak loads according to recent peak loads, dispatchable load management programs, and load growth factors.[55]
- PJM forecasts loads based upon a range of weather conditions and forecast economic growth.[56]
- SPP's capacity requirements are based upon members' 10-year forecast of loads.[57]

Capacity Prices

Because of transmission limitations, supply and demand are differentiated by zones within each RTO, with the consequence that capacity prices vary by zone. Significant events, such as additions of new generation or transmission facilities, can change zonal definitions and impact prices.

Capacity prices, which vary by season as well as by zone, are set according to the intersection of the demand curve with the resources offered. To limit the exercise of seller market power, capacity offers are subject to ceilings (to limit monopoly power) and, in some cases, floors (to limit monopsony power). All resources that have offered capacity at prices at or below the market-clearing price are accepted and paid the market-clearing price of capacity net of the profits that a new peaking generator would earn on energy and ancillary services sales. Such resources are committed to provide capacity to the RTO during some future time period, generally by bidding their capacity into the real-time energy market and following RTO commitment, dispatch, and maintenance scheduling instructions.

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[52] In SPP, system peak responsibility of an LSE is defined as: a) its greatest net load in the delivery year; plus b) the contract amount of firm power sold to others under agreements in effect at the time of the greatest net load; minus c) the contract amount of firm power purchased from others under agreements in effect at the time the greatest net load.

[53] Southwest Power Pool, *Southwest Power Pool Criteria*, Section 2.1.9, April 25, 2011.

[54] ISO New England, *ISO-NE Forecast Methodology*, presentation to the Regional Energy Efficiency Forum, July 7, 2009.

[55] New York Independent System Operator, *NYISO Load Forecasting Manual*, Manual 6, April 2010, pp. 1-1 – 1-2, http://www.nyiso.com/public/markets_operations/documents/manuals_guides/index.jsp.

[56] PJM Interconnection, Load Forecasting and Analysis, Manual 18, November 16, 2011.

[57] Southwest Power Pool, *Southwest Power Pool Criteria*, p. 1-1, April 25, 2011.

Penalties are levied on capacity resources that are not available as promised. In some RTOs, there are additional penalties when the unavailability occurs during peak periods or at times when reserves fail to meet reserve requirements.[58] Existing resources can have histories that indicate how well qualified they are to provide capacity. New resources not only lack such histories but may turn out to be unavailable because unforeseen circumstances may delay or prevent completion of their construction.

Resource Qualifications

Generally, to qualify to participate in the RTO capacity markets, a resource must demonstrate the capability (unforced capacity) to deliver the offered capacity when called upon or, in the case of load management or demand response resources, to deliver the offered reduction in load for the requested time period. In addition, capacity resources must provide financial assurance that, if the resource does not deliver as promised, it will pay for replacement capacity and any other costs for delivery failure. The types of resources that can participate in the capacity markets nonetheless vary somewhat among the RTOs.[59] Acceptable resources are as follows:

- ISO-NE: Traditional generation (oil, coal, natural gas, etc.), intermittent generation (wind, solar, etc.), imports, energy efficiency, load management, and distributed generation.
- NYISO: Fossil fuel and nuclear steam units, hydro stations, internal combustion units and combustion turbines, external generation, intermittent power resources, special case resources (load reductions achieved through local generation), and energy-limited and capacity-limited resources.
- PJM: Internal generation, external generation, load management resources, energy efficiency, qualified transmission upgrades, and bilateral transactions.

ISO-NE tries to keep barriers to entry low by requiring relatively low financial assurance from new capacity suppliers, in lieu of which such suppliers must undergo a "rigorous qualification process" to assure that promised capacity will actually be built. Demand-side capacity must submit measurement and verification plans that specify how demand reduction will be achieved, after which the RTO reviews the plans' feasibility to assure compliance with industry standards.

The Non-RTO Regions

With a few exceptions,[60] electric utilities in the non-RTO areas of the Eastern Interconnection continue to have monopoly franchise service areas for the provision of bundled retail electric service, with an obligation to serve all existing and future retail customers within those areas. This bundled retail service is provided subject to cost-of-service regulation by state utility commissions, usually accompanied by integrated resource planning (IRP) requirements. Aside from economic development programs designed to attract new large industrial or commercial

[58] In New England, penalties are merely loss of capacity revenue.

[59] The RTOs' requirements for each resource are listed in Appendix D.

[60] For example, customers over a minimum size threshold have a one-time choice of electric supplier in several states in the Southeast.

customers to individual service areas, there is little or no competition for customers. Consequently, load-serving utilities in non-RTO areas have the obligation to procure sufficient supply- and demand-side capacity to meet customer loads within their service areas on an economic and reliable basis pursuant to state law and oversight.

In most states in the non-RTO areas, utilities conduct either formal or informal IRP processes to identify new resources required to meet their incremental capacity obligations. IRP processes identify the load-serving utility's incremental needs, including load growth, and then set forth plans for providing or procuring the needed capacity at the lowest overall cost to consumers given all supply- and demand-side capacity options as well as the transmission costs associated with those options. IRPs also consider critical factors such as reliability, public policy requirements, fuel diversity and stability, and environmental attributes. Utilities implement their IRPs after obtaining any necessary state commission approvals. Typically, utilities must update their IRPs every two to three years.

In some states in non-RTO regions, utilities are required to issue an RFP by which third parties (other utilities, independent generators, or other resource providers) can offer to satisfy the capacity needs identified by IRPs.[61] The RFP specifies the characteristics of the needed capacity, including the time frame in which it is needed. Utilities may or may not be allowed to bid themselves, either as a regulated rate-based project or as an unregulated project, the latter usually occurring through a utility affiliate. Utilities with renewable energy portfolio requirements or other specialized requirements may issue multiple RFPs for different types of capacity or for different time frames. The utility evaluates proposals and accepts winning bidders. For regulated public utilities, these RFP processes are typically subject to transparency and oversight requirements, often involving an independent monitor, and are monitored and overseen by their public service commission, with the winning resource typically being subject to a state-regulated certification of convenience and necessity proceeding. The winning resource is either a self-build option if the utility issuing the RFP won the process or a power purchase agreement if a third party won the RFP.

The use of power purchase agreements to obtain long-term generation commitments has become an established means of adding incremental capacity on a long-term basis in non-RTO regions. Under this model, merchant generators in the competitive wholesale market find a willing purchaser (often through the above-described IRP and RFP processes) and then build the generating resource to meet that customer's need, with the rights, obligations, and project risk allocations delineated in the power purchase agreement. Through such delineation, the merchant generator is able to move forward with constructing its generating unit.

Utilities in the Southeast that are not vertically-integrated (primarily government-owned and cooperative utilities) may own generation to meet part of their needs and procure the remainder through purchase power agreements. Such utilities often participate in the joint development of power plants, including large base load plants (such as new nuclear facilities). These entities also often depend on bilateral contractual arrangements to secure the benefits of more diverse generation portfolios through procurement of "requirements" or "partial requirements" services. Although not as common as in the past, there are also some full-requirements customers in non-

[61] Demand-side resources in the RFP are usually satisfied by utility-operated or funded programs, although some states will allow bids for demand-side programs as well.

RTO areas that rely on their transmission providers to plan for and provide all of their needs. The Tennessee Valley Authority (TVA) is unusual in primarily being a wholesale power provider (although it has several large industrial customer loads) that meets the needs of wholesale distributors within a geographic area defined in the Tennessee Valley Authority Act of 1933, as amended. TVA is under a statutory requirement to build or procure capacity needed for this area.

Reserve-sharing arrangements provide another form of bilateral or multilateral capacity arrangement in non-RTO areas. These arrangements are most typically used by multi-state holding companies to govern the capacity arrangements among affiliated companies, but there are a few reserve-sharing arrangements among non-affiliated companies as well. For example, TVA, East Kentucky Power Cooperative, Louisville Gas & Electric, and Kentucky Utilities Service Company entered into a contingency reserve-sharing arrangement in 2010. Contingency reserve-sharing arrangements are primarily to allow utilities to rely on one another during times of emergency or unforeseen outages. By contrast, other reserve-sharing arrangements specify capacity requirements of each member of the pooling arrangement and allow utilities to rely on each other's capacity on a daily basis to reduce the amount of overall reserves needed within the reserve-sharing arrangement.

In summary, capacity markets in the Southeast are bilateral in nature, in that capacity that is not self-built by the utility to meet its own franchise area requirement is procured through negotiated purchase power agreements. Whether the utility self-builds or purchases through wholesale markets is determined in a least-cost manner through the IRP process.

3.1.5. Demand Response Integration

In 2008, FERC issued Order No. 719, which is a Final Rule on "Wholesale Competition in Regions with Organized Electric Markets."[62] Order No. 719 addresses four specific topics:

- It requires "RTOs and ISOs to amend their market rules as necessary to permit an [Aggregator of Retail Customers] ARC to bid demand response on behalf of retail customers directly into the RTOs or ISOs organized markets, unless the laws or regulations of the relevant electric retail regulatory authority do not permit a retail customer to participate."
- It requires RTOs and ISOs to ensure comparable treatment of supply- and demand-side response resources.
- It requires each RTO to accept bids from demand response resources if they are technically capable of providing the ancillary service, unless the laws or regulations of the relevant electric retail regulatory authority do not permit retail customers to participate.
- It requires RTOs to assess and report to the Commission any remaining barriers to comparable treatment of demand response resources that are within FERC's jurisdiction, and to propose solutions and a timeline for implementation.[63]

[62] Federal Energy Regulatory Commission, *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, 73 FR 64100 (Oct. 28, 2008), FERC Stats. & Regs. ¶ 31,281 (2008).

Each of the RTOs in the Eastern Interconnection have developed their own plans and revised their own tariffs to permit demand response to participate in the energy markets and some or all of their other markets. Appendix B summarizes the markets in which demand response is permitted to participate and some of the principal features of these programs. For ISO-NE, MISO, NYISO, and PJM, demand response can participate in energy, reserve, and capacity markets. Until SPP moves to a Day-Two market in 2014, demand response participation is limited to the energy market.

In the non-RTO regions, utilities primarily pursue demand-side options through state-approved demand-side programs that have been integrated into utility supply planning. Almost all states within the non-RTO regions require that supply-side and demand-side options be considered comparably. Utilities and states have been very active in pursuing energy efficiency and demand-side options as part of their responsibility to ensure cost-effective service to consumers. For example, many utilities in non-RTO regions have real-time or time-of-use pricing programs that have apparently reduced peak demand levels.

3.1.6. Transmission Rights

A "transmission right" is a right to transfer a specific quantity of power from one or more source (generation) locations to one or more sink (load) locations under terms and conditions (including price) that are known with a fair degree of certainty in advance. Such rights are generally not absolute: depending upon power system and market conditions, power transfers can be cut, prices can be revised, and service can be subject to surcharges.

Transmission rights are important because the limited transfer capabilities of power networks inevitably create situations in which some lower-cost energy cannot be delivered to all loads. When the demand for the use of transmission facilities exceeds the capacity of those facilities, transmission is said to be "congested," in which case some loads must be served by nearby higher-cost resources rather than by lower-cost distant resources. Transmission rights have value that can be measured by the difference between the costs of the lower-cost resources that a rights owner can access with the rights and the higher-cost resources that they would need to use without the rights. This difference is called "congestion costs." The congestion costs between different pairs of source and sink locations can be very different: some pairs will have no congestion costs, while other pairs can have substantial congestion costs. Furthermore, because power system conditions are continually changing, the congestion costs associated with a single pair of source and sink locations can vary substantially over time.[64]

Transmission rights are created by the OATTs that all FERC-jurisdictional transmission owners file with FERC pursuant to Order No. 888. There are two types of transmission service:

- *Point-to-point transmission service* is based on the fiction that power flows from source to sink locations through certain transmission facilities ("contract paths") that, in fact, only roughly correspond to actual power flows. This service is usually priced according

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[63] Federal Energy Regulatory Commission, *Assessment of Demand Response & Net Metering*, Staff Report, September 2009.

[64] In fact, because locational prices are recomputed every five minutes, congestion costs associated with a single pair of source and sink locations can change twelve times per hour.

to the level of firmness, which may be "firm," "non-firm," or "conditional firm."[65] Rates are based on annual transmission revenue requirements that are in turn based on transmission service-related costs. These rates may be discounted on a non-discriminatory basis.

- *Network integration transmission service* allows the transmission customer to access the transmission provider's entire network to integrate the customer's loads and resources on a basis that is comparable to the transmission provider's use of the system to serve its own native load. The utility must plan its transmission system to accommodate all network customers, including all of the utility's native load customers. Network service is usually priced on a load-ratio share basis, so that all transmission customers pay a share of the fixed costs of transmission based on the proportion of total load they comprise within the transmission provider's service area.

Transmission rights have the effect of partly or wholly insulating the transmission customer from the congestion costs associated with their transmission service. Ordinarily, the customer will pay something – explicitly or implicitly – for this protection from congestion costs. RTO and non-RTO regions differ dramatically in the ways that they expose customers to and protect customers from congestion costs.

The RTO Regions

In RTOs' Day Two markets, LMPs not only induce a market-based allocation of scarce generation capacity, but they also induce a market-based allocation of scarce transmission capacity. This latter allocation arises because the difference in the LMPs between any two locations indicates the price of congestion between those two locations.[66] By receiving the prices at their source (generator) locations and paying the prices at their sink (load) locations, customers "pay" the congestion costs inherent in their power transfers among two locations. The result is that LMPs implicitly allocate transmission capacity to its highest-valued uses: only customers with the highest-valued uses for transmission service will be willing to pay the congestion charges over constrained transmission facilities. Although the market-based allocation of transmission capacity offers efficiency benefits, it also imposes upon individual customers potentially serious financial risks due to the uncertainty in the congestion prices that they must pay for their transmission service in day-ahead or real-time markets.

Financial Transmission Rights and Auction Revenue Rights

Because the financial risks of uncertain congestion in Day Two markets are tied to the LMP structure of those markets, the instruments that hedge against congestion are also tied to LMPs. Reflecting the LMP structures of their energy markets, the RTOs offer transmission rights that are "financial" in the sense that the owner of such right is compensated for differences in the economic values of power at their source and sink locations. These financial transmission rights

[65] Conditional firm service is firm in all but a handful of hours of the year, in which power system conditions do not permit the transmission system to serve all firm and conditional firm service.

[66] Differences in LMPs among locations depend upon both transmission congestion and transmission losses, so the congestion price between two locations does not account for the entire difference in the LMPs between those locations.

(FTRs)[67] entitle the owner to receive revenues equal to the day-ahead transmission congestion charges between particular pairs of locations. If the owner of an FTR has a quantity of generation and load at those two locations exactly equal to the quantity covered by the FTR, the revenues from the right will exactly offset the congestion charge that the owner would need to pay, thus providing a perfect hedge against congestion charges. In general, however, transmission customers inevitably have FTRs that do not exactly match their generation and load patterns, in terms of both quantities and locations; so the hedges provided by FTRs are inevitably imperfect, sometimes hedging too little and sometimes hedging too much.

In addition to FTRs, some RTOs also convey transmission rights in the form of Auction Revenue Rights (ARRs) that provide their owners with the proceeds received from FTR auctions. ARR owners can directly or indirectly convert their ARRs into the corresponding FTRs. Consequently, at least on an expected basis, the values of ARRs equal the values of the corresponding FTRs; so the ARRs provide the same hedge against transmission congestion cost risk as do the corresponding FTRs.

FTRs and ARRs are purely financial. They do not give their owners the right to physical delivery of electricity, nor do they impose upon their owners any obligation to deliver electricity to or take electricity from the power system.

<u>FTR Options versus Obligations</u>

Because FTRs are directional, representing congestion from one point to another point, and because congestion can reverse so that prices at an FTR's source (generator) location can be higher than prices at the FTR's sink (load) location, FTRs can impose a financial obligation upon their owner even if the owner has no corresponding power flow. Consequently, FTRs can be issued in two forms:

- *FTR obligations* have hourly values based on the LMP at the FTR's sink location (e.g., where load is) minus the LMP at the FTR's source location (e.g., where generation is). This hourly value is positive (i.e., a benefit to the FTR holder) when the path designated in the FTR is in the same direction as the congested flow, and is negative (i.e., a liability to the FTR holder) when the designated path is in the direction opposite to the congested flow. To put it a different way, an FTR obligation provides a benefit to its holder when the LMP at its sink location is *higher* than the LMP at its source location, and is a liability to its holder when the LMP at its sink location is *lower* than the LMP at its source location. If the FTR holder actually delivered energy along the designated path in a MW amount equal to their FTR reservation, they would pay congestion charges or receive a congestion credit that would exactly offset the value (or liability) of their FTR obligation.
- *FTR options* have hourly values based on the *excess* of the LMP at the FTR's sink location (e.g., where load is) over the LMP at the FTR's source location (e.g., where generation is). This hourly value is positive (i.e., a benefit to the FTR holder) when the path designated in the FTR is in the same direction as the congested flow, and is zero

[67] The RTOs have a variety of names for FTRs, including Transmission Congestion Contracts and Congestion Revenue Rights.

> when the designated path is in the direction opposite to the congested flow. To put it a different way, an FTR option provides a benefit to its holder when the LMP at its sink location is higher than the LMP at its source location, and has zero value when the LMP at its sink location is lower than the LMP at its source location.

While the mathematics for determining the simultaneous feasibility of FTR obligations is fairly simple, the mathematics for determining the simultaneous feasibility of FTR options is complex. Consequently, PJM is the only RTO in the Eastern Interconnection that presently offers FTR options. More specifically, each PJM market participant that is eligible to receive FTRs may elect to receive them in the form of either obligations or options. Because options are more costly to provide than obligations, and because options are more valuable to FTR holders than are obligations, the price of options generally exceeds that of obligations.

Transmission Rights Sufficiency

The Day Two RTOs make available quantities of FTRs and ARRs that represent the value of the physical transfer capabilities that they expect can be provided by their transmission systems. When transmission customers want transmission systems to deliver more power than these systems are capable of delivering, the demand for FTRs and ARRs at a zero price will exceed the supply that the RTOs can make available. This excess demand will give positive prices to FTRs and ARRs, which is another way of saying that transmission customers will not be able to obtain, for free, all the hedges against congestion price uncertainty that they may want.

The "sufficiency" of a transmission system's ability to support financial hedges against congestion price uncertainty can be measured as the ratio of: a) the total value of the FTRs and ARRs that can be supported by the transmission system; to b) the total value of the FTRs and ARRs that market participants want at a zero price. Because this ratio will be less than 100% in a normal power system that has some congestion, FTRs and ARRs cannot be expected to provide a full hedge against all congestion price risk.

Transmission Rights Adequacy

RTOs have the challenge of matching the quantities of FTRs and ARRs that they issue to the quantities of FTRs and ARRs that can actually be supported by the transmission network. The challenge arises because real-time conditions on the transmission network inevitably differ from the conditions forecast at the time the FTRs and ARRs are issued. These conditions, particularly the availability of transmission equipment and of generators, affect the network's transfer capabilities. If the RTO under-forecasts the transmission network's capabilities, transmission customers receive fewer hedges than were actually feasible. If the RTO over-forecasts the transmission network's capabilities, then congestion revenues will not be adequate to pay FTR and ARR owners the full nominal values of their transmission rights. In this latter case, ISO-NE, MISO, and PJM pro rate the congestion revenue deficiency among transmission rights owners so that they receive less than the full values of their rights; while NYISO pays the transmission rights owners in full and recovers the revenue deficiency from transmission owners.

The methods by which the RTOs address revenue shortfalls for holders of FTRs and ARRs are as follows:

- ISO-NE uses all their auction revenue (including monthly) to fund ARRs only. Any excess goes back to ARR holders. Monthly surpluses carry forward to fund monthly shortfalls.
- MISO uses monthly auction residual surpluses to fund monthly shortfalls. The annual FTR auction revenue is distributed to ARR holders.
- NYISO fully funds all financial transmission rights by recovering any funding shortfalls from transmission owners.
- PJM uses the revenue from all their auctions (long-term, annual, and monthly) to first fund all ARRs and then apply the excess to FTR funding.

Transmission Rights Allocations

The RTOs tend to provide allocations of transmission rights to customers who pay transmission access charges, who have a history of firm usage of the transmission system, or who have "grandfathered" rights to transmission service. In some RTOs, these allocations tend to be proportional to some measure of customers' loads, such as peak loads. Transmission rights are also allocated to customers who pay for transmission upgrades to the extent that such upgrades create value through congestion relief.

Transmission customers can also purchase transmission rights from RTOs when the RTOs have available transmission rights that have not been allocated, or from other market participants who happen to own FTRs or ARRs that they are willing to sell. Transmission rights trades occur through both centralized RTO auctions and bilateral transactions among market participants.

Auction Procedures

The RTOs administer auctions in which prices are set at market-clearing levels and the quantities of rights sold are limited by the capabilities of their transmission networks. If the auctioned quantity of transmission rights closely matches the real-time physical capabilities of the transmission system, the auctions will, on average, yield revenues that closely match the eventual congestion revenues associated with the auctioned rights.

The RTOs conduct auctions for several future time periods, with some distinctions made for zones. Each auction is conducted before the period to which is applies.

- ISO-NE conducts one annual FTR auction for each year, making available up to 50% of the expected transfer capability. It also conducts twelve monthly FTR auctions for transmission needs that vary by month, making available up to 95% of the expected transfer capability for each month.
- MISO conducts an annual FTR auction for each planning year, which distinguishes between four seasons and two periods (on-peak and off-peak) within each season, and which has three rounds in which a third of available capacity is offered in each round. MISO also conducts seasonal FTR auctions and twelve monthly auctions, all of which distinguish between two periods.
- NYISO conducts an FTR auction prior to each six-month capability period. There are a series of sub-auctions that offer FTRs of varying durations between six months and five

years. NYISO determines the relative amounts of available FTRs for each duration after surveying stakeholders' interests in FTRs of the various durations. NYISO also conducts monthly reconfiguration auctions just prior to each month of the capability period.

- PJM's FTRs have terms varying from one month to three years, in each of which there are FTRs for on-peak hours, off-peak hours, and all hours. Consequently, PJM has a long-term FTR auction for the next three planning years, as well as FTR auctions for annual periods and monthly periods, where the latter allows for short-term adjustments in positions. PJM operates a secondary market in which participants can buy and sell existing FTRs.

Long-Term Transmission Rights

FERC's Order No. 681 requires RTOs to provide long-term transmission rights (LTTRs) with total durations, including renewals and extensions, of a minimum of ten years.[68] The existence of these LTTRs has the virtue of encouraging generation investment by creating a mechanism by which generator investors can be accorded some certainty about the terms under which their power can reach market for a moderate period of time.[69]

On the other hand, the LTTRs have three important limitations. First, consistent with Order No. 681's guidelines and the Energy Policy Act of 2005, the LTTRs are available for only a portion of the transmission service that transmission customers want, so they cannot reduce financial risks for a large portion of transmission service. Second, as implemented by ISO-NE, MISO, and PJM, the values of LTTRs may be compromised by congestion revenue deficiencies: owners of LTTRs will not receive the full dollar value of the LTTRs when congestion revenues are not sufficient to fund that full value. Third, although transmission plans should *in principle* promise expansions sufficient to fully serve LTTRs, in practice the transmission planning processes provide no such assurance. The missing link is that the RTOs lack the authority to ensure that transmission is constructed when the benefits of such investment exceed costs, especially for "economic" upgrades.

When ISO-NE implemented its Standard Market Design in 2003, it planned to evaluate making available FTRs with terms exceeding one year (in one-year increments).[70] ISO-NE has not yet implemented LTTRs, however.

PJM offers a quantity of long-term FTRs based upon the system capability that remains after assuming that all allocated ARRs are self-scheduled into short-term FTRs. In determining this quantity, PJM models short-term FTRs as fixed injections and withdrawals in the long-term FTR auction. The long-term FTRs are auctioned in two rounds, with 50% of the available system capability being offered in each round.[71]

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[68] Federal Energy Regulatory Commission, *Long-Term Firm Transmission Rights in Organized Electricity Markets*, Order No. 681, 116 FERC ¶ 61,077, July 20, 2006. See also Order No. 681-A, November 16, 2006.

[69] For a generation investment that will take four years to reach operation, ten-year LTTRs allow six years of transmission price certainty. This six-year period is fairly short relative to the life (e.g., forty years) of a generation investment, but is more certainty than was available before the LTTRs came into existence.

[70] ISO New England, *ISO New England Manual for Transmission Rights*, M-06, January 1, 2012, p. 3-1.

[71] PJM Interconnection, *Financial Transmission Rights*, Manual 06, July 1, 2009, p. 10.

