Least Cost Integrated Resource Plan

Granite State Electric Company and New England Power Company d/b/a National Grid

nationalgrid

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1. Executive Summary

Granite State Electric Company and New England Power Company d/b/a National Grid ("National Grid" or "Company") are submitting this least-cost integrated resource plan pursuant to RSA 378:38. This filing provides an overview of National Grid's transmission and distribution planning processes and explains how demand response and energy efficiency are incorporated into the planning processes. The Company's planning processes are intended to provide safe, reliable, efficient and cost-effective service to its customers. They have been designed to align with the requirements of the North American Electric Reliability Council ("NERC"), the Northeast Power Coordinating Council ("NPCC"), and all applicable federal and state laws and regulations. Furthermore, the Company continues to collaborate with stakeholders and market participants to design a transmission planning process that is transparent, that complies with FERC procedures, and that is coordinated with neighboring utilities and the Independent System Operator of New England ("ISO-NE").

In traditional integrated resource planning ("IRP"), electric utilities would evaluate different options for meeting future electricity demands of its customers and select the optimal mix of resources that minimizes the cost of electricity supply while meeting reliability needs and state policy objectives. With the advent of restructured electricity markets, many stakeholders, including state and federal policymakers, utilities, independent power producers, power markets, and regional transmission operators ("RTOs") play an integral role in system planning. Moreover, the role of the electric utility (particularly with respect to generation) has changed so that an IRP in the traditional sense can no longer be conducted. With restructuring of electricity markets, National Grid's transmission planning is coordinated with ISO-NE and other regional transmission owners. Through this coordinated process, projects that have a regional benefit are identified. Likewise, the Company's distribution planning has also been restructured to accommodate distributed resources and will need to undergo further changes as smart grid, plug-in electric vehicles ("PHEV") and innovative new technologies are deployed.

In this Plan, National Grid describes the processes that it uses to ensure that its transmission and distribution systems are maintained to meet both state and federal requirements. Section 2 of the Plan describes the energy markets currently administered by ISO-NE and how they are being structured to procure adequate supply and demand resources to meet reliability objectives at the lowest cost. Sections 3 and 4, respectively, describe the transmission and distribution planning processes that National Grid has adopted to ensure the reliable operations of the electric grid. Section 5 describes the role of demand response and distributed generation in the electric markets and how National Grid incorporates such resources into its transmission and distribution planning processes. Lastly, Section 6 describes National Grid's participation in the State's CORE Energy Efficiency Programs and how they interrelate to the Company's resource planning.

2. Electricity Markets in New England

2.1 ISO-NE, NEPOOL, and National Grid's Role

ISO-NE, with input from the New England Power Pool ("NEPOOL") stakeholder process, is responsible for the administration of the wholesale electricity markets and for ensuring reliability throughout the New England region. Wholesale markets consist of energy, capacity, and various ancillary services. Through the ISO-NE markets, load serving entities, including National Grid, are able to procure supply from across the region to best meet the demands of their retail customers.

As a transmission owner, National Grid is an active stakeholder in ISO-NE and NEPOOL. The Company is engaged in all stakeholder committees, and plays an integral role in the development of market rules and in the formulation of market structure. National Grid believes that its customers are best served through competitive markets where the most efficient resources (both traditional supply and demand-side) are used to serve customers.

Competitive markets are most efficient when a delivery system is in place that allows open access to all participants. As such, National Grid is actively engaged in the ISO-NE planning process to address the reliability and economic needs of the system. Furthermore, as policymakers increasingly recognize the need to address climate change, National Grid believes that an increasing commitment to developing new infrastructure will be necessary to support the integration of renewable resources into the electric grid. Significant increases in renewable resources in New England will be critical if New Hampshire and the entire New England region are to be able to meet renewable portfolio standards and combat climate change. National Grid is fully committed to meeting these important policy objectives and regulatory requirements.

2.2 Forward Capacity Markets and Demand Response

ISO-NE and NEPOOL have made significant gains in the area of integrating demand side resources into the wholesale capacity market via the recent implementation of the Forward Capacity Market ("FCM"). Through the FCM, New England is able to secure capacity for the region to meet long-term electricity needs. The structure of the FCM allows for competitive auctions that are held more than three years ahead of one-year capacity commitment periods in which new and existing resources compete to provide the Installed Capacity Requirement for New England. National Grid plays a significant role in ensuring that this market framework is beneficial to the consumer and brings sufficient resources to the region. Moreover, a key benefit of this structure has been the ability of demand side resources to be fully integrated and compete with traditional generation resources in satisfying long-term resource adequacy needs of the region.

Demand resources participating in the FCM fall into two groups: passive and active. Passive resources are primarily energy efficiency programs implemented by utility and state programs, such as the CORE programs in New Hampshire. These measures are classified as passive because they are not dispatchable; load reductions from these resources are incorporated into load forecasts. Active resources, which are the majority of demand side resources, include dispatchable demand response and emergency generation. For the most part, market participants with active resources have aggregated many customer facilities into resources by dispatch zone, so that they can respond to day ahead and real-time dispatch instructions in much the same way that generators are dispatched. There are great benefits in having dispatchable demand response resources available; however, these benefits are limited to those parts of the transmission and distribution system where participating customers are located. In addition, system operators must factor both expected load reductions and load restoration into system operations considering both import and export constrained zones within the system.

National Grid is considering mechanisms it might put in place to potentially leverage active demand resources to assist with local or regional congestion and/or contingency operations. As end use customers increasingly are committing to respond to FCM dispatch, there may be opportunities to leverage this participation to address the needs of the local transmission and distribution system; however, more work must be done to examine the costs and benefits. Highly congested areas of the system will first be explored to determine if such resources could be used to avoid or defer the need to make capital investments.

2.3 Price Responsive Demand Resource Integration

In addition to the FCM, ISO-NE and stakeholders are developing energy market "Price Responsive Demand" programs that would allow demand resource integration into the hourly energy markets. Both supply side and demand side approaches are being developed. To facilitate greater participation and market efficiencies, demand resources might be allowed to submit energy offers for day ahead dispatch in the energy market under the supply side approach. Discussions are ongoing to determine the proper compensation levels and cost allocations for such resources that would ensure the most efficient market outcomes.

ISO-NE is also exploring a demand side product that would bundle wholesale markets into a dynamic hourly price that could be utilized for a retail customer offering. Such an alignment of retail tariff options with the wholesale hourly energy markets could allow the benefits of competitive markets to be directly realized by end-use customers, and it could also drive participant behavior changes that would benefit all customers. In a recent five year period analysis comparing a fully bundled wholesale hourly supply product with the fully hedged basic service rates in Massachusetts, ISO-NE estimated savings in the range of 13% to 20% for the hourly product. To the extent that participants modify their load, either by reducing load during high priced periods or by moving load from higher priced hours to lower priced hours, significant economic and system operational efficiencies will be attained. Customers choosing this type of commodity tariff could achieve cost reductions in two ways: by taking on the commodity risks inherent in an unhedged product, or by deploying load management equipment and procedures and responding to the dynamic price. Such load management would provide a physical hedge against price fluctuations as compared with the financial hedge inherent in most retail fixed price commodity products such as default service. However, implementation of hourly tariff options will require a commitment to invest in the necessary infrastructure such as hourly metering.

3. Transmission Planning and Investment

3.1 Goals and Objectives

The New England Transmission System is comprised of Pool Transmission Facilities ("PTF") and Non-Pool Transmission Facilities ("non-PTF") within the New England Control Area that are subject to ISO-NE's operational authority or control pursuant to the ISO Tariff and/or various transmission operating agreements. National Grid manages its New England transmission system – that is, its facilities in New England that are operated at voltages of 69 kV and up – as a single integrated system in order to achieve efficiencies and align processes across the business.

National Grid plans its transmission system in coordination with ISO-NE to meet applicable reliability standards and criteria. Currently, the ISO-NE process is focused on transmission upgrades that are primarily reliability driven; however, through the New England Governors' Blueprint for Renewables, ISO-NE has evaluated New England's potential to integrate large scale renewable generation into the electricity grid. The study found that through cooperation among the New England states there is great potential to economically deliver low carbon resources to consumers. National Grid is working with policymakers and other transmission owners to evaluate the potential to expand the grid that will enable New England to meet policy objectives to support the anticipated increase in renewable generation development.

3.2 ISO-NE's Integrated Planning Structure

Due to the interconnected nature of the regional transmission system, the Company's transmission system planning process necessarily requires extensive interaction and communication with the other Transmission Owners within the region. This coordination is accomplished through ISO-NE processes that ensure review and input from all appropriate stakeholders.

All transmission that is classified as PTF is evaluated through the ISO-NE Regional System Plan ("RSP")[1] process. The RSP is a compilation of the regional system planning process activities conducted by ISO-NE during a given year. This planning process focuses on meeting reliability criteria, complying with national and regional standards, while at the same time accounting for market performance and economic, environmental and other considerations. As part of this process, Needs Assessments are performed to ensure the reliability of PTF while promoting the operation of efficient wholesale electric markets in New England.

ISO-NE incorporates planned market responses into these Needs Assessments. Where these market responses do not eliminate or address the needs identified by ISO-NE, ISO-NE will develop and evaluate regulated transmission solutions. These regulated transmission solutions are then incorporated into the RSP, which is approved annually by the ISO-NE Board of Directors. The RSP undergoes extensive stakeholder review and input through the Planning Advisory Committee before being approved by ISO-NE.

Individual Transmission Owners have exclusive planning authority for those transmission facilities that are not considered PTF. However, under ISO-NE's rules for local planning, these Transmission Owners are responsible for developing a Local System Plan, which is fully vetted in open stakeholder meetings. This ensures that all transmission is planned in accordance with FERC requirements and is considered with full input from all interested stakeholders.

[1] Attachment K of Section II of the OATT describes the regional system planning process conducted by the ISO. Additional details regarding the regional system planning process are also provided in the ISO New England Planning Procedures and ISO New England Operating Procedures, which are available on ISO's website.

3.3 Transmission Planning Criteria

The goals of the Company's transmission planning criteria are to provide all customers with reliable electric service at the lowest possible cost while minimizing adverse environmental effects. Transmission planning studies are done to determine the adequacy of the transmission system and the facilities necessary to maintain adequacy. Specifically, testing is done to ensure compliance with the following:

- NERC standards. These standards apply to the Bulk Electric System ("BES") and various transmission planning ("TPL"), modeling ("MOD"), and facilities ("FAC") standards are applied. (The BES currently is the same as the NPCC Bulk Power System.)

- NPCC criteria. NPCC document A-2, Basic Criteria for Design and Operation of Interconnected Power Systems, is applied to the NPCC Bulk Power System ("BPS"), as determined through application of NPCC document A-10, Classification of Bulk Power System Elements.

- The Company's internal document, TGP28, Transmission Planning Guide. The guidance in this document applies to the Company's entire transmission system, not just the BPS or BES.

All of these documents focus on system performance under normal (all lines in service) conditions, and under specified contingencies (one element out of service, often referred to as an N-1 condition, and two elements out of service with time to make system adjustments before the second is lost, often referred to as an N-1-1 condition). They establish the framework for the use of models to predict such performance for both the current year of operation and for future years.

For its transmission planning studies, the Company utilizes PSS/E powerflow and transient stability models and Aspen OneLiner short circuit models that are developed in coordination with ISO-NE. This ensures that the best available representations for interconnected transmission facilities not owned by the Company are incorporated in the Company's studies. These models contain data on system configuration, impedances, generation sources, and loads. As necessary, the Company makes adjustments to the data obtained from

ISO-NE to reflect localized load patterns and other details not included in ISO-NE's representations, prior to beginning each study.

Compliance with NERC and NPCC standards and criteria for those parts of the PTF that are considered Bulk Power requires that the Company study at least three time periods: near term (the next year), mid-term (typically five years from when the study is being done) and long-term (typically ten years from when the study is being done). These periods are also used in planning studies of PTF that are not bulk as well as non-PTF. As appropriate to each study, limited testing of other years may also be done. Longer term studies (greater than 10 years) may also be done in conjunction with ISO-NE and other Transmission Owners.

As part of the Regional Planning Process, Needs Assessments are performed to ensure the reliability of PTF while promoting the operation of efficient wholesale electric markets in New England. Therefore, the Needs Assessments are not only done as stated above for meeting applicable reliability standards, but they are also done to ensure that: (1) adequate transfer capability is available to support local, regional, and inter-regional reliability; (2) there is adequate transfer capability to support the efficient operation of the wholesale electric markets; and (3) there is adequate transfer capability to integrate new resources and loads on an aggregate or regional basis.

ISO-NE, in coordination with the Transmission Owners and the Planning Advisory Committee, performs these Needs Assessments. A Needs Assessment that is focused on additional transfer capability may be triggered by any of the following: (1) ISO-NE's ongoing evaluation of PTF adequacy and performance; (2) NPCC reliability-based Needs Assessment; or (3) studies of proposed generation additions or retirements. In addition, ISO-NE's stakeholders may request that ISO-NE initiate a Needs Assessment to reduce congestion.

3.4 Deterministic vs. Probabilistic Planning

Transmission planning must conform to applicable reliability criteria. Two approaches are often used to conduct studies to meet criteria, often referred to as deterministic and probabilistic planning. In deterministic planning, studies are performed using cases that are set up to assume reasonably anticipated operating conditions. A set of design contingencies are tested against these cases to determine the adequacy of the system based on the criteria found in the Company's Transmission Planning Guide. The Company's Transmission Planning Guide, which is attached to this Plan as Attachment 1, defines the criteria and standards used to assess the reliability of the existing and future Company-owned transmission system. These planning criteria are followed so that transmission system facility loadings remain within system capabilities and transmission equipment is kept within a reasonable range of voltages for foreseeable contingencies under reasonably stressed conditions, including the loss of a single element such as a transmission line or substation transformer. The loading capabilities are determined using maximum allowable equipment temperatures as criteria. The allowable temperatures are established by manufacturer's design, American National Standards Institute ("ANSI") and other national standards, known material properties, or in the case of a transmission line, the design basis of the line. The range of allowable voltage is established by manufacturer's design, and ANSI and other standards. The transmission system is designed to meet these deterministic criteria to promote the reliability and efficiency of electric service on the bulk power system.

Probabilistic Planning takes into account statistical data such as forced outage rates, frequency of outages, and average duration of outages to determine the likelihood that a set of conditions and critical contingencies may occur concurrently that will result in the violation of planning criteria.

3.5 Ongoing ISO-NE Transmission Planning Studies

At this time, two major studies encompassing New Hampshire are being conducted by ISO-NE with the Company's participation: the New Hampshire Transmission Study and the Greater Boston Transmission Planning Study. The New Hampshire Transmission Study focuses on transmission facilities throughout the state. The Greater Boston Transmission Planning Study is focused on the metropolitan Boston area, but includes the extra-high voltage (345 kV) connections from PSNH's Scobie Pond substation and FPL's Seabrook substation into the 345 kV system in Northeast Massachusetts ("NEMA"), as well as 115 kV connections from the Company's NEMA system into New Hampshire. Both of these studies are being conducted according to the ISO-NE Regional Planning Process outlined above. The studies were originally announced at Planning Advisory Committee ("PAC") meetings and the results will be made public at the PAC once the studies are completed

3.6 Transmission Capital Investment Program

Based on assessments of asset condition and system performance against applicable reliability criteria, Transmission Asset Strategy and Transmission Planning are responsible for the development of strategies relative to transmission overhead lines, underground cable systems, and substations. The strategies developed have implementation ranges from medium-term (1-5 years) to long-term (over 5 years).

From these strategies, Transmission Investment Management develops capital plans which cover investment in customer connections, system reinforcement and asset replacement. A major update of the capital plan is made annually. The capital program is comprised of mandatory and non-mandatory investments. Mandatory capital investments generally consist of transmission system additions, improvements and connections that are executed in accordance with requests made by generator and load customers, and which are required to comply with reliability criteria promulgated by ISO-NE, NYISO, NYSERC and NERC and all applicable laws and regulations. Non-mandatory investments are under the Company's control in the short and medium term and consist mainly of asset replacement and refurbishment programs designed to improve and sustain system reliability. After conducting a thorough analysis, National Grid has determined that no transmission projects are needed for reliability of its New Hampshire transmission system in the near term.

3.7 Integrating Renewables to Meet Regional RPS Targets

The Company participated in ISO-NE's "Renewable Blueprint for New England" which evaluates the ability of the region to meet renewable supply targets. The study identifies that the region as a whole has sufficient resources within the region to meet New England States RPS targets (and includes potential wind resources that have been identified in Northern New Hampshire). Further, the study found that it is possible for an increased amount of wind resources (both onshore and offshore) of 12,000 MW, which could provide consumers with 23 percent of their energy consumption produced by renewable resources; however, such a possibility cannot occur without investments in transmission. The New England states must work together and coordinate in order to bring cost-effective, secure, low carbon resources to the market. National Grid's own analysis shows that through robust transmission planning, both operational and integration issues associated with intermittent generation can be overcome.[2]

The Company is actively working with policymakers throughout the region to develop the roadmap for bringing cost-effective, low carbon resources to market and aggressively pursuing energy efficiency as the most cost effective way to allow our customers to manage their

[2] National Grid, "Transmission and Wind Energy: Capturing the Prevailing Winds for the Benefits of Customers" (Sept. 2006), pp. 12-17. A copy of this document is attached to this Plan as Attachment 2.

energy consumption. We believe that it is imperative that we act now to combat climate change and achieve the goal of integrating renewable resources into the State's electric grid and wider New England electricity markets.

3.8 Identification of System Constraints

The Company's planning process does not explicitly evaluate the reduction of congestion on the transmission system as ISO-NE is best suited to conduct this evaluation given that such an evaluation must be conducted on a regional basis. In conducting such an analysis, the ISO will evaluate potential bottlenecks that may have a reliability or market impact and would work with the Transmission Owners on solutions. Under the requirements of FERC, ISO-NE is also engaged in conducting long range market efficiency studies that evaluate market dynamics under various scenarios. Stakeholders can propose scenarios for the ISO to study annually. This year, the New England States Committee on Electricity (NESCOE) requested that ISO conduct a study on New England's power system with a 20 year outlook. The study, intended to follow on the "New England Blueprint for Renewables" study, could provide a forecast that would extend the ISO-NE Reliability System Plan and would provide inputs into the Eastern Interconnection-wide Planning Collaborative, commissioned by the U.S. Department of Energy to evaluate electric system planning throughout the interconnection. The New England Blueprint for Renewables study will address transmission necessary to accommodate the incorporation of renewables resources needed to meet regional RPS targets and the retirement of less efficient carbon intensive generation.

4. Distribution Planning and Investment

4.1 Goals and Objectives

The primary goals of the Company's distribution planning process are to provide adequate capacity for each element of the electrical system and to ensure reliable and economic service to customers. System enhancements are planned to optimize capital expenditures while maintaining acceptable standards of service. In order to meet these goals, planning engineers utilize tools and processes to evaluate the capability and performance of the system with respect to anticipated loading. Efficiency is met by utilizing existing capability on circuits that are under-utilized before building new circuits to offset circuits loaded beyond capability, thus making the system more reliable. As such, system performance is measured as a percentage of asset utilization.

4.2 Applicable Distribution Terminology

For purposes of distribution planning, it is important to distinguish between the terms "supply system," "supply line," "distribution system" and "distribution line." A supply system is a collection of electrical facilities including transformers and lines that transports power between substations. The objective of a supply system is to move power from one substation to another for use at its final destination. From a distribution perspective, a supply system in New England operates at voltages below 69 kV down to 13 kV, and the voltage is not regulated.

A supply line may be overhead or underground that operates within the voltage levels and conditions described above. A typical supply line may feed power to three or more substations. With occasional exceptions, supply lines are part of a network grid, that is, more than one line is connected between the same two substations. They are part of a system in which there is more than one route between any two substations. Usually, at least two supply line routes flow into any one substation, so that feed can be maintained if one line fails.

A distribution system is a collection of overhead and underground lines that route the power from the substation to customers for direct use. Transformers change voltage at substations from transmission or supply lines to primary distribution levels, which range from 13 to 4 kV. Distribution voltages are regulated. Additional transformation occurs throughout each distribution line to convert voltage to a more practical useable value, such as 120 or 240 volts.

A distribution line is a single radial feeder that can serve up to 12 MVA of load. The main line of each feeder branches into several main routes that end at open points where the feeder meets the ends of other feeders. Each feeder is usually divided into several switchable elements. During emergencies, segments can be re-switched to isolate damaged sections and route power around outaged equipment to customers who would otherwise have to remain out of service until repairs were made. All individual distribution lines in an area constitute a distribution system.

4.2 Distribution Planning Process

The distribution systems in New England are, in general, summer peaking and summer limited. Therefore, capacity reviews are performed following the summer season. Capacity reviews consist of reviewing the ratings of the limiting elements on each substation and circuit in comparison to its actual loading to screen for immediate concerns. In addition, load growth forecasts are updated annually and applied to each circuit to predict future loading constraints. These forecasts include estimated load growth net of known energy efficiency activities and typically assume that any existing distributed generation (discussed further in Section 5) continues to operate as it has historically. Those distribution facilities expected to exceed their capabilities during the next peak period will have action plans developed for immediate implementation. For those facilities in which loading constraints are forecasted further in the future, long range area planning studies are defined and prioritized and alternatives are considered.

In addition to reviewing each circuit's performance under peak load conditions, a contingency response screening is performed considering the loading and emergency capability of various interconnections. Following these reviews and resulting studies, projects are defined, funded and scheduled in the work plan to meet the forecasted capacity needs.

It should be noted that losses occur on any electrical system due to the impedance of different equipment such as conductors and transformers. Power is used up by the electrical system in the form of losses in the process of delivering power. The planning process results in infrastructure development projects that impact system losses (typically reducing them). One example includes the installation of shunt capacitors which compensate for system reactive demands and reduce the real losses associated with supplying them. Another system improvement which reduces system losses is the installation of larger conductors or additional circuits to address thermal constraints.

4.3 National Grid's Reliability Metrics

The indices of service reliability are the system average interruption frequency index ("SAIFI") and the customer average interruption duration index ("CAIDI"). The product of these two indices is the average annual duration of interruption per customer served ("SAIDI"). Since the total system is involved in supplying the customer, ensuring an acceptable reliability of service to all customers requires designing the supply and the distribution systems in an integrated manner to limit the interruption of energy delivery.

The Company measures its reliability performance in New Hampshire using SAIDI and SAIFI as required by the New Hampshire Public Utilities Commission ("NHPUC").

These indices are mathematically calculated as follows:

$$SAIFI = \frac{\text{Total Number of Customer Interruptions (CI)}}{\text{Total Number of Customers Served (CS)}}$$

$$SAIDI = \frac{\sum \text{ Customer Interruption Durations (CMI)}}{\text{Total Number of Customers Served (CS)}}$$

CI = Customers Interrupted

CMI = Customer Minutes Interrupted

CS = Customers Served (averaged over a period of time, such as month or year)

The main causes of distribution system related outages in New Hampshire are tree contacts, animal contacts, equipment deterioration and lightning. The planning strategy to limit the number of customers affected by these outages include the Feeder Hardening Program, Inspection and Maintenance Program, Recloser Program, space cable installations and Substation Animal Fence installations. The Feeder Hardening Program identifies the best feeders for remediation based on overhead deteriorated equipment and lightning protection needs. Overhead equipment identified for replacement includes cutouts, crossarms, insulators, poles, guys and anchors and switches. Lightning protection upgrades include the installation of arresters, grounding and equipment bonding. Additional actions include animal protection, overloaded transformer replacement and recloser installations. The Feeder Hardening Program is expected to conclude at the end of FY11, to be replaced with the Inspection and Maintenance Program.

The Inspection and Maintenance Program involves comprehensive surveys of overhead lines which identifies issues similar in nature to the Feeder Hardening Program. The I&M Program is augmented with infrared inspections of both line and substation equipment, substation equipment visual and operational inspections and helicopter patrols of distribution supply facilities. The Recloser Program installs automatic switching devices at selected locations to isolate faulted feeder sections, and limit the number of customers affected by a fault on the electric distribution system.

Spacer cable is an overhead primary distribution system consisting of covered conductors held in a close triangular configuration by spacers that are supported by a messenger and attached to a bracket on a pole. Spacer cable installations are recommended on heavily treed areas to mitigate the potential for outages caused by incidental contact of tree limbs to the primary conductors. Substation Animal Fence Installations are effective against ground animal (squirrels, raccoons, etc.) contact of electrical equipment.

4.4 Tools used to Model and Evaluate National Grid's Distribution System

Loadflow Analysis - These tools enable engineers to evaluate loading and voltage on all electrical system elements such as transformers, lines and other pieces of equipment. The actual electrical configuration can be modeled in these programs, which allows the simulation of various system conditions, and subsequent analysis.

The PSLF and PSSE loadflow programs are used to evaluate the transmission and supply systems. The CYME application enables analysis of distribution feeders.

Short Circuit Duty - The ASPEN program assists in determining the short circuit duty at all transmission and distribution facilities that are modeled in the system.

Mapping Tools - The Graphical Interface System ("GIS") geographically maps supply and distribution lines throughout New England.

Load Data - The Energy Management System ("EMS") provides real time loading and voltage data for monitored facilities.

The Plant Information ("PI") system provides historical load and voltage data for various electrical facilities throughout New England.

The FeedPro application records historic manual load readings for all New England facilities.

The Remote Access Pulse Recorder ("RAPR") system provides monthly minimum and peak loading information for selected sites throughout New England.

4.5 Capital Investment Plans

The following capital projects were completed or are being implemented in New Hampshire by National Grid in calendar years 2009 to 2012. The expected year in service indicated below for each project is a calendar year.

(a) New Feeder Position and Distribution Line – 13L3

Facilities Involved: Spicket River #13 substation

Voltages: 13.2 kV

Geographic Area Impacted: Salem

Narrative Description of Project: A new feeder position (13L3) and associated distribution line work was constructed for a 13kV feeder supplied from the Spicket River #13 substation. Construction included adding one 23/13kV, 7.5/9.375 MVA Transformer and a modular feeder position including circuit breaker, relays and 3-333 kVA regulators along with 1,400 circuit feet of 1000 Al underground cable and re-conductoring approximately 1,000 feet of 4/0&1/0 Al bare open wire with 477 ACSR.

Problem Being Solved: Loading on the Spicket River 13L2, Pelham 14L1, and Old Trolley 18L3 and Pelham T1 transformer was forecasted to reach summer normal ratings during peak loading periods in 2010. The new Spicket River 13L3 provides capacity to enable load transfers from these feeders, and keep loading within ratings.

Completed, in service: 2009

(b) Line Reconductoring – 2352 and 2393

Facilities Involved: Salem Depot #9 and Golden Rock #19 substations

Voltages: 23 kV

Geographic Area Impacted: Salem

Narrative Description of Project: Re-conductor the 2352 and 2393 lines in order to resolve existing contingency loading concerns for the loss of the 2352 or 2393 lines. Construction includes reconductoring 1.42 miles of 2352 line from Barron Ave. to Olde Trolley with 1113 kcmil ACSR 54/19 conductor and replacement of 43 poles with crossarms and associated hardware. Re-conductor the Golden Rock 2393 underground getaway with parallel 1500 kcmil cable.

Problem Being Solved: The 2352 line from Barron Ave. to Olde Trolley is forecasted to reach its summer emergency ratings for the loss of the 2393 line and also the 2393 is anticipated to exceed its summer emergency rating for the loss of the 2352 line in 2010. The line re-conductoring will provide 2352 and 2393 with enough capacity and keep loading within ratings.

Expected Year in service: 2012

(c) Feeder Regulator replacement - 6L3

Facilities Involved: Hanover 6L3 Feeder

Voltages: 13.2 kV

Geographic Area Impacted: Hanover

Narrative Description of Project: Replace the 6L3 voltage regulators in order to increase the feeder thermal capability. Construction includes replacing the existing regulator with three single phase 3-333 kVA units.

Problem Being Solved: The feeder was forecasted to exceed its summer normal rating during the summer 2008 peak loading period. The regulator replacement has provided the feeder with additional feeder and has kept loading within ratings.

Completed, in service: 2009

(d) Substation Capacitor Bank – Slayton Hill

Facilities Involved: Slayton Hill Substation

Voltages: 13.2 kV

Geographic Area Impacted: Lebanon

Narrative Description of Project: Add 3.6 MVAr capacitor bank to bus 1 to provide voltage support for the loss of bus 2, Transformer 2 or supply line.

Problem Being Solved: Bus voltage under contingency conditions is low.

Expected Year in service: 2011

5. Demand-Side Resources

Demand-Side Resources can be broadly defined as systems and controls in customer facilities that allow customers to reduce or control their use of energy. These generally consist of energy efficiency measures, demand response, distributed generation, energy storage, and load controls. Energy efficiency measures generally produce savings whenever a particular load is running, while renewable distributed generation such as wind and solar PV provides energy on an intermittent and uncontrollable basis. These types of resources are therefore considered passive resources. Other demand resources are dynamic and can be utilized when economically justified; these are considered active demand resources.

Active demand resources, coupled with incentives such as demand response payments or dynamic or time of use rate design, can create opportunities for customers to benefit from time specific reductions in energy consumption and/or shifting the times that energy from the grid is consumed. Through the use of active demand resource technologies and appropriate incentive mechanisms, retail costs can more closely reflect time varying costs to produce and deliver electricity, resulting in behavior changes that create higher system efficiencies. Generally, this approach works in conjunction with smart metering systems that measure hourly consumption and provide information directly to the customer. Demand resources are key to National Grid's long term strategy for least cost system planning and operation. The Company anticipates that, over the long term, increasing use of demand resources and smart grid technologies will result in lower load factors, resulting in reductions in capital investment on capacity related transmission, distribution, as well as generation projects.

As various demand resource technologies mature and costs are reduced, the Company intends to analyze whether further developing or accelerating the adoption of these technologies and systems in a particular area may be a cost effective alternative to specific upgrades of the transmission or distribution system. As appropriate models for demand side alternatives are developed, their analysis will be incorporated into the Company's planning processes. In cases where such demand side approaches are cost effective and are expected to provide equivalent or superior levels of reliability and service quality as compared with traditional capital projects, the Company may propose such demand side alternatives.