In MISO, LTTRs convey to their owners' annual rollover rights lasting at least ten years. Market participants can convert up to 50% of their ARRs into LTTRs with equivalent specifications (e.g., points of receipt and delivery). MISO holds annual auctions of long-term FTRs.[72]

In NYISO, holders of Existing Transmission Agreements, which existed prior to the start of NYISO operations, can convert those instruments into FTRs called "Fixed Price Transmission Congestion Contracts." These contracts satisfy the FERC Order No. 681 requirement to provide LTTRs for historic points of injection and withdrawal. NYISO has also proposed to the FERC an LTTR product that would address non-historic points of injection and withdrawal.[73]

In SPP, which does not presently have a Day Two market, transmission rights rules vary according to the tariff rates set by each transmission service provider. With the implementation of its Day Two market in 2014, however, SPP plans to introduce FTRs and ARRs.[74,75]

The Non-RTO Regions

In non-RTO regions, transmission rights are "physical" in the sense that transmission customers taking firm service have the right to use the underlying physical transmission capacity. Customers with physical rights are not exposed to congestion costs for power transfers among locations to which the rights apply, up to the MW values of the rights. When the physical use of the transmission system would otherwise exceed the physical capabilities of the system, transmission is allocated among customers based on their relative transmission service priorities. These priorities, which are set by OATTs, resolve congestion by using Transmission Loading Relief (TLR) procedures to curtail the power transactions that significantly contribute to line overloading.[76] Transmission service is curtailed by priority level, beginning with non-firm service and then continuing with increasingly higher-priority firm service. Most transactions within a Balancing Authority Area are typically handled with network service, while most transmission service between Balancing Authority Areas is point-to-point.

Consistent with the provision of these physical rights to customers taking long-term firm service, transmission systems in non-RTO regions are planned, expanded, and operated so that those who have made long-term firm commitments receive service without congestion or constraint to the extent physically feasible. Accordingly, when a transmission customer or stakeholder desires long-term transmission capacity, it commits to the long-term firm service necessary to obtain the physical rights to such capacity, including (if necessary) the expansion of the transmission

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[72] Midwest Independent Transmission System Operator, Midwest ISO Tariff, Fourth Revised Volume, Sections 1.30 and 1.368.

[73] New York Independent System Operator, *Revised Compliance Implementation Plan and Status Report*, before the Federal Energy Regulatory Commission, Docket No. ER07-521-009, December 1, 2011.

[74] Consistent with the electric power industry's persistent affinity for applying multiple names to the same thing, SPP intends to use the term "transmission congestion rights" for its brand of FTRs.

[75] Boston Pacific Company Inc., *A Review of the Southwest Power Pool's Integrated Marketplace Proposal*, December 30, 2010, p. 13, http://www.bostonpacific.com/assets/documents/BPCReviewofSPPIntegratedMarketplaceProposal_12_30_10.pdf.

[76] RTOs have also used TLR procedures to resolve congestion; but RTOs' use of LMP has provided a market-based mechanism for congestion management that has helped them reduce or avoid use of TLRs. The RTOs' use of TLRs tends to be most frequent at the seams between RTOs and between RTO and non-RTO regions.

system necessary to effectuate such a service request. Once a customer has subscribed to firm point-to-point transmission service, it may resell those rights; so there is a limited resale market for physical transmission rights in the non-RTO regions.

In non-RTO regions, transmission services needed to serve retail load are provided through bundled retail transmission service in accordance with state regulation. The majority (generally exceeding 80%) of a transmission-owning utility's load consists of bundled retail customers while the remaining load consists of wholesale service taken under the utility's OATT. Under the OATTs, the transmission-providing utility is required to provide to its OATT customers transmission service that is "comparable" to the service that it provides to its own bundled retail customers. Among other things, this requirement means that network customers under such an OATT are provided long-term firm transmission service that allows them to integrate their load and generating resources in a manner comparable to how the transmission provider integrates its own load and generation.

3.2. Extent of Vertical Integration

The electric power industry has four basic vertical levels: generation, transmission, distribution, and customer services. There are efficiencies in integration of these levels, particularly because of the partial substitutability of generation, transmission, and distribution services (e.g., loads can be served either by building generation locally or by building distant generation coupled with transmission) and partly because of economies of scope (e.g., customer service can be cheaper for generation, transmission, and distribution together than separately). On the other hand, competition in generation and customer services can also create benefits by encouraging innovation.

Table 7 presents the state-by-state percentages of energy served by full-service providers (i.e., those who provide generation, transmission, distribution, *and* customer services) to residential, commercial, and industrial customers. In the 24 non-retail access states and 1 of the 15 retail access states, end-use customers (i.e., residential, commercial and industrial customers) receive 100% of their service from full-service providers. In the remaining 14 retail access states (plus the District of Columbia), end-use customers receive less than 100% of their energy from full-service providers. Percentages below 100% are served by "energy only" providers who likely depend on the transmission and distribution service provided by the local wires utility.

The electric power industry has long had a mixture of vertically integrated and vertically separated enterprises. A common pattern is for a state or region to be dominated by one or a few vertically integrated supplies, with a plethora of smaller firms, such as municipal utilities and rural electric cooperatives, relying on the vertically integrated firms for transmission service and some generation services.

Table 7
Percentage of Energy (MWh) Served by Full-Service Providers in the States of the Eastern Interconnection - 2010[77]

State	Residential	Commercial	Industrial	State	Residential	Commercial	Industrial
AL	100%	100%	100%	MT	100%	96%	37%
AR	100%	100%	100%	NC	100%	100%	100%
CT	71%	25%	25%	ND	100%	100%	100%
DC	95%	15%	0%	NE	100%	100%	100%
DE	98%	41%	45%	NH	100%	61%	26%
FL	100%	100%	100%	NM	100%	100%	100%
GA	100%	100%	100%	NJ	99%	46%	25%
IA	100%	100%	100%	NY	85%	40%	35%
IL	100%	44%	15%	OH	81%	61%	61%
IN	100%	100%	100%	OK	100%	100%	100%
KS	100%	100%	100%	PA	91%	65%	73%
KY	100%	100%	100%	RI	100%	53%	31%
LA[78]	100%	100%	100%	SC	100%	100%	100%
MA	89%	45%	27%	SD	100%	100%	100%
MD	92%	28%	16%	TN	100%	100%	100%
ME	2%	1%	1%	TX	100%	100%	100%
MI	100%	88%	85%	VA	100%	100%	100%
MN	100%	100%	100%	VT	100%	100%	100%
MO	100%	100%	100%	WI	100%	100%	100%
MS	100%	100%	100%	WV	100%	100%	100%

Table 8 summarizes ownership structure in the Eastern Interconnection states in terms of the percentage of delivered retail sales (MWh) (to end-use customers) by utility ownership type in 2010.

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[77] Energy Information Administration, "Retail Sales of Electricity to Ultimate Customers By End-Use Sector, by State, by Provider, Annual Back to 1990 (Form EIA-861)," Excel spreadsheet, November 9, 2011, *Electric Power Annual*, http://www.eia.gov/electricity/data.cfm#sales.

[78] The provision of electricity services in New Orleans, is regulated by the New Orleans City Council Utilities Regulatory Office. Like the rest of Louisiana, all electrical energy in the City of New Orleans is provided by a full-service provider, which for the City is Entergy New Orleans, a subsidiary of Entergy Louisiana.

Table 8
Percentage of Delivered Retail Sales (MWh) Served by Utility Type in the States of the Eastern Interconnection – 2010[79]

State	Electric Coop	Federal Power Authority	Investor Owned Utility	Public Power	State	Electric Coop	Federal Power Authority	Investor Owned Utility	Public Power
AL	13%	6%	62%	19%	MT	36%	4%	60%	0%
AR	27%	0%	61%	13%	NC	14%	0%	74%	12%
CT	0%	0%	86%	14%	ND	53%	1%	43%	2%
DC	0%	0%	100%	0%	NE	2%	1%	0%	97%
DE	17%	0%	59%	25%	NH	9%	0%	89%	2%
FL	9%	0%	76%	16%	NJ	0%	0%	97%	2%
GA	29%	0%	62%	9%	NM	22%	1%	67%	10%
IA	14%	0%	75%	12%	NY	0%	0%	70%	30%
IL	8%	0%	83%	9%	OH	7%	0%	83%	10%
IN	12%	0%	80%	7%	OK	20%	0%	72%	9%
KS	16%	0%	66%	17%	PA	2%	0%	96%	1%
KY	29%	16%	47%	7%	RI	0%	0%	99%	1%
LA[80]	11%	0%	83%	6%	SC	19%	0%	62%	18%
MA	0%	0%	75%	25%	SD	34%	3%	50%	13%
MD	13%	0%	85%	2%	TN	22%	7%	2%	69%
ME	8%	0%	0%	92%	TX	12%	0%	75%	14%
MI	4%	0%	88%	8%	VA	11%	0%	84%	4%
MN	21%	0%	65%	14%	VT	9%	0%	77%	14%
MO	17%	0%	70%	13%	WI	6%	0%	83%	11%
MS	37%	8%	47%	8%	WV	0%	0%	99%	0%

3.3. Extent of Centralized Power Market Coordination

The RTO regions have a high degree of centralized market coordination among multiple utilities. The non-RTO regions, while lacking centralized coordination, sometimes rely on coordination by the larger utilities, particularly utility holding company systems operating under inter-company pooling arrangements. In some cases, the non-RTO regions' unit commitment or economic dispatch functions may be separated from the transmission system operations but are nonetheless centralized.

[79] Energy Information Administration, "Retail Sales of Electricity to Ultimate Consumers: All Sectors by State and Utility," Excel spreadsheet, http://www.eia.gov/electricity/data.cfm#sales.

[80] In the City of New Orleans, 100% of sales are served by an investor-owned utility.

The Day Two RTOs offer centralized trading of energy, regulation, operating reserves, capacity, and transmission rights. SPP offers centralized trading of energy, but will offer the other services as well when it becomes a Day Two RTO in 2014. All of these services subject to centralized trading may also be traded bilaterally.[81]

Outside of the RTOs, most of these services are traded through electronic trading platforms, marketers and brokers, and negotiated bilateral agreements. There are also some reserve-sharing arrangements that involve coordination among utilities.

3.4. Extent of Customer Choice

Electricity consumers have traditionally been the captive customers of their local distribution utilities. Over the past two decades, however, several states have permitted retail competition (or "retail choice") that allows consumers to choose among their incumbent utility supplier and an array of competitive suppliers for their electricity services. Competitive suppliers put together packages of the generation and delivery services that comprise delivered electricity service; and they do so under a variety of service plans that give consumers flexibility in their energy purchases. This flexibility can include services to hedge against price fluctuations, choices for alternative energy resources, and energy efficiency projects, among others. These opportunities allow consumers to choose the services that best meet their needs.

In most retail competition states, customers who do not choose to leave their incumbent distribution utility continue to be served by that utility under default services that go by names such as Standard Offer Service (SOS) and Provider of Last Resort (POLR) service. The default supplier may procure its electric power from its own generation resources, from the wholesale market (perhaps through a competitive bidding process), or from a combination thereof.

Competitive retail markets are regulated by the states. State regulatory commissions approve alternative competitive suppliers before they can serve customers. They also oversee incumbent utilities' default service power procurement processes to ensure that the processes are fair and that the resulting consumer prices are just and reasonable.

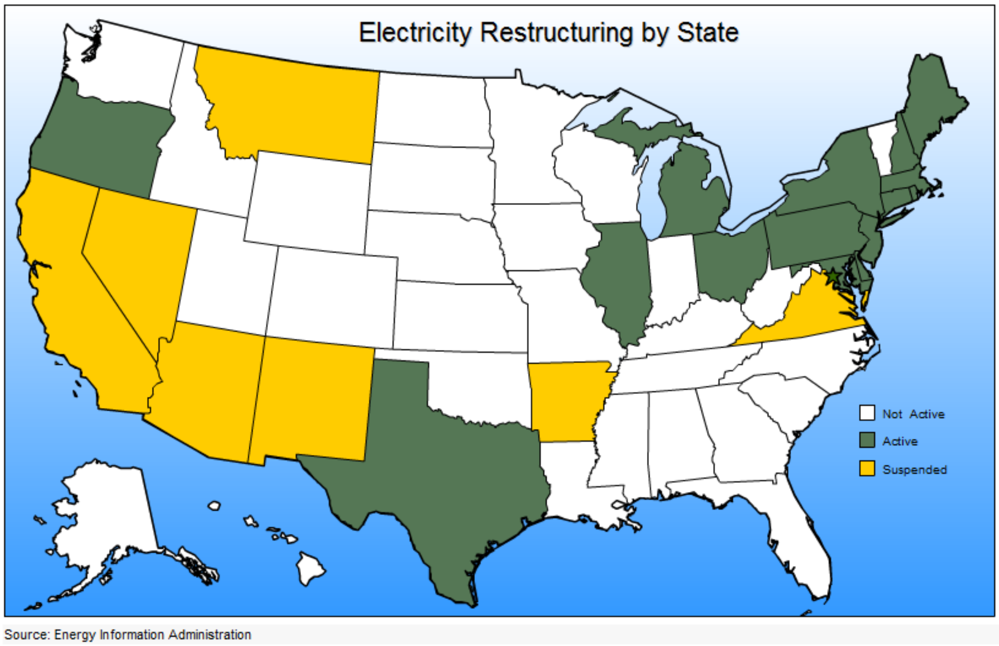
Customer choice varies by state according to policies set by state legislatures and/or regulators. Figure 3 shows those states where competition at the retail level is active, where it has been suspended, and where it is not active. Appendix B provides a summary of the rules governing the provision of SOS/POLR service in the states that have retail competition, and also provides links to the relevant commission or legislative documents.

In the non-RTO areas of the Eastern Interconnection, electric utilities generally continue to have monopoly franchise service areas with an obligation to serve all existing and future customers within those areas. With regard to those exceptions, several of the states in non-RTO areas

[81] The RTOs sometimes treat bilateral transactions as "out-of-market" even though such transactions may dwarf, in volume and dollar amount, the transactions that occur in the centralized markets; but this is a semantic issue. As a matter of economics, "out-of-market transactions" are defined as those that would *not* occur between willing buyers and sellers, which particularly includes the RTOs' out-of-market payments (e.g., "make-whole payments") to generators who are needed for reliability purposes but (for reasons of cost) are not willing to provide services at market-clearing prices. Except in the cases of transactions that are somehow subsidized by implicit taxes on captive ratepayers (as is the case for "make-whole payments, for example) or by government funds, bilateral trades are market transactions.

promote economic development by sometimes allowing one-time competition for new large industrial customers. Aside from such programs, there is little to no competition for customers in the non-RTO regions.

Figure 3
Electricity Restructuring by State[82]



3.5. State Regulatory Requirements

This section begins with an overview of the delineation between state and federal jurisdiction of the electric power industry. It then looks at the resource requirements that state regulatory authorities impose on utilities.

3.5.1. Scope of State Jurisdiction Relative to Federal Jurisdiction

The Federal Power Act (FPA), as subsequently amended by other federal laws, defines the extent of FERC's jurisdiction of the electric power industry. State jurisdiction is more or less defined by the limits of FERC's jurisdiction.

In general, Part II of the FPA gives FERC jurisdiction over electricity transmission in interstate commerce, wholesale electricity sales in interstate commerce, all facilities for interstate transmission and sales, and hydroelectric dam licensing and safety.[83] This allows FERC to regulate the following:

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[82] http://www.eia.gov/cneaf/electricity/page/restructuring/restructure_elect.html.

[83] 16 USC 824(b); e.g., Pennsylvania Power & Light Company, 23 FERC ¶ 61,006 at 61,018, reh'g denied, 23 FERC ¶ 61,325 (1983); Southern Company Services, Inc., 37 FERC ¶ 61,256 at 61,652 (1986); Florida Power & Light Company, 40 FERC ¶ 61,045 at 61,120-21, reh'g denied, 41 FERC ¶ 61,153 at 61,382 (1987); Houlton Water Company v. Maine Public Service Company, 60 FERC ¶ 61,141 at 61,515 (1992); Northern Indiana Public Service

- transmission of electric energy in interstate commerce by public utilities, including the rates, terms and conditions of interstate electric transmission by public utilities;[84]
- sales of electric energy at wholesale in interstate commerce by public utilities, including the rates, terms and conditions of wholesale electric sales by public utilities;[85]
- corporate activities and transactions by public utilities, including mergers, securities issuances, and interlocking directorates;[86]
- accounting by public utilities;[87] and
- bulk electric system reliability.[88]

The FPA defines a "public utility" as "any person who owns or operates facilities subject to the jurisdiction of the Commission," where such facilities are for "the transmission of electric energy in interstate commerce and [for] the sale of electric energy at wholesale in interstate commerce."[89] "Public utilities" are not necessarily the same as "electric utilities"[90] nor as "transmitting utilities."[91]

Consequently, the states have authority over the following issues:

- Intra-state distribution of electric energy, including the rates, terms, and conditions of such distribution;
- Retail sales of electric energy to end users, and the rates, terms, and conditions of such sales, including all aspects of bundled retail electric sales;
- Siting and construction of non-hydroelectric generation and transmission facilities, with the exception of FERC's "backstop" siting authority;[92]

Company, 66 FERC ¶61,213 at 61,488 (1994); Connecticut Light and Power Company, 70 FERC ¶ 61,012 at 61,030, reconsid. denied, 71 FERC ¶ 61,035 (1995); Central Vermont Public Service Corporation, 84 FERC ¶ 61,194 at 61,973-75 (1998); Progress Energy, Inc., 97 FERC ¶ 61,141 at 61,628 (2001); Armstrong Energy Limited Partnership, LLLP, 99 FERC ¶ 61,024 at 61,104 (2002); Niagara Mohawk Power Corporation, 100 FERC ¶61,019 at P 17 (2002); Barton Village, Inc. v. Citizens Utilities Company, 100 FERC ¶ 61,244 at P 12 (2002); Virginia Electric and Power Company, 103 FERC ¶ 61,109 at P 6 (2003); Southern California Edison Company, 106 FERC ¶ 61,183 at P 14, 19 (2004); Midwest Independent Transmission System Operator, Inc., 106 FERC ¶ 61,337 at P 14 & n.17 (2004); Entergy Services, Inc., 120 FERC ¶ 61,020 at P 28 (2007); Aquila Merchant Services, Inc., 125 FERC ¶ 61,175 at P 17 (2008).

[84] FPA sections 201, 205, 206 (16 USC 824, 824d, 824e).

[85] *Id.*

[86] FPA sections 203, 204, 305(b) (16 USC 824b, 824c, 825d(b)).

[87] FPA section 301 (16 USC 825).

[88] FPA section 215 (16 USC 824o).

[89] 16 USC 824(e).

[90] 16 USC 796(22).

[91] 16 USC 796(23).

[92] FPA section 216 (16 USC 824p). For example, Californians for Renewable Energy Inc. v. California Independent System Operator Corp., 117 FERC ¶ 61,072 at P 10 (2006); PacifiCorp, 72 FERC ¶ 61,087 at 61,488 & n.3 (1995); Duke Power Co., 43 FERC ¶ 61,001 at 61,003 (1988): Northeast Maryland Waste Disposal Authority, 53 FERC ¶

- Environmental matters not related to hydroelectric generation;[93] and
- Safety matters not related to hydroelectric generation.

FERC can have jurisdiction over sellers located within the same state as a buyer because "interstate commerce" has been interpreted to give FERC jurisdiction when the transmission system "is interconnected and capable of transmitting [electric] energy across the State boundary, even though the contracting parties and the electrical pathway between them are within one State" because transaction relies on the "interconnected interstate transmission grid."[94]

FERC has little authority over the siting and construction of non-hydroelectric facilities. The Energy Policy Act of 2005 did give FERC limited backstop authority where transmission lines are proposed in DOE-designated National Interest Electric Transmission Corridors and when a state fails to act within one year of an application for permitting. This authority has not been used to date. Most jurisdiction for the siting, licensing, permitting, or certification for generation and transmission facilities remains with the states.

3.5.2. State Resource Requirements

This section summarizes the Eastern Interconnection states' resource planning requirements, renewable portfolio requirements, and energy efficiency requirements.

Resource Planning and Siting Authority

Some states have both resource planning and siting authority. For example, Ohio develops a 10-year load and resource forecast and has resource siting authority. The Ohio Public Utilities Commission also has authority to order as LSE to build or acquire resources if it finds that the LSE needs resources to adequately meet demand and at reasonable cost.

Power Procurement

Most states require utilities to take responsibility for procuring power and preparing plans for doing so, and delegate to state regulators the authority to review and oversee the plans and their implementation. Examples include the following:

61,161 at 61,587 (1990), reh'g denied, 54 FERC ¶ 61,058 (1991); Southern Company Services, Inc., 22 FERC ¶ 61,047 at 61,084 (1983)).

[93] For FERC's authority over hydro-related environmental matters, see, for example, San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Services, 96 FERC ¶ 61,117 at 61,448 (2001); PSI Energy, Inc., 56 FERC ¶ 61,237 at 61,911 & n.27 (1991); Duke Power Co., 43 FERC ¶ 61,001 at 61,003 (1988); Monongahela Power Co., 39 FERC ¶ 61,350 at 62,096, reh'g denied, 40 FERC ¶ 61,256 (1987)).

[94] For example, Florida Power & Light Company, 29 FERC ¶ 61,140 at 61,291-92 (1984). (Accord, e.g., Wisconsin Electric Power Company, 62 FERC ¶ 61,142 at 62,008 n.40 (1993), reh'g denied, 66 FERC ¶ 61,096 (1994); People's Electric Cooperative, 84 FERC ¶ 61,229 at 62,108-12, 62,113-14, 62,130-31 (1998), reh'g denied, 93 FERC ¶ 61,218 at 61,727, 61,730-31 (2000); Promoting Wholesale Competition Through Open-Access Non-Discriminatory Transmission Services by Public Utilities and Transmitting Utilities, Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,966-69 (1996), order on reh'g, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 (1997), . . ., aff'd in relevant part, 225 F.3d 667, 690-95 (D.C. Cir. 2000), aff'd in relevant part, 535 U.S.1 (2002)).

- The Maryland Public Service Commission oversees and monitors the power procurement process administered by the utilities to secure energy for standard offer service.
- The Illinois Power Agency (IPA) prepares annual electricity procurement plans, conducts competitive electricity procurement processes subject to Public Service Commission approval, develops electric generation and co-generation facilities that use Illinois coal or renewable resources, and supplies electricity from IPA facilities at cost to Illinois municipal electric systems, governmental aggregators, and rural electric cooperatives.[95]
- The Maine Public Utilities Commission administers the procurement process for standard offer service (SOS), including issuing RFPs for bids from competitive electricity suppliers to supply SOS for customers of the utilities who have not designated a competitive electricity supplier.
- The New Jersey Board of Public Utilities is responsible for the coordination of the Energy Master Plan, which includes drafting a plan or plan update, facilitating public comment, and working with Rutgers University to develop and update the data needed to support the plan and monitoring and reporting on plan implementation.[96]

Reserve Margin Requirements

The states have the authority to assure the reliability of the electric power systems that serve them. For example, the Energy Policy Act of 2005 makes clear that states have the authority to set planning reserves.[97] As most state commissions have statutory authority to assure adequate reliability, state commissions' purview over reliability is comprehensive.[98] With the development of RTOs, many states have come to rely upon the reserve margin requirements set by the RTOs, though the RTOs will defer to states that have their own reserve margin requirements when those requirements exceed the RTO standards. Nonetheless, the ultimate responsibility for establishing and overseeing these reserve margins – even those established by the RTOs – lies with the states.

Integrated Resource Planning Requirements[99]

IRP is a process by which utilities produce long-term plans to meet consumers' electricity needs through a least-cost combination of supply- and demand-side resources. This process typically occurs at the individual utility level, even within multi-state holding companies. IRP processes

[95] Illinois Power Agency, http://www2.illinois.gov/ipa/Pages/default.aspx.

[96] New Jersey's Energy Master Plan Statute, N.J.S.A. 52:27F-14, enacted in 1977, was a response to the energy crisis of the mid-1970s and called for a "master plan" for the "production, distribution, and conservation of energy in New Jersey."

[97] Public Law 109–58, Energy Policy Act of 2005, August. 8, 2005.

[98] According to NERC, "As of June 18, 2007, the U.S. Federal Energy Regulatory Commission (FERC) granted NERC the legal authority to enforce Reliability Standards with all U.S. users, owners, and operators of the Bulk Power System, and made compliance with those standards mandatory and enforceable." NERC, 2011 Summer Reliability Assessment, footnote 1, p. 2.

[99] Synapse Energy Economics, Inc., *A Brief Survey of State Integrated Resource Planning Rules and Requirements*, prepared for the American Clean Skies Foundation, April 28, 2011.

are often formal, with regulations established by the state legislatures and/or commissions. In a few states they are less formal, but still undertaken by utilities in one form or another.

Creating an IRP generally requires forecasting loads, identifying supply-side and demand-side resources that can meet serve those loads, forecasting the costs of those resources, and identifying the least-cost combination of resources. Transmission costs are considered so that the final IRP is based on the lowest overall costs to reliably meet expected customer needs – taking into account generation costs, transmission costs, demand-side resource costs, fuel diversity concerns, environmental costs and regulations, other public policy requirements, reliability impacts, and other factors. In many states, the IRPs are submitted to state regulatory commissions for approval. Several states also require their jurisdictional utilities to issue RFPs to meet the identified supply and or demand-side needs identified in the IRP. Public participation is often a part of the process.

Table 9 indicates whether or not each of the states of the Eastern Interconnection has an IRP process. For those states *without* an IRP process, the table indicates whether there is a requirement for some other long-term planning process. For states *with* an IRP process, the table shows the approximate length of the IRP planning horizon.

Table 9
Integrated Resource Planning Horizon and Status, by State[100]

	No IRP		With IRP, Planning Horizon			
State / District	**No Plan**	**LT Plan**	**10 Year**	**15 Year**	**20 Year**	**Other**
Alabama					X	
Arkansas			X			
Connecticut		X				
Delaware			X			
District of Columbia	X		X			
Florida			X			
Georgia					X	
Illinois		X				
Indiana					X	
Iowa	X					
Kansas	X					
Kentucky				X		
Louisiana[101]						X
Maine	X					
Maryland	X					
Massachusetts	X					
Michigan		X				
Minnesota				X		
Mississippi					X	
Missouri					X	

[100] *Id*., except that the information for Alabama, Florida, and Mississippi are updated based on information obtained from the Southern Company.

[101] In the City of New Orleans, the IRP process has a 10-year time horizon.

Integrated Resource Planning Horizon and Status, by State (continued)

State / District	No IRP: No Plan	No IRP: LT Plan	With IRP, Planning Horizon: 10 Year	15 Year	20 Year	Other
Montana						X
Nebraska					X	
New Hampshire						X[102]
New Jersey	X					
New Mexico					X	
New York	X					
North Carolina				X		
North Dakota					X	
Ohio		X				
Oklahoma			X			
Pennsylvania		X				
Rhode Island						X[103]
South Carolina				X		
South Dakota			X			
Tennessee[104]	X					
Texas		X				
Vermont					X	
Virginia				X		
West Virginia	X					
Wisconsin		X				

Renewable Portfolio Standards[105,106]

Table 10 shows the renewable portfolio standards (RPS)[107] for those states of the Eastern Interconnection that have such standards. The RPS programs generally require utilities to obtain certain percentages of their electrical energy supply from the eligible resource types indicated in Table 11.[108] The percentages generally rise over time, and they may differ by type of utility and type of renewable energy technology.

[102] New Hampshire's least-cost planning horizon is five years.

[103] Rhode Island's least-cost planning horizon is three years.

[104] TVA serves virtually all of Tennessee as well as portions of six adjacent states. Although some of these states do not have an IRP requirement, TVA develops an IRP every 2 years with a 20-year horizon.

[105] Pew Charitable Trust Portfolio Standards.pdf.

[106] The tables in this section provide an overview of many of the important characteristics of state renewable resource programs. Nonetheless, the tables do not reflect *all* the characteristics of such programs, such as all the tariff, rate programs and contracting mechanisms by which states encourage renewable energy development.

[107] These are sometimes called "alternative energy portfolio standards."

[108] In New York, a state agency procures resources of the preferred technology types.

Table 10
Renewable Portfolio Standards by State[109]

State	Renewables Requirement
Connecticut	27% by 2020: 20% from Class I, 3% from Class I or II and 4% from Class III[110] (HB 7432, 2007; SB 1423, 7/1/2011)
Delaware	25% by 2025 (with at least 3.5% from PV). (SB 119, 7/24/2007)
District of Columbia	20% by 2020 (with 2.5% solar by 2023) (DC Code §34-1431 et seq 4/12/2005).
Illinois	25% by 2025 (75% from wind power generation) (Public Act 095-0481, 8/28/2007)
Indiana	10% by 2025 (voluntary)[111] (SB 251, 5/2011)
Iowa	The two IOUs (MidAmerican and Alliant) must have a combined 105 MWs of generation from renewable resources.[112] (Iowa Alternative Energy Production Law, 1983)
Kansas	20% by 2020 [113] (HB 2369, 5/22/2009)
Maine	40% by 2017 (Maine UC, 1999 RPS 2007 Law)
Maryland	20% by 2022 (at least 2% from solar) (SB 209, 4/24.2008)
Massachusetts	15% by 2020, rising 1% annually to 25% in 2030 (SB 2768, 7/2008)
Michigan	10% by 2015 (SB 213, 10/6/2008)
Minnesota	25% by 2025[114] (SB 4, 2/22/2007)
Missouri	2% by 2011, 5% by 2014, 10% by 2018, 15% by 2021 (including 2% from solar) (Clean Energy Initiative (Ballot vote) 11/4/2008; SB 54, 2007)
Montana	15% by 2015 (SB 415, 4/28/2005)
New Hampshire	23.8% by 2025 (HB 873, 5/11/2007)
New Jersey	20.38% by 2021 plus 5,316 GWh of solar by 2026 (NJBPU, 4/12/2006; AB3520 1/17/2010; SB 2036 8/19/2010)
New Mexico	For public utilities, 10% by 2011, 15% by 2015, 20% by 2020. For distribution cooperatives, 5% by 2015, 5%, increasing 1% per year up to 10% by 2020. (SB 418)

[109] Information about RPS or state mandate for some states has been acquired from http://38.96.246.204/cneaf/solar.renewables/page/trends/table28.html. For a comprehensive summary of the details of state renewable portfolio standards, see Center for Climate and Energy Solutions, *Detailed Table of State Policies*, found at http://www.c2es.org/what_s_being_done/in_the_states/rps.cfm.

[110] Class I sources include solar, wind, new sustainable biomass, landfill gas, fuel cells (using renewable or non-renewable fuels), ocean thermal power, wave or tidal power, low-emission advanced renewable energy conversion technologies, and new run-of-the-river hydropower facilities with a maximum capacity of five megawatts. Class II sources include trash-to-energy facilities, biomass facilities not included in Class I, and certain hydropower facilities. Class III sources include customer-sited combined heat and power systems with a minimum operating efficiency of 50% installed at commercial or industrial facilities; electricity savings from conservation and load management programs; and systems that recover waste heat or pressure from commercial and industrial processes.

[111] Minimum qualifying clean energy is 4% in 2013-2018, 7% in 2019-2024, and 10% thereafter.

[112] Iowa Alternative Energy Production Law of 1983.

[113] The Renewable Energy Standard mandates that utilities (excluding municipal utilities) obtain 10% of their energy from renewable sources by 2011, 15% by 2016, and 20% by 2020.

[114] Xcel Energy, which currently generates about half of the state's electricity, must produce 30% of its power from renewable sources by 2020.

Renewable Portfolio Standards by State (continued)

State	Renewables Requirement
New York	30% by 2015[115] (NYPSC Standard, 9/22/2004)
North Carolina[116]	12.5% by 2021 (including 0.2% solar and 0.2% swine waste by 2018)[117] (SL 2007-397, 8/20/2007)
North Dakota	10% by 2015 (voluntary) (HB 1506, 3/2007)
Ohio	12.5% by 2025 (at least 0.5% from solar)[118] (SB 221, 5/1/2008)
Oklahoma	15% by 2015 (HB 3028, 5/27/2010)
Pennsylvania	18% by 2020 (at least 0.5% from solar)[119] (Alternative Energy Portfolio Standard, 12/6/2004)
Rhode Island	16% by 2019 (Clean Energy Act, 6/29/2004)
South Dakota	10% by 2015 (voluntary) (HB 1272, 2/21/2008)
Tennessee (TVA footprint)	Up to 2,000 MW of wind (voluntary)
Texas	5,880 MW by 2015, 10,000 MW by 2025 (including 500 MW of non-wind resources) (SB 7, 1999)
Vermont	25% by 2025 (Energy Efficiency & Affordability Act, 3/20/2008)
Virginia	12% of base year (2007) sales by 2022 and 15% by 2025 (voluntary) 9SB 1416, 4/11/2007)
West Virginia	10% by 2015, 15% by 2020, 25% by 2025 (HB 103, 6/17/2009)
Wisconsin	10% by 2015 (SB 459, 3/17/2006; SB 273, 5/19/2010)

[115] The standard identifies two tiers of eligible resources, a "Main Tier" and a "Customer-Sited Tier." The Main Tier will meet 92% of the standard through generation power by biogas, biomass, liquid biofuel, fuel cells, hydroelectric, solar, ocean or tidal power, and wind. The Customer-Sited Tier will meet 6% of the standard, while the voluntary market will account for the remainder.

[116] A North Carolina utility is in compliance with the law when it expends a specified "cost cap" per customer each year. The cost caps change over time. The current cost cap is $12 per year for each residential account, $150 per year per commercial account, and $1,000 per year for each industrial account. The residential cost cap increases to $34 in 2015. There is no financial penalty or alternative payment structure for utilities that fail to comply. Energy efficiency and demand-side management programs run by utilities are counted toward satisfying the target.

[117] This is the standard for IOUs. Electric membership corporations and municipalities must meet a standard of 10% by 2018.

[118] While 12.5% must be generated by renewable sources, an additional 12.5% by 2025 must come from "alternative energy resources" like third-generation nuclear power plants, fuel cells, energy-efficiency programs, and clean coal technology that can control or prevent carbon dioxide emissions.

[119] Of the 18%, 8% must be Tier 1 resources (wind, solar, coalmine methane, small hydropower, geothermal, and biomass) and 10% must be Tier 2 resources (waste coal, demand-side management, large hydropower, municipal solid waste, and coal integrated gasification combined cycle).

Table 11
Eligible Renewable Resources, by State[120,121,122,123,124]

			Mandatory RPS or AEPS																											
State	**CT**	**DC**	**DE**	**IA**	**IL**	**KS**	**MA**	**MD**	**ME**	**MI**	**MN**	**MO**	**MT**	**NC**	**NH**	**NJ**	**NM**	**NY**	**OH**	**PA**	**RI**	**TN**	**TX**	**VT**	**WV**	**WI**	**IN**	**ND**	**SD**	**VA**
Renewable Energy Technologies																														
Anaerobic Digester			X	X			X	X		X	X	X	X	X	X	X	X	X	X	X	X			X	X				X	X
Biofuels	X	X	X	X	X		X	X	X	X	X	X	X	X	X	X	X	X	X	X	X		X	X	X	X		X	X	X
Biomass	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Fuel Cells	N		R			R	R		N		N	R			N	N	R	N	N	N	R			R	N	R	N		R	
Geothermal Heat																							X							
Geothermal		X	X				X	X	X	X		X	X	X	X	X	X		X	X	X		X		X	X	X	X	X	X
Hydro	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Landfill Gas	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Municipal Waste	X	X		X			X	X		X	X	X			X	X			X	X				X					X	
Ocean Thermal	X	X	X				X	X							X			X	X		X		X				X		X	X
Photovoltaics	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X		X	X	X	X	X	X	X	X
Solar Space Heat		X				X								X						X							X			
Solar Thermal Electric	X	X	X	X	X	X	X		X	X	X	X	X	X	X	X	X		X	X			X	X	X	X	X	X	X	X
Solar Thermal Water		X			X	X								X	X			X		X			X	X			X			
Tidal	X	X	X				X	X	X	X				X	X	X		X	X		X		X			X			X	X
Wave	X	X	X				X	X	X	X				X	X	X		X	X		X		X			X			X	X
Wind	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X

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[120] Table provided by Center for Climate and Energy Solutions, http://www.c2es.org/what_s_being_done/in_the_states/rps.cfm, July 7, 2011.

[121] N denotes allowable technology regardless of whether the input fuel is renewable or not. P denotes pending allowable technology. R denotes allowable technology if the input fuel is renewable. X denotes allowable technology.

[122] Solar can include thermal energy. LFG and biogas can include co-firing and come with emission limits or sustainable growth conditions. Small hydro has various size, technology, and vintage definitions.

[123] West Virginia utilities may also generate credits from projects that reduce or offset greenhouse gas emissions from the forestry and agricultural sectors.

[124] The Tennessee entry includes voluntary commitments by TVA for its footprint.

Eligible Renewable Resources, by State (continued)

			Mandatory RPS or AEPS																											
	CT	**DC**	**DE**	**IA**	**IL**	**KS**	**MA**	**MD**	**ME**	**MI**	**MN**	**MO**	**MT**	**NC**	**NH**	**NM**	**NJ**	**NY**	**OH**	**PA**	**RI**	**TN**	**TX**	**VT**	**WV**	**WI**	**IN**	**ND**	**SD**	**VA**
Alternative Energy Technologies																														
Advanced Nuclear																			X								X			
Carbon Capture and Sequestration										X									X						X		X			
Coal Gasification																				X					X					
Coal Mine Methane																				X					X		X			
Integrated Gasification Combined Cycle																									X					
Natural Gas																									X		X			
Synthetic Gas																									X					
Waste Coal																				X					X					
Waste Tire																					X				X					
Energy Efficiency Eligible Under Different Policies[125]																														
Energy Efficiency	X				X					X				X					X	X		X			X		X			
Electricity-displacing technology																										P				
CHP/Waste Heat[126]	X						X			X				X				X	X	X					X		X	X	X	
State Carve-Out Requirements																														
Photovoltaics		X	X					X						X	X	X	X		X	X										
Wind					X											X														
Offshore Wind																	X													
Geothermal																X														
Animal Waste														X																
Distributed Energy																X		X												

[125] Energy efficiency is an eligible resource under different state policies, including a Renewable Portfolio Standard, Alternative Energy Portfolio Standard, or Energy Efficiency Portfolio Standard.

[126] CHP is combined heat and power (e.g., cogeneration). West Virginia's standard also includes useful thermal, mechanical or electrical energy produced from certain waste gas or waste fuel sources and energy extracted from a pressure drop in any gas.

Furthermore, some states RPS programs include "carve-outs" that require particular percentages to be generated by favored technologies. In addition to being favored by these carve-outs, solar resources are further supported by the financial incentives described in Table 12. Because renewable energy has been sold to the states as an economic development tool, some states, as indicated in Table 11, require that renewable resources be physically located within the state.

Table 12
Financial Incentives for RPS Solar Carve-Outs, by State[127]

State	Incentive
Delaware	Delaware Electric Coop: PV: \$0.45 - \$0.90/W in general; \$0.52 - \$1.05/W for non-profits; Solar Thermal (water and radiant space heating): 20% of installed costs. DEMEC: PV: 33.3% of installed costs (except 25% for Lewes); Solar Thermal: 50% of installed costs (except 25% for Lewes) Dover Public Utilities: PV: \$0.35 - \$1.25/W in general; \$0.70 - \$2.55/W for non-profits; Solar Thermal: \$1.00/annual kWh displaced
District of Columbia	PV: \$1.50/W for first 3 kW, \$1.00/W for next 7 kW; \$0.50/W for next 10 kW; Solar Thermal Residential: 20% of installed cost; Solar Thermal Non-Residential: 15% of installed cost. Maximum incentive: PV, \$16,500 per site per program year. Solar residential, \$5,000 per system per year. Solar non-residential, \$7,000 per system per year.
Georgia	Georgia Power: Solar buyback program – \$0.17/kWh.
Iowa	Various utility rebate programs for solar thermal and PV.
Illinois	State rebate program: Residential and business PV, \$2.25/W or 30% of project costs; Public sector and non-profit PV, \$3.75/W or 50% of project costs. Residential and business solar thermal: 30% of project costs. Public sector and non-profit solar thermal: 50% of project costs
Maryland	Commercial, Industrial, Non-profit: PV, \$500/kW; Solar Water Heater (SWH), 15% of installed cost; Max – PV \$50,000, SWH \$1,000. Residential: PV, \$1,000 per installation/household; SWH, 20% of installed cost; Max – PV \$1,000, SWH \$500.
Massachusetts	Alternative Compliance Payment Rate for the Solar Carve-Out, \$550 per MWh for 2011 through 2013 compliance year, thereafter falling by 5% per year through 2020.[128]
Minnesota	Various utility rebate programs available.
Missouri	Various utility rebate programs available.
New Hampshire	Combination of state and utility rebate programs available.
New Jersey	Solar rebate for PV decreases yearly. In 2010, it was \$1.35 per kilowatt of capacity. The state rebate funds were exhausted after four months of 2010.
New Mexico	PNM Solar Thermal Systems and PV: Systems up to 10 kW: \$0.05/kWh for RECs; >10 kW up to 100 kW: \$0.05/kWh for RECs; >100 kW up to 1 MW: \$0.02/kWh; MW+: Fully subscribed. El Paso Electric PV: Systems 10 kW or less installed: PV: \$0.10/kWh; Systems > 10 kW and < 100 kW installed after 1/1/2012: PV: \$0.12/kWh.

127 National Renewable Energy Laboratory, *Renewable Portfolio Standards in the States: Balancing Goals and Implementation Strategies*, Technical Report NREL/TP-670-41409, December 2007, p. 12, Table 3. Also see http://www.dsireusa.org/solar/incentives for details on individual states.

128 Massachusetts Department of Energy Resources, *Renewable Energy Portfolio Standard Guideline on the Forward Schedule of the Solar Carve-Out Alternative Compliance Payment (ACP) Rate*, http://www.mass.gov/eea/energy-utilities-clean-tech/renewable-energy/solar/rps-solar-carve-out/about-the-rps-solar-carve-out-program.html.

Financial Incentives for RPS Solar Carve-Outs, by State (continued)

State	Incentive
New York[129]	\$1.75/W system rebate up to 7 kW for residential and 50 kW for non-residential (25 kW for non-profit)[130,131] Capped at 40% of installed costs.
North Carolina	Various utility rebate programs offered.
Ohio	AEP Ohio: Solar: \$1.50/watt; Max Credit - Residential Solar: 50% or \$12,000; Non-Residential Solar: 50% or \$75,000
Pennsylvania	Various state and utility rebate programs.
Texas	Various utility rebate programs.
Vermont	State rebate program for all customer sectors, amount varies with sector and technology. For Solar PV, only first 60 kW are incentivized.
Wisconsin	State solar rebate program becomes available mid-2012.

Table 13 summarizes the number of types of rules, regulations, policies and programs in connection with renewable energy in the Eastern Interconnection states at the either the local (L), state (S), or utility (U) level. The number next to the letter in each cell indicates the number of rules or programs that exist at the associated level in the given state.

[129] New York does not have a solar carve-out as that term is normally used. The Customer-Sited Tier includes distributed solar, and the Main Tier accepts bids from larger systems.

[130] The program administrator, New York State Energy Research and Development Authority, limits expenditures on incentives to approximately \$2.0 million/month.

[131] A petition to the Commission seeks to raise the NFP to the same level as other non-residential customers.

Table 13
Rule, Regulations, & Policies for Renewable Energy[132]

State	Public Benefit Fund	RPS	Net Metering	Inter-connection	Contract. License	Equip. Certification	Access Laws	Constr. & Design	Green Power Purchasing	Req'd Green Power
Alabama				1-S						
Arkansas			1-S	1-S	1-S			1-S		
Connecticut	1-S	1-S	1-S	1-S	1-S			3-S		
Delaware	1-S 2-U	1-S	1-S	1-S			1-S	2-S		
D.C.	1-S	1-S	1-S	1-S				1-S		
Florida		1-U	1-S	1-S	1-S	1-S	1-S 1-L	1-S		
Georgia			1-S	1-S			1-S	2-L		
Illinois	1-S	1-S	1-S	1-S			1-S	2-S 1-L		
Indiana		1-S	1-S	1-S			1-S	1-S 1-L		
Iowa		1-S	1-S	1-S			1-S	1-S		1-S
Kansas		1-S	1-S	1-S			1-S	1-L		
Kentucky			1-S	1-S			1-S			
Louisiana			1-S 1-L	1-S	1-S		1-S			
Maine	1-S	1-S	1-S	1-S	1-S		2-S	2-S		1-S
Maryland		1-S	1-S	1-S			1-S	1-S		
Massachusetts	2-S	1-S	1-S	1-S			1-S	3-S		
Michigan	1-S	1-S	1-S	1-S	1-S			1-S 1-L		
Minnesota	1-S	2-S	1-S	1-S		1-S	1-S	1-S		
Mississippi										
Missouri		1-S 1-L	1-S	1-S			1-S	1-S		
Nebraska			1-S	1-S			1-S			
New Hampshire		1-S	1-S	1-S			1-S	1-S		
New Jersey	1-S	1-S	1-S	1-S			2-S	4-S		
New Mexico		1-S	1-S 1-U	1-S			1-S			1-S
New York[133]	1-S	1-S	1-S	1-S			1-S	1-S 1-L		
North Carolina		1-S	1-S	1-S			1-S 1-L	2-S 12-L		
North Dakota		1-S	1-S				2-S			
Ohio	1-S	1-S	1-S	1-S			1-S	1-S		
Oklahoma		1-S	1-S					2-S		
Pennsylvania	1-S	1-S	1-S	1-S				1-S		
Rhode Island	1-S	1-S	1-S	1-S			1-S	1-S		
South Carolina			3-U	1-S				1-S		
Tennessee							1-S			
Vermont	1-S	1-S	1-S	1-S			1-S			
Virginia	1-S	1-S	1-S 1-L	1-S			2-S	2-S 1-L		1-S
West Virginia		1-S	1-S	1-S						
Wisconsin	1-S	1-S	1-S	1-S	1-L		1-S 1-L	2-S		

Table 14 summarizes the type and number of financial incentive programs for renewable energy present at the state, utility, and local levels. L, S, and U denote policies imposed by localities, states, and utilities, respectively. The number that accompanies each letter indicates the number of incentive programs of the type available in that state. The vast majority of programs consist of a combination of rebates, grants, and loans divided between state-sponsored programs and utility-sponsored (regulator-approved) programs. In a few states, incentives have been created through a combination of personal income, corporate income, sales or property tax breaks. There does not appear to be any significant difference between RTO states and non-RTO states as to the types and number of financial incentives at the state and utility levels.

[132] Database of State Incentives for Renewables & Efficiency (DSIRE), http://www.dsireusa.org/summarytables/rrpre_printable.cfm, accessed December 2, 2011. The DSIRE website provides links to each of the rules, regulations, policies and programs. The information for Alabama was provided by the Southern Company.

[133] RPS requirements are due to regulatory policy, while net metering is mandated by legislation.

Table 14
Financial Incentives for Renewable Energy[134]

State	Personal Tax	Corp. Tax	Sales Tax	Prop. Tax	Rebates	Grants	Loans	Bonds
Federal	2-F	3-F				3-F	4-F	
Alabama					8-U		2-S 6-U	
Arkansas					10-U		3-S 4-U	
Connecticut			1-S		1-S 10-U		3-S 3-U	
Delaware					1-S		1-S	
District of Columbia					1-S		1-S	
Florida					32-U	2-U	1-S 5-U	
Georgia		1-S			21-U		1-S 6-U	
Illinois					2-S 25-U	4-S	2-S	1-S
Indiana					43-U		1-U	
Iowa					32-U	1-U	1-S 2-U	
Kansas					6-U		1-S 1-U	
Kentucky	1-S	1-S	1-S		1-S 20-U	1-S	2-S 2-U	
Louisiana					4-S 3-U		2-S	
Maine					3-S 1-U		3-S	
Maryland	1-S	1-S	1-S	2-S	1-S 17-U		8-S	
Massachusetts					2-S 29-U	1-S	1-S 4-U	
Michigan	1-S				24-U	1-S	3-S	
Minnesota					89-U	4-U	7-S 5-U	
Mississippi					12-U		1-S 2-U	
Missouri	1-S		1-S		1-S 36-U		2-S 3-U	
Nebraska					9-U		1-S	
New Hampshire					2-S 17-U	1-S 2-U	5-S 3-U	
New Jersey					9-S 2-U	4-U	2-S 1-U	
New Mexico	6-S	5-S	4-S	1-S	1-U		2-S	1-S
New York			1-S[135]	1-S				
North Carolina			1-S		2-S 24-U		3-S 7-U	
Ohio					23-U		2-S 2-U	
Oklahoma	1-S	1-S			13-U		4-S 3-U	
Pennsylvania					18-U	5-S	5-S 1-U	
Rhode Island					5-U			
South Carolina	1-S		1-S		19-U		1-S 4-U	
Tennessee					1-S 14-U	1-S	3-S 3-U	
Vermont					10-S 5-U		3-S 1-U	
Virginia	1-S		1-S	1-S	2-S 12-U		2-S 1-U	
West Virginia					1-S 2-U			
Wisconsin					9-S 17-U	2-U	3-S 6-U	

Table 15 shows the state-level non-compliance penalties or alternative compliance payments (ACPs) that utilities can pay instead of purchasing renewable energy. F, L, S, and U denote incentives created by federal authorities, localities, states, and utilities, respectively. Regardless of what they are called, these penalties or ACPs effectively set a cap on utilities' costs of procuring renewable energy: when the cost of renewable energy exceeds the penalty or ACP, it is cheaper for the utility to pay the penalty or ACP.