5.1 The Link Between Demand Response and Planning

As of June 1, 2010, demand response resources will participate on a comparable basis along with generation in the regional FCM administered by ISO-NE. Such resources are able to compete with generation and imports, allowing New England to meet its resource adequacy requirements. Beginning in June 2010, ISO-NE will dispatch active demand response resources in order to prevent supply deficiencies. The dispatched resources are expected to reduce overall system peak loads; however, their impact on peak loads on National Grid's transmission and distribution systems will depend on the location of the specific demand resources dispatched in each instance.

To the extent that FCM dispatch of demand resources does affect peak loads within the Company's system, this will alter the Company's system planning going forward. Therefore, the positive impacts of demand response participating in the FCM will be realized in the Company's planning process after those savings have been achieved. Because individual demand response resources participating in the FCM are typically obligated for as little as one year and there are opportunities for resource owners to transfer obligations between supply and demand resources, there is also an increased level of risk that resources will be in placed in the same locations within the system over time.

Under the FCM construct, the Company will have no ability to dispatch these resources due to a local loading or contingency issue. In limited cases, the Company has used targeted, or local, demand response in cases where a transmission or distribution solution was unable to fulfill a need in a timely manner; however, in most cases, the Company has found that demand response by itself is either uneconomic or not of enough scale to eliminate the need for a transmission investment. The Company will incorporate screening of targeted demand response programs into its alternative analysis for system upgrades going forward, potentially leveraging the increasing amounts of demand response resources participating in the FCM.

5.2 Incorporation of DG Facilities Into Distribution Planning

National Grid has experienced a significant increase in the amount of distributed generation (DG) being interconnected to its distribution system. The decision to install and run DG systems is made by customers based on economic, environmental, and operational drivers. Because the Company does not control and cannot be assured of the development or operation of specific DG systems, their impact on system planning is typically felt after they are in place. Once in place, the Company does incorporate existing DG output into future load projections, while at the same time recognizing its obligation in some cases to provide back-up service to customers with DG systems.

The majority of the newer DG systems are renewable photovoltaic (PV) and wind generation systems. The output of these systems is intermittent and, in general, uncontrollable. PV systems typically offer peak reductions during summer peaks in the range of 20-25% of their ratings, because summer peaks typically occur in the mid afternoon on the hottest days when the sun is not at the optimal angle and PV panels are less efficient due to ambient temperatures. PV typically does not impact winter peak loads, because winter peaks occur in the evenings after the sun is down. Wind resources are also highly variable and may not impact peak loads the Company expects to experience at any given location due to this variability. It is likely that additional combined heat and power (CHP) generation may be installed as fuel prices increase and technologies become more mature. However, in many cases such systems are run coincident with thermal requirements that are heavily weighted towards the winter months and therefore may not be able to significantly impact summer peak loads. To the extent that DG does impact peak loads, the Company incorporates their historic output into system planning going forward.

The interconnection process for customers to install and run DG in parallel with the Company's distribution system is dependent on the DG size and technology.[3] Larger DG systems proposed to interconnect with the Company must apply for interconnection and supply sufficient technical information to allow the Company to determine the scope and cost of any potential modifications to the Company's distribution system that may be required in order to accommodate the DG system. This typically requires an engineering study performed by the Company at the DG developer's cost. Safety, system operation, protection, and service quality are the primary needs the Company considers in such studies.

6. Energy Efficiency Programs

New Hampshire's electric utilities (Granite State Electric Company d/b/a National Grid, New Hampshire Electric Cooperative, Inc., Public Service Company of New Hampshire and Unitil Energy Systems, Inc.) jointly prepare and file the CORE Energy Efficiency Programs. CORE programs have been offered since 2002.

[3] The simplified process for inverter based systems under 100 KW (typical most solar and small wind systems) can be found at https://www.nationalgridus.com/granitestate/business/energyeff/4_interconnect.asp

National Grid's most recently approved energy efficiency programs are described in the CORE filing in Docket No. DE 09-170, approved by Order Nos. 25,062 (January 5, 2010) and 25,099 (April 30, 2010).[4] Current programs must be filed annually. While these are one-year approvals, the New Hampshire electric utilities also have authority to make commitments in the current year for projects that will be completed in future years.

There are eight CORE programs providing products and services tailored for business, residential and income-eligible customers or members[5]. Each year the New Hampshire electric utilities work together to review the CORE Programs, make adjustments and improvements as needed or suggested by customers, interested parties, Staff and program administrators. The plans also include utility-specific programs that are used to test certain aspects of energy efficiency and to try new programs that may be pertinent to one utility's customers or to test new technologies.

Since the introduction of the CORE Programs in June 2002, the New Hampshire electric utilities have reported program results quarterly. In the beginning, results were slow in coming, but customer demand for energy efficiency products and services has steadily grown to the point where, today, the electric utilities are making commitments for projects that will be completed next year and the year after.

The CORE Programs in place today have been thoughtfully developed and enhanced by many different parties since 1998. The results of the CORE Programs since their inception on June 1, 2002, through December 31, 2008, have consistently exceeded expectations. Key statewide benchmarks highlighting the results include:

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[4] SB 300, passed shortly after the Commission approved the 2010 CORE Programs, adjusted downward the funding for energy efficiency in 2010. CORE utilities revised and refiled the joint plans for 2010, which were approved by the Commission on April 30, 2010. Where appropriate, the values in this section for 2010 reflect the revised plans.
[5] Hereinafter the word "customer" means both customers and NHEC members.

The programs have saved 6.1 billion lifetime kWh – enough energy to power the city of Concord for 16 years!

Saving 6.1 billion kWh is equivalent to saving $955 million at today's average cost of 14.39¢/kWh – benefiting both customers and the New Hampshire economy. Based on CORE Program expenditures, this represents a return for customers of more than $8 for every program dollar invested.

The CORE Programs have provided customers with 474,000 efficiency products or services and reached customers in every city and town served by the New Hampshire electric utilities. In addition, the CORE Programs have provided training and information through customer seminars, point-of-sale displays, brochures, and catalogs to tens of thousands more.

Reducing customers' energy needs has the added benefit of reducing power plant emissions. Based on the regional dispatch of plants, the New Hampshire electric utilities will reduce emissions of CO_2, SO_2, and NO_X by 3.7 million tons – equivalent to the annual emissions of more than 780,000 cars.

The table below shows more information on savings over the past few years. Results for 2009 have not yet been filed and finalized.

New Hampshire CORE Energy Efficiency Programs Results Summary							
	2003	2004	2005	2006	2007	2008	Total
Lifetime kWh Savings (Million)	1,368	925	1,022	973	997	811	6,096
Customers Served	59,699	51,136	81,581	86,555	86,113	109,155	474,239
Dollars Saved (Millions)	$217.1	$146.8	$162.2	$154.4	$158.2	$116.8	$955.5
Emissions Reductions (Tons)	1,036,277	546,431	603,754	539,520	552,982	450,100	3,729,064
Lifetime kWH Cost (Cents)	1.70	1.80	1.95	1.95	1.90	2.35	1.93

The CORE Programs have saved energy at an average cost under 2.0 cents per lifetime kWh as compared to the average retail price of 14.39 cents/kWh[6]. As energy costs continue to increase, these comparisons become even more compelling. While the New Hampshire electric utilities are proud of the results achieved to-date, they are very much aware of the need to be looking ahead and to work with Staff and other interested parties to find opportunities to improve the quality and effectiveness of the CORE Programs.

The electric utilities requested and the Commission approved[7] the use of a single avoided cost methodology for Generation, Transmission, and Distribution. Use of common avoided costs by the utilities ensures that all New Hampshire customers will have access to the same programs and services. The electric utilities use the avoided generation costs from the *Avoided-Energy-Supply Costs in New England: 2009 Report*[8] ("2009 AESC") in determining the Benefit-to-Cost ratios of the CORE Programs.

The present value of avoided costs over the life of program measures was calculated using a nominal discount rate of 3.25% and a general inflation rate of 1.56%[9]. The 2009 AESC avoided costs also include a 9% generic wholesale risk premium to account for the expected differential between retail and wholesale market prices[10].

In accordance with Commission Order No. 23,850, in DE 01-057, dated November 29, 2001, the electric utilities have based their avoided transmission and distribution costs on the weighted average of New Hampshire utility costs and have escalated them for inflation and put

[6] OEP's "Average Fuel Prices as of September 2, 2008", http://www.nh.gov/oep/programs/energy/fuelprices.htm.
[7] DE 01-057, Order No. 23,850, November 29, 2001, page 19.
[8] *Avoided Energy Supply Costs in New England: 2009 Report*, Revised October 23, 2009.
[9] Prime rate as of June 1, 2009, in accordance with Energy Efficiency Working Group Report, Section 7, page 17. Prime rate data taken from http://www.moneycafe.com/library/primerate.htm
[10] In recognition of diversity among states and utilities in energy service procurement and retail pricing policies, the contractor provided the sponsors the option to remove the adder from the avoided cost data. Some of the CORE utilities have concluded that the 2009 AESC forecasted wholesale prices of energy and capacity represent a better approximation to the cost of energy service avoided by their retail customers than the prices which include a 10% increase to the wholesale prices.

them in 2009 dollars. Use of common avoided costs by the utilities ensures that all New Hampshire customers will have access to the same programs and services.

Table 1 below also includes an adjustment to reduce the energy and capacity line loss multipliers by the estimated losses that are accounted for in the 2009 forecast of energy prices.

Table 1

Marginal T&D Costs and Line Loss Factors ($2008)

	MDC ($/kW-yr)		MTC	Line Loss Multipliers				
				Transmission	Summer	Winter	On-Peak	Off-Peak
	Res.(1)	C&I(2)	($/kW-yr)	Capacity	Capacity	Capacity	Energy	Energy
Granite State	$51.11	$51.11	$24.78	1.1220	1.1500	1.1350	1.0630	1.0890
PSNH	$25.12	$25.12	$3.76	1.0000	1.0820	1.0820	1.0820	1.0840
Unitil	$71.57	$71.57	$28.67	1.0000	1.1217	1.1217	1.1217	1.0152
NHEC	$101.38	$101.38	$64.57	1.0000	1.0917	1.0917	1.0917	1.0917

MWh Sales to Ultimate Customers in 2008

Granite State	639,471	6.04%
PSNH	7,970,949	75.34%
Unitil	1,224,893	11.58%
NHEC	744,150	7.03%
Total	10,579,463	100.00%

Weighted Average Marginal T&D Costs and Line Loss Factors
(2009 Energy Line Loss Multipliers have been reduced by estimated transmission losses.)

	MDC ($/kW-yr)		MTC	Line Loss Multipliers				
				Transmission	Summer	Winter	On-Peak	Off-Peak
	Res.(1)	C&I(2)	($/kW-yr)	Capacity	Capacity	Capacity	Energy	Energy
2009$	$37.44	$37.44	$12.19	1.007	1.071	1.070	1.062	1.053

Avoided generation costs for New Hampshire, in 2009 dollars, may be found in Appendix B, pages B-5 and B-6 of the 2009 AESC study.

To evaluate each program, savings for each component are multiplied by the appropriate avoided cost factor for each year of the expected measure life of the measure or program. Benefits are present valued back to the base year using the real discount rate.

Savings projections for the Company's 2010 CORE Programs are found in Table 2. Implementation costs for the Company's 2010 CORE programs are found in Table 3. Avoided costs, or benefits, for the Company's 2010 CORE programs are found in Table 3 Total Resource Cost Test results for the Company's 2010 programs are found in Table 4. Because CORE activities have reduced historic loads, they are by default incorporated into the Company's load forecasts used to conduct distribution and transmission planning efforts.

Table 2: 2010 Savings

Sector and Program		Load Reduction			MWh Saved	
		Summer kW	Winter kW	Lifetime kW	Annual	Lifetime
Residential		426	566	6,211	600	5,463
	Energy Star Homes	380	442	5,763	52	736
	Home Energy Solutions	6	18	59	85	1,080
	Energy Star Lighting	23	87	153	378	2,502
	Energy Star Appliances	17	20	236	85	1,145
Low Income		7	11	106	65	1,010
	Home Energy Assistance	7	11	106	65	1,010
Com/Ind		805	581	10,517	4,652	60,779
	New Construction	68	50	1,039	296	4,578
	Large Business Energy Solutions	637	476	8,287	3,928	51,065
	Small Business Energy Solutions	99	54	1,191	428	5,136
Grand Total		1,237	1,158	16,834	5,316	67,252

Table 3. National Grid Program Cost-Effectiveness

Sector and Program		Total Benefits	Capacity				Energy				
			Generation				Winter		Summer		Non-Electric
		Total Benefits	Summer	Winter	Trans	MDC	Peak	Off Peak	Peak	Off Peak	Resource
Residential		$2,024,209	$177,423	$0	$68,562	$210,579	$112,101	$135,922	$57,407	$66,075	$1,196,141
	Energy Star Homes	$1,354,638	$163,256	$0	$63,492	$195,008	$14,685	$18,552	$8,254	$9,101	$882,289
	Home Energy Solutions	$84,382	$1,783	$0	$675	$2,073	$22,390	$27,237	$11,199	$13,221	$5,804
	Energy Star Lighting	$181,295	$5,751	$0	$1,761	$5,408	$51,662	$61,486	$25,504	$29,724	$0
	Energy Star Appliances	$403,894	$6,633	$0	$2,634	$8,090	$23,363	$28,647	$12,449	$14,029	$308,049
Low Income		$455,047	$3,448	$0	$1,147	$3,523	$20,909	$25,516	$10,507	$12,479	$377,518
	Home Energy Assistance	$455,047	$3,448	$0	$1,147	$3,523	$20,909	$25,516	$10,507	$12,479	$377,518
Com/Ind		$5,157,508	$296,444	$0	$117,898	$362,108	$1,967,566	$941,862	$1,019,353	$452,276	$0
	New Construction	$411,840	$29,120	$0	$11,448	$35,162	$168,211	$54,165	$87,527	$26,207	$0
	Large Business Energy Solutions	$4,275,259	$233,359	$0	$92,984	$285,588	$1,595,696	$838,582	$826,535	$402,516	$0
	Small Business Energy Solutions	$470,410	$33,965	$0	$13,466	$41,358	$203,660	$49,116	$105,291	$23,553	$0
Grand Total		$7,636,764	$477,314	$0	$187,607	$576,210	$2,100,576	$1,103,300	$1,087,267	$530,831	$1,573,659

Table 4. National Grid Program Cost-Effectiveness

2010 TRC BENEFIT COST TEST								
National Grid								
				Program				
		TRC	**Total**	**Total**	**Implementa tion**	**Customer**	**Evaluation**	**Shareholder**
		Benefit/	**Benefits**	**Costs**	**Expenses**	**Contribution**	**Cost**	**Incentive**
Sector	**Program Name**	**Cost**	**($000)**	**($000)**	**($000)**	**($000)**	**($000)**	**($000)**
Commercial & Industrial	New Construction	1.22	$412	$336.9	$282.4	$40.4	$14.1	NA
	Large Business Energy Solutions	4.75	$4,275	900.9	$239.3	$649.6	$12.0	NA
	Small Business Energy Solutions	1.25	470	375.6	$299.2	$61.4	$15.0	NA
Commercial & Industrial Total		**3.08**	**$5,158**	**$1,676.2**	**$820.9**	**$751.3**	**$41.0**	**$62.9**
Residential	Energy Star Homes	7.41	$1,355	$182.9	$131.4	$44.9	$6.6	NA
	Home Energy Solutions	1.80	$84	46.9	$40.8	$4.1	$2.0	NA
	Energy Star Lighting	2.96	$181	61.3	$38.9	$20.5	$1.9	NA
	Energy Star Appliances	3.45	$404	117.2	$42.2	$72.8	$2.1	NA
	Home Energy Assistance	2.38	$455	191.3	$182.2	$0.0	$9.1	NA
Residential Total		**3.84**	**$2,479**	**$645.9**	**$435.5**	**$142.4**	**$21.8**	**$46.2**
Grand Total		**3.29**	**$7,637**	**$2,322.1**	**$1,256.4**	**$893.7**	**$62.8**	**$109.1**