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[134] Database of State Incentives for Renewables & Efficiency, http://www.dsireusa.org/summarytables/finre_printable.cfm, accessed December 2, 2011.

[135] New York exempts some renewable generation equipment from state sales taxes.

Table 15
RPS Alternative Compliance Payments, by State[136]

State	Incentive
Connecticut	5.5¢/kWh
Delaware	Non-Solar: 2.5¢/kWh (first year of noncompliance), 5.0¢/kWh (second year), 8.0¢/kWh (subsequent years) Solar: 25¢/kWh (first year of noncompliance), 30¢/kWh (year 2), 35¢/kWh (subsequent years)
District of Columbia	2.5¢/kWh for Tier 1 resources, 1.0¢/kWh for Tier 2 resources, 30.0¢/kWh for solar
Illinois	State regulators have authority to impose penalties, but amounts are not specified.
Iowa	None
Maine	5.712¢/kWh, adjusted for inflation
Maryland	System: 2.0¢/kWh (Tier 1 resources), 1.5¢/kWh (Tier 2 resources) Solar: 30¢/kWh in 2013, decreasing 5¢ bi-annually until it reaches 5¢/kWh in 2023
Massachusetts[137]	System: 5.0¢/kWh in 2003, adjusted annually for inflation Solar: $550 per Solar Renewable Energy Credit in 2012-13 and declines 5% per year thereafter.
Minnesota	State regulators have authority to impose penalties, but amounts are not specified.
Montana	1.0¢/kWh
New Hampshire	5.712¢/kWh for Class I (new renewables); 15¢/kWh for Class II (solar); and 2.8¢/kWh for Class III and IV (existing biomass, methane and hydroelectric)
New Jersey*	5.0¢/kWh for Class I and II resources 30.0¢/kWh for solar
New Mexico	State regulators may impose penalties, but amounts are not specified.
New York	None (RPS is centrally procured at prices set by competitive auction)
North Carolina	State regulators may impose but amounts have not been specified
Pennsylvania	4.5¢/kWh for Tier 1 and Tier 2 resources For solar, 200% of average market value of solar credits
Rhode Island	5.0¢/kWh (2003$)
Texas	Lesser of 5¢/kWh or 200% of the average cost of credits traded during the year
Wisconsin	Up to $500,000

Because the availability of renewable resources can depend upon location, some utilities have better access to renewable resources than do other utilities. Consequently, some utilities can satisfy RPS requirements at lower cost than can other utilities. To encourage the least-cost

[136] National Renewable Energy Laboratory, *Renewable Portfolio Standards in the States: Balancing Goals and Implementation Strategies*, Technical Report NREL/TP-670-41409, December 2007, p. 16, Table 5. Several of the penalties change over time with general inflation indexes. Some states allow penalties to be recovered in rates, while others do not.

[137] Massachusetts Department of Energy Resources, *Renewable Energy Portfolio Standard Guideline on the Forward Schedule of the Solar Carve-out Alternative Compliance Payment (ACP) Rate*, Pursuant to the Renewable Energy Portfolio Standard Class I Regulation in 225 CMR 14.00, December 28, 2011, p 2.

provision of renewable energy, many states therefore allow utilities to trade renewable energy credits (RECs). This allows utilities that are deficient in meeting their RPS requirements to meet those requirements by purchasing RECs from other utilities that have exceeded their RPS requirements. States or regions do not necessarily give full value, or any value, to RECs from other states or regions.

Because RECs are a relatively new instrument, there are continuing challenges in their definitions and authenticity. Although one REC can represent 1 MWh of renewable energy, differences among the states in their definitions of "renewable energy" (as indicated by Table 11) can create differences among the states in their definitions of RECs. The authenticity problem arises from the difficulty of tracking an REC to the renewable energy that allegedly backs it up.

Energy Efficiency Standards

Energy efficiency resource standards (EERS) are promulgated for the purpose of encouraging more efficient production and consumption of electricity. Like RPS, EERS require utilities to reduce energy use by targeted percentages or amounts over time; and utilities may be penalized for failing to meet these targets. While some states have separate EERS and RPS, other states combine the two requirements so that progress in meeting one standard counts toward meeting the other standard.[138]

Table 16 summarizes the EERS for each Eastern Interconnection state, indicating the near-term and long-term sales reduction targets set for electric utilities by state law or PUC order. Twenty-two of the 39 states in the EI have established energy efficiency targets. While the state targets require utilities to achieve reductions that are small percentages of their total sales, the combined effect within a given region, such as the RTO regions, may shape the demand for generation capacity and the planning for both generation and transmission.

[138] Center for Climate and Energy Solutions, http://www.c2es.org/what_s_being_done/in_the_states/efficiency_resource.cfm.

Table 16
Energy Efficiency Resource Standards, by State

State	Existing EERS Policy
Arkansas	Order 17 (Docket No. 08-144-U) sets electric sales reduction target requirements: 2011 reductions: 0.25%; 2012 reductions 0.50%; 2013 reductions: 0.75%.
Connecticut 2005[139]	Starting in 2007, the state's utilities must procure a minimum 1% of electricity sales from "Class III" resources such as energy efficiency and Combined Heat and Power (CHP), with an additional 1% required in 2008, 2009, and 2010. Utilities must acquire "all cost-effective efficiency" and establish savings goals. The DPUC is now reviewing a combined Conservation and Load Management plan with annual savings goals averaging about 1.5%.
Delaware 2009[140]	The goals are 15% electricity consumption and peak-demand savings by 2015.
Illinois (2007)	SB 1592 (August 28, 2007) requires utilities to implement cost-effective energy efficiency programs to meet escalating savings targets that reach 2% of energy delivered in 2015. It also requires a reduction in peak demand of 0.1% each year from 2008 to 2018. Requirements can be modified if implementation costs more than 2% of total utility revenues per year.
Indiana 2009[141]	The goals begin at 0.3% annual savings in 2010, increasing to 1.1% in 2014, and leveling at 2% in 2019.
Iowa 2009[142]	The Iowa Utilities Board (IUB) requires IOUs to submit plans for achieving 1.5% annual electricity savings. Iowa law requires municipal and cooperative utilities to set energy-savings goals, create plans to achieve those goals, and report to the IUB on progress.
Maine (2010)	The Maine PUC approved the plan of the Efficiency Maine Trust, which develops, plans, coordinates, and implements energy efficiency programs in the state. The Trust commits to annual energy savings goals in 2011 of 1%, ramping up to 1.4% in 2013.
Maryland (2008)	SB 205 sets a statewide target of reducing per capita electricity consumption and peak energy demand by 15% by 2015 based on 2007 electricity consumption. The legislation specifies that the PSC shall adopt regulations or issue orders that each company must provide cost-effective energy efficiency and conservation programs to achieve at least 10% of the savings by 2015. The Maryland Energy Administration (MEA) is responsible for the remaining 5%.
Massachusetts 2009[143]	Utilities must acquire all energy efficiency that costs less that new energy. The Department of Public Utilities requires annual electricity savings of 2.4% by 2012.
Michigan 2008[144]	By 2011, electricity providers must have saved 0.75 percent of prior-year sales. The standard will continue increasing after 2011 in increments of 1.0 percent. There is no penalty for failing to achieve savings targets, but there are incentives for outperforming the targets.
Minnesota (2007)	Minnesota Statutes § 216B.241 sets energy-saving targets of 1.5% of annual retail sales for the state's electric utilities including savings from energy conservation programs, rate design, energy codes, appliance standards, market transformation programs, programs to change human behavior, improvements to utility infrastructure, and waste heat recovery. The law allows a utility to request a lower savings target (based on historical experience, an energy conservation potential study, and other factors), but in no case lower than 1% per year.
New Jersey Pending[145]	The goals may be as high as 20% savings by 2020 relative to predicted consumption. The BPU has yet to issue an order establishing targets.
New Mexico	The Efficient Use of Energy Act of 2005 (Act) allows public electric and natural gas utilities to implement cost-effective energy-reduction and load management programs, subject to Commission approval. The programs may be funded through a tariff rider, with charges on the consumer not to exceed $75,000 per year. The Act also provides for monitoring, verification, and periodic reporting by the utility on its energy efficiency expenditures and overall program effectiveness. All investor-owned utilities have now received approval for their energy efficiency programs.
North Carolina (2007) (Senate Bill 3)	A combined renewable energy and energy efficiency portfolio standard requires public electric utilities to obtain renewable energy and energy efficiency savings of 3% of prior-year electricity sales in 2012, increasing to 12.5% in 2021 and thereafter. Energy efficiency is capped at 25% of the 2012-2018 targets and at 40% of the 2021 target. Cooperatives and municipal utilities are allowed to use demand-side management or energy efficiency to satisfy the standard without limitation.

[139] The 2007 Electricity and Energy Efficiency Act (H.B. 7432); Conn. Gen. Stat. §16a-3a (2007). Docket 09-10-03.

[140] SB 106.

[141] Cause No. 42693.

[142] Docket No. 199 IAC 35.4(1) (EEP-02-38, EEP-03-1, EEP-03-4); 2009 Iowa Code Title XI, Subtitle 5, h. 476 C.

[143] D.P.U. 09-116 through D.P.U. 09-128.

[144] SB 213.

[145] Executive Order 54; New Jersey Energy Master Plan.

Energy Efficiency Resource Standards, by State (continued)

State	Existing EERS Policy
New York (2008)	The NYPSC's Energy Efficiency Portfolio Standard seeks to reduce electric energy usage 15% by 2015 relative to projected usage. The NYPSC has established funding and targets that are designed to achieve this energy use reduction goal. Non-jurisdictional entities such as the New York Power Authority and the Long Island Power Authority have also established energy efficiency programs and long-term goals.
Ohio 2008[146]	Law requires a gradual ramp-up to a 22% reduction in electricity use by 2025. Starting in 2009, electric distribution utilities must achieve 0.3% savings, which ramps up to 1% per year by 2014, then jumps to 2% per year in 2019 through 2025.
Pennsylvania 2004, 2008[147]	Energy efficiency is an eligible resource in Tier II of Pennsylvania's Alternative Energy Portfolio standard, though there is no minimum efficiency target. Law requires electric distribution companies to meet 1% electricity savings in 2011 and a total of 3% by 2013, as a percent of 2009-2010 electricity sales.
Rhode Island 2006[148]	Utilities must acquire all energy efficiency that costs less than new energy supply. Utilities are required to submit three-year and annual procurement plans with detailed energy efficiency targets. There are no penalties for non-compliance.
Texas 1999, 2007[149]	In 1999, Texas required electric utilities to offset 10% of load growth through end-use energy efficiency. In 2007, the legislature increased the standard to 15% of load growth by 2009, and 20% of load growth by 2010.
Vermont 2000[150]	Efficiency Vermont (EV) — an independent efficiency utility — is contractually required to achieve energy and demand goals. EV cumulatively met over 7% of Vermont's electricity requirements by the end of 2007. EV has energy savings goals of 360,000 total annual MWh, 51.2 total summer peak MW, and 54 total winter peak MW. The projected MWh savings amount to 6% of 2008 sales for these three years combined.
Virginia (2007)	HB 3068 sets a reduction target for retail electric energy consumption of 10% from 2006 to 2022 that includes demand-side management, conservation, energy efficiency, load management, real-time pricing, and consumer education to achieve the goal.
Wisconsin Pending[151]	Energy efficiency goals will be a percentage of future use and demand. The levels of goals, measurable targets, funding and evaluation of programs are still under consideration.

3.6. Environmental Requirements

The U.S. Environmental Protection Agency (EPA) is presently finalizing environmental regulations under the Clean Air Act, the Clean Water Act, and the Resource Conservation and Recovery Act. The affected regulations include the Clean Air Transport Rule, Utility Air Toxics Rule, and the Cooling Water Intake Rule. All generators must comply with these regulations, implying significant capital investments in retrofits for some existing generators and modified designs for new generators. Affected installed capacity in the Eastern Interconnection will be in the tens of thousands of MW. In some cases, generation units will be retired because the capital cost of retrofits will render the units uneconomic relative to other generation alternatives.

One common way of regulating emissions is through output-based environmental regulations (OBRs) that relate the quantity of emissions to the quantity of output from a productive process. For electricity, such regulation can measure emissions on the basis of pounds of pollutant per megawatt-hour of electricity output, allowing environmental improvements to be assessed according to reductions in this ratio. Traditional "input-based" environmental regulations for power generators and boilers establish emission limits based on heat input (e.g., pounds of

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[146] Ohio Revised Code 4928.66.

[147] Act 129; Alternative Energy Portfolio Standards (AEPS) Act (Act 213)

[148] 2006 SB 2903.

[149] Texas Statutes 39.905; PUCT Substantive Rule Sec. 25.181.

[150] 30 V.S.A. Sec. 209(d)(e); VT PSB Docket 5980; Draft 2009-2011 Energy Efficiency Utility Contract.

[151] Docket 5-GF-191.

pollutant per million British thermal units of fossil heat input) or exhaust concentration (parts per million) in the exhaust stream. These input-based limits do not account for the pollution prevention benefits of increased efficiency in the generation of heat or electricity. Output-based emission limits, on the other hand, promote clean energy by accounting for the air pollution effects of energy efficiency in the compliance computation.

EPA has established a number of output-based rules for limiting emissions. For example, the New Source Performance Standards (NSPS) for NO_x from electric utility boilers and the proposed NSPS for combustion turbines are structured as OBRs.[152] As another example, EPA is presently reconsidering recently issued air toxics standards for boilers (often referred to as the "boiler Maximum Achievable Control Technology") that include an output-based emissions standard as an option.

Several states have adopted OBRs and developed rules that account for the efficiency benefits of CHP. Table 17 presents a summary of various types of state OBR programs. Fifteen of the 39 states in the Eastern Interconnection have adopted OBR regulations, all of which reside in an RTO area.

[152] References to these regulations, which provide excellent examples of OBR language and technical documentation, can be found at http://www.epa.gov/ttn/oarpg/t3pfpr.html. These NSPS rules also contain compliance provisions for CHP.

Table 17
State Output-Based Environmental Regulations[153]

State	Conventional Emissions Limit	Small DG Rule[154]	Allowance Trading	Allowance Set-Asides[155]	Emissions Performance Standard[156]
Arkansas			X		
Connecticut		X	X	X	X
Delaware	X				
Illinois			X	X	
Indiana			X	X	
Maine	X				
Massachusetts	X	X	X	X	X
Missouri			X	X	
New Hampshire	X				
New Jersey			X	X	
New York		P			
Ohio			X		
Pennsylvania			X		
Rhode Island	X				
Texas	X	X			
Wisconsin			X		

4. TRANSMISSION PLANNING PROCESSES

This section identifies who is responsible for transmission planning, the scope of that responsibility, the forums in which planning occurs, and the parties who participate in those forums. It then describes some of the details of planning studies, the processes for adding projects to a transmission plan, if and how alternatives to transmission investments are considered, who transmission investors are, and how transmission costs are allocated to and recovered from customers. The section concludes with discussion of environmental and siting requirements.

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[153] EPA, http://www.epa.gov/chp/state-policy/obr_factsheet.html, accessed January 7, 2012. X denotes existing regulation, and P denotes proposed regulation.

[154] This column indicates those states that have promulgated output-based environmental regulations that apply to small distributed generation (DG), including combined heat and power units.

[155] This column indicates those states have allocated ("set aside") – to new generation entrants, distributed generators, or renewable generation resources – certain percentages of the total generator emission allowances issued. The states vary in the designations of the favored recipients and in the quantities of the set-asides.

[156] This column indicates those states that have emissions performance standards (i.e., limits) under output-based environmental regulations. Such standards differ from conventional emissions limits in that the latter are based on either heat input or exhaust concentration, whereas output-based limits are defined in terms of emissions per unit of energy output (e.g., pounds of pollutant per MWh).

4.1. Planning Responsibility

Throughout the Eastern Interconnection, transmission owners are responsible for assuring that their systems meet NERC planning criteria and for meeting the planning requirements mandated by FERC policy (e.g., Order Nos. 890 and 1000). Nonetheless, because of loop flows and the consequent ability of transmission owners to affect the reliability of other transmission owners' systems, there are a variety of arrangements under which groups of transmission owners share the responsibility to maintain reliable power systems.

RTOs

The RTO planning processes share planning responsibilities between transmission owners and the RTOs. In general, individual transmission owners are responsible for creating plans that will meet their own individual transmission needs, and the RTOs are responsible for integrating the individual plans into regional plans. In creating their regional plans, the RTOs identify alternative or additional transmission upgrades that promise to maintain or improve reliability relative to the individual plans, or that can do so at lower cost than the aggregate of the individual plans.

Non-RTO Areas

Two NERC Regional Entities – SERC[157] and FRCC – cover the non-RTO areas of the Eastern Interconnection. These two entities are responsible for ensuring that reliability standards are satisfied in their respective areas. Each planning entity within SERC and FRCC is responsible for developing transmission plans that meet all of the applicable NERC, SERC, FRCC, and transmission planning entity-specific transmission planning criteria and reliability standards. Importantly, SERC itself does not engage in any transmission planning but instead provides the organizational/committee structure for additional coordination and reliability assessments of its NERC-registered planning entities.

SERC and FRCC have adopted bottom-up transmission planning processes. These regions are generally populated by vertically-integrated utilities that have franchise service obligations that include an obligation to plan to meet the needs of current and future customers in their service territories. Many of these utilities also have contractual obligations to serve part or all of the resource needs of full- or partial-requirements wholesale customers within or adjacent to their service areas. These utilities are responsible for creating plans that meet the applicable reliability requirements. As such, their transmission planning is primarily driven by resource and load requirements as identified in their state-regulated IRP and RFP processes, as well as by long-term firm transmission service commitments made by the utility's customers under the FERC-regulated OATTs. The IRP process identifies the most cost-effective and reliable transmission solutions for meeting future load and resource needs. The long-term firm transmission service commitments made under its FERC-regulated OATT represent additional transmission needs. The transmission planning process then identifies a comprehensive, least-cost transmission plan

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[157] SERC's sub-regions include Central (formerly the TVA Sub-region), Delta (formerly the Entergy Sub-region), Southeastern (formerly the Southern Sub-region), and VACAR (covering Virginia and the Carolinas). SERC also includes the "Gateway Region" that includes utilities that are members of SPP or MISO, as well as Dominion Power, which is in PJM.

to satisfy all of these requirements, which are then coordinated and combined to develop a transmission expansion plan for that utility's Attachment K transmission planning region. In addition, the transmission planning utilities in SERC then present their transmission plans to SERC's transmission planning committee to facilitate simultaneous interregional feasibility and consistency in models and data. This SERC-wide analysis effectively rolls the regional transmission plans into a set of unified, interregional transmission base cases. Similarly, the FRCC roll-ups the individual plans in its footprint into regional plans and stress-tests those plans to ensure that reliability standards can be satisfied at the FRCC-wide level.

Both SERC and FRCC are members of the NERC Eastern Interconnection Reliability Assessment Group and its Multiregional Modeling Working Group (MMWG). The MMWG rolls-in the transmission base cases from the different planning regions to form interconnection-wide base cases that provide the foundation for essentially all transmission planning studies in the Eastern Interconnection.

4.2. Scope of Planning

The "scope of planning" refers to: a) types of transmission projects considered by plans (e.g., reliability versus economic projects, voltage levels); b) the inclusion or exclusion of generation; c) geographic coverage (e.g., utility versus intra-regional versus inter-regional); and d) the length of the forecast period. FERC's Order Nos. 890 and 890-A require that transmission providers must coordinate their plans with their customers and neighboring transmission providers and must participate in a regional process for coordinating with interconnected systems.[158] The NERC regions and NERC planning entities are not necessarily the same as the Order No. 890 planning regions. For example, SERC is a regional entity for NERC purposes but constitutes an "interregional" footprint for purposes of Order No. 890.

Order No. 1000

FERC's recent Order No. 1000[159] applies to the planning of new transmission facilities that are evaluated or re-evaluated after the effective date of the transmission provider's filing adopting the reforms required by the Order. The Order requires transmission providers to do the following:

- make a compliance filing within twelve months of the effective date of the Order with respect to regional planning and cost allocation requirements;
- make a compliance filing within eighteen months of the effective date of the Order with respect to interregional planning and cost allocation requirements;
- explain in their compliance filings how they would determine which facilities are subject to the Order's requirements;

[158] Federal Energy Regulatory Commission, *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890-A, 121 FERC ¶ 61,297, December 28, 2007, ¶181 *et seq*.

[159] Federal Energy Regulatory Commission, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 18 CFR Part 35, 136 FERC ¶ 61,051, Docket No. RM10-23-000, Order No. 1000, July 21, 2011.

- consider transmission needs driven by federal or state laws or regulations;
- remove federal rights of first refusal from Commission-approved tariffs and agreements;[160]
- coordinate with neighboring transmission planning regions in identifying cost-effective solutions to transmission needs;
- participate in a regional transmission planning process that produces a single regional transmission plan consistent with the nine planning principles of Order No. 890;
- develop cost allocation mechanisms applicable to transmission facilities within their regions that are consistent with the six regional and interregional cost allocation principles of Order No. 1000;
- add a tariff provision that requires the provider to reevaluate the regional transmission plan to determine if alternative solutions need to be evaluated when there is a delay in the development of a transmission facility;[161] and
- develop, with transmission providers in neighboring planning regions, a common interregional cost allocation method for new interregional transmission facilities, which satisfies the six inter-regional cost allocation principles.

Order No. 1000 also includes the following key provisions:

- Participant funding of new transmission facilities is permitted, but not as part of the regional or interregional cost allocation methodology applicable to transmission facilities that are part of a regional plan and eligible for cost allocation under the tariff; and
- States and localities retain their authority concerning construction of transmission facilities, including siting and permitting.

At the time of publication of this report, Order No. 1000 was subject to numerous rehearing requests and may be appealed to the Courts; so its long-term impact is presently unsettled.

RTOs

ISO-NE

ISO-NE's transmission planning process provides an ongoing ten-year plan that complies with the standards and criteria of NERC and the NPCC. This process determines whether the power system is adequate for maintaining reliable and efficient operations and wholesale electric markets. This process considers the challenges that generators must address, and the costs that

[160] This removal requirement would not apply to a transmission facility not selected in a regional transmission plan for purposes of cost allocation nor to upgrades to transmission facilities (i.e., tower change-outs or reconductoring). This removal requirement would allow, but not require, competitive bidding to solicit transmission projects or developers.

[161] Such alternative solutions can include those proposed by the transmission provider.

they will incur, to meet a variety of requirements concerning air emissions, cooling water intake, and solid waste product handling.

ISO-NE is conducting studies to examine future wind development scenarios and the associated need for transmission expansion. Because additional intermittent renewable resources will increase regulation and reserve requirements, ISO-NE is concerned about new stresses on gas-fired generators and the natural gas delivery system, the latter of which will need to flexibly provide fuel to generators on short notice.

MISO[162]

MISO's planning process addresses transmission needs driven by reliability, economic, and public policy considerations (e.g., integration of renewable energy resources). The process identifies issues and opportunities to strengthen the transmission system, develops alternatives for consideration, and evaluates options to determine which solutions are most effective. The process identifies projects that ensure system reliability, provide economic benefits, facilitate public policy objectives, and address other issues identified by stakeholders. Transmission owners are responsible for submitting their transmission construction plans to MISO for evaluation and possible inclusion in the MISO Transmission Expansion Plan (MTEP). Projects identified as the best solutions are recommended for approval to the MISO Board of Directors. Once approved by the Board, such projects are included in the MTEP, and transmission owners are required to make good faith efforts to complete them.

NYISO[163]

NYISO's Comprehensive System Planning Process (CSPP) evaluates resource adequacy and transmission system security of the state's bulk electricity grid over a 10-year period and evaluates solutions to meet reliability and congestion relief needs. The CSPP contains three major components: local transmission planning, reliability planning, and economic planning. Each two-year planning cycle begins with the local transmission plans of the New York transmission owners, followed by NYISO's Reliability Needs Assessment and Comprehensive Reliability Plan. Finally, economic planning is conducted through the Congestion Analysis and Resource Integration Study.