New Hampshire CORE Energy Efficiency Goals - 2009

	National Grid		NHEC		PSNH		UNITIL		TOTALS	
PROGRAMS										
Energy Star Homes										
Number of Homes / Lifetime kWh Savings	101	438,600	23	124,000	347	3,987,604	41	394,756	512	4,944,960
B/C Ratio / Planned Budget	3.48	$275,717	1.17	$113,052	1.70	$823,577	1.40	$150,000		$1,362,346
Home Energy Solutions										
Number of Units / Lifetime kWh Savings	98	907,654	35	1,416,000	650	3,870,107	85	966,400	868	7,160,161
B/C Ratio / Planned Budget	0.91	$85,548	1.24	$139,109	0.90	$1,560,462	1.90	$234,270		$2,019,389
Energy Star Appliances										
Number of Rebates / Lifetime kWh Savings	710	1,035,370	956	1,384,000	9,965	15,243,734	1,089	1,882,681	12,720	19,545,785
B/C Ratio / Planned Budget	1.30	$88,614	1.47	$93,738	1.97	$606,846	1.30	$100,000		$889,198
Home Energy Assistance (see Note 1)										
Number of Units / Lifetime kWh Savings	55	1,373,943	46	571,000	514	7,201,690	76	10,597,445	691	19,744,078
B/C Ratio / Planned Budget	1.47	$264,904	1.28	$160,832	0.64	$1,935,309	1.20	$280,697		$2,641,742
Energy Star Lighting										
Number of Rebates / Lifetime kWh Savings	11,710	3,442,104	13,838	4,519,000	224,009	67,325,855	50,644	15,673,876	300,201	90,960,835
B/C Ratio / Planned Budget	2.47	$81,652	2.68	$90,738	3.75	$996,962	4.40	$170,000		$1,339,352
C&I New Equipment & Construction										
Number of Participants / Lifetime kWh Savings	24	19,342,474	14	5,414,000	106	67,241,635	7	5,635,348	151	97,633,457
B/C Ratio / Planned Budget	4.13	$400,760	2.07	$133,665	2.88	$1,902,903	3.70	$150,000		$2,587,328
Large C&I Retrofit										
Number of Participants / Lifetime kWh Savings	13	16,442,574	18	15,109,000	120	114,598,762	17	19,058,974	168	165,209,310
B/C Ratio / Planned Budget	2.17	$339,674	3.08	$131,253	2.33	$2,242,707	2.50	$325,000		$3,038,634
Small Business Energy Solutions										
Number of Participants / Lifetime kWh Savings	59	8,796,866	15	2,335,000	404	75,020,685	50	16,550,739	528	102,703,290
B/C Ratio / Planned Budget	2.20	$323,443	1.37	$92,656	1.90	$2,174,746	2.70	$347,769		$2,938,614
Educational Programs (see Note 2)										
B/C Ratio / Planned Budget		$8,608		$29,063		$127,720		$15,000		$171,783
Company Specific Programs										
Number of Participants / Lifetime kWh Savings			15	5,077,000	43	30,011,098				35,088,098
B/C Ratio / Planned Budget		$0	1.55	$191,977		$852,495		$64,994		$1,109,466
Smart Start Program										
Number of Participants / Planned Budget		$0		$15,263		$50,000		$0		$65,263
Utility Incentive										
B/C Ratio / Planned Budget		$148,825		$95,308		$1,061,898		$147,018		$1,453,049
TOTAL PLANNED BUDGET		$2,009,136		$1,286,654		$14,335,625		$1,984,748		$19,616,163

NOTES:
(1) Unitil's HEA savings target equals 410,513 lifetime kWh + (34,768 lifetime MMBtu ÷ 0.003413) = 10,597,445 lifetime kWh
(2) National Grid's Educational Program budget is included within other program budgets and therefore is not included in the total to avoid double counting.

nationalgrid

United States Operations

Transmission Group Procedure

TGP28

Transmission Planning Guide

Authorized by

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1.0 Change Control

Version	Date	Modification	Author(s)	Reviews and Approvals by
Issue 1	06 August 2007	Initial Document	Philip J. Tatro	David Wright
Issue 2	29 February 2008	Removed "Confidential" from page header	Philip J. Tatro	David Wright

2.0 Introduction

2.1 Objective of the Transmission Planning Guide

The objective of the Transmission Planning Guide is to define the criteria and standards used to assess the reliability of the existing and future National Grid transmission system for reasonably anticipated operating conditions and to provide guidance, with consideration of public safety and safety of operations and personnel, in the design of future modifications or upgrades to the transmission system. The guide is a design tool and is not intended to address unusual or unanticipated operating conditions. This Planning Guide is applicable to all National Grid facilities operated at 69 kV and above.

2.2 Planning and Design Criteria

All National Grid facilities that are part of the bulk power system and part of the interconnected National Grid system shall be designed in accordance with the latest versions of the NERC Reliability Standards, Northeast Power Coordinating Council (NPCC) Criteria, ISO-New England Reliability Standards, New York State Reliability Council (NYSRC) Reliability Rules, and the National Grid Design Criteria. The fundamental guiding documents are:

- NERC Reliability Standards TPL-001, *System Performance Under Normal Conditions*, TPL-002, *System Performance Following Loss of a Single BES Element*, TPL-003, *System Performance Following Loss of Two or More BES Elements*, and TPL-004, *System Performance Following Extreme BES Events*,
- NPCC *Basic Criteria for Design and Operation of Interconnected Power Systems* (NPCC Document A-2) and *Bulk Power System Protection Criteria* (NPCC Document A-5),
- *Reliability Standards for the New England Area Bulk Power Supply System* (ISO-NE Planning Procedure No. 3),
- *New York State Reliability Council Reliability Rules for Planning and Operation of the New York State Power System*, and
- National Grid Transmission Planning Guide (this document).

Interconnections of new generators to the National Grid transmission system in New England shall be configured and designed in compliance with the ISO-New England document, "General Transmission System Design Requirements for the Interconnection of New Generators (Resources) to the Administered Transmission System." If corresponding New York ISO requirements are established, interconnections to the National Grid transmission system in New York will be configured and designed in compliance with those requirements.

All National Grid facilities that are not part of the bulk power system, but are part of the interconnected National Grid system shall be designed in accordance with the latest version of this document.

All National Grid or National Grid transmission customers' facilities which are served by transmission providers other than National Grid shall be designed in accordance with the planning and design criteria of the transmission supplier and the applicable NERC, NPCC, ISO-NE, and NYSRC documents.

Detailed design of facilities may require additional guidance from industry or other technical standards which are not addressed by any of the documents referenced in this guide.

2.3 Operational Considerations in Planning and Design

The system should be planned and designed with consideration for ease of operation. Such considerations include, but are not limited to:

- utilization of standard components to facilitate availability of spare parts
- optimization of post contingency switching operations
- reduction of operational risks
- judicious use of Special Protection Systems (SPSs)

3.0 System Studies

3.1 Basic Types of Studies

The basic types of studies conducted to assess conformance with the criteria and standards stated in this guide include but are not limited to Powerflow, Stability, Short Circuit, and Protection Coordination.

3.2 Study Horizon

The lead time required to plan, permit, license, and construct transmission system upgrades is typically between one and ten years depending on the complexity of the project. As a result, investments in the transmission system should be evaluated for different planning horizons in the one to ten-year range. The typical horizons are referred to as near term (one to three years), mid-term (three to six years), and long term (six to ten years). The long term time frame may be extended for development of long term transmission infrastructure planning, to aid in development of long term expansion plans, and to assess the adequacy of proposed facilities beyond the ten year horizon. Projects taking less than a year to implement tend to consist of non-construction alternatives that are addressed by operating studies.

3.3 Future Facilities

Planned facilities should not automatically be assumed to be in-service during study periods after the planned in-service date. Sensitivity analysis should be performed to identify interdependencies of the planned facilities. These interdependencies should be clearly identified in the results and recommendations.

3.4 Equipment Thermal Ratings

Thermal ratings of each load carrying element in the system are determined such that maximum use can be made of the equipment without damage or undue loss of equipment life. The thermal ratings of each transmission circuit reflect the most limiting series elements within the circuit. The existing rating procedures are based on guidance provided by the NEPOOL System Design Task Force (SDTF), the NYPP Task Force on Tie Line Ratings, and industry standards. A common rating procedure has been developed for rating National Grid facilities in New England and New York which will be applied to all new and modified facilities. The principal variables used to derive the ratings include specific equipment design, season, ambient conditions, maximum allowable equipment operating temperatures as a function of time, and physical parameters of the equipment. Procedures for calculating the thermal ratings are subject to change.

Equipment ratings are summarized in the following table by durations of allowable loadings for three types of facilities. Where applicable, actions that must be taken to relieve equipment loadings within the specified time period also are included.

Equipment	RATINGS			
	Normal	Long Time Emergency (LTE)	Short Time Emergency (STE)	Drastic Action Limit (DAL)[4]
Overhead Transmission	Continuous	Loading must be reduced below the Normal rating within 4 hours[2]	Loading must be reduced below the LTE rating within 15 minutes	requires immediate action to reduce loading below the LTE rating
Underground Cables[1]	Continuous	Loading must be reduced below the 100 hr or 300 hr rating within 4 hours[2]	Loading must be reduced below the 100 hr or 300 hr rating within 15 minutes	requires immediate action to reduce loading below the LTE rating
Transmission Transformers	Continuous	Loading must be reduced below the Normal rating within 4 hours[2]	Loading must be reduced below the LTE rating within 15 minutes[3]	requires immediate action to reduce loading below the LTE rating

[1] Ratings for other durations may be calculated and utilized for specific conditions on a case-by-case basis. Following expiration of the 100 hr or 300 hr period, loading of the cable must be reduced below the Normal rating. Either the 100 hr or the 300 hr rating may be utilized after the transient period, but not both. If the 100 hr rating is utilized, the loading must be reduced below the Normal rating within 100 hr, and the 300 hr rating may not be used.

[2] The summer LTE rating duration is 12 hours in New England. The winter LTE rating duration in New England, and the summer and winter LTE rating duration in New York is 4 hours. The time duration does not affect the calculated value of the LTE rating. The duration difference reflects how the LTE ratings are applied by the ISO in each Area.

[3] The transformer STE rating is based on a 30 minute duration to provide additional conservatism, but is applied in operations as a 15 minute rating.

[4] The DAL rating is only calculated only in New England based on historical ISO requirements.

3.4.1 Other Equipment

Industry standards and input from task forces in New England and New York should continue to be used as sources of guidance for developing procedures for rating new types of equipment or for improving the procedures for rating the existing equipment.

3.4.2 High Voltage DC

High Voltage dc (HVdc) equipment is rated using the manufacturer's claimed capability.

3.5 Modeling for Powerflow Studies

The representation for powerflow studies should include models of transmission lines, transformers, generators, reactive sources, and any other equipment which can affect power flow or voltage. The representation for fixed-tap, load-tap-changing, and phase shifting transformers should include voltage or angle taps, tap ranges, and voltage or power flow control points. The representation for generators should include reactive capability ranges and voltage control points. Equipment ratings should be modeled for each of these facilities including related station equipment such as buses, circuit breakers and switches. Study specific issues that need to be addressed are discussed below.

3.5.1 Forecasted Load

The forecasted summer and winter peak active and reactive loads should be obtained annually from the Transmission Customers for a period of ten or more years starting with the highest actual seasonal peak loads within the last three years. The forecast should have sufficient detail to distribute the active and reactive coincident loads (coincident with the Customers' total peak load) across the Customers' Points of Delivery. Customer owned generation should be modeled explicitly when the size is significant compared to the load at the same delivery point, or when the size is large enough to impact system dynamic performance.

The Point of Delivery for powerflow modeling purposes may be different than the point of delivery for billing purposes. Consequently, these points need to be coordinated between National Grid and the Transmission Customer.

To address forecast uncertainty, the peak load forecast should include forecasts based on normal and extreme weather. The normal weather forecast has a 50 percent probability of being exceeded and the extreme weather forecast has a 10 percent probability of being exceeded. Due to the lead time required to construct new facilities, planning should be based conservatively on the extreme weather forecast.

3.5.2 Load Levels

To evaluate the sensitivity to daily and seasonal load cycles, many studies require modeling several load levels. The most common load levels studied are peak (100% of the extreme weather peak load forecast), intermediate (70 to 80% of the peak), and light (45 to 55% of the peak). The basis can be either the summer or winter peak forecast. In some areas, both seasons may have to be studied.

Sensitivity to the magnitude of the load assumptions must be evaluated with the assumed generation dispatch to assess the impact of different interactions on transmission circuit loadings and system voltage responses.

3.5.3 Load Balance and Harmonics

Balanced three-phase 60 Hz ac loads are assumed at each Point of Delivery unless a customer specifies otherwise, or if there is information available to confirm the load is not balanced. Balanced loads are assumed to have the following characteristics:

- The active and reactive load of any phase is within 90% to 110% of the load on both of the other phases
- The voltage unbalance between the phases measured phase-to-phase is 3% or less
- The negative phase sequence current (RMS) in any generator is less than the limits defined by the current version of ANSI C50.13

Harmonic voltage and current distortion is required to be within limits recommended by the current version of IEEE Std. 519.

If a customer load is unbalanced or exceeds harmonic limits, then special conditions not addressed in this guide may apply.

3.5.4 Load Power Factor

Load Power Factor for each delivery point is established by the active and reactive load forecast supplied by the customer in accordance with Section 3.5.1. The reactive load may be adjusted as necessary to reflect load power factor observed via the Energy Management System (EMS) or metered data. The Load Power Factor in each area in New England should be consistent with the limits set forth in Operating Procedure 17 (OP17).

3.5.5 Reactive Compensation

Reactive compensation should be modeled as it is designed to operate on the transmission system and, when provided, on the low voltage side of the supply transformers. Reactive compensation on the feeder circuits is assumed to be netted with the load. National Grid should have the data on file, as provided by the generator owners, to model the generator reactive capability as a function of generator active power output for each generator connected to the transmission system.

3.5.6 Generation Dispatch

Analysis of generation sensitivity is necessary to model the variations in dispatch that routinely occur at each load level. The intent is to bias the generation dispatch such that the transfers over select portions of the transmission system are stressed pre-contingency as much as reasonably possible. An exception is hydro generation that should account for seasonal variation in the availability of water.

A merit based generation dispatch should be used as a starting point from which to stress transfers. A merit based dispatch can be approximated based on available information such as fuel type and historical information regarding unit commitment. Interface limits can be used as a reference for stressing the transmission system. Dispatching to the interface limits may stress the transmission system in excess of transfer levels that are considered normal.

3.5.7 Facility Status

The initial conditions assume all existing facilities normally connected to the transmission system are in service and operating as designed or expected. Future facilities should be treated as discussed in Section 3.3.

3.6 Modeling For Stability Studies

3.6.1 Dynamic Models

Dynamic models are required for generators and associated equipment, HVdc terminals, SVCs, other Flexible AC Transmission Systems (FACTS), and protective relays to calculate the fast acting electrical and mechanical dynamics of the power system. Dynamic model data is maintained as required by NERC, NPCC, ISO-NE, and NYSRC.

3.6.2 Load Level and Load Models

The load levels studied in stability studies vary between New England and New York consistent with accepted practices in each Area. Stability studies within New England typically exhibit the most severe system response under light load conditions.

Consequently, transient stability studies are typically performed for several unit dispatches at a system load level of 45% of peak system load. At least one unit dispatch at 100% of system peak load is also analyzed. Other system load levels may be studied when required to stress a system interface, or to capture the response to a particular generation dispatch.

Stability studies within New York typically exhibit the most severe system response under summer peak load conditions. Consequently, transient stability studies are typically performed with a system load level of 100% of summer peak system load. Other system load levels may be studied when required to stress a system interface, or to capture the response to a particular generation dispatch.

System loads within New England and New York are usually modeled as constant admittances for both active and reactive power. These models have been found to be appropriate for studies of rotor angle stability and are considered to provide conservative results. Other load models are utilized where appropriate such as when analyzing the underfrequency performance of an islanded portion of the system, or when analyzing voltage performance of a local portion of a system.

Loads outside NEPOOL are modeled consistent with the practices of the individual Areas and regions. Appropriate load models for other Areas and regions are available through NPCC.

3.6.3 Generation Dispatch

Generation dispatch for stability studies typically differs from the dispatch used in thermal and voltage analysis. Generation within the area of interest (generation behind a transmission interface or generation at an individual plant) is dispatched at full output within known system constraints. Remaining generation is dispatched to approximate a merit based dispatch. To minimize system inertia, generators are dispatched fully loaded to the extent possible while respecting system reserve requirements.

3.7 Modeling for Short Circuit Studies

Short Circuit studies are performed to determine the maximum fault duty on circuit breakers and other equipment and to determine appropriate fault impedances for modeling unbalanced faults in transient stability studies.

Short Circuit studies for calculating maximum fault duty assume all generators are on line, and all transmission system facilities are in service and operating as designed.

Short Circuit studies for determining impedances for modeling unbalanced faults in stability studies typically assume all generators are on line. Switching sequences associated with the contingency may be accounted for in the calculation.

3.8 Modeling for Protection Studies

Conceptual protection system design should be performed to ensure adequate fault detection and clearing can be coordinated for the proposed transmission system configuration in accordance with the National Grid protection philosophy and where applicable, with the NPCC "Bulk Power System Protection Criteria". Preliminary relay settings should be calculated based on information obtained from powerflow, stability, and short circuit studies to ensure feasibility of the conceptual design.

When an increase in the thermal rating of main circuit equipment is required, a review of associated protection equipment is necessary to ensure that the desired rating is achieved. The thermal rating of CT secondary equipment must be verified to be greater than the required rating. Also, it is necessary to verify that existing or proposed protective relay trip settings do not restrict loading of the protected element and other series connected elements to a level below the required circuit rating.

3.9 Development and Evaluation of Alternatives

If the projected performance or reliability of the system does not conform to the applicable planning criteria, then alternative solutions based on safety, performance, reliability, environmental impacts, and economics need to be developed and evaluated. The evaluation of alternatives leads to a recommendation that is summarized concisely in a report.

3.9.1 Safety

All alternatives shall be designed with consideration to public safety and the safety of operations and maintenance personnel. Characteristics of safe designs include:

- adequate equipment ratings for the conditions studied and margin for unanticipated conditions
- use of standard designs for ease of operation and maintenance
- ability to properly isolate facilities for maintenance
- adequate facilities to allow for staged construction of new facilities

Consideration shall be given to address any other safety issues that are identified that are unique to a specific project or site.

3.9.2 Performance

The system performance with the proposed alternatives should meet or exceed all applicable design criteria.

3.9.3 Reliability

This guide assesses deterministic reliability by defining the topology, load, and generation conditions that the transmission system must be capable of withstanding safely. This deterministic approach is consistent with NERC, NPCC, ISO-NE, and NYSRC practice. Defined outage conditions that the system must be designed to withstand are listed in Table 4.1. The transmission system is designed to meet these deterministic criteria to promote the reliability and efficiency of electric service on the bulk power system, and also with the intent of providing an acceptable level of reliability to the customers.

Application of this guide ensures that all customers receive an acceptable level of reliability, although the level of reliability provided through this approach will vary. All customers or groups of customers will not necessarily receive uniform reliability due to inherent factors such as differences in customer load level, load shape, proximity to generation, interconnection voltage, accessibility of transmission resources, customer service requirements, and class and vintage of equipment.

3.9.4 Environmental

An assessment should be made for each alternative of the human and natural environmental impacts. Assessment of the impacts is of particular importance whenever expansion of substation fence lines or transmission rights-of-way are proposed. However, environmental impacts also should be evaluated for work within existing substations and on existing transmission structures. Impacts during construction should be evaluated in addition to the impact of the constructed facilities. Evaluation of environmental impacts will be performed consistent with all applicable National Grid policies.

3.9.5 Economics

Initial and future investment cost estimates should be prepared for each alternative. The initial capital investment can often be used as a simple form of economic evaluation. This level of analysis is frequently adequate when comparing the costs of alternatives for which all expenditures are made at or near the same time. Additional economic analysis is required to compare the total cost of each alternative when evaluating more complex capital requirements, or for projects that are justified based on economics such as congestion relief. These analyses should include the annual charges on investments, losses, and all other expenses related to each alternative.

A cash flow model is used to assess the impact of each alternative on the National Grid business plan. A cumulative present worth of revenue requirements model is used to assess the impact of each alternative on the customer. Evaluation based on one or both models may be required depending on the project.

If the justification of a proposed investment is to reduce or eliminate annual expenses, the economic analysis should include evaluation of the length of time required to recover the investment. Recovery of the investment within 5 years is typically used as a benchmark, although recovery within a shorter or longer period may be appropriate.

3.9.6 Technical Preference

Technical preference should be considered when evaluating alternatives. Technical preference refers to concerns such as standard versus non-standard design or to an effort to develop a future standard. It may also refer to concerns such as age and condition of facilities, availability of spare parts, ease of operations and maintenance, ability to accommodate future expansion, ability to implement, or reduction of risk.

3.9.7 Sizing of Equipment

All equipment should be sized based on economics, operating requirements, standard sizes used by the company, and engineering judgment. Economic analysis should account for indirect costs in addition to the cost to purchase and install the equipment. Engineering judgment should include recognition of realistic future constraints that may be avoided with minor incremental expense. As a guide, unless the equipment is part of a staged expansion, the capability of any new equipment or facilities should be sufficient to operate without constraining the system and without major modifications for at least 10 years. As a rough guide, if load growth is assumed to be 1% to 2%, then the minimum reserve margin should be at least 20% above the maximum expected demand on the equipment at the time of installation. However, margins can be less for a staged expansion.

3.10 Recommendation

A recommended action should result from every study. The recommendation includes resolution of any potential violation of the design criteria. The recommended action should be based on composite consideration of factors such as safety, the forecasted performance and reliability, environmental impacts, economics, technical preference, schedule, availability of land and materials, acceptable facility designs, and complexity and lead time to license and permit.

3.11 Reporting Study Results

A transmission system planning study should culminate in a concise report describing the assumptions, procedures, problems, alternatives, economic comparison, conclusions, and recommendations resulting from the study.

4.0 Design Criteria

4.1 Objective of the Design Criteria

The objective of the Design Criteria is to define the design contingencies and measures used to assess the adequacy of the transmission system performance.

4.2 Design Contingencies

The Design Contingencies used to assess the performance of the transmission system are defined in Table 4.1. In association with the design contingencies, this table also includes information on allowable facility loading. Control actions may be available to mitigate some contingencies listed in Table 4.1.

The reliability of local areas of the transmission system may not be critical to the operation of the interconnected NEPOOL system and the New York State Power System. Where this is the case, the system performance requirements for the local area under National Grid design contingencies may be less stringent than what is required by NERC Reliability Standards, NPCC Criteria, ISO-NE Reliability Standards, or NYSRC Reliability Rules.

4.2.1 Fault Type

As specified in Table 4.1, some contingencies are modeled without a fault; others are modeled with a three phase or a single phase to ground fault. All faults are considered permanent with due regard for reclosing facilities and before making any manual system adjustments.

4.2.2 Fault Clearing

Design criteria contingencies involving ac system faults on bulk power system facilities are simulated to ensure that stability is maintained when either of the two independent protection groups that performs the specified protective function operates to initiate fault clearing. In practice, design criteria contingencies are simulated based on the assumption that a single protection system failure has rendered the faster of the two independent protection groups inoperable.

Design criteria contingencies involving ac system faults on facilities that are not part of the bulk power system are simulated based on correct operation of the protection system on the faulted element. Facilities that are not part of the bulk power system must be reviewed periodically to determine whether changes to the power system have caused facilities to become part of the bulk power system. National Grid utilizes for this purpose a methodology based on applying a three-phase fault, uncleared locally, and modeling delayed clearing of remote terminals of any elements that must open to interrupt the fault.

4.2.3 Allowable Facility Loading

The normal rating of a facility defines the maximum allowable loading at which the equipment can operate continuously. The LTE and STE ratings of equipment may allow an elevation in operating temperatures over a specific period provided the emergency loading is reduced back to, or below, a specific loading in a specific period of time (for specific times, see Section 3.4).

The system should be designed to avoid loading equipment above the normal rating prior to a contingency and to avoid loading equipment above the LTE rating following a design contingency (see Table 4.1 contingencies a through i). Under limited circumstances, however, it is acceptable to design the system such that equipment may be loaded above the LTE rating, but lower than the STE rating. Loading above the LTE rating up to the STE rating is permissible for contingencies b, c, e, f, g, h, and i, for momentary conditions, provided automatic actions are in place to reduce the loading of the equipment below the LTE rating within 15 minutes, and it does not cause any other facility to be loaded above its LTE rating. Such exceptions to the criteria will be well documented and require acceptance by National Grid Network Operations.

The STE rating is dependent on the level of loading prior to applying a contingency. The published STE rating is valid when the pre-contingency loading is within the normal rating. When the pre-contingency loading exceeds the normal rating, the STE rating must be reduced to prevent equipment from exceeding its allowable emergency temperature.

In New England an additional rating, the Drastic Action Limit (DAL), is calculated for use in real-time operations. The DAL is an absolute operating limit, based on the maximum loading to which a piece of equipment can be subjected over a five-minute period without sustaining damage. Although the DAL is computed based on a five minute load duration, if equipment loadings reach a level between the STE and DAL limits, then immediate action is required to reduce loading to below LTE. The DAL is not used in planning studies or for normal operating situations. In some cases when the STE rating may be exceeded, it may be necessary to provide redundant controls to minimize the risk associated with failure of the automated actions to operate as intended.

4.2.4 Reliability of Service to Load

The transmission system is designed to allow the loss of any single element without a resulting loss of load, except in cases where a customer is served by a single supply. Where an alternate supply exists interruption of load is acceptable for the time required to transfer the load to the alternate supply.

Loss of load is acceptable for contingencies that involve loss of multiple elements such as simultaneous outage of multiple circuits on a common structure, or a circuit breaker failure resulting in loss of multiple elements. For these contingencies, measures should be evaluated to mitigate the frequency and/or the impact of such contingencies when the amount of load interrupted exceeds 100 MW. Such measures may include differential insulation of transmission circuits on a common structure, or automatic switching to restore unfaulted elements. Where such measures are already implemented, they should be assumed to operate as intended, unless a failure to operate as intended would result in a significant adverse impact outside the local area.

A higher probability of loss of customer load is acceptable during an extended generator or transformer outage, maintenance, or construction of new facilities. Widespread outages resulting from contingencies more severe than those defined by the Design Contingencies may result in loss of customer load in excess of 100 MW and/or service interruptions of more than 3 days.

4.2.5 Load Shedding

NPCC requires that each member have underfrequency load shedding capability to prevent widespread system collapse. As a result, load shedding for regional needs is acceptable in whatever quantities are required by the region. In some cases higher quantities of load shedding may be required by the Area or the local System Operator.

Manual or automatic shedding of any load connected to the National Grid transmission system in response to a design contingency listed in Table 4.1 may be employed to maintain system security when adequate facilities are not available to supply load. However, shedding of load is not acceptable as a long term solution to design criteria violations, and recommendations will be made to construct adequate facilities to maintain system security without shedding load.

4.2.6 Expected Restoration Time

The transmission restoration time for the design contingencies encountered most frequently is typically expected to be within 24 hours. Restoration times are typically not more than 24 hours for equipment including overhead transmission lines, air insulated bus sections, capacitor banks, circuit breakers not installed in a gas insulated substation, and transformers that are spared by a mobile substation. For some contingencies however, restoration time may be significantly longer. Restoration times are typically longer than 24 hours for generators, gas insulated substations, underground cables, and large power transformers. When the expected restoration for a particular contingency is expected to be greater than 24 hours, analysis should be performed to determine the potential impacts if a second design contingency were to occur prior to restoration of the failed equipment.

4.2.7 Generation Rejection or Ramp Down

Generation rejection or ramp down refers to tripping or running back the output of a generating unit in response to a disturbance on the transmission system. As a general practice, generation rejection or ramp down should not be included in the design of the transmission system. However, generation rejection or ramp down may be considered if the following conditions apply:

- acceptable system performance (voltage, current, and frequency) is maintained following such action
- the interconnection agreement with the generator permits such action
- the expected occurrence is infrequent (the failure of a single element is not typically considered infrequent)
- the exposure to the conditions is unlikely or temporary (temporary implies that system modifications are planned in the near future to eliminate the exposure or the system is operating in an abnormal configuration).

Generation rejection or ramp down may be initiated manually or through automatic actions depending on the anticipated level and duration of the affected facility loading. Plans involving generation rejection or ramp down require review and approval by National Grid Network Operations, and may require approval of the System Operator.

4.2.8 Exceptions

These Design Criteria do not apply if a customer receives service from National Grid and also has a connection to any other transmission provider regardless of whether the connection is open or closed. In this case, National Grid has the flexibility to evaluate the situation and provide interconnection facilities as deemed appropriate and economic for the service requested.

National Grid is not required to provide service with greater deterministic reliability than the customers provide for themselves. As an example, if a customer has a single transformer, National Grid does not have to provide redundant transmission supplies.

4.3 Voltage Response

Acceptable voltage response is defined in terms of maximum and minimum voltage in per unit (p.u.) for each transmission voltage class (Table 4.2), and in terms of percent voltage change from pre-contingency to post-contingency (Table 4.3). The values in these tables allow for automatic actions that take less than one minute to operate and which are designed to provide post-contingency voltage support. The voltage response also must be evaluated on the basis of voltage transients.