Consistent with the NYISO's Transmission Owner Agreement and OATT, the NYISO does not "approve" or "require" facilities to be constructed for reliability purposes. Instead, the NYISO evaluates and monitors the reliability of the system, identifies reliability needs, and solicits market solutions. Transmission owners have assumed the obligation to provide backstop solutions in the event that market based solutions are insufficient to meet identified reliability needs in a timely manner. The New York Public Service Commission, and not NYISO, approves the resources that will be constructed to meet reliability needs.

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[162] ISO/RTO Council, *ISO/RTO 2010 Metrics Report*, p. 157, December 7, 2010

[163] ISO/RTO Council, *ISO/RTO 2010 Metrics Report*, pp. 212-215, December 7, 2010.

PJM[164]

PJM has a transmission planning process that looks fifteen years into the future and involves four types of analyses.

- *Baseline reliability analyses* test for violations of NERC reliability criteria regarding stability, thermal line loadings and voltage limits. They also test for load and generation deliverability.
- *Generation and transmission interconnection analyses* assess deliverability in the local area of each generation or interconnection request.
- *Market efficiency analyses* assess the economic impacts of proposed transmission enhancements, including the impacts of security constraints on production costs and congestion charges.
- *Operational performance analyses* identify steps that are necessary to assure that transmission system equipment is maintained in safe and reliable operating condition.

SPP[165]

SPP's Integrated Transmission Planning (ITP) process looks forward to the near term, the next ten years, and the next twenty years. It is an iterative three-year process that looks at the trade-off between transmission investment costs and transmission congestion costs. The ITP integrates the planning evaluations of the Extra High Voltage Overlay, the Balanced Portfolio, and the SPP Transmission Expansion Plan Reliability Assessment.

Non-RTO Areas

In SERC and FRCC, the bulk electric system is defined as consisting of the transmission lines and interconnections with neighboring systems, and associated equipment, that are operated at voltages of 100 kV or higher, excluding radial transmission facilities that serve only load with one transmission source. SERC utilities also generally include in the bulk power system electric generation resources directly connected on the high side of the step-up transformer to transmission facilities operated at voltages of 100 kV or higher.

Because transmission planning in SERC and FRCC aims to serve long-term firm commitments without constraint or congestion, the transmission planning processes in SERC and FRCC cover all firm transmission services, including transmission service for native load customers, network service for customers within the provider's service area, firm point-to-point service, and generator interconnection service. Transmission planning entities conduct their planning in accordance with NERC and Regional Entity reliability criteria and in accordance with the transmission planning entities' respective transmission planning criteria. These planning processes utilize a long-term transmission planning horizon of ten (10) years.

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[164] PJM Interconnection, *PJM Region Transmission Planning Process*, December 22, 2011, p. 11 ff.

[165] Southwest Power Pool, *Integrated Transmission Planning Manual*, July 13, 2011.

In the non-RTO areas, seams issues are dealt with through bilateral agreements. An example is the planning agreement between the North Carolina Transmission Planning Collaborative and PJM that was implemented in 2009 to enhance planning activities between them.

4.3. Planning Forums

In addition to the resource planning conducted within utilities and the IRP processes described in Section 3.5.2, utilities have joined together in a variety of planning forums.

RTOs

FERC Order Nos. 890 and 1000 require RTOs to conduct long-term planning in an open, transparent manner. Each RTO has adopted a planning process in compliance with Order No. 890, and is presently working on complying with Order No. 1000. While the processes developed by the RTOs vary according to each RTO's organizational and committee structure, they are similar in that stakeholders, including transmission owners and state commissions, are usually able to participate in the development of regional plans from the outset.

In ISO-NE, the Planning Advisory Committee (PAC) provides a forum for study proposals, scopes of work, assumptions, and presentation of study results. ISO-NE's website includes PAC presentations, meeting minutes, reports, and databases.

In MISO, transmission owners develop and propose plans for potential inclusion in the MTEP. The annual regional planning process, coordinated by the Planning Advisory Committee and the Planning Subcommittee, allows stakeholder to evaluate and discuss these plans, which are then considered by the Technical Review Group. This latter group, which is composed of MISO participants, provides feedback to transmission owners about their plans. Transmission projects are then examined by MISO staff in collaboration with the relevant transmission owners. The staff provides its assessments and recommendations to the Planning Advisory Committee and Planning Subcommittee.[166]

In NYISO, the Electric System Planning Working Group and the Transmission Planning Advisory Subcommittee are the principal forums for stakeholder input to the Comprehensive System Planning Process. These two committees provide input data, review and provide comments on interim analyses and planning reports, and make recommendations to the Business Issues Committee, the Operating Committee, and the Management Committee. Plans are also reviewed by the NYISO Independent Market Advisor before they are ultimately reviewed and approved by the NYISO Board.[167]

In PJM, the planning process centers on the annual Regional Transmission Expansion Plan (RTEP). The Transmission Expansion Advisory Committee, the Subregional RTEP Committee, and the PJM Planning Committee provide forums for stakeholder input through oral and written

[166] Midwest Independent Transmission System Operator, *MTEP Stakeholder Review Process*, presentation to Planning Advisory Committee, April 2, 2008.

[167] New York Independent System Operator, *NYISO Economic Planning Process*, NYISO Economic Planning Process Course, Rensselaer, New York, October 2010.

exchange of information. The planning process, which has an annual cycle, culminates in the PJM staff's presentation of the RTEP for approval by the PJM Board of Managers.[168]

In SPP, the Economic Studies Working Group (ESWG) provides the forum for initial development of the transmission expansion plan. The ESWG, which is composed of market participants, is responsible for the ten-year and twenty-year assessments. The Transmission Working Group (TWG) is responsible for the near-term assessment. The recommendations by ESWG and TWG are reviewed by the Market Operations and Policy Committee and ultimately approved by the Board of Directors.[169]

Some RTOs entered into joint planning agreements with their RTO and non-RTO neighbors well before Order No. 1000 was issued. For example, ISO-NE, NYISO, and PJM entered into the Northeast ISO/RTO Coordination of Planning Protocol in 2004 and have engaged in coordinated planning activities since that time in consultation with an inter-regional stakeholder advisory group that is open to all interested parties from the three regions.

Non-RTO Areas

In addition to the individual utility IRPs, there are multiple forums for stakeholders to have input into transmission planning processes in the non-RTO areas. State commissions also exercise their regulation of transmission planning through the RFP and state certification and siting proceedings. With respect to the individual transmission plans developed pursuant to Attachment K of the transmission provider's OATTs, the process is open to general stakeholder participation and transparent under the rules of FERC Order No. 890. The forums differ within the non-RTO areas and between reliability and economic planning, but a few examples are provided here for both processes.

In the non-RTO regions, utilities have joined several transmission planning groups or processes. Each of these groups develops transmission plans or evaluates potential transmission upgrades that are used for both reliability and economic planning. These groups include the following:

- The Southeast Interregional Participation Process (SIRPP) provides a means by which several transmission planning entities in SERC[170] coordinate their performance of stakeholder-requested economic/scenario transmission studies that are inter-regional in nature. Furthermore, the SIRPP sponsors reviews of regional data assumptions and reliability assessments that are being performed in the SERC region-wide reliability studies. Importantly, only economic/scenario transmission planning occurs in the SIRPP.
- The Entergy-SPP Regional Planning Process is structured similarly to the SIRPP. Through this process, the Entergy Operating Companies work with neighboring transmission owners and with SPP, their Independent Coordinator of Transmission (ICT), to evaluate potential transmission upgrades and opportunities for regional optimization of

[168] PJM Interconnection, *PJM Region Transmission Planning Process*, December 22, 2011, p. 7

[169] Southwest Power Pool, *Integrated Transmission Planning Manual*, July 13, 2011.

[170] The SIRPP is sponsored by, Dalton Utilities, Duke Energy Carolinas, Entergy Companies, Georgia Transmission Corporation, Kentucky Utilities/Louisville Gas & Electric, MEAG, PowerSouth Energy Cooperative, Progress Energy Carolinas, Santee Cooper, South Carolina Electric & Gas, South Mississippi Electric Power Association, Southern Companies, and the Tennessee Valley Authority.

each transmission owner's transmission construction plans. The parties assess the simultaneous feasibility of system plans and the consistency of assumptions and data. In addition, the parties perform a regional study in which they perform analyses, develop solution options, evaluate stakeholder-suggested solution options, and develop reports.

- The Southeastern Regional Transmission Planning Process (SERTP) is the Attachment K transmission planning region for the transmission planning entities in the Southeastern sub-region of SERC.[171] The SERTP provides for four meetings a year concerning the development of the SERTP sponsors' annual transmission expansion plan. The SERTP is an open, transparent, and coordinated planning process that is open to all stakeholders, which is defined as all interested parties. Through the SERTP processes, stakeholders are: provided a forum for the discussion of the data gathering and transmission model assumptions that are used for the development of each year's transmission expansion plan; apprised of the underlying criteria and methodologies that the transmission planning entities used; and provided with the transmission planning entities' preliminary transmission expansion plans, regarding which they can provide comments and recommend alternative transmission projects and non-transmission alternatives. Any such alternatives will be evaluated, from a transmission planning perspective, based upon factors such as the proposed alternative's impacts on reliability, relative economics, effectiveness of performance, impact on transmission service (and/or cost of transmission service) to other customers and on third-party systems, project feasibility/viability and lead time to install. The SERTP has a Regional Planning Steering Group that allows stakeholders to select five economic/scenario planning studies for detailed study each year under the terms of Southern Companies' Attachment K.
- The North Carolina Transmission Planning Collaborative (NCTPC), which is in VACAR, provides advice and recommendations to the NCTPC participants to aid in the development of an annual collaborative transmission plan.[172] NCTPC works through a four-part structure that includes an Oversight-Steering Committee, a Planning Working Group, a Transmission Advisory Group (TAG), and an Independent Third Party that facilitates the Collaborative and chairs TAG meetings. Essentially all stakeholders are provided an opportunity to serve on the TAG.
- The South Carolina Regional Transmission Planning process (SCRTP), which is also in VACAR, discusses present and planned studies.[173] Through the SCRTP, South Carolina Electric & Gas and Santee Cooper host quarterly meetings with stakeholders that are regularly attended, either in person or electronically, by FERC staff and the South Carolina Office of Regulatory Staff.
- TVA is its own transmission planning region. While TVA is partly non-jurisdictional, it voluntarily posted its equivalent to Attachment K in response to Order No. 890. Its

[171] SERTP includes Dalton Utilities; Georgia Transmission Corporation; MEAG Power; PowerSouth Energy Cooperative; South Mississippi Power Association, and the retail operating subsidiaries of The Southern Company (Alabama Power Company, Georgia Power Company, Gulf Power Company, and Mississippi Power Company).

[172] NCTPC was formed by Duke Energy Carolinas, Progress Energy Carolinas, ElectriCities, and the North Carolina Electric Membership Corporation.

[173] SCRTP was formed by South Carolina, South Carolina Electric & Gas (SCE&G) and Santee Cooper.

Central Public Power Partners process provides three meetings a year that are open to stakeholders and offers stakeholder-proposed intraregional project assessments at no charge. Interregional projects are evaluated through SIRPP and other relationships.

- Entergy and Kentucky Utilities/Louisville Gas & Electric plan through SPP, which serves as their mutual ICT.

In Florida, the transmission providers and owners develop transmission plans through the FRCC. In compliance with Order No. 890, stakeholder involvement is incorporated into FRCC's annual planning processes with specified dates for stakeholder input to, and review of, the development of transmission plans at every level. Throughout this process, stakeholders have the opportunity to propose alternative transmission and non-transmission solutions.

Both SERC and FRCC utilize a transmission planning committee structure that effectuates the roll-up of the transmission plans of individual planning entities in their respective footprints into a unified set of transmission base cases. Utilizing these rolled-up base cases, transmission planners perform a future year transfer capability analysis to further assist the individual planning authorities in identifying any potential "optimization" that can be further addressed through existing bilateral arrangements. Stakeholder participation in the committee structure of both SERC and FRCC is encouraged.

The Eastern Interconnection Planning Cooperative (EIPC) initiative provides another forum for stakeholders with respect to transmission planning and opportunities for stakeholder-driven scenario analyses on an interconnection-wide basis.

Some of these forums are fairly new, having been established as a direct result of FERC Order No. 890, while others have been in place for years, particularly those related to ensuring compliance with reliability standards within the region. Additional forums may be created or modifications to existing forums may be made as RTOs and utilities in non-RTO areas develop plans to comply with Order No. 1000.

An important distinction between RTO and bilateral markets is that, while economic planning in an RTO might lead directly to the construction of transmission upgrades, economic planning in bilateral markets largely refers to stakeholder-requested, speculative planning that analyzes the transmission system based upon hypothetical scenarios developed by those stakeholders. In that manner, stakeholders are provided significant amounts of information pertaining to potential economic opportunities. Such economic planning generally does not directly lead to transmission expansion unless an entity commits to fund the upgrades identified in such an economic plan or commits to long-term firm transmission service in an OATT so as to expand the system in a manner comparable to that identified in the economic plan.

NERC

The North American Electric Reliability Corporation (NERC), as the bulk power system reliability standards setting organization, also represents a kind of planning forum. NERC conducts periodic, independent assessments of the reliability and adequacy of the bulk power system. NERC prepares three reliability assessments each year: a long-term (10-year) reliability assessment; a winter assessment; and a summer assessment. NERC develops these assessments based on data and information it receives from eight regional reliability organizations that, in turn, receive data and information from individual utilities or from RTOs. NERC analyzes the data and information to estimate current and future electricity demand, and to assess the adequacy of the bulk power system to meet that demand. Power generation, transmission, fuel delivery, fuel supply, demand-side resources, and environmental regulations factor into the assessments.

4.4. Planning Participants

FERC's Order Nos. 890 and 890-A specified that transmission providers must satisfy nine principles, including opening planning meetings to all affected parties and making transparent the planning methods, criteria, and processes.[174] This section looks at the types of parties who participate in planning.

RTOs

All the Eastern Interconnection RTOs made compliance filings at FERC following issuance of Order No. 890. These filings ensured that their regional system planning processes were open to all stakeholders, including state regulatory commissions. The types of participants in the RTO planning processes are basically identical for all RTOs: transmission-owning utilities, who may prepare initial plans for transmission enhancements; transmission-dependent utilities; wholesale and retail customers; generators, including independent power producers; power marketers; demand response providers; state regulatory commissions; and RTO personnel responsible for transmission plan development and analysis. Some RTOs' governance processes also include participation by consumer representatives and environmental organizations. Market participants typically provide input to the RTOs' system reliability assessments and economic efficiency analyses through working groups or subcommittees of the RTOs' planning committees.

Non-RTO Areas

The participants in individual IRP, RFP, and certification proceedings adjudicated at state commissions in non-RTO areas tend to be those parties directly affected by the rate changes caused by such proceedings,. Thus, the participants primarily include retail customers, retail customer groups, environmental groups, and state consumer representatives. Wholesale customers may participate as well. For the regional and sub-regional transmission planning processes, stakeholders include transmission providers and owners, wholesale customers, federal utilities (such as TVA), rural electric cooperatives, municipal electric system groups or power authorities, and large retail customers. State regulatory and FERC staff often participate as observers.

Intervenors may participate in formal state regulatory IRP, RFP, and certification proceedings. Generally, because such proceedings primarily deal with how utilities are going to meet their native load resource needs under state law and because the plans are subject to adjudicatory proceedings at state regulatory commissions, stakeholders (who may become intervenors) are not directly involved in the development of the IRP, except perhaps in settlement proceedings once the plan has been filed.

[174] Federal Energy Regulatory Commission [2007, ¶181 *et seq*].

As with the RTO regions, Order No. 890 requires that the regional transmission planning processes adopted by the transmission providers in non-RTOs be open to all stakeholders. Since the transmission providers in non-RTOs remain largely vertically integrated, the sponsors of the regional transmission planning processes generally consist of not only the transmission providers in that region but also many (if not most) of the LSEs. Stakeholders in the regional planning process may include transmission-dependent utilities, merchant generation and transmission developers, public service commissions, energy consultants, and non-governmental organizations. Given the bottom-up nature of transmission planning in the non-RTOs, input from state commissions and native load customers is largely effectuated through the state-regulated IRP, RFP, and/or certification proceedings. Wholesale transmission customers typically provide their input through the OATT service request and designated network resources processes. The results of both those state-regulated and OATT process are combined and form the underlying basis for the regional transmission plans.

4.5. Planning Studies

Transmission planning study requirements have been specified by a series of FERC Orders (such as Nos. 890 and 890-A). Most recently, FERC Order No. 1000, issued on July 21, 2011, extends these requirements, particularly by mandating regional and inter-regional coordination of transmission planning. Because Order No. 1000 is currently subject to rehearing and compliance filings are not due at the earliest until October 2012, it is difficult to assess at this point how current planning processes may be affected.

RTOs

RTOs' transmission planning processes distinguish between "reliability upgrades" that assure reliable power system operation and "economic upgrades" that reduce power system costs (such as transmission congestion costs). Some of these processes also consider projects that would advance public policy (such as encouraging renewable energy). Reliability upgrades are treated as necessities, while economic upgrades are treated as desirable but not mandatory. In addition to promoting reliability and economic efficiency, Order No. 1000 will require all planning processes to consider transmission needs driven by public policies (such providing market access for renewable resources).

RTOs' transmission planning processes usually look at multiple time periods, including a short-term period (of only a few years) that focuses on the upgrades that are needed immediately and a long-term period (of perhaps ten or twenty years). Because of transmission constraints within each RTO's footprint, the planning processes look at transmission needs for both the whole footprint and sub-regions within the footprint. Efforts are made to meet transmission needs through market-based solutions (like merchant transmission lines or merchant generation in import-constrained areas), though regulated solutions (like rate-based transmission lines) are generally available when needed. Both needs and solutions are vetted through stakeholder processes.

ISO-NE Regional System Plans are based upon five- and ten-year forecasts of annual and peak electricity loads; forecast amounts, locations, and characteristics of generation and demand resources; forecast locations and characteristics of merchant transmission facilities; and plans of neighboring transmission systems. The transmission planning process develops a study scope, identifies key data inputs, develops a needs assessment, and evaluates potential transmission system solutions for cost-effectiveness.

MISO's planning process develops its transmission expansion plan (MTEP) based upon individual transmission owners' plans, stakeholder input, and its own analysis of reliability and efficiency needs. MTEP looks ten and twenty years into the future. The planning process uses power flow network analyses to evaluate the system reliability impacts of transmission service requirements, including long-term firm transmission service requests (i.e., with reservation periods of one year or longer).[175] The process distinguishes between five kinds of transmission upgrades, and allocates the costs of these upgrades among market participants according to the perceived beneficiaries of these upgrades.[176]

NYISO's Comprehensive System Planning Process assesses reliability needs five and ten years into the future, considering resource adequacy, transmission security, and transmission congestion. It begins with transmission owners' local plans and a Reliability Needs Assessment that identifies potential reliability needs. NYISO solicits market-based solutions that rely only upon the NYISO's energy, capacity, and ancillary services markets for cost recovery. Transmission owners are responsible for proposing regulated generation, transmission, or demand-side backstop solutions to the identified reliability needs so that they will be available if market-based solutions cannot meet the need in a timely manner. Parties may also offer alternative regulated solutions. Although NYISO evaluates whether the solutions meet the reliability needs, it does not evaluate the economics of those solutions nor does it select the projects that will go forward — that is determined by the New York Department of Public Service. NYISO's economic planning process begins with a prioritization of the most significant congested facilities on the New York bulk power system, followed by an analysis of generic potential solutions (including transmission, generation, and demand response). Developers may submit a proposed economic transmission project to the NYISO for analysis to determine its eligibility for cost recovery under the NYISO Tariff.

PJM's transmission system planning considers both near-term (five-year) and long-term (fifteen-year) needs. The near-term plan addresses needs to meet scheduled in-service dates. The long-term plan addresses new transmission construction and right-of-way acquisition, identifies the transmission system enhancements required to maintain the ten-year feasibility of long-term transmission rights (i.e., long-term ARRs), and recommends for incorporation into the PJM RTEP any transmission upgrades (or accelerations of previously planned upgrades) needed to

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[175] Midwest Independent Transmission System Operator, *Transmission Planning Business Practices Manual*, BPM-020-r3, November 20, 2010.

[176] *Multi-value projects* are built in response to public policy mandates (e.g., for renewable energy), and their costs are allocated 100% to customers throughout the whole MISO footprint. *Reliability upgrades* of 345 kV and above have their costs allocated 20% to customers throughout the whole MISO footprint, with costs otherwise being allocated to the transmission pricing zone in which the upgrades are located. *Market efficiency projects*, which must include some facilities at 345 kV or higher, have their costs allocated 20% to customers throughout the whole MISO footprint, with the remaining costs being allocated to the transmission pricing zone in which the upgrades are located. *Generation interconnection upgrades* of 345 kV and above have their costs allocated 10% to customers throughout the whole MISO footprint, with costs otherwise being allocated to the generation customers for whom the upgrades are built. *Transmission service request upgrades* have their costs assigned entirely to the customers requesting such service.

resolve any reliability violation.[177] The long-term plan also identifies potential overloads induced by load growth in transmission facilities at voltages of 230 kV and higher, and therefore proposes upgrades and right-of-way acquisitions needed at 230 kV and higher.

SPP's transmission planning process looks at near-term and long-term (ten-year and twenty-year) needs. The process begins with planning studies performed by transmission owners in cooperation with SPP Transmission Expansion Plan and other SPP-coordinated studies. These studies identify planning criteria violations that may exist and develop plans to mitigate them. Transmission owners notify the SPP Transmission Working Group about facilities in the conceptual planning stage so that they can be integrated optimally in the long-term plans and so that the parties that may benefit from them can be identified. Planned facilities affecting more than one system owner or user are conducted on a joint system basis. Reliability studies examine post-contingency steady-state, stability, overload, cascading, and voltage collapse conditions. Updates to the studies will be performed when significant changes in system conditions are anticipated.

Non-RTO Regions

The foundations of planning in the non-RTO regions are the resource and load requirements that result from the IRP and RFP processes and the long-term firm transmission service commitments made under the OATT. The transmission needs that result from the approved IRP, RFP, and OATT processes become inputs to the transmission planning process in the non-RTO areas, and are combined with the long-term firm commitments made under the utility's OATT. Each transmission planning entity (usually one or more transmission providers and/or transmission owners) develops a transmission plan based on the combined needs and commitments.[178] Such plans are created according to procedures in the Attachment K to each OATT that FERC jurisdictional utilities have filed pursuant to Order No. 890. The resulting transmission plan then becomes the base case plan for further coordination and study in an iterative manner. The exact process by which these utility plans are reviewed and modified in the non-RTO areas depends both on the type of transmission facility (whether it is proposed for reliability or economic purposes) and on the Attachment K planning process that the utility has filed.

The SERC and FRCC transmission planning committees then conduct SERC- and FRCC-wide reliability transmission assessments. These assessments, which are based upon shared transmission system plans that include information on the assumptions and data inputs used in the development of those plans, determine whether the plans are simultaneously feasible. SERC and FRCC create transmission models for their respective boundaries and conduct long-term reliability assessments as a part of this process. When a region-wide assessment identifies projected planning criteria concerns that were not addressed in the individual plans, those issues are resolved through changes to the individual planning entities' transmission plans in an iterative fashion so that each planning entity has a plan that is consistent with maintenance of

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[177] PJM Interconnection, *Financial Transmission Rights*, Manual 06, July 1, 2009 and *PJM Regional Planning Process*, Manual 14B, September 15, 2011.

[178] There are two exceptions to transmission providers and owners developing their own plans in the non-RTO areas of the Eastern Interconnection: Entergy and Kentucky Utilities/Louisville Gas & Electric (jointly) have an Independent Coordinator of Transmission (ICT) that conducts transmission planning on their behalf, but the processes are generally the same. Currently, SPP is the ICT for both of these utilities.

region-wide reliability. Stakeholders are provided open and transparent access to these iterative changes though the affected Attachment K regional planning processes.

With respect to addressing stakeholder-requested economic studies associated with new transmission or modifications to the existing system, the process is somewhat different than the process for reliability-driven upgrades. The same base transmission plans and studies used for reliability planning are again used for economic studies; but because there would be a very large number of possible combinations of transmission projects (and alternatives to transmission) to study in the planning process, only a limited number of economic studies are conducted on a regular basis through Attachment K regional and inter-regional planning processes. The transmission providers in SERC and FRCC have developed processes for including such studies upon request from stakeholders in their planning, and have again detailed these processes in Attachment K of their individual OATTs. Within SERC, the SIRPP was developed to address the regional participation principle of Order No. 890 for examining projects that might cross multiple transmission systems (or sub-regions). FRCC has a similar process for examining economic projects crossing utility boundaries in Florida.