4.4 Stability

4.4.1 System Stability

Stability of the transmission system shall be maintained during and following the most severe of the Design Contingencies in Table 4.1, with due regard to reclosing. Stability shall also be maintained if the outaged element as described in Table 4.1, is re-energized by autoreclosing before any manual system adjustment.

In evaluating the system response it is insufficient to merely determine whether a stable or unstable response is exhibited. There are a number of system responses which may be considered unacceptable even though the bulk power system remains stable. Each of the following responses is considered an unacceptable response to a design contingency:

- Transiently unstable response resulting in wide spread system collapse.
- Transiently stable response with undamped power system oscillations.
- Entry of the line 396 apparent impedance at Keswick into the Keswick GCX SPS relay characteristic. (This SPS will be removed from service upon completion of the second 345 kV New Brunswick-New England tie line between Pt. Lepreau and Orrington.)

4.4.2 Generator Unit Stability

With all transmission facilities in service, generator unit stability shall be maintained on those facilities that remain connected to the system following fault clearing, for

a. A permanent single-line-to-ground fault on any generator, transmission circuit, transformer, or bus section, cleared in normal time with due regard to reclosing.

b. A permanent three-phase fault on any generator, transmission circuit, transformer, or bus section, cleared in normal time with due regard to reclosing.

Isolated generator instability may be acceptable. However, generator instability will not be acceptable if it results in adverse system impact or if it unacceptably impacts any other entity in the system.

Table 4.1: Design Contingencies

Ref.	CONTINGENCY (Loss or failure of:)	Allowable Facility Loading
a	A permanent three-phase fault on any generator, transmission circuit, transformer, or bus section	LTE
b	Simultaneous permanent single-line-to-ground faults on different phases of two adjacent transmission circuits on a multiple circuit tower (> 5 towers)[2]	LTE[1]
c	A permanent single-line-to-ground fault on any transmission circuit, transformer, or bus section, with a breaker failure	LTE[1]
d	Loss of any element without a fault (including inadvertent opening of a switching device	LTE
e	A permanent single-phase-to-ground fault on a circuit breaker with normal clearing	LTE[1]
f	Simultaneous permanent loss of both poles of a bipolar HVdc facility without an ac system fault	LTE[1]
g	Failure of a circuit beaker to operate when initiated by an SPS following: loss of any element without a fault, or a permanent single-line-to-ground fault on a transmission circuit, transformer, or bus section	LTE[1]
h	Loss of a system common to multiple transmission elements (e.g., cable cooling)	LTE[1]
i	Permanent single-line-to-ground faults on two cables in a common duct or trench	LTE[1]

Notes:

[1] Loading above LTE, but below STE, is acceptable for momentary conditions provided automatic actions are in place to reduce the loading of equipment below the LTE rating within 15 minutes.

[2] If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded. Other similar situations can be excluded on the basis of acceptable risk, subject to approval in accordance with Regional (NPCC) and Area (NYSRC or ISO-NE) exemption criteria, where applicable.

Table 4.2: Voltage Range

CONDITION	345 & 230 kV		115 kV[1] & Below	
	Low Limit (p.u.)	**High Limit (p.u.)**	**Low Limit (p.u.)**	**High Limit (p.u.)**
Normal Operating	0.98	1.05	0.95	1.05
Post Contingency & Automatic Actions	0.95	1.05	0.90	1.05

[1] Buses that are part of the bulk power system, and other buses deemed critical by Network Operations shall meet requirements for 345 kV and 230 kV buses.

Table 4.3: Maximum Percent Voltage Variation at Delivery Points

CONDITION	345 & 230 kV (%)	115 kV[1] & Below (%)
Post Contingency & Automatic Actions	5.0	10.0
Switching of Reactive Sources or Motor Starts (All elements in service)	2.0 *	2.5 *
Switching of Reactive Sources or Motor Starts (One element out of service)	4.0 *	5.0 *

[1] Buses that are part of the bulk power system, and other buses deemed critical by Network Operations shall meet requirements for 345 kV and 230 kV buses.

* These limits are maximums which do not include frequency of operation. Actual limits will be considered on a case-by-case basis and will include consideration of frequency of operation and impact on customer service in the area.

Notes to Tables 4.2 and 4.3:

a. Voltages apply to facilities which are still in service post contingency.
b. Site specific operating restrictions may override these ranges.
c. These limits do not apply to automatic voltage regulation settings which may be more stringent.
d. These limits only apply to National Grid facilities.

5.0 Interconnection Design Requirements

5.1 Objective of the Interconnection Design Requirements

The objective of the interconnection design requirements is to provide guidance on the minimum acceptable configurations to be applied when a new generator or transmission line is to be interconnected with the National Grid transmission system. The goal is to assure that reliability and operability are not degraded as a consequence of the new interconnection. National Grid will determine the configuration that appropriately addresses safety, reliability, operability, maintainability, and expandability objectives, consistent with this Transmission Planning Guide for each new or revised interconnection.

5.2 Design Criteria

5.2.1 Safety

Substation arrangements shall be designed with safety as a primary consideration. Standard designs shall be utilized for ease of operation and maintenance and to promote standardization of switching procedures. Substation arrangements shall also provide means to properly isolate equipment for maintenance and allow appropriate working clearances for installed equipment as well as for staged construction of future facilities. Consideration shall be given to address any other safety issues that are identified that are unique to a specific project or site.

5.2.2 Planning and Operating Criteria

Substation arrangements shall be designed such that all applicable Planning and Operating Criteria are met. These requirements may require ensuring that certain system elements do not share common circuit breakers or bus sections so as to avoid loss of both elements following a breaker fault or failure; either by relocating one or both elements to different switch positions or bus sections or by providing two circuit breakers in series. These requirements may also require that existing substation arrangements be reconfigured, e.g. from a straight bus or ring bus to a breaker-and-a-half configuration.

5.2.3 System Protection

Substation arrangements shall provide for design of dependable and secure protection systems. Designs that create multi-terminal lines shall not be allowed except in cases where Protection Engineering verifies that adequate coordination and relay sensitivity can be maintained when infeed or outfeed fault current is present.

To ensure reliable fault clearing, it generally is desirable that no more than two circuit breakers be required to be tripped at each terminal to clear a fault on a line or cable circuit. For transformers located within the substation perimeter, the incidence of faults is sufficiently rare that this requirement may be relaxed to permit transformers to be connected directly to the buses in breaker-and-a-half or breaker-and-a-third arrangements.

5.2.4 Reliability

Factors affecting transmission reliability shall be considered in interconnection designs. These factors include, but are not limited to:

- additional exposure to transmission outages resulting from additional transmission line taps, with consideration to length of the proposed tap,
- the number of other taps already existing on the subject line. In general, new taps will be avoided if three or more taps already exist,
- the number and type of customers already existing on the subject line and potential impacts to these customers resulting from a proposed interconnection,
- the existing performance of the subject line and how the proposed interconnection will affect that performance, and
- the impact on the complexity of switching requirements, and the time and personnel required to perform switching operations.

Periodic transmission assessments shall consider whether system modifications are necessary to improve reliability in locations where greater than three taps exist on a single transmission line.

5.2.5 Operability

Substation switching shall be configured to prevent the loss of generation for normal line operations following fault clearing. Generators shall not be connected directly to a transmission line through a single circuit breaker position except as noted in Section 5.4.2.

5.2.6 Maintainability

Substations shall be configured to permit circuit breaker maintenance to be performed without taking lines or generators out of service, recognizing that a subsequent fault on an element connected to the substation might result in the isolation of more than the faulted element. At existing substations with straight bus configurations, consideration will be given to modifying terminations in cases where an outage impacts the ability to operate the system reliably.

5.2.7 Future Expansion

Substation designs shall be based on the expected ultimate layout based on future existing system needs and physical constraints associated with the substation plot.

5.3 Standard Bus Configurations

Given the development of the transmission system over time and through mergers and acquisitions of numerous companies, several different substation arrangements exist within the National Grid system. Future substation designs are standardized on breaker-and-a-half, breaker-and-a-third, and ring bus configurations, depending on the number of elements to be terminated at the station. Other substation configurations may be retained at existing substations, but are evaluated in periodic transmission assessments to consider whether continued use of such configurations is consistent with the reliable operation of the transmission system.

Determination of the appropriate substation design is based on the total number of elements to be terminated in the ultimate layout, and how many major transmission elements will be terminated. Major transmission elements include networked transmission lines 115 kV and above and power transformers with at least one terminal connected at 230 kV or 345 kV.

5.3.1 Breaker-and-a-Half

A breaker-and-a-half configuration is the preferred substation arrangement for new substations with an ultimate layout expected to terminate greater than four major transmission elements or greater than six total elements. If the entire ultimate layout is not constructed initially, the substation may be configured initially in a ring bus configuration. Cases will exist where a breaker-and-a-half configuration is required with fewer elements terminated in order to meet the criteria stated above.

Major transmission elements are terminated in a bay position between two circuit breakers in a breaker-and-a-half configuration. Other elements such as capacitor banks, shunt reactors, and radial 115 kV transmission lines may be terminated on the bus through a single circuit breaker. Transformers with no terminal voltage greater than 115 kV may be terminated directly on a bus. It may be permissible to terminate 345-115 kV or 230-115 kV transformers directly on a 115 kV bus if there is no reasonable expectation that more than two such transformers will be installed. Such a decision requires careful consideration however, given the difficulty of re-terminating transformers to avoid tripping two transformers for a breaker fault or failure in the event that a third transformer is installed at a later time.

5.3.2 Breaker-and-a-Third

A breaker-and-a-third configuration is an acceptable alternate to a breaker-and-a-half configuration in cases where a breaker-and-a-half arrangement is not feasible due to physical or environmental constraints. Considerations for terminating elements on a bus are the same as for breaker-and-a-half, except that 345-115 kV or 230-115 kV transformers may be terminated directly on a 115 kV bus since additional transformers may be terminated in a bay without a common breaker between two transformers.

5.3.3 Ring Bus

A ring bus may be utilized for new substations where four or fewer major elements will be terminated or six or fewer total elements will be terminated. A ring bus also may be utilized as an interim configuration during staged construction of a substation.

5.3.4 Straight Bus

Many older substations on the system have a straight bus configuration, with each element terminating on the bus through a single breaker. Variations exist in which the bus is segmented by one or more bus-tie breakers, provisions are provided for a transfer bus, or the ability exists to transfer some or all elements from the main bus to an emergency bus. Periodic transmission assessments shall consider whether continued use of existing straight bus configurations is consistent with maintaining reliable operation of the transmission system.

New bulk power system substations shall not utilize a straight bus design. Straight bus designs may be utilized at non-bulk power system substations subject to the following conditions:

- A transfer bus is provided to facilitate circuit breaker maintenance.
- The transfer breaker protection system is capable of being coordinated to provide adequate protection for any element connected to the bus.

- Justification is provided to support deviating from the standard breaker-and-a-half, breaker-and-a-third, or ring bus configuration.
- All requirements of Section 5.2 are met.

5.4 Issues Specific to Generator Interconnections

5.4.1 Interconnection Voltage

It is desirable to connect generators at the lowest voltage class available in the area for which an interconnection is feasible. In general, small generators no larger than 20 MW will be interconnected to the transmission system only when there is no acceptable lower voltage alternative in the area and it is not feasible to develop a lower voltage alternative.

5.4.2 Interconnection Facilities

The minimum interconnection required for all generators is a three-breaker ring bus. Additional circuit breakers and alternate substation configurations may be required when interconnecting multiple generating units. Generators shall not be connected directly to a transmission line through a single circuit breaker position unless an exception is granted as noted below.

Exceptions to the Generators Interconnection Requirements

Exceptions may be granted for (1) generators connected to radial transmission lines, and (2) for small generators no larger than 20 MW. Exceptions shall be evaluated on a case-by-case basis and shall be granted only when the following conditions are met:

- Protection Engineering verifies that the transmission line and interconnection facilities can be protected adequately, while ensuring that transmission system protective relay coordination and relay sensitivity can be maintained.
- Transmission Planning verifies that transmission reliability is not adversely impacted by assessing the Design Criteria listed above in Section 5.2 above pertaining to safety, planning and operating criteria, reliability, and maintainability.
- Provisions acceptable to National Grid are made to accommodate future expansion of the interconnection to at least a three-breaker ring bus.

5.4.3 Status of Interconnection Design

The design for any generator interconnection is valid only for the generating capacity and unit characteristics specified by the developer at the time of the request. Any modifications to generating capacity and unit characteristics require a separate system impact study and may result in additional interconnection requirements.

Modifications to the interconnection design may be required as a result of future modifications to the transmission system. National Grid will notify the generation owner when such modifications are required.

6.0 Glossary of Terms

Bulk Power System
The interconnected electrical system comprising generation and transmission facilities on which faults or disturbances can have a significant impact outside the local area.

Contingency
An event, usually involving the loss of one or more elements, which affects the power system at least momentarily.

Element
Any electric device with terminals which may be connected to other electric devices, such as a generator, transformer, transmission circuit, circuit breaker, an HVdc pole, braking resistor, a series or shunt compensating device or bus section. A live-tank circuit breaker is understood to include its associated current transformers and the bus section between the breaker bushing and its free standing current transformer(s).

Fault Clearing - Delayed
Fault Clearance consistent with correct operation of a breaker failure protection group and its associated breakers or of a backup protection group with an intentional time delay.

Fault Clearing - Normal
Fault Clearance consistent with correct operation of the protection system and with correct operation of all circuit breakers or other automatic switching devices intended to operate in conjunction with that protection system.
Note: Zone 2 clearing of line-end faults on lines without pilot protection is normal clearing, not delayed clearing, even though a time delay is required for coordination purposes.

High Voltage dc (HVdc) System, Bipolar
An HVdc system with two poles of opposite polarity and negligible ground current.

Interface
A group of transmission lines connecting two areas of the transmission system.

Load Cycle
The normal pattern of demand over a specified time period (typically 24 hours) associated with a device or circuit.

Load Level
A scale factor signifying the total load relative to peak load or the absolute magnitude of load for the year referenced.

Loss of Customer Load (or Loss of Load)
Loss of service to one or more customers for longer than the time required for automatic switching.

Point(s) of Delivery
The point(s) at which the Company delivers energy to the Transmission Customer.

Special Protection Systems
A protection system designed to detect abnormal system conditions and take corrective action other than the isolation of faulted elements. Such action may include changes in load, generation, or system configuration to maintain system stability, acceptable voltages, or power flows. Automatic underfrequency load shedding and conventionally switched locally controlled shunt devices are not considered to be SPSs.

Supply Transformer
Transformers that only supply distribution load to a single customer.

Transfer
The amount of electrical power that flows across a transmission circuit or interface.

Transmission Customer
Any entity that has an agreement to receive wholesale service from the National Grid transmission system.

Transmission Transformer
Any transformer with two or more transmission voltage level windings or a transformer serving two or more different customers.

Transmission and Wind Energy:

Capturing the Prevailing Winds for the Benefit of Customers

nationalgrid

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September 2006

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Executive Summary

The potential benefits of wind power as a clean, renewable, economic, domestically available power source have captured the attention of energy policy leaders, consumers, and the electricity industry. The United States (US) has tremendous wind energy resources. California is viewed as one of the leaders in the modern US wind industry in terms of capacity installed; however, 16 other states have even greater wind potential. Only a small portion of that potential has been tapped. The US currently derives approximately 1% of its electricity from wind power, whereas parts of Europe use wind power to meet up to 25% or more of their electricity needs.