In the non-RTO regions, up to five studies examining the need for transmission upgrades to reduce system costs can be requested each year by stakeholders. These studies can be requested both at the sub-regional level and at the regional level through SIRPP or FRCC, as appropriate. The need for transmission to meet reliability requirements is studied as part of the IRP processes and the sub-regional, SERC, and FRCC reliability transmission planning processes.

Beyond the SERC and FRCC planning processes, there is also seams coordination that occurs between SERC and FRCC. Such coordination includes the sharing of planning assumptions and the coordination of transmission enhancements and stakeholder-requested economic planning studies. A key purpose of this coordination is to support the development of simultaneously feasible transmission plans both internal and external to the region-wide processes.

The relatively new EIPC transmission studies process provides a means for examining economic transmission opportunities at the Interconnection-wide level.

Planning occurs at the individual utility level, a sub-regional level, and a NERC Regional Entity level. Through a bottom-up process, individual utilities first analyze their resource and transmission needs, and then coordinate their plans with neighboring utilities and regional utilities to ensure that the local plan will maintain reliability in a larger area and to identify potential economies of combining plans.

Initially, incremental transmission needs to reliably serve native load customers (retail and full or partial requirements wholesale customers) and to serve firm transmission service requests are identified in the transmission planning process of individual utilities and then rolled-up into the sub-regional transmission plans developed within SERC or the regional plan developed by FRCC.

Individual utility transmission planning processes take into account requests for long-term firm and network transmission service from third parties. Under individual utility's OATTs, which all FERC jurisdictional utilities are required to file, utilities are required to plan for third-party needs in a comparable fashion to the utilities' planning for its own transmission needs. Thus, known third-party uses of transmission are accounted for in those plans.

4.6. Process for Adding Projects to the Transmission Plan

This section provides a few additional remarks concerning how transmission projects are added to transmission plans.

RTOs

The treatment of an additional transmission project generally depends upon whether it is classified as a reliability, market efficiency (i.e., economic), or public policy project.

For reliability projects, a baseline reliability analysis is conducted for a baseline planning case. Reliability upgrade needs are identified as necessary to address a defined set of contingency events that impact the power system's thermal and voltage characteristics and generation and load deliverability.

For market efficiency projects, an analysis is performed to identify the economic benefits of accelerating the implementation of reliability projects and to identify any potential new projects that may have net economic benefits. Such analyses generally consider the transmission constraints that most affect present and future congestion costs as well as the sufficiency of ARRs and FTRs as hedges against congestion. The analyses compare the costs of accelerated or new transmission upgrades with the costs of the congestion that they help avoid. The RTOs generally have minimum benefit/cost ratio thresholds that a transmission project must exceed to be included in the transmission plan.

For public policy transmission projects, RTOs have heretofore performed analyses similar to those performed for economic efficiency projects. In response to Order No. 1000, RTOs are presently in the midst of developing methods for appropriately analyzing the benefits and costs of such projects. These methods build on those already in place for measuring reliability and economic efficiency impacts; but some RTOs seek to broaden the definition of benefits and identify ways to reflect benefits that are difficult to measure, such as changes in expected outage costs and changes in environmental costs.[179]

Non-RTO Areas

In the non-RTO areas, projects are added to transmission plans of individual transmission-owning utilities either through needs identified in the IRP and RFP processes or through firm transmission service commitments under the utilities OATTs. In multi-utility situations, changes may be suggested to transmission plans to ensure that intra-regional reliability can be maintained. There are also instances wherein projects of multiple utilities can be combined for cost savings.

Projects that provide economic benefits to one or more stakeholders are identified through the economic planning studies performed by request at the planning entity level and region-wide by the FRCC or the SIRPP. In the non-RTO areas, these projects are only added to the transmission plan if the project requestors or beneficiaries have reached agreement to pay for the facilities

[179] For a discussion of measuring benefits and costs of transmission expansion, see M.J. Morey, *Transmission Investment Benefit-Cost Evaluation: Reasonableness Assessment of Transmission Investment Cost Allocation in SPP*, Christensen Associates Energy Consulting, September 16, 2011.

being added to the plan,[180] or if a transmission customer commits to long-term firm service under the OATT that would result in the addition of the identified transmission project to the transmission plan.

4.7. Alternatives to Transmission Investment

As a general rule, all types of resources – large central-station generation, renewable energy (local and remote), distributed generation, storage, demand response, and energy efficiency – are considered to be alternatives to transmission investment, in both RTO and non-RTO areas.

RTOs

The RTOs planning processes recognize the partial substitutability of transmission upgrades on the one hand and supply- and demand-side resources, on the other. Although supply- or demand-side alternatives with firm commitments can be considered in the regional transmission planning process, the RTOs generally lack authority to perform integrated resource planning; so these non-transmission alternatives cannot be proposed in the RTOs' regional transmission plans.

In principle, LMPs are supposed to signal the value of investments in supply- and demand-side resources, inducing investments in such resources in locations where LMPs are high and for which transmission upgrades might be necessary in the absence of such investments. In practice, the RTOs have some non-market programs and procedures that are specifically designed to encourage supply- and demand-side investments in import-constrained locations and to discourage retirement of supply- and demand-side resources in such locations.

Non-RTO Areas

The transmission planning processes used in the non-RTO areas inherently consider alternatives to transmission investment. This occurs because a primary input to the transmission plan is the IRP, which has the goal of identifying the least-cost combination of generation, transmission, and demand-side resources that meets reliability standards. If a particular proposed generation resource will obviate the need for new transmission to maintain reliability, for example, then it can be studied and incorporated into the IRP, which then feeds the transmission planning process.

Even after the transmission components of the IRP become part of an overall transmission plan, there are additional opportunities to consider alternatives. For example, if the initial transmission plan indicates the need for a transmission upgrade to address congestion, it is foreseeable that a stakeholder in the planning process could propose a generating facility or demand-side program that could redirect flows to relieve the congestion. If the planning process studies find such an alternative to be viable, then the alternative can be included in a subsequent plan or a revision to the existing plan, as appropriate. Any such changes would be subject to review and approval by the state commission overseeing the transmission plan.

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[180] Under Order No. 1000, transmitting utilities will be required to include economic transmission facilities in their plans, with costs to be allocated according to rules contained in compliance filings in October 2012.

4.8. Transmission Investors

In all regions, transmission investment is primarily made by incumbent vertically integrated utilities. Some transmission has been built by cooperative G&T or municipal joint action agencies. There are a few transmission-only firms, such as American Transmission Company and International Transmission Company, that are in the business of building significant transmission infrastructure in the Eastern Interconnection; and there are some firms that have built (or have proposed to build) transmission in certain opportunistic situations (such as between the New York City or Long Island load pockets and the nearby markets of other RTOs).

Order No. 1000 may provide additional opportunities for merchant transmission; but the parties who build transmission will still by and large be governed by individual state laws that vary significantly in the non-RTO areas.

4.9. Authority to Mandate Transmission Investment

To the extent that authority is granted to the RTO by their transmission owner members, the RTO can mandate investment in transmission facilities that are needed to assure reliability. On the other hand, RTOs tend to have only limited authority to mandate investment in transmission facilities that relieve congestion and thereby improve market efficiency. In some RTOs (e.g., MISO), transmission owners must make good faith efforts to build projects approved in the regional plan, including economic projects.

State regulatory commissions have authority to mandate transmission investment, although the extent of that authority varies from state to state. Usually the state commission can enforce territorial or franchise laws, which require utilities to reliably serve all existing and future customers within defined service boundaries, and which may require the construction of transmission in certain instances.

FERC jurisdictional transmitting utilities have an obligation to make "best efforts" to build new transmission to satisfy requests for firm transmission service under their FERC-filed OATTs. While the extent of this obligation and what constitutes "best efforts" has not yet been tested, this Order No. 888 requirement falls short of an absolute mandate.

Individual transmission utilities may have obligations to build transmission for others under bilateral or multilateral contracts.

4.10. Transmission Cost Allocation Policies and Pricing Mechanisms

With regard to transmission service regulated by FERC, the basic rules for transmission cost allocation are set by several FERC orders, including Order Nos. 888, 890, and 890-A. Among other things, these orders specify that transmission providers must offer transmission service on a non-discriminatory basis, giving similar treatment to similarly situated customers. The general rule is that the costs of Network Integration Transmission Service are allocated among network customers in proportion to their relative loads, while the costs of Point-to-Point Service are allocated among point-to-point customers based upon their MW reservations. Order No. 1000 also contains new requirements for regional and interregional cost allocation.

4.10.1. Pricing Mechanisms

There are four fundamental mechanisms for pricing transmission service to collect the costs of the transmission investment that have been applied in the RTO and non-RTO regions: postage stamp pricing, license plate pricing, direct assignment, and voluntary participant funding.

Postage stamp pricing: Every transmission customer pays a single rate for any transmission transaction within a defined region, regardless of the contractual origin and destination of the electricity transmitted. That rate is the same rate for every customer. The rate is an "average rate" because the total costs of the region's transmission network are divided by the total units transmitted, resulting in an average cost per unit. A postage stamp rate means that every customer pays the same average rate regardless of how the cost caused or benefit derived by that customer from a given transaction varies from the average. Postage stamp pricing is also known as a "rolled in" pricing because all transmission facility costs of the network are "rolled in" to the total cost before dividing that total cost by the units transmitted.

License plate pricing: As under postage stamp pricing, every transmission customer pays a single rate for any transmission transaction within a defined region, regardless of the contractual origin and destination of the electricity transmitted. Unlike the postage stamp rate, however, the license plate rate is not the same for every customer in the region. Instead, each customer's rate is a rate reflecting the cost of transmission facilities within that customer's utility service territory. A customer residing in a high-transmission-cost territory will pay a higher rate than a customer in a low-cost territory. But having paid that single rate, the customer is entitled to have power transmitted between any two locations in the region. License plate rates are also referred to as "zonal rates." This type of rate is most commonly utilized for the recovery of the costs of existing transmission facilities in both RTO and non-RTO regions.

Direct assignment: Direct assignment allocates transmission investment costs to the party or parties who are clearly identifiable as causing the costs to be incurred. Under FERC Order No. 888 and subsequent case rulings, direct assignment is particularly used for allocation of certain interconnection costs between a generator and the bulk power grid.[181] While direct assignment rules are in a state of flux, some RTOs use it for economic projects that benefit only certain customers or zones within the RTO. Utilities in non-RTO areas also use a form of direct assignment under the Commission's "higher of embedded or incremental" pricing policy of FERC Order No. 888.

Voluntary participant funding: Voluntary participant funding gives potential developers of transmission facilities the ability to own the financial or physical rights associated with the development of a particular facility or set of facilities and then to auction those rights in an open season or negotiate a price for the use of the facilities outside of the regulatory process. Voluntary participant funding may also be used for projects that don't have broad benefits but are economic to a particular user or set of users. Under Order No. 1000, participant funding cannot be the sole form of cost allocation for a region.

There are fundamental jurisdictional differences with regard to transmission cost allocation issues between RTOs and non-RTOs. In RTOs, FERC essentially regulates the provision of transmission service to all wholesale and retail loads in an RTO's footprint because all such

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[181] See the discussion pertaining to Table 19 below.

loads take transmission service from the RTO under the RTO's region-wide OATT, which provides the means for region-wide cost allocation. In non-RTOs, by contrast, FERC does not regulate bundled retail transmission service; instead, it remains subject to state jurisdiction. Moreover, in non-RTOs, there generally are no such region-wide OATTs that would provide the means for region-wide cost allocation. Instead, in non-RTO planning regions, there are often regulated and non-regulated transmission providers, with the regulated utilities providing service under their FERC-regulated OATTs for wholesale service and the unregulated transmission providers rendering service under their separate mechanisms.

4.10.2. Order No. 1000

Order No. 1000 requires every FERC-jurisdictional transmission-owning utility to change the ways that their OATTs handle transmission expansion and transmission cost allocation in response to the transmission projects proposed by transmission developers.

First, each such utility must revise its OATT to demonstrate that the regional transmission planning process in which it participates has appropriate qualification criteria for determining entities' eligibility to propose transmission projects for inclusion in the regional transmission plan for purposes of cost allocation. Such entities must include incumbent transmission providers as well as non-incumbent transmission developers. The criteria must allow each potential transmission developer the opportunity to demonstrate that it has the necessary financial resources and technical expertise to develop, construct, own, operate and maintain transmission facilities.[182]

Second, each such utility must identify in its OATT the information that transmission developers must submit to support their transmission project proposal, including the date(s) by which such information must be submitted to be considered in a given transmission planning cycle. This information requirement must be identical to the information in all providers' OATTs in the same transmission planning region.[183]

Third, each such utility must have a transparent and non-discriminatory process for evaluating and selecting proposed transmission facilities for inclusion in the regional transmission plan for purposes of cost allocation. The process must be transparent so that stakeholders can understand the choice of transmission projects.[184] The transmission-owning utilities must also amend their OATTs to describe the circumstances and procedures under which they will reevaluate the regional transmission plan to determine if delays in the development of a selected transmission facility require evaluation of alternative solutions.[185]

Fourth, all transmission developers, regardless of their incumbency, must have the same eligibility to use the allowable regional cost allocation methods for any selected transmission

[182] Order No. 1000, P 323.

[183] *Id.*, P 325.

[184] *Id*., P 328.

[185] *Id.*, P 329.

facility. The costs of transmission facilities that are not selected may *not* be recovered through the transmission planning region's cost allocation methods.[186]

Regional Transmission Cost Allocation

Each transmission provider must have a method (or methods) for allocating the costs of new transmission facilities selected in the regional transmission plan. If the transmission provider is an RTO, then the cost allocation method must be set forth in the RTO's OATT. In non-RTO transmission planning regions, each public utility transmission provider must set forth in its OATT the same language regarding the cost allocation method used in its transmission planning region.[187]

Interregional Transmission Cost Allocation

Each transmission provider in a transmission planning region must reach agreement with its neighboring transmission planning regions on a common method (or methods) for allocating the costs of new interregional transmission facilities. The method must allocate costs of a transmission facility among the beneficiaries of that facility. The cost allocation method between regions may differ from the cost allocation method within regions.[188] Instead of providing specific methods, Order No. 1000 establishes six principles for designing regional and interregional cost allocation methods to be adopted by RTOs and utility transmission providers. These principles are as follows:

- *Regional Cost Allocation Principle 1*: "The cost of transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits. In determining beneficiaries of transmission facilities, a regional transmission planning process may consider benefits including, but not limited to, the extent to which transmission facilities, individually or in the aggregate, provide for maintaining reliability and sharing reserves, production cost savings and congestion relief, and/or meeting Public Policy Requirements."[189]
- *Interregional Cost Allocation Principle 1*: "The costs of a new interregional transmission facility must be allocated to each transmission planning region in which that transmission facility is located in a manner that is at least roughly commensurate with the estimated benefits of that transmission facility in each of the transmission planning regions. In determining the beneficiaries of interregional transmission facilities, transmission planning regions may consider benefits including, but not limited to, those associated with maintaining reliability and sharing reserves, production cost savings and congestion relief, and meeting Public Policy Requirements."[190]

[186] *Id.*, P 332.

[187] *Id.*, P 558.

[188] *Id.*, P 578.

[189] *Id.*, P 622.

[190] *Id.*, P 622.

- *Regional Cost Allocation Principle 2*: "Those that receive no benefit from transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of those transmission facilities."[191]

- *Interregional Cost Allocation Principle 2*: "A transmission planning region that receives no benefit from an interregional transmission facility that is located in that region, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of that transmission facility."[192]

- *Regional Cost Allocation Principle 3*: "If a benefit to cost threshold is used to determine which transmission facilities have sufficient net benefits to be selected in a regional transmission plan for the purpose of cost allocation, it must not be so high that transmission facilities with significant positive net benefits are excluded from cost allocation. A public utility transmission provider in a transmission planning region may choose to use such a threshold to account for uncertainty in the calculation of benefits and costs. If adopted, such a threshold may not include a ratio of benefits to costs that exceeds 1.25 unless the transmission planning region or public utility transmission provider justifies and the Commission approves a higher ratio."[193]

- *Interregional Cost Allocation Principle 3*: "If a benefit-cost threshold ratio is used to determine whether an interregional transmission facility has sufficient net benefits to qualify for interregional cost allocation, this ratio must not be so large as to exclude a transmission facility with significant positive net benefits from cost allocation. The public utility transmission providers located in the neighboring transmission planning regions may choose to use such a threshold to account for uncertainty in the calculation of benefits and costs. If adopted, such a threshold may not include a ratio of benefits to costs that exceeds 1.25 unless the pair of regions justifies and the Commission approves a higher ratio."[194]

- *Regional Cost Allocation Principle 4*: "The allocation method for the cost of a transmission facility selected in a regional transmission plan must allocate costs solely within that transmission planning region unless another entity outside the region or another transmission planning region voluntarily agrees to assume a portion of those costs. However, the transmission planning process in the original region must identify consequences for other transmission planning regions, such as upgrades that may be required in another region and, if the original region agrees to bear costs associated with such upgrades, then the original region's cost allocation method or methods must include provisions for allocating the costs of the upgrades among the beneficiaries in the original region."[195]

- *Interregional Cost Allocation Principle 4*: "Costs allocated for an interregional

[191] *Id.*, P 637.

[192] *Id.*, P 637.

[193] *Id.*, P 646.

[194] *Id.*, P 646.

[195] *Id.*, P 657.

transmission facility must be assigned only to transmission planning regions in which the transmission facility is located. Costs cannot be assigned involuntarily under this rule to a transmission planning region in which that transmission facility is not located. However, interregional coordination must identify consequences for other transmission planning regions, such as upgrades that may be required in a third transmission planning region and, if the transmission providers in the regions in which the transmission facility is located agree to bear costs associated with such upgrades, then the interregional cost allocation method must include provisions for allocating the costs of such upgrades among the beneficiaries in the transmission planning regions in which the transmission facility is located."[196]

- *Regional Cost Allocation Principle 5*: "The cost allocation method and data requirements for determining benefits and identifying beneficiaries for a transmission facility must be transparent with adequate documentation to allow a stakeholder to determine how they were applied to a proposed transmission facility."[197]
- *Interregional Cost Allocation Principle 5*: "The cost allocation method and data requirements for determining benefits and identifying beneficiaries for an interregional transmission facility must be transparent with adequate documentation to allow a stakeholder to determine how they were applied to a proposed interregional transmission facility."[198]
- *Regional Cost Allocation Principle 6*: "A transmission planning region may choose to use a different cost allocation method for different types of transmission facilities in the regional transmission plan, such as transmission facilities needed for reliability, congestion relief, or to achieve public policy requirements. Each cost allocation method must be set out clearly and explained in detail in the compliance filing for this rule."[199]
- *Interregional Cost Allocation Principle 6*: "The public utility transmission providers located in neighboring transmission planning regions may choose to use a different cost allocation method for different types of interregional transmission facilities, such as transmission facilities needed for reliability, congestion relief, or to achieve public policy requirements. Each cost allocation method must be set out clearly and explained in detail in the compliance filing for this rule."[200]

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[196] *Id*., P 657.

[197] *Id*., P 668.

[198] *Id*., P 668.

[199] *Id*., P 685.

[200] *Id*., P 685.

4.10.3. RTOs[201]

The RTOs classify transmission upgrades into the three broad categories of reliability upgrades (needed to assure power system reliability), economic upgrades (needed to reduce congestion costs), and generation interconnection and transmission service upgrades (needed to connect generators to the transmission network). The RTOs differ, however, in their criteria for determining the category into which a particular upgrade falls, their upgrade subcategories, and their methods for allocating transmission costs.

Table 18 summarizes the cost allocation policies and criteria of the Eastern Interconnection RTOs with respect to reliability and economic upgrade projects. "Regional allocation" means that costs are allocated to loads throughout the whole RTO footprint, while "zonal allocation" means that costs are allocated to loads within the zones that are deemed to benefit from the upgrades. The costs of upgrades that serve both MISO and PJM are allocated between the two RTOs according to each RTO's contribution to the constraint that is alleviated by the upgrade.

Table 19 summarizes the cost allocation policies of the RTOs with respect to interconnection projects. In addition to the types of projects shown in the table, MISO also has "Multi-Value Project" transmission projects that address public policy requirements, such as facilitating the delivery of power generation fueled by renewable energy resources. Multi-Value Projects must be analyzed as part of a portfolio that provides net benefits across the entire MISO footprint; so the costs of such projects are allocated to all load within the MISO footprint (i.e., 100% regional allocation).

The cost allocation schemes may change as the RTOs comply with FERC Order No. 1000.

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[201] Parts of this section rely upon S. Fink, K. Porter, C. Mudd, and J. Rogers, *A Survey of Transmission Cost Allocation Methodologies for Regional Transmission Organizations*, Exeter Associates, Columbia, Maryland, prepared for National Renewable Energy Laboratory, February 2011.

Table 18
Transmission Cost Allocations for Major Projects

RTO/ISO	Reliability Projects	Economic Projects
ISO-NE	Regional allocation based on zonal monthly peak load if the project is: • 115 kV and above; or • In the regional system plan Merchant transmission costs are directly assigned. Zonal allocation of other projects.	

MISO	Projects 345 kV and above:
	• Regional allocation of 20% of costs, based on load
	• Zonal allocation of 80% of costs, based on beneficiaries according to power flow analysis
	Projects 100-345 kV:
	• Zonal allocation of 100% of costs, based on beneficiaries according to power flow analysis
	Projects below 100kV:
	• Allocated to the local zone in which the facility is located
		Projects 345 kV and above that pass the benefit-cost threshold:
		• Regional allocation of 20% of costs, based on load
		• Zonal allocation of 80% of costs, allocated among zones:
		  o 70% based on production cost benefits
		  o 30% based on expected LMP energy price savings

NYISO	Allocation depends on whether need arises locally, in a bounded region of the state, or statewide: • NYC and Long Island pay 100% of projects to meet local reliability needs • Remaining statewide needs allocated to zones based on peak load • Remaining need for bounded regions allocated to zones based on a "binding interface test"	Costs are allocated among zones by LMP energy price savings, (net of TTCs and bilateral contracts) and within zones by ratio share based on energy usage load. To be eligible for cost sharing, a project must pass three tests: • Capital cost exceeds $25 million • Benefits exceed costs in first ten years of commercial operation • 80% of the beneficiaries vote for it
PJM	Projects 500 kV and above: • 100% regional allocation, based on zonal non-coincident peak load Projects less than 500 kV: • Zonal allocation based on power flow analysis of beneficiaries	Projects 500 kV and above: • 100% regional allocation, based on zonal non-coincident peak load Projects less than 500 kV: • Zonal allocation based on LMP energy price savings

SPP	Projects 300 kV and above:
	• 100% regional allocation
	Projects between 100 kV and 300 kV:
	• 1/3 regional allocation
	• 2/3 zonal allocation
	Projects 100 kV and below:
	• 100% zonal allocation
		Projects 300 kV and above:
		• If portfolio benefits exceed costs in all zones, 100% regional allocation.
		• If portfolio benefits do not exceed costs in all zones:
		  ▪ Allocated as agreed among project sponsors
		  ▪ Sponsors get transmission revenues for use by others

Table 19
Transmission Cost Allocations for Interconnection Projects Methodology Summary

RTO/ISO	Interconnection Projects
ISO-NE	Projects that provide system-wide benefits are allocated like Reliability Upgrades. Otherwise, allocation is to the generator.
Midwest ISO	Projects 345 kV and above: • Regional allocation of 10% of costs, based on load • 90% allocated to the interconnection customer Projects less than 345 kV: • 100% allocated to the interconnection customer Interconnection customers are fully refunded for upgrade costs of projects interconnecting to American Transmission Company, International Transmission Company, Michigan Electric Transmission Company, or ITC Midwest
NYISO	Energy Resource Interconnection Service • 100% allocated to the interconnection customer Capacity Resource Interconnection Service[202] • 100% allocated to the interconnection customer
PJM	100% allocated to the interconnection customer
SPP	100% allocated to the interconnection customer, though the customer's contribution towards Network Upgrades are eligible for revenue credits

4.10.4. Non-RTO Regions

In non-RTO regions, the costs of a utility's transmission revenue requirements are allocated between its FERC-regulated OATT customers and its state-regulated, bundled retail customers based upon their respective loads. Thus, only a small proportion of a utility's total transmission-related revenue requirements is subject to FERC jurisdiction in non-RTO regions.