In 2005, wind power in the US grew rapidly and became more competitive as volatile natural gas prices increased and crude oil prices reached record highs. Improved technology, federal tax credits and public policies that encourage utilities to use clean energy sources helped fuel the growth from coast to coast. Projections are that US wind capacity could reach 100 gigawatts (GW) by 2020, meeting 6% or more of national electricity needs.[1]

The objective of this paper is to examine the transmission policy issues around wind and renewable sources of generation. Reliability and commercial issues are reviewed, both in the US and abroad, and recommendations are provided for effective integration of wind sources into the US electric system. Key findings of this paper are:

- Over-reliance in the US on any one fuel type results in reliability and economic consequences, highlighting the benefits of diversified energy resources.
- Wind generation is becoming an economic power source, and has the further benefit of mitigating environmental climate change concerns.
- In order to tap the vast potential of new generation sources such as wind power in the US, we must address the existing challenges in generator interconnection and transmission cost and planning policies.
- The current US transmission system was not built to support competitive regional markets nor is it sufficient to integrate planned and potential new generation sources; additional transmission infrastructure will be required.
- Operating techniques for intermittent generation resources, properly structured market rules, and effective transmission policies for regional planning, cost allocation, and cost recovery and incentives will help to facilitate wind power as well as other new sources of generation.
- Transcos (for-profit independent transmission companies) focus on delivering low-cost reliable energy to consumers by facilitating robust electricity markets and providing transmission access to new generation sources including renewable energy. Because of their for-profit structure, a further advantage is that Transcos can be held firmly accountable by regulators for system performance and operating costs.

1 See http://www.awea.org/newsroom/Wind_Energy_Basics.pdf. Also, in his visit to National Renewable Energy Laboratory (NREL) on February 21, 2006 President Bush described the possibility of generating 20% of US electricity needs from wind.

- Robust transmission infrastructure policies in countries outside the US have helped them progress toward achieving their goals for renewable sources of energy while maintaining system reliability. The challenges to effective integration of wind power in the US are not insurmountable; they can be addressed with industry, public, and regulatory commitment.
- Several countries, including Denmark, Germany, Spain and the UK have had coordinated government efforts and policies to facilitate wind power, and these are proving very effective. Some areas of North America, such as Alberta and Texas, are also employing planning and cost allocation policies that are helpful to new generation sources.

Specific recommendations for changes needed to take advantage of US renewable resources to the benefit of electricity market users and customers are:

- *Employ greater use of available operational techniques, such as wind forecasting tools, for reliable operation of wind resources;*
- *Properly structure market rules to address imbalance and capacity value in a manner that reliably and economically facilitates renewable generation sources;*
- *Engage industry and stakeholders in long-term, robust, and comprehensive regional planning for transmission infrastructure, including infrastructure needed for new sources of generation;*
- *Incorporate economic and customer cost metrics, in addition to reliability, into regional planning processes;*
- *Implement workable cost-allocation and recovery mechanisms to recoup the costs of transmission infrastructure improvements;*
- *Provide regulatory incentives for transmission infrastructure investment and independent ownership/operation of the nation's transmission system.*

Several countries, including Denmark, Germany, Spain, and the UK, have had coordinated government efforts and effective regulatory policies to help facilitate wind power development.

Driving Trends

Regulatory and Public Policy

Due to load growth and generation retirements, coupled with an increasing interest in replacing old, inefficient and dirty generators, US energy policymakers are looking to facilitate new generation sources. Over-reliance on any one fuel type (such as natural gas in the Northeast markets) has resulted in reliability and economic challenges highlighting the benefits of a diversified energy mix.[2]

The global community's increased focus on clean and renewable sources of energy is due to its concerns about the negative environmental effects of burning fossil fuels. The growing consensus among scientists is that the burning of fossil fuels and the associated release of carbon dioxide and other greenhouse gases stoke global climate change, intensify droughts in some parts of the world, floods and storms in others, and add to the deterioration of air quality, among other negative health and environmental consequences.[3] As a result, there is heightened public policy attention on wind energy, which produces no harmful air emissions, no greenhouse gases, and does not consume nor pollute water sources.[4]

Federal initiatives promoting cleaner sources of generation include the Advanced Energy Initiative announced in President Bush's January 2006 State of the Union Address – a 22% increase in energy research in zero-emission technologies such as clean coal, solar, and wind power. The Energy Policy Act of 2005 included an extension of a federal Production Tax Credit (PTC) providing tax credits for electricity generation with wind turbines and other renewables.[5] Also, the Federal Energy Regulatory Commission (FERC) has begun to put in place policy changes to facilitate the interconnection of new wind plants.[6]

Individual states have taken the lead in promoting the development of renewable energy including wind power. Many states have established Renewable Portfolio Standards (RPS) programs, which require a percentage of electricity supply to come from renewable sources. By the end of 2005, 22 states had an RPS program or similar goal. Examples include New York with a goal of meeting 24% of its power supply needs from renewable sources by the year 2013, California with a goal of 20% by year 2010,[7] Colorado and Minnesota each with a goal of 10% by 2015, and Vermont with a 10% goal by 2012.

In the international arena, the US is focusing on a six-nation multilateral agreement to promote near-term deployment of clean energy technologies, the Asia-Pacific Partnership on Clean Development and Climate, authorized by the Energy Policy Act of 2005. Other countries have also made an aggressive commitment to environmental energy policies, such as the Kyoto Protocol climate change pact.[8] A European Commission position that 21% of total electricity generation in 2010 come from renewable resources was established in 2004.[9] Several countries, including Denmark, Germany, Spain, and the UK, have had coordinated government efforts and policies to facilitate wind power, and these are proving very effective; Figure 1 illustrates domestic and international levels of wind capacity as a percentage of peak load.

2 The Northeast markets have recently faced risks of power shortages during severe cold weather events that taxed the availability of natural gas to fuel the high percentage of generation resources that run on natural gas while serving domestic heating demand. Also, recent run-ups in fossil fuel costs have occurred in international markets and as a result of severe domestic hurricane activity in the US gulf coast region.

3 See http://www.pewclimate.org/global-warming-basics/basic_science/

4 Although wind power has many advantages, environmentalists continue to voice their concerns about the direct and indirect impacts of siting new wind plants. Their main concerns relate to avian mortality, visual/noise impacts and interference with natural habitats.

5 The PTC provides a tax credit of 1.9¢/kWh for a 10-year period for qualified renewable energy facilities on-line by December 31, 2007. The PTC can be key for financing wind projects; for instance, in the case of FPL Energy Wind, PTC payments make up 38% of its annual revenues. "Pre-sale, FPL Energy National Wind LLC," Feb. 10, 2005, Standard and Poors.

6 FERC's Order 661 adopts technical requirements for new wind plants to ensure reliable system operation. "Interconnection for Wind Energy," Docket No. RM05-4-001.

7 As of the end of 2005, 10.7% of electricity in California is from renewable sources. California State Energy Commission Report CEC-300-2006-009-F, April 2006.

8 Under the Kyoto Protocol, 34 industrialized countries and the Energy Environment Council (EEC) are required to reduce greenhouse gas emissions by at least 5% below 1990 levels between 2008 and 2012. A total of 161 parties to the protocol have ratified the treaty.

Figure 1: Penetration of Wind Resources 2005[10]

	Peak Load	Installed Wind	Penetration
Denmark (west)	4 GW	2.4 GW	60%
Germany	81 GW	18.5 GW	23%
Spain	41 GW	10.0 GW	24%
California	45 GW	2.3 GW	5.1%
Texas	60 GW	2.0 GW	3.3%

Industry Developments

The wind power industry is young by electricity industry standards, but in the last 20 years it has made great strides. Single wind turbine capacity has grown from 50 kilowatt (kW) production machines to 2 to 3 megawatts (MW) and more. Over the last two decades, the cost of wind energy at the bus bar has dropped by more than 80%, from 15 - 20 cents per kilowatt hour (¢/kWh) to approximately 4 - 6 ¢/kWh today due to technology advances.[11] Increasing reliability has accompanied the cost decline, with availability of modern machines reaching rates of 97 to 99%. Additional contributing factors to increased reliability include economies of scale associated with larger rotors, improved energy capture with customized airfoils and variable speed controls, taller towers reaching higher wind speeds and improved forecasting technologies.

These technical advances have helped wind power to become a competitive alternative generation source. While the wind industry is highly capital-intensive, there are negligible operating costs compared to thermal units. The economics of wind are also aided by its relative price stability in that it is not dependent on a source of supply with volatile prices, as is the case with most fossil fuel sources. In addition, wind appears to compare favorably to fossil fuels when environmental and health effects and costs are taken into account.[12]

There are a number of studies that support the improving economics of wind power relative to other sources of generation.[13] A current comparison focused on natural gas at various prices is shown in Figure 2. With the recent price of gas around $8.85 MMBTU,[14] wind power is gaining a competitive advantage over energy supply from gas. A recent report by the Electric Power Research Institute (EPRI) reached similar conclusions about the competitiveness of wind power relative to coal, as well as gas generation.[15]

Figure 2: Natural-Gas Plant Fuel Cost Compared to Wind Power[16]

	Gas			Wind
$ / MMBTU (Gas cost)	5	6	8	
¢ / kWh	3.5 - 5	4.2 – 6	5.6 - 8	3.5 4.5 (without PTC)

9 "Commission Report in Accordance with Article 3 of Directive 2001/77/EC," Commission of the European Communities communication to the Council and the European Parliament Brussels, May 26, 2004.

10 Most industry analyses express wind penetration rates as rated capacity of wind plant relative to system peak load, however, there is no single uniform definition of wind penetration.

11 "Winds of Change – Issues in Utility Wind Integration," IEEE Power & Energy Magazine, November/December, 2005; and "Renewable Electricity: Poised to Make a Difference," Power Engineering Magazine, Dan Arvizu, Director, National Renewable Energy Laboratory, May 2006.

12 "Wind Energy the Facts", Volume 4, European Wind Energy Association, December 2003.

13 A 1996 California Energy Commission report presents a comparison of the cost of wind compared to the cost of energy from other types of fuels. The report found that the levelized cost of energy for wind is 3.3 - 5.3 ¢/kWh (with PTC) and 4 - 6 ¢/kWh (without PTC), compared to coal at 4.8 - 5.5 ¢/kWh and gas at 3.9 - 4.4 ¢/kWh. Although this comparison is 10 years old, it is still useful; the cost of natural gas has increased since 1996, so the levelized cost of gas-fired plants is now expected to be higher. Energy Technology Status Report, California Energy Commission, 1996.

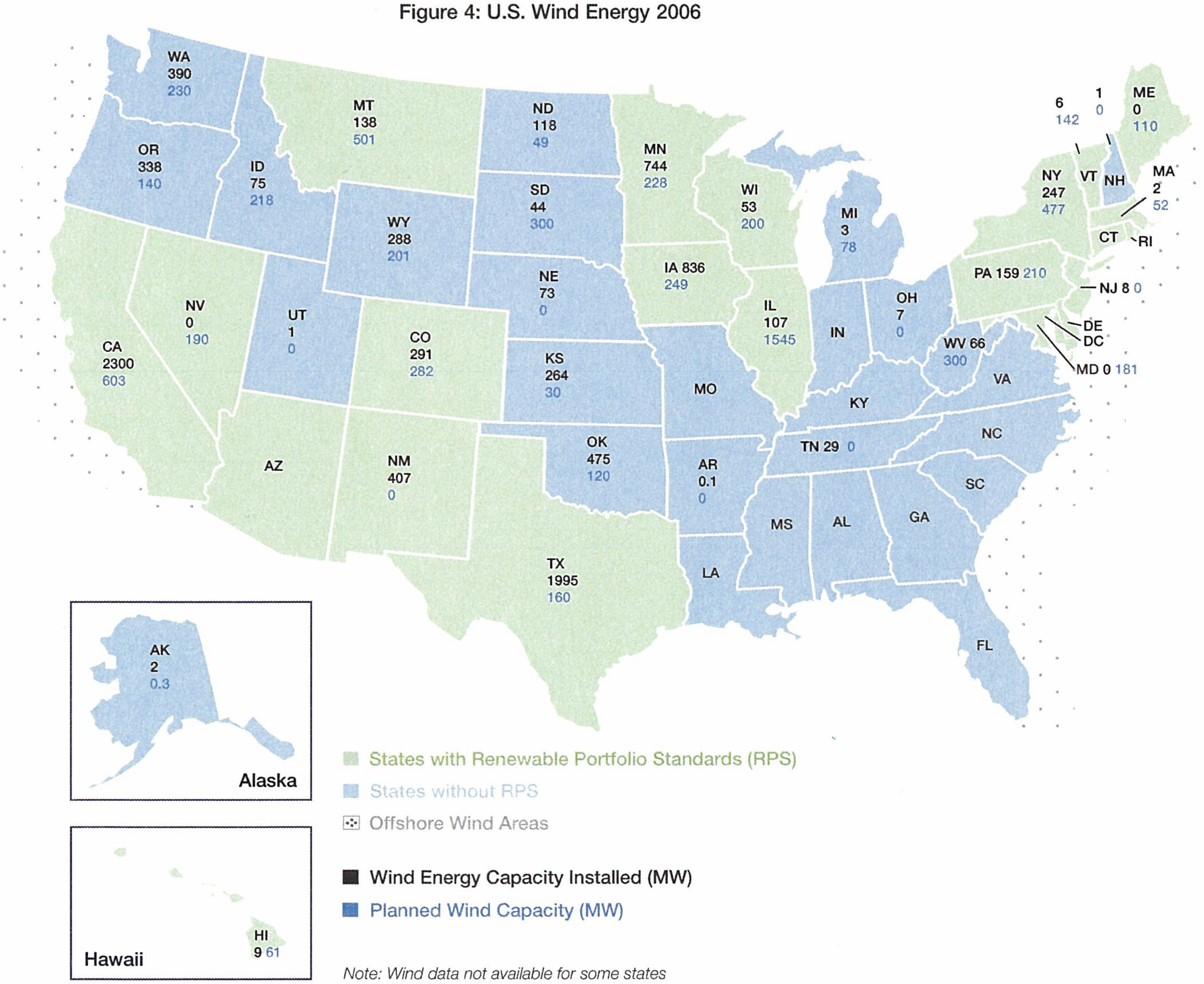
14 Energy Information Administration, Henry Hub price, January 19, 2006.

15 "Making Billion Dollar Advanced Generation Investments in an Emissions-Limited World," EPRI Summer Seminar, August 8 & 9, 2005, pp. 24-25.

16 "Integrating Wind Power into the Electric Power System," Ed DeMeo, Renewable Energy Consulting Services, Inc., NARUC Energy Resources and Environment Committee meeting, November 15, 2005.

Figure 4 shows the current installed and planned wind capacity for the US. Installed wind capacity in the US as of May 2006 was nearly 9,500 MW, and there are plans for nearly 7,000 MW more in the next few years. These numbers are still a fraction of the theoretical wind energy potential in the US.[17] In addition to the more than 1,200 GW of on-shore wind potential, off-shore areas of coastal states could provide almost as much again.[18] Off-shore wind projects are currently being pursued in Texas and Massachusetts.[19] While the full technical potential of wind is not likely to be tapped, if even a fraction of it is developed, wind power would contribute significantly to meeting US electricity needs.