For FERC jurisdictional transmission service in non-RTO regions, transmission cost allocation is established by transmission providers' individual OATTs and is governed by FERC's Order No. 888 comparability principles. While there are variations among the various OATTs of the utilities in non-RTO areas, there is a general model that predominates. For bundled service to retail customers and network wholesale service, the embedded costs of the existing transmission system are generally allocated on a load ratio share basis according to the contribution to system peak load of the users. When transmission is added to allow the transmission provider to continue to meet applicable reliability standards in its planning area, costs are also allocated on a load ratio share basis to native load and wholesale network customers within the planning area.

In principle, transmission service is provided under the higher of embedded *or* incremental costs policy specified in FERC Order No. 888. When new facilities are required to provide network or point-to-point transmission service and the facilities are not otherwise required to meet applicable reliability requirements, then the requestors of such service are responsible for

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[202] Capacity Resource Interconnection Service "interconnect[s] the Developer's Large Generating Facility, Merchant Transmission Facility or Small Generating Facility larger than 2 MW to the New York State Transmission System, or to the Distribution System under Attachment Z, in accordance with the NYISO Deliverability Interconnection Standard, to enable the New York State Transmission System to deliver electric capacity from the Large Generating Facility, Small Generating Facility or Merchant Transmission Facility, pursuant to the terms of the NYISO OATT." New York Independent System Operator, NYISO Tariffs, *OATT Attachment S*, June 30, 2010.

funding the necessary upgrades under this "or" policy, in return for which they get firm transmission service under the OATT. The funding parties also get credit for transmission service taken over those facilities after the lines are constructed, so that eventually their up-front payment may be refunded (depending on the length of service needed). In practice, however, the embedded rate almost always proves to be the higher rate because (among other reasons) the customer can expand the duration of its service request so as to lower what would be its incremental rate. Regardless of whether incremental or embedded costs are higher, the existing OATT "or" pricing cost allocation processes place the costs of transmission upgrades upon those transmission customers who directly cause those costs to be incurred or who desire the service that the new facilities make possible. It is unclear at this point how FERC Order No. 1000 will affect this predominant cost allocation method currently used in the non-RTO areas or what alternatives might be adopted.

4.11. Environmental Requirements

Many environmental requirements affect transmission planning. There are basically two sorts of such requirements.

First, some requirements concern the placement and environmental impacts of transmission facilities. Transmission planning recognizes these requirements as constraints on where and how transmission facilities can be built.

Second, other requirements concern the placement, technologies, and environmental impacts of generation facilities. For example, generation may not be sited in certain environmentally sensitive locations; most states require that certain minimum percentages of electrical energy be generated by generators using preferred (e.g., renewable) technologies; and various federal and state laws and regulations place increasingly stringent limits on allowable emissions of pollutants into air and water, threatening early retirement of many generation facilities. Transmission planning must recognize how these requirements are likely to affect the locations and performance of generation facilities.

5. FUTURE RESEARCH QUESTIONS

The foregoing examination of the market structures and planning processes in the Eastern Interconnection raises questions that should be investigated thoroughly by the EISPC as it continues in its role to help inform and guide the states in their policy decision making.

Regarding generation investment: What planning rules and market structures actually induce investment in generation resources and participation by demand-side resources? What are the incentive effects on generation investment of different planning rules and market structures? To what extent do these different incentives affect generation investment?[203]

Regarding transmission investment: What are the incentive effects on transmission investment of different planning rules and market structures? To what extent do these different incentives affect transmission investment?

[203] There is also the question as to what constitutes resource adequacy. Because of technology and policy changes over the past several decades, the long-standing current standard of 1 day of generation-related outage in 10 years is coming under scrutiny.

Regarding the diversity of state policies: In view of the increasing role of interstate and inter-regional trade in electricity, how and to what extent is resource development affected by the differences among states and regions in their planning processes, market structures, and technology preferences? How can state integrated resource and long-term planning processes benefit from taking a broader view of resource development in the Eastern Interconnection?

Regarding federal environmental regulations: What will be the likely effect of the EPA's environmental regulations on: a) the implementation of state RPS and EERS policies; and b) state implementation of integrated resource plans?

Regarding FERC Order No. 1000: What will be the likely impacts of this Order on: a) the implementation of state RPS and EERS policies; b) state authority over intra- and inter-regional transmission projects; and c) state authority over integrated resource plans?

APPENDIX A.
GLOSSARY OF TERMS

The following terms are among those used in this report.

Access Charge. A charge paid by market participants for the right to send power through a utility's transmission or distribution system.

Aggregation. The process of aggregating many customers or generators into a single bargaining unit, generally for the purpose of buying or selling power services in bulk.

Aggregator. An entity (such as a utility, cooperative, or broker) that engages in aggregation.

Ambient Temperature. The temperature of a medium, such as air, that contacts or surrounds a building or device.

Ancillary Services. Services that are necessary for the transmission of energy from resources to loads. Such services include regulation, operating reserves, voltage control, and black start.

Average Cost. Total cost of production and/or delivery divided by the quantity produced and/or delivered.

Avoided Cost. The production and delivery costs that a utility saves by obtaining power service from a third party.

Balancing Authority Area. An electric power system (or combination of systems) to which a common automatic generation control (AGC) is applied to continually match power supply and demand.

Bilateral Trades. Direct trade between willing buyers and sellers, outside of a centralized market.

Biofuel. Fuel produced from biomass.

Biogas. A combustible gas created by decomposition of organic material, composed primarily of methane, carbon dioxide, and hydrogen sulfide.

Biomass. Organic matter that can be burned to produce heat energy, including algae, agricultural crops and waste, animal waste, aquatic plants, municipal waste, sewage, wood and wood wastes,

Black Start. The ability of a generating plant to start without electricity input from other generating plants.

Bulk Power System. The aggregate of electric generating plants, transmission lines, and related equipment, of one or more utilities.

Capacity. The capability to produce or transport electric power, by generation, transmission, or other electrical apparatus. As applied to tradable commodities, "capacity" refers to installed physical generating capacity and its demand-side analog in the RTO regions, and to an option to obtain energy and operating reserve services under contractually specified conditions in non-RTO regions.

Captive Customer. A customer who lacks realistic alternatives to buying power from the local utility.

Coincident Peak Load. Maximum system load. Also called "coincident peak demand."

Combined Cycle. A generating technology that achieves high efficiency by using waste heat from its gas turbines to produce steam for conventional steam turbines.

Combustion Turbine. A turbine that generates power from the combustion of gas or oil.

Commitment. The advance arrangement (such as a day in advance) for a power system component (such as a generator) to be available to provide services.

Comparability. Non-discriminatory treatment, particularly of customers with respect to the terms and conditions on which they have access to transmission service, and of resources with respect to the terms and conditions on which they can offer services.

Competitive Bidding. A procedure by which utilities select suppliers of new electric capacity and energy.

Conditional Firm Transmission Service. Transmission service that is firm in all but a handful of hours of the year, in which power system conditions do not permit the transmission system to serve all firm and conditional firm service.

Congestion. A condition that occurs when transmission transfer capacity is not sufficient to serve all of transmission customers' preferred schedules simultaneously.

Congestion Charge. For a transmission customer's service between a pair of locations, the congestion price applicable to those locations times the quantity of the customer's transmission service between those locations.

Congestion Cost. The difference between the costs of the lower-cost resources that would be available without transmission congestion and the higher-cost resources that must instead be used with congestion.

Congestion Price. For any pair of locations, the difference between the locational marginal prices at those locations, net of any transmission loss component in that difference.

Congestion Revenues. For the owner of a transmission right between a pair of locations, the congestion price applicable to those locations times the quantity of the owner's transmission right between those locations.

Conservation. A foregoing or reduction of electricity usage for the purpose of saving energy resources.

Control Area. See "Balancing Authority Area."

Cooperative Utility. A utility established to be owned by and operated for the benefit of those using its services.

Day-Ahead Market. A centralized, RTO-administered forward market for energy and (usually) ancillary services, which clears one business day before the services are physically delivered.

Day Two Market. A centralized, RTO-administered market that includes for energy, operating reserve, and regulation services, and has locational (LMP) pricing of energy service.

Demand. The rate (in watts) at which electricity is delivered to loads during a specified time period.

Demand Response. Changes in electricity consumption due to price or other signals regarding power system conditions.

Derating. Temporary or permanent reduction in the expected service capability of a power system component.

Dispatch. The real-time coordination of the availability and output of power system equipment (such as generators).

Distributed Generation. Small-scale power generation facilities located near the electricity consumer (like a home or business).

Distribution. The delivery of electricity to retail consumers through low-voltage systems of wires, switches, and transformers.

Electrical Energy. The real power (measured in watt-hours) that the useful work that consumers seek from electricity.

Embedded Cost. The financial costs of providing service, based upon actual expenditures that (for existing capital equipment) may not reflect current market costs or values.

Energy Efficiency. In the physical sense, using the minimum amount of energy to perform a given function. In the economic sense, using the minimum cost means of providing a given energy service.

Environmental Attributes. The impacts of a power system facility (particular generators) upon air or water.

Firm Transmission Service. Transmission service that may be curtailed only when necessary to preserve power system reliability.

Forced Outage. An equipment failure that results from emergency conditions and that requires a component to be taken out of service unexpectedly.

Frequency. The number of cycles through which an alternating current moves in each second. In the U.S., the standard is 60 cycles (Hertz) per second.

Fuel Diversity. The extent to which firm or power system relies on several different types of fuel.

Generation. The process of producing electricity by transforming non-electrical energy into electrical energy.

Generator. A machine that transforms non-electrical energy into electrical energy.

Grid. An electricity transmission and distribution system.

Incremental Cost. The extra production and delivery cost that a utility incurs to provide an extra block of power.

Independent Power Producer (IPP). A non-utility entity that develops, owns, and/or operates one or more generation facilities and sells power to retail customers either directly or through utilities.

Independent System Operator (ISO). An organization with no direct financial interest in generation or transmission that coordinates, controls and monitors the operation of the electrical power system for the purpose of providing non-discriminatory access to electricity markets in compliance with FERC Order No. 888.

Installed Capacity. The total productive capability of generation equipment.

Integrated Resource Plan (IRP). A comprehensive and systematic evaluation of supply- and demand-side resource options for meeting electricity demand and public policy goals at least cost, for some future period.

Intermittent Resources. Generators that are dependent upon an uncontrollable and highly variable power source, particularly the wind or the sun.

Load. 1) The amount of electric power delivered or required at any specified point or points on a system, also called "demand." 2) An end-use device or an end-use customer that consumes power.

Load Ratio Share. For a particular transmission customer, that customer's network load divided by the transmission provider's total load.

Locational Marginal Pricing (LMP). A pricing regime under which the price of electrical energy varies by location (electrical node) according to the as-bid marginal cost of providing energy to that location, considering transmission constraints and losses.

Loop Flow. For a particular transmission service contract, unscheduled flows of power over the systems of transmission owners who are not parties to the contract.

Losses. The energy lost as waste heat during the generation, transmission, and distribution of electricity.

Marginal Cost. The extra production and delivery cost that a utility incurs to provide an extra megawatt of power.

Market-Based Price. A price set by the mutual decisions of many buyers and sellers in a competitive market.

Market-Clearing Price. The price at which supply equals demand.

Monopoly. A market with a single dominant seller.

Monopsony. A market with a single dominant buyer.

Native Load Customers. Retail customers who the utility has an obligation to serve.

Network. An electricity transmission and distribution system.

Network Customers. Customers receiving service under the terms of the Transmission Provider's Network Integration Tariff.

Network Integration Transmission Service. A transmission service that allows the customer to plan and dispatch its Network Resources on an integrated basis.

Non-Coincident Peak Load. The sum of peak loads of individual customers or groups of customers, not necessarily occurring at the same time.

Non-Firm Transmission Service. Transmission service that is reserved and/or scheduled on an as-available basis.

Non-Spinning Reserve. Generating capability, in excess of load, that is not synchronized with the power system but can nonetheless be producing energy within a short time period (like ten minutes).

Obligation to Serve. The obligation of a utility to provide electric service to any customer who seeks that service, and is willing to pay the rates set for that service.

Off-peak. Periods of relatively low system demands.

Operating Reserve. Generating capability, in excess of load, that can be producing energy within a short time period (like ten minutes).

Outage. Inability of equipment to provide service.

Peak. Periods of relatively high system demands.

Peak Load. Maximum system load. Also called "peak demand."

Peaking Capacity. The capacity of generating equipment intended for operation during the hours of highest daily, weekly, or seasonal loads.

Plant. A facility containing electric generators and other equipment for producing electric energy.

Point(s) of Delivery. Interconnection location(s) at which the transmission customer delivers power to the network.

Point(s) of Receipt. Interconnection location(s) at which the transmission customer takes power from the network.

Point-to-Point Transmission Service. A transmission service that allows the customer to transfer power from specific source locations to specified sink locations.

Power Pool. Two or more interconnected electric systems that agree to coordinate operations.

Ramping Capability. The ability of a resource to change output level rapidly in response to system operators' instructions or automatic generation control signals.

Real-Time Market. A centralized, RTO-administered market for energy and (usually) ancillary services, which clears at the time that the services are physically delivered.

Regional Transmission Operator (RTO). An organization with no direct financial interest in generation or transmission that coordinates, controls and monitors the operation of the electrical power system for the purpose of providing non-discriminatory access to electricity markets in compliance with FERC Order No. 2000.

Regulation. The service provided by resources with automatic generation control that enables instantaneous generator, storage, or load responses to frequency control signals that indicate imbalances between power supply and demand.

Reliability. The ability ("adequacy") of the electric system to supply the aggregate electric demand of customers at all times, considering scheduled and unscheduled outages of system facilities; and the ability ("security") of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system facilities.

Renewable Energy. Energy sources – like hydro, wind, biomass, geothermal, and solar – that renew themselves or that are regarded as practically inexhaustible.

Renewable Resources. Generation resources that rely upon renewable energy.

Reserve Margin. The difference between a power system's resource capacity and its peak load.

Restructuring. The reorganization of electric power industry, usually referring to changes (like separation) in the relationship between the various functions (like generation, transmission, and distribution).

Retail. Pertaining to electricity consumers.

Retail Competition. A system under which more than one provider can offer electricity to retail customers, and retail customers are allowed to choose among providers.

Service Territory. The area or region served exclusively by a single entity or group of entities.

Spinning Reserve. Generating capability, in excess of load, that is synchronized with the power system and can be producing energy within a short time period (like ten minutes).

System Coordination. The set of activities that allows system operators to coordinate the operations of generation and transmission facilities in real time.

Tariff. A document, approved by the responsible regulatory agency, listing the terms and conditions, including prices, under which utility services will be provided.

Transmission. The delivery of electricity to retail consumers through high-voltage systems of wires, towers, and transformers.

Upgrade. An electrical equipment replacement or addition that results in increased generation or transmission capability.

Utility. A regulated entity that provides a network service and has the characteristics of a natural monopoly.

Vertical Integration. An arrangement whereby a single company engages in all levels of production, which in the case of electricity is generation, transmission, distribution, and customer services.

Voltage. The force or pressure of moving energy.

Voltage Control. Activities by which generation, transmission, and distribution facilities keep voltage levels within narrow bounds throughout the network.

APPENDIX B.
RTO DEMAND RESPONSE PROGRAM FEATURES[204]

RTO Product / Service				*Product / Service Features*					
Region	**Acronym**	**Name**	**Service Type**	**Minimum Eligible Resource Size**	**Minimum Reduction Amount**	**Aggregation Allowed**	**Participation**	**Response Required**	**Primary Driver**
ISO-NE	**DALRP / RTDR**	Day-Ahead Load Response Program for Real-Time Demand Response Program	Energy	100 kW	100 kW	Yes	Voluntary	Mandatory	Economic
ISO-NE	**DALRP / RTDR**	Day-Ahead Load Response Program for RTPR	Energy	100 kW	100 kW	Yes	Voluntary	Mandatory	Economic
ISO-NE	**RTDR**	Real Time Price Response Program	Energy	100 kW	100 kW	Yes	Voluntary	Voluntary	Economic
ISO-NE	**RTDR**	Real Time Demand Response Resource	Capacity	100 kW	1 kW	Yes	Voluntary	Mandatory	Reliability
ISO-NE	**OP**	FCM: On-Peak Demand Resources	Capacity	100 kW	1 kW	Yes	Voluntary	Mandatory	Reliability
ISO-NE	**SP**	FCM: Seasonal Peak Demand Resources	Capacity	100 kW	1 kW	Yes	Voluntary	Mandatory	Reliability
ISO-NE	**RTEG**	Real Time Emergency Generation Resource	Capacity	100 kW	1 kW	Yes	Voluntary	Mandatory	Reliability
ISO-NE	**DARD**	Dispatchable Asset Related Demand	Reserve	1 MW	1 kW	Yes	Voluntary	Mandatory	Economic

[204] Information in this table is from an Excel spreadsheet obtained from the ISO/RTO Council at http://www.isorto.org/site/c.jhKQIZPBImE/b.2604461/k.6151/Documents_and_Issues.htm.

RTO Product / Service				*Product / Service Features*					
MISO[205]	**DRR-I**	Demand Response Resource Type I (Energy)	Energy	5 MW	100 kW	Yes	Voluntary	Voluntary	Economic
MISO	**DRR-I**	Demand Response Resource Type-I (Reserve)	Reserve	5 MW	100 kW	Yes	Voluntary	Mandatory	Economic
MISO	**DRR-II**	Demand Response Resource Type II (Energy)	Energy	5 MW	100 kW	No	Voluntary	Voluntary	Economic
MISO	**DRR-II**	Demand Response Resource Type-II (Reserve)	Reserve	5 MW	100 kW	No	Voluntary	Mandatory	Economic
MISO	**DRR-II**	Demand Response Resource Type-II (Regulation)	Regulation	5 MW	100 kW	No	Voluntary	Mandatory	Economic
MISO	**EDR**	Emergency Demand Response	Energy	100 kW	100 kW	Yes	Voluntary	Voluntary	Reliability
MISO	**LMR**	Load Modifying Resource	Capacity	100 kW	100 kW	Yes	Voluntary	Mandatory	Reliability
NYISO	**DADRP**	Day-Ahead Demand Response Program	Energy	1 MW	1 MW	Yes	Voluntary	Mandatory	Economic
NYISO	**DSASP**	Demand Side Ancillary Services Program	Reserve	1 MW	1 MW	No	Voluntary	Mandatory	Economic
NYISO	**DSASP**	Demand Side Ancillary Services Program	Reserve	1 MW	1 MW	No	Voluntary	Mandatory	Economic
NYISO	**DSASP**	Demand Side Ancillary Services Program	Regulation	1 MW	1 MW	No	Voluntary	Mandatory	Economic
NYISO	**EDRP**	Emergency Demand Response Program	Energy	100 kW (per Zone)	100 kW (per Zone)	Yes	Voluntary	Voluntary	Reliability
NYISO	**SCR**	Installed Capacity Special Case Resources (Energy Component)	Energy	100 kW (per Zone)	100 kW (per Zone)	Yes	Voluntary	Mandatory	Reliability
NYISO	**SCR**	Installed Capacity Special Case Resources (Capacity Component)	Capacity	100 kW (per Zone)	100 kW (per Zone)	Yes	Voluntary	Mandatory	Reliability

205 The MISO DRR programs all allow consideration of resources smaller than 5 MW on a case-by-case basis.

RTO Product / Service				Product / Service Features					
PJM	-	Economic Load Response (Energy)	Energy	100 kW	100 kW	Yes	Voluntary	Voluntary	Economic
PJM	-	Economic Load Response (Synchronized reserves)	Reserve	500 kW	500 kW	Yes	Voluntary	Mandatory	Reliability
PJM	-	Economic Load Response (Day ahead scheduling reserve)	Reserve	500 kW	500 kW	Yes	Voluntary	Mandatory	Reliability
PJM	-	Economic Load Response (Regulation)	Regulation	500 kW	500 kW	Yes	Voluntary	Mandatory	Reliability
PJM	-	Emergency Load Response - Energy Only	Energy	100 kW	100 kW	Yes	Voluntary	Voluntary	Economic
PJM	-	Full Emergency Load Response (Capacity Component)	Capacity	100 kW	100 kW	Yes	Voluntary	Mandatory	Reliability
PJM	-	Full Emergency Load Response (Energy Component)	Energy	100 kW	100 kW	Yes	Voluntary	Mandatory	Reliability
SPP		Controllable Load	Energy	1 MW	1 MW	Aggregation to a single withdrawal point from the Transmission Grid (and single Retail Provider) is permitted	Voluntary	Mandatory	Economic

APPENDIX C.
CHARACTERISTICS OF CUSTOMER CHOICE PROGRAMS[206]

<u>Connecticut</u>

Standard Offer Service (SOS): Yes. Called Default Service / Generation Service Charge.

SOS Providers: EDC

SOS Procurement Process: Utilities must obtain Default Service on a quarterly basis through the wholesale market. Utilities obtain wholesale market full requirements contracts pursuant to RFPs. The contracts are laddered and reflect terms of 6 to 12 months, with prices that change no more frequently than quarterly; but the actual portfolios that are currently in effect call for annual price changes.

Competitive Providers of Electricity: Electric Supplier

Eligible Customer Group: All customers that have not chosen an alternative Electric Supplier

<u>Delaware</u>

Standard Offer Service (SOS): Yes

SOS Providers: Delmarva Power and Light Company

SOS Procurement Process: A competitive RFP process is used to procure the full requirements of customers eligible for a FP-SOS. Supply is procured using the World Energy reserve auction process.

Competitive Providers of Electricity: Alternative Electric Supplier

SOS Rate: A competitive RFP process is used to procure the full requirements of customers eligible for a FP-SOS. Bidders bid seasonally, but the retail rates convert the bids into the existing rate design structures. The Full Requirements Cost (FRC) is comprised of the costs that Delmarva pays to the winning bidders. Absent a Commission finding of exceptional circumstances, the FRC is reset and fixed for 12 months. It is trued up annually, thus resulting in the retail rate for SOS being reset on an annual basis. SOS rates vary by customer type because prices are based on winning bids and supply requirements vary by customer type.

Eligible Customer Group: Fixed Price SOS is available to all but the largest customers (GS-T customers). Hourly Priced Service is mandatory for GS-T customers and optional for GS-P customers

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[206] EDC denotes electric distribution company. Standard Offer Service (SOS) is also referred to in some jurisdictions as Default Service. There are no programs in Alabama, Arkansas (suspended), Florida, Georgia, Indiana, Iowa, Kansas, Kentucky, Louisiana, Minnesota, Mississippi, Missouri, Montana, Nebraska, North Carolina, North Dakota, Oklahoma, South Carolina, South Dakota, Tennessee, Vermont, Virginia (suspended), West Virginia, and Wisconsin.

District of Columbia

Standard Offer Service (SOS): Yes

SOS Providers: Potomac Edison

SOS Procurement Process: Potomac Edison acquires SOS from wholesale market bidders pursuant to full requirements fixed price contracts. Potomac Edison solicits power to serve 1/3 of the residential and small commercial load every year for a three-year term.

Competitive Providers of Electricity: None for distribution (exists only for generation and transmission)

SOS Rate: Competitive bidding process occurs each year over a 3-month period. SOS prices change annually. Each year, new SOS rates are effective for the Summer on June 1 and for Winter on October 1. Customers are charged for SOS rates are approved by the District of Columbia Public Service Commission.

Eligible Customer Group: Pepco is required to buy electricity for customers who do not choose an alternative electricity supplier.

Illinois

Standard Offer Service (SOS): Yes. Called Default Supply.

SOS Providers: Ameren and Commonwealth Edison

SOS Procurement Process: Utilities have a three-year procurement of a variety of contracts and hedging instruments (e.g., fixed price swap contracts) in the wholesale market, with purchases on the spot market as needed.

Competitive Providers of Electricity: Retail Electric Suppliers (RES)

Eligible Customer Group: All customers who choose not to receive power from a RES.

Maine

Standard Offer Service (SOS): Yes

SOS Providers: Retail suppliers chosen by the Commission through competitive bid processes

SOS Procurement Process: SOS is priced through a competitive bidding process, conducted by the Commission, in which proposals are evaluated primarily on price. The Commission conducts an annual RFP for one-third of the SOS load for residential and small commercial customers. The winning bid(s) sets the standard offer prices that customers pay. T&D utilities cannot bid to provide standard offer service, and affiliates of T&D utilities are restricted to providing no more than 20% of SOS in the affiliated T&D utility's service territory. If retail bids are insufficient or unacceptable, SOS is provided by the T&D utilities through wholesale contracts.

Competitive Providers of Electricity: Suppliers, Aggregators

SOS Rate: The SOS rate is based on suppliers' competitive bids in a load auction. The rate is a fixed price that does not vary by level of usage or time of day. The customer SOS price changes annually.

Eligible Customer Group: All customer classes

<u>Maryland</u>

Standard Offer Service (SOS): Yes

SOS Providers: Unregulated wholesale suppliers

SOS Procurement Process: Supply may be acquired through: a) a competitive RFP process for laddered full requirements fixed-price contracts; and b) bilateral contacts approved by the Commission. Baltimore Gas & Electric (the state's largest electric utility) conducts the RFPs twice per year, seeking 25% of the residential load for a 24-month period. The result must be a "portfolio of blended wholesale supply contracts of short, medium or long terms, and other appropriate electricity products and strategies, as needed to meet demand in a cost effective manner."

<u>Massachusetts</u>

Standard Offer Service (SOS): Yes

SOS Providers: Competitive Suppliers pursuant to agreements with EDCs

SOS Procurement Process: 1 year contracts for 50% of SOS demand every 6 months

Eligible Customer Group: Residential, small commercial and industrial (C&I), Large C&I

<u>Michigan</u>

Standard Offer Service (SOS): Yes

SOS Providers: EDC

Competitive Providers of Electricity: Alternative Electric Supplier

Other: Choice limited to 10% of utility's average weather adjusted retail sales

<u>New Hampshire</u>

Standard Offer Service (SOS): Yes. Called Default Service.

SOS Providers: Incumbent electric utilities

SOS Procurement Process: Public Service of New Hampshire (PSNH) provides default service from its generation supply portfolio. Other utilities procure supply from wholesale market entities, usually through the use of laddered "full requirements" contracts that vary in length from six months to twelve months.

Competitive Providers of Electricity: Competitive Supplier

SOS Rate: For PSNH's customers, the rate is based on PSNH's actual, prudent, and reasonable costs of providing power, as approved by the Commission. For the other utilities' customers, the costs are those of the wholesale supply, as approved by the Commission.

Eligible Customer Group: Residential, small C&I, Large C&I

New Jersey

Standard Offer Service (SOS): Yes. Called Default Service or Basic Generation Service.

SOS Providers: EDC

SOS Procurement Process: Supply is procured through standardized contracts in the wholesale market, as per a state-supervised descending-clock auction process. Contracts are "laddered" so that 1/3 of supply is acquired every year for a three-year fixed price.

Competitive Providers of Electricity: Alternative electric supplier

SOS Rate: Service for residential and small commercial customers is provided at a fixed price that changes every year according to the results of the auction.

Eligible Customer Group: Any customer not served by a competitive supplier.

New York

Standard Offer Service (SOS): No. New York has opened its markets to competition but the utilities do not have a "standard offer." Each of the utilities resets their commodity prices regularly - some, if not all, set it daily.

SOS Providers: EDC

SOS Procurement Process: There is no explicit "restructuring" statute in New York and, as a result, there is no statutory guidance on default service procurement policy. There is no uniform method of purchasing and pricing default service. Each utility has litigated or agreed to specific portfolio requirements in the context of base rate cases or other proceedings.

Competitive Providers of Electricity: There is no uniform method of purchasing and pricing default service. Each utility has litigated or agreed to specific portfolio requirements in the context of base rate cases or other proceedings.

Ohio

Standard Offer Service (SOS): Yes

SOS Providers: EDC

SOS Procurement Process: Utilities can procure power through either of two approaches. Using an Electric Security Plan, the utility uses its own generation or its affiliated generation to provide SOS. Using a Market Rate Offer, a utility acquires standard service via wholesale market contracts. Most utilities use the former approach.

Competitive Providers of Electricity: Alternative Electric Supplier, Electric Service Companies and Governmental Aggregators

SOS Rate: Market-based.

Pennsylvania

Standard Offer Service (SOS): Yes, called Default Service

SOS Providers: EDC

SOS Procurement Process: The default service provider must submit a plan to acquire generation supply by competitive means to obtain "generation supply at the least cost" and obtain a "prudent mix of contracts to obtain least cost on a long-term, short-term and spot market basis…" Long-term is defined as between 4 and 20 years. Auctions, requests for proposals, and bilateral agreements are permitted.

Competitive Providers of Electricity: EGS – wholesale supplier, aggregator, marketer, broker

SOS Rate: The default price (called the Price to Compare) varies by utility and reflects their underlying wholesale market contracts. It must be a fixed rate that changes quarterly for residential customers and monthly for larger C&I customers.

Eligible Customer Group: Residential, small C&I, Large C&I not entering power supply arrangements with an EGS.

Rhode Island

Standard Offer Service (SOS): Yes

SOS Providers: EDC

SOS Procurement Process: Supply is procured under laddered contract terms for full requirements contracts and a 5% purchase of block spot purchase contracts. Supply can have a semi-annual price adjustment, with contract terms of 6, 12, 18, and 24 months to mitigate price volatility.

Competitive Providers of Electricity: Non-regulated Power Producers

SOS Rate: Rates cover costs and must be approved by the commission, which may average costs over periods of time.

Eligible Customer Group: All customers that have not elected to enter into power supply arrangements with other non-regulated power suppliers

Texas

Standard Offer Service (SOS): No. Provider of Last Resort service is a short term service that is provided at a premium of 130% to 135% over monthly wholesale market prices.

SOS Providers: The commission shall designate retail electric providers in areas of the state in which customer choice is in effect to serve as providers of last resort.

Competitive Providers of Electricity: Retail Electric Provider

SOS Rate: Provider of Last Resort service is priced by regulation at 130-135% above prevailing wholesale market prices and is the most expensive option in the Texas market.

APPENDIX D.
RTO CAPACITY SUPPLIER REQUIREMENTS

PJM Interconnection[207]	
Resource Type	**Requirements**
Internal Generation	• The unit is pre-certified by PJM as meeting the generation deliverability test. PJM‟s certification process for internal generating resources is described in the Tariff and the Operating Agreement • The resource owner or operator submits the required operating and maintenance information into PJM‟s eDART and eGADs systems. • The resource owner or operator performs winter and summer testing as described in PJM‟s Rules and Procedures for Determination of Generating Capability (M-21) to verify the net capability of each unit. • The unit resides in the eRPM resource portfolio of a signatory of the PJM Operating Agreement. This is accomplished by having an “Approved” Capacity Modification in the eRPM system. • The relevant portion of the unit was not specified in any FRR Capacity Plan for the Delivery Year. • The unit must have been offered in the Base Residual Auction for the Delivery Year in order to be eligible to offer into the First, Second or Third Incremental Auctions for that Delivery Year.
External Generation	• An indication of the intended ATC path to deliver the existing external capacity into PJM is provided. (Firm transmission service from the unit to the border of PJM and generation deliverability in PJM must be demonstrated by the start of the Delivery Year.) • The unit resides in the eRPM resource portfolio of a signatory of the PJM Operating Agreement. This is accomplished by having a “Provisionally Approved” or “Approved” unit-specific transaction with “External Party” (i.e., “EXT”) as the “Seller” of the transaction in the eRPM system. • Twelve months of NERC/GADs unit performance data in PJM format is required to establish a unit’s EFORd. • The resource owner or operator submits the required operating and maintenance information into PJM‟s eDART and eGADs systems. • The resource owner or operator performs winter and summer testing as described in PJM‟s Rules and Procedures for Determination of Generating • Capability (M-21) to verify the net capability of each unit. • The external capacity without firm transmission must establish an RPM Credit Limit prior to an RPM Auction. • Credit requests should be made to PJM‟s Treasury Department at least two weeks prior to an RPM Auction. • The resource owner provides a letter of non-recallability assuring PJM that the energy and capacity from the unit is not recallable to any other control area. • A communication path (acceptable to PJM Dispatching/Operations personnel) must be established between the PJM Dispatchers and the operator of the unit.
Load Management Resource	• Must be interruptible up to 10 times per year for up to 6 hours per interruption • Must be registered in the Emergency Load Response Program (see more detail in later the Emergency Load Response Registration section) • Provide (or contract with another party to provide) supplemental status reports during the Delivery Year, detailing availability of the load management resource, as requested by PJM System Operations in accordance with the PJM Manuals; • Provide (or contract with another party to provide) customer-specific compliance and verification information within 45 days after the end of the month in which a PJM-initiated Load Management event occurred, in accordance with the Load Management Compliance section of Section 8 of this Manual. • Load drop estimates for all Load Management events (whether initiated by PJM or the resource provider) in accordance with PJM Manual 19: Load Forecasting & Analysis.
Energy Efficiency (EE)	• EE installation must be scheduled for completion prior to DY; • EE installation is not reflected in peak load forecast posted for the BRA for the DY initially offered; • EE installation exceeds relevant standards at time of installation as known at time of commitment; • EE installation achieves load reduction during defined EE Performance Hours; • EE installation is not dispatchable

[207] PJM Interconnection, Manual 18, *PJM Capacity Market*, November 17, 2011, Section 4, Supply Resources in the Reliability Pricing Model, p. 22 ff.

<table>
<tr><th colspan="2">New York Independent System Operator [208]</th></tr>
<tr><th>Resource Type</th><th>Requirements</th></tr>
<tr><td>All Resources</td><td>The requirements necessary to qualify as an Installed Capacity Supplier include Dependable Maximum Net Capability (DMNC) testing and maintenance schedule reporting.
The Resources listed below must meet the applicable DMNC test conditions specified below in order to be qualified as Installed Capacity Suppliers.
Maintenance Scheduling Requirements:
Notify the NYISO, in a confidential notice, of proposed outage schedules for the next two (2) calendar years on or before September 1 at 5:00:00 P.M. of the current calendar year.
If Operating Reserve deficiencies are projected to occur in certain weeks for the upcoming calendar year, based upon the ISO's reliability assessment, Resources may be requested to voluntarily reschedule planned maintenance.
The NYISO will provide the Resource with alternative acceptable times for the rescheduled maintenance.
If the Resource is a Generator that qualifies as an Installed Capacity Supplier that does not voluntarily re-schedule its planned maintenance within the alternative acceptable times provided by the NYISO, the NYISO will invoke mandatory re-scheduling using the procedures prescribed in the NYISO Outage Scheduling Manual.
A Resource that did not qualify as an Installed Capacity Supplier prior to the Obligation Procurement Period and that intends to be an Installed Capacity Supplier within the Obligation Procurement Period must provide the NYISO with its proposed outage schedule for the current Capability Year and the following 2 calendar years, no later than 5:00:000 P.M. on the first business day of the month preceding the month in which it intends to supply Unforced Capacity, so that it may be subject to the voluntary and mandatory rescheduling procedures described above.</td></tr>
<tr><td>Fossil Fuel & Nuclear Steam Units</td><td>Valid DMNCs for fossil fuel or nuclear steam units are determined by the following:
The unit's sustained maximum net output averaged over a four (4) consecutive hour period
For common-header turbine-generators, the DMNC is determined on a group basis. Each such turbine-generator is assigned a rating by distributing the combined Capacity among them.
The sum of the DMNC of individual turbine-generators in a generating station cannot be greater than the capacity of the station taken as a whole; also the sum of the DMNC of individual turbine-generators under a single Point Identifier (PTID) cannot be greater than the DMNC of the PTID taken as a whole station. Each such turbine- generator is assigned a rating by distributing the combined Capacity among the units comprising the PTID.</td></tr>
<tr><td>Hydro Stations</td><td>Valid DMNCs for hydro units are determined by the following:
The sustained net output averaged over a four (4) consecutive hour period using average stream flow and/or storage conditions within machine discharge Capacity.
For a multi-unit hydro station, the DMNC is determined as a group and each hydro unit in such a station is assigned a rating by distributing the combined station DMNC among them.
The sum of the DMNC of individual units in a multi-unit hydro station cannot be greater than the capacity of the station taken as a whole; also the sum of the DMNC of individual hydro units under a single PTID cannot be greater than the DMNC of the PTID taken as a single station. Each such hydro unit is assigned a rating by distributing the combined Capacity among the units comprising the PTID.</td></tr>
<tr><td>Internal Combustion Units</td><td>Valid DMNCs for internal combustion units and combustion turbines are determined by the following:
The sustained maximum net output for a one (1) hour period.
The unit's winter DMNC rating is determined on the basis of the average ambient and cooling system temperature experienced at the time of the Transmission District's winter peak during the previous four (4) Winter Capability Periods.
The unit's summer DMNC is determined on the basis of the average ambient and cooling system temperature experienced at the time of the Transmission District's summer peak during the previous four (4) Summer Capability Periods.
The sum of the DMNC of individual units in a multi-unit station cannot be greater than the capacity of the station taken as a whole; also the sum of the DMNC of individual units under a single PTID cannot be greater than the DMNC of the PTID taken as a single station. Each unit in the station is assigned a rating by distributing the combined Capacity among the units comprising the PTID.</td></tr>
</table>

[208] New York Independent System Operator, icap_mnl.pdf, Section 4, Installed Capacity Requirements Applicable to Installed Capacity Suppliers, p. 4-1

New York Independent System Operator (continued)	
Resource Type	**Requirements**
Combined Cycle Stations	Valid DMNCs for combined cycle stations are determined by the following: • The sustained maximum net output over four (4) consecutive hours. • A combined cycle station's winter DMNC rating is determined on the basis of the average ambient and cooling system temperature experienced at the time of the Transmission District's winter peak during the previous four (4) Winter Capability Periods. • A combined cycle station's summer DMNC rating is determined on the basis of the average ambient and cooling system temperature experienced at the time of the Transmission District's summer peak during the previous four (4) Summer Capability Periods. • In cases where the sum of the DMNC rating of individual units in a combined cycle plant is greater than the DMNC of the plant taken as a single station, each unit is assigned a rating by distributing the plant DMNC among the units.
Intermittent Power Resources	• The DMNC value of Intermittent Power Resources will be the combined nameplate capacity of all units (usually aggregated in groups of small individual units) in each station, net of any station service Load required for operation and delivery to the New York Control Area • Transmission system. The sum of the DMNC values of all units under a single PTID cannot be greater than the DMNC of the PTID taken as a single unit. Each such individual unit is assigned a rating by distributing the combined Capacity among the units comprising the PTID.
Special Case Resources	A Special Case Resource that supplies Load reductions solely through the use of a distributed generator must submit a demonstration test of the generator maximum net output for a one (1) hour period net of any auxiliary loads (including, but not limited to station service Load).
Energy Limited and Capacity Limited Resources	Valid DMNCs for Energy Limited and Capacity Limited Resources are determined by the following: • The sustained maximum net output averaged over a four (4) consecutive hour period, with the exception of Internal Combustion units or Combustion Turbines that are approved as Energy Limited or Capacity Limited Resources, which will instead use the sustained maximum net output for a one (1) hour period. • For a multi-unit station, the DMNC is determined for the group and each unit in such a station is assigned a rating by distributing the combined station DMNC among them. • The sum of the DMNCs of individual units in a multi-unit station cannot be greater than the capacity of the station taken as a whole; also the sum of the DMNC of individual units under a single PTID cannot be greater than the DMNC of the PTID taken as a single plant. Each such unit is assigned a rating by distributing the combined Capacity among the units comprising the PTID.

ISO New England[209]	
Resource Type	**Requirements**
New Generating Capacity Resources	For a resource to qualify as a New Generating Capacity Resource, the resource's Project Sponsor must make two separate submissions to the ISO: 1. The Project Sponsor must submit a New Capacity Show of Interest Form during the New Capacity Show of Interest Submission Window. This form should include: (a) The project name; the Project Sponsor's contact information; the Project Sponsor's ISO customer status; the project's expected Commercial Operation date; the project address or location; capacity (in MW) of the resource; the Economic Minimum Limit (in MW) of the New Generating Capacity Resource; a general description of the project's equipment configuration; a simple location plan and a one-line diagram of the plant and station facilities etc. (b) The form shall also specify the Queue Position associated with the project. (c) For all Forward Capacity Auctions and reconfiguration auctions after the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2010, the Project Sponsor must submit documentation demonstrating that the Project Sponsor has already achieved control of the project site for the duration of the relevant Capacity Commitment Period. (d) The Project Sponsor must indicate if the New Generating Capacity Resource is incremental capacity associated with a resource previously listed as a capacity resource, or if it is incremental capacity associated with a resource previously listed as a capacity resource that has been de-rated for three or more years at the time of the Forward Capacity Auction. (e) With the New Capacity Show of Interest Form, the Project Sponsor must submit the Qualification Process Cost Reimbursement Deposit. 2. The Project Sponsor must submit a New Capacity Qualification Package no later than the New Capacity Qualification Deadline. This should include: (a) Documentation demonstrating that the Project Sponsor has already achieved control of the project site for the duration of the relevant Capacity Commitment Period. (b) A critical path schedule for the project with sufficient detail to allow the ISO to evaluate the feasibility of the project being built and the feasibility that the project will meet the requirement that the project achieve Commercial Operation as qualified no later than the start of the relevant Capacity Commitment Period and at least 12 months after the date of the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2010. (c) All New Generating Capacity Resources that might submit offers in the Forward Capacity Auction at prices below 0.75 times the Cost of New Entry ("CONE") must have included such offers in the New Capacity Qualification Package in the form of a supply curve (up to five price-quantity pairs) for all prices below 0.75 times CONE. (d) The Project Sponsor must specify whether, if its New Capacity Offer clears in the Forward Capacity Auction, the associated Capacity Supply Obligation and Capacity Clearing Price (indexed for inflation) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to four additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only. The Project Sponsor must also submit to the ISO an Interconnection Request prior to submitting a New Capacity Show of Interest Form during the New Capacity Show of Interest Submission Window. Upon submission of the financial assurance deposit by the Project Sponsor, the resource is obligated to participate and will be included in the Forward Capacity Auction at its FCA Qualified Capacity amount at the Forward Capacity Auction Starting Price.
Existing Generating Capacity Resources	• For each Existing Generating Capacity Resource, no later than 15 Business Days before the Existing Capacity Qualification Deadline, the ISO will notify the resource's Lead Market Participant of the resource's summer Qualified Capacity and winter Qualified Capacity and the Load Zone in which the Existing Generating Capacity Resource is located. • If the Lead Market Participant believes that an ISO-determined summer Qualified Capacity or winter Qualified Capacity for an Existing Generating Capacity Resource is not accurate, then the Lead Market Participant must notify the ISO within 5 Business Days of receipt of the Qualified Capacity notification. The ISO shall notify the Lead Market Participant of the outcome of any such challenge no later than 5 Business Days before the Existing Capacity Qualification Deadline. • No later than 127 days before the Forward Capacity Auction, the ISO shall send notification to the Lead Market Participant that submitted each Static De-List Bid, Permanent De-List Bid, Export Bid, and Administrative Export De-List Bid indicating whether the bid has been accepted for participation in the Forward Capacity Auction. Each accepted Static De-List Bid, Permanent De-List Bid, Export Bid, and Administrative Export De-List Bid shall be binding and shall be entered into the Forward Capacity Auction.

[209] ISO New England, FERC Electric Tariff No. 3, 5th Rev Sheet No. 7308, Section III.13 - Forward Capacity Market

ISO New England (continued)	
Resource Type	**Requirements**
Import Capacity	• The qualification requirements for import capacity shall depend on whether the import capacity is an Existing Import Capacity Resource or a New Import Capacity Resource. • Both Existing Import Capacity Resources and New Import Capacity Resources clearing in the Forward Capacity Auction shall have a Capacity Supply Obligation and shall receive payments only for the one-year Capacity Commitment Period associated with that Forward Capacity Auction. • Both Existing Import Capacity Resources and New Import Capacity Resources clearing in the Forward Capacity Auction must be backed by one or more External Resources or by an external Control Area throughout the relevant Capacity Commitment Period.
Demand Resources	• The amount of capacity offered by a Demand Resource shall be a minimum of 100 kW aggregated in a Load Zone. • Beginning with the Capacity Commitment Period starting June 1, 2011, a Real-Time Demand Response Resource and a Real-Time Emergency Generation Resource shall be a minimum of 100 kW aggregated in a Dispatch Zone. • A Demand Resource may continue to offer capacity into Forward Capacity Auctions and reconfiguration auctions for Capacity Commitment Periods in an amount less than or equal to its remaining Measure Life. • Demand Resources are not permitted to submit import or export bids or Administrative Export De-list Bids. • A Demand Resource that certifies in writing to the ISO no later than 45 days prior to the start of the second Forward Capacity Auction that the resource will be retired as of the start of the second Capacity Commitment Period will not be included in the second Forward Capacity Auction. • A Demand Resource shall no longer be eligible to participate in the Forward Capacity Market if its Permanent De-list Bid is accepted.
Offers Composed of Separate Resources	Separate resources seeking to participate together in a Forward Capacity Auction shall submit a composite offer form no later than 10 Business Days after the date on which the ISO provides qualification determination notifications. Offers composed of separate resources may not be modified or withdrawn after the deadline for submission of the composite offer form. Separate resources may together participate in a Forward Capacity Auction as a single resource if the following conditions are met: (a) In all months of the summer period of the Capacity Commitment Period, only one resource may be used to supply the amount of capacity offered during the entire summer period. In all months of the winter period, multiple resources may be combined to supply the amount of capacity offered, provided that: i) the resources together meet the amount of the offer in all months of the winter period; and ii) to combine for a month, that month must be considered a winter month for both the summer resource and the resource combining with that summer resource in that month. (b) If an offer is composed of separate resources, and is intended to meet the Local Sourcing Requirement in an import-constrained Capacity Zone, then each resource comprising the offer must be located in that import-constrained Capacity Zone. (c) If an offer is composed of separate resources, and is intended to meet the capacity requirement in the Rest-of-Pool Capacity Zone, then each resource comprising the offer must be located in a Capacity Zone that is not export-constrained. (d) If an offer is composed of separate resources, and is for capacity in an export-constrained Capacity Zone, then each resource comprising the offer must be located inside of the export-constrained Capacity Zone or be located in any non-export constrained Capacity Zone. (e) A Real-Time Emergency Generation Resource may only participate in an offer composed of separate resources as a winter resource if the summer resource is also a Real-Time Emergency Generation Resource. No later than 5 Business Days after the deadline for submission of offers composed of separate resources, the ISO shall notify the Project Sponsor or Lead Market Participant for each New Generating Capacity Resource, New Import Capacity Resource, and New Demand Resource of the resource's final FCA Qualified Capacity for the Forward Capacity Auction.

ISO New England (continued)	
Resource Type	**Requirements**
Self-Supplied FCA Resources	• Where a Project Sponsor elects to designate all or a portion of a New Generating Capacity Resource or an Existing Generating Capacity Resource as a Self-Supplied FCA Resource, the Project Sponsor must make such designation in writing to the ISO no later than the date by which the Project Sponsor is required to submit the financial assurance deposit and, if the Project Sponsor is not also the associated load serving entity, the Project Sponsor must at that time provide written confirmation from the load serving entity regarding the Self-Supplied FCA Resource designation. • A New Import Capacity Resource or Existing Import Capacity Resource may be designated as a Self-Supplied FCA Resource. • A load serving entity seeking to self-supply using a Demand Resource shall realize the benefit through the actual reduction in its annual system coincident peak load, shall not receive credit for a resource and, therefore, is not required to participate in the qualification process. • All offers submitted in a Forward Capacity Auction by a new Self-Supplied FCA Resource shall be counted as Out of Market. • If designated as a Self-Supplied FCA Resource and otherwise accepted in the qualification process, the resource will clear in the Forward Capacity and, with the exception of demand programs for Self-Supplied FCA Resources, shall offset an equal amount of the load serving entity's share of Installed Capacity Requirement in the Capacity Commitment Period. All designations as a Self-Supplied FCA Resource in the Forward Capacity Auction qualification process are binding. • The total quantity of capacity that an load serving entity designates as Self-Supplied FCA Resources may not exceed the load serving entity's projected share of the Installed Capacity Requirement during the Capacity Commitment Period which shall be calculated by determining the load serving entity's most recent percentage share of the Installed Capacity Requirement multiplied by the projected Installed Capacity Requirement for the commitment year. No resource may be designated as a Self-Supplied FCA Resource for more MW than the lesser of that resource's summer Qualified Capacity and winter Qualified Capacity. • In order to participate in the Forward Capacity Auction as a Self-Supplied FCA Resource for purposes of fulfilling a Local Sourcing Requirement applicable to a load in an import-constrained Capacity Zone, the Self-Supplied FCA Resource must be located in the same Capacity Zone as the associated load, unless the Self-Supplied FCA Resource is a pool-planned unit or other unit with a special allocation of Capacity Transfer Rights.