Figure 4: U.S. Wind Energy 2006



Note: Wind data not available for some states

17 Wind Energy Potential-An Assessment of the Available WIndy Land Area and Wind Energy Potential in the United States, Pacific Northwest Laboratory, 1991. Installed and planned MW are from AWEA website as of May 2006. www.awea.org/projects/

18 The US Department of Energy estimates there are more than 900,000 MW of potential wind energy off the coasts of the United States. Much of the potential offshore wind resources exist near major urban load centers. US DOE, Massachusetts Technology Collaborative and GE, "A Framework for Offshore Wind Energy Development in the US," September 2005.

19 In Texas, plans are moving forward for a 500 MW off-shore wind farm, the largest currently in the US (Superior Renewable Energy, LLC), and a 150 MW off-shore project (Galveston-Offshore Wind, LLC). In Massachusetts, plans are being considered for a 420 MW wind farm (Cape Wind) and a 300 MW offshore wind farm (Patriot Renewables, LLC) in Buzzards Bay.

Challenges of Wind Power

In order to realize the tremendous potential of new generation sources such as wind power in the US, we must address the existing challenges of interconnecting these new renewable resources. Many of these interconnection challenges are rooted in current transmission system planning policies, system operation, and electricity market policies and practices. However, some of these challenges are beginning to be addressed and based on international and domestic experience, none appear to be insurmountable.

Reliable and Sustainable Wind Operation

The FERC has addressed some operational issues associated with wind generation in Order 661. In the order, FERC adopted a joint recommendation by the North American Electric Reliability Council (NERC) and the American Wind Energy Association (AWEA) requiring wind generators to be able to remain in service during and following system fault conditions. FERC requires a wind plant to maintain adequate reactive power and meet voltage support requirements if necessary to ensure system safety and reliability. The wind plant must also provide supervisory control and data acquisition (SCADA), or communications capability, to transmit data and receive instructions from the transmission provider to protect system reliability. Industry concerns remain, however, regarding the intermittency of wind power.

Intermittency

As with some other renewable sources, intermittency is a characteristic of wind generation; wind plants only generate when the wind is blowing within a particular range of speed. Historically, grid operators have relied primarily on dispatchable generation that can be adjusted by system operators to increase or decrease output on demand. Fossil and nuclear generation can be scheduled well in advance, but it can be difficult for wind generators to provide firm schedules far in advance because of their dependence on the weather.

Due to their intermittency, a major concern is whether wind plants need to be backed up with a significant amount of dispatchable generation, adding costs and complexity to system operation. Several studies have analyzed the intermittency issues around wind power and have concluded that the additional amounts of dispatchable generation needed in association with wind power are modest, that the additional costs associated with dispatchable generation do not destroy the economics of wind power, and that system operation need not be compromised. In fact, the interconnectedness of the US transmission system compared to the European system can aid in rounding out variances in wind production across regions, suggesting that the US may be able to accommodate an even greater percentage of wind power than Europe:

- A report prepared for New York State analyzed a 10% penetration of wind on its 33,000 MW system.[20] It covered the impacts of the cost of wind generation itself, reductions in conventional plant operating costs from their displacement by wind energy, and conventional plant operating cost increases attributable to wind intermittency. The report concluded that with 10% penetration of wind, the net New York system load variability will increase by approximately 6%. According to the report, at this level of penetration any rapid drop in production from the wind farms is not expected to affect the existing operating reserve requirement for the state. In terms of cost, the report showed an annual net reduction of $350 M on total variable cost to the New York Independent System Operator (NYISO). This represents the displacement value of variable operating expenses, such as fuel and plant startup costs for fossil fuel plants. The report found that the $350 M reduction may be higher with improved wind forecasting ability.

20 "The Effects of Integrating Wind Power on Transmission System Planning, Reliability, and Operations," GE Power Systems Energy Consulting, Phase I and II, February 2004 and March 2005.

There are many successful examples, internationally and in the US, of reliable and cost-effective integration of wind power.

- Several studies from the UK, including the March 2006 UK Energy Research Center study, assessed wind penetration levels of 10 to 20%, and concluded that wind energy is neither prohibitively expensive nor limited by intermittency.[21]
- A recent study released by the European Wind Energy Association concluded that 20% of demand on a large electricity network can be met by wind energy without posing any serious technical or practical problems today.[22] The report also noted that chief among the barriers to wind generation is the lack of adequate cross-border transmission.

Wind Forecasting

Forecasting plays a major role in minimizing the impacts of the intermittency of wind on the electricity system. Wind is not random. It can be forecasted, with greater accuracy on shorter timescales. Such forecasting becomes essential with a higher penetration of wind resources on a system. Forecasting abilities improve day-ahead scheduling of intermittent resources, allowing a decrease in spinning reserve requirements and subsequent savings to customers.[23]

The industry's forecasting ability has been improving, and efforts continue to develop better tools and strategies to deal with forecast error and wind volatility in the day-ahead, hour-ahead and intra-hour time frames. Using current forecasting tools, the error for a 36-hour forecast for a single wind farm has decreased by 13 to18% of the total installed wind power capacity and slightly less for day-ahead.[24] Aggregation of wind power over a wider area increases forecasting accuracy.[25]

State-of-the-art wind forecasting technology is being used in other countries including Denmark, Germany, and Spain, and parts of the US, bringing increased certainty for advance scheduling. California has led the US in adopting state-of-the-art forecasting. Its new forecasting capability went into operation in August 2004 under a FERC-approved tariff amendment called the Participating Intermittent Resource Program (PIRP).[26] The PIRP reduces the risks of incurring 10-minute imbalance charges for wind generators from bidding into the forward energy markets.

In Denmark, wind forecasting is required of each wind developer interested in joining the market. Most of the wind power participates in the day-ahead market. Energinet, the system operator and transmission owner, continues to conduct research and development projects to further develop state-of-the-art forecasting methodologies and tools to minimize imbalance deviations.

Electricity Storage

Technological advances in electricity storage may also hold promise for mitigating many of the effects of wind's intermittency. Storage can assist in overcoming intermittency by storing energy and then providing that energy when needed. Electricity storage can reduce the need for increased balancing generation to counter the effects of wind intermittency, and reduce associated balancing costs and resulting penalties on the generators. There are ongoing worldwide industry research and development efforts directed at the commercialization of energy storage technologies.[27] Developers are beginning to couple wind generators with non-intermittent generator sources or with storage capacity. As these storage technologies become more commercially viable, the effects of intermittency can be reduced even further.[28]

21 "The Costs and Impacts of Intermittency," UK Energy Research Center, March 2006; "Total cost estimates for large-scale wind scenarios in the UK," Lewis Dale, David Milborrow, Richard Slark and Goran Strbac, 2004; "Renewable Energy: Practicalities," House of Lords Science and Technology Committee 4th Report of Session 2003-04, July 15, 2004.

22 "Large Scale Integration of Wind Energy in the European Power Supply: Analysis, Issues and Recommendations," The European Wind Energy Association, December 15, 2005.

23 "The Effects of Integrating Wind Power on Transmission System Planning, Reliability, and Operations," GE Power Systems Energy Consulting, February 2004 and March 2005. The report indicated that there are large savings in operating costs of the New York system from using wind energy forecasts for day-ahead unit commitment amounting to $95 M of cost reductions a year.

24 "Overview of Wind Energy Generation Forecasting," TrueWind Solutions, LLC & AWS Scientific, Inc, for the New York State Energy Research and Development Authority and New York State Independent System Operator, December 17, 2003.

25 System wide forecasting errors for multiple dispersed wind plants may be reduced by 30-50% compared to errors of individual wind plants due to the smoothing effect of geographic dispersion. "The Future of Wind Forecasting and Utility Operations," Ahlstrom, Jones, Zavadil, and Grant, IEEE Power & Energy Magazine, November/December 2005.

26 AWS Truewind was selected to be the California ISO's forecast provider.

27 In 2004, a UK House of Lords report urged the British government to promote research and provide incentives to encourage the commercialization of promising storage technologies. "Renewable Energy: Practicalities", House of Lords, Science and Technology Committee, 4th Report of Session 2003-04, July 15, 2004 p. 63.

Imbalance Charges

Many transmission tariffs include imbalance penalties in their rules. These apply to the differences, or imbalances, between the day-ahead scheduled energy and actual real-time production. The intent of such penalties has historically been to promote good scheduling practices, including prevention of gaming, and thus ensure system operators that sufficient generation will be available to serve the load. These penalties are often not based on cost, but structured to motivate market participants to keep to their schedules.

Wind generators face challenges with predicting wind output as they do not have the same control over their fuel source (wind) as traditional generation sources. As wind generators are not generally subject to the same gaming concerns as traditional generation sources, a wind imbalance penalty does not encourage efficient scheduling. Such traditional penalties do not make sense for wind; they can be unfairly punitive and can render wind plant financing uneconomical. In some cases, the penalties for deviation can exceed the value of the wind energy provided. Many regions have made attempts to modify their imbalance penalty policies for intermittent resources;[29] however wind developers continue to describe imbalance charges as a major impediment to wind generation.[30]

One appropriate method of designing imbalance charges for intermittent resources, as well as all resources, may be to structure the charges to recoup the true costs of such imbalances.[31] The proper allocation of actual imbalance costs should provide the necessary incentives for suppliers to remain in balance without resulting in unfairly punitive measures. Such imbalance charges should reflect all applicable categories of costs created by a deviation from forward schedules, including regulation costs and other costs such as start-up and no-load costs, and the costs for reserves that the system operator would not have obtained but for the imbalance. Together with a robust transmission infrastructure, as described later, gaming potential for traditional generators would be mitigated without penalizing intermittent sources of energy such as wind.

The ability to aggregate balancing responsibilities among wind developments may also help resolve imbalance concerns. Aggregation in the same geographic location and time period should be explored; however, aggregation may not work well and could threaten reliability if the wind generators are located in separate reliability zones or control areas. Options for aggregation, combined with a cost-based imbalance charge regime and the implementation of state-of-the-art wind forecasting, will contribute to making US electricity markets more conducive to wind generation.

Capacity Value

The industry is debating at what level, if any, should wind generators receive capacity credits or payments given that wind generation is intermittent. Although a wind generator has high mechanical reliability, unavailability of the wind source can lead to effective forced outage rates of 50-80%.[32] Wind patterns are not correlated well with demand or load patterns.

Many studies have been done concerning capacity credits and the value of wind for reliability and capacity. In general, studies have shown that there is some appropriate capacity credit for wind resources. In the US, capacity credits vary by region:

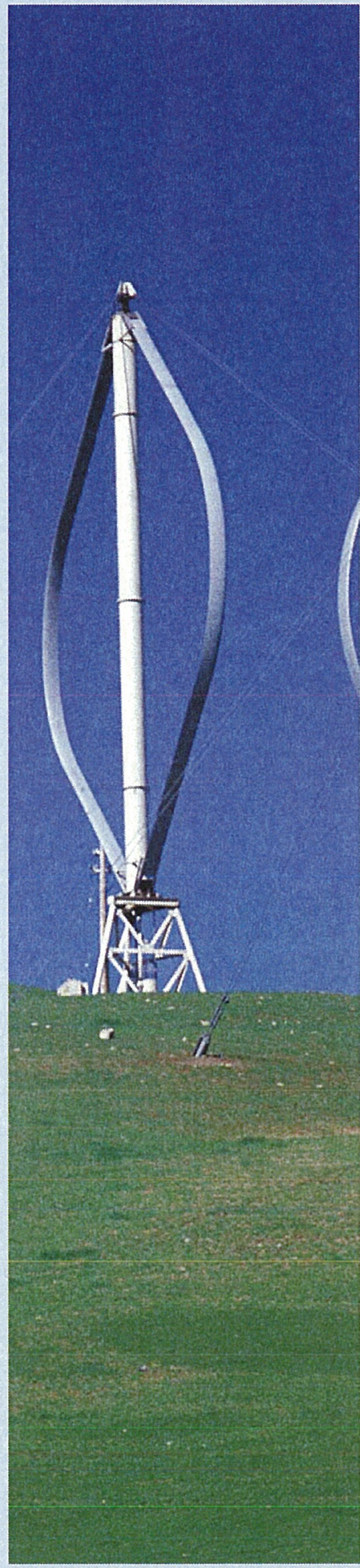
28 One example is the EPOD EMT Power Storage System technology that has been developed specifically to store commercial volumes of solar electric power for later use or resale. Pilot testing for wind power usage is underway. By storing some or all of the wind power generated during off-peak periods when power prices are at their lowest, users are able to time the sale of this stored power to peak periods when power prices may be 10 times that of off-peak. The storage of wind power in the EMT also allows wind power developers to offer guaranteed volumes of power at fixed times, known as "firm capacity."

29 Several regions have modified their transmission tariffs in an attempt to accommodate intermittent resources such as wind. The Western Area Power Administration's Rocky Mountain Region has waived the penalty bandwidth for intermittent resources and simply requires a financial settlement at market prices, netted at the end of the month. Both PacifiCorp and the Bonneville Power Administration have modified their tariffs to allow intermittent generators to change their day-ahead schedule up to 20 minutes before the operating hour waiving the $100/MWh penalty (but applying a lesser cost-based charge). NYISO's present market rules relieve up to approximately 500 MW of new wind power of the obligation of balancing charges or penalties. PJM does not assess imbalance penalties on any generators; all imbalances in PJM are resolved financially using the real-time energy market. California uses a wind forecasting approach and allows wind generators to "net out" energy imbalances and potentially avoid penalties for deviations. ERCOT permits 50% deviation from schedules without subjecting renewable resources to penalties.

30 Testimony of Mr. Robert Sims, Senior Vice President of SeaWest Wind Power, FERC Technical Conference "Assessing the State of Wind Energy in Wholesale Electricity Markets," December 1, 2004.

31 See "Preventing Undue Discrimination and Preferences in Transmission Service," FERC Notice of Proposed Rulemaking Docket Nos. RM05-17-000 and RM05-25-000, May 19, 2006, pp. 42, 53, and National Grid comments in these dockets filed August 7, 2006.

32 "Wind Project Evaluation Webcast," Barbara Y. Coley, New Energy Associates, December 2005.



- PJM has a 20% capacity credit in its standards based on wind generators' historical capacity factors during peak hours.
- NYISO and ISO-NE allow wind projects to submit a request for capacity payment on terms similar to thermal generators. These regions are currently reviewing the appropriateness of arrangements for intermittent resources.
- In the Southwest Power Pool, 3 to 8% of the rated wind capacity can be considered for capacity credits.
- In ERCOT, 16.8% of wind actual capacity can qualify as firm capacity credit.

The industry needs to continue to work toward a consistent and appropriate approach to recognize the capacity value of wind resources both to ensure reliability and fairly credit the contribution of wind power.

Getting Interconnected

Although there is sufficient evidence showing that wind generation can be reliably integrated into the electricity system, and efforts are underway to explore appropriate market mechanisms to address imbalance and capacity value for wind generation, obstacles to new generation sources continue to exist due to the lack of adequate transmission system access. The remoteness of wind sources, an underinvested transmission infrastructure, and lack of workable transmission investment policies all hinder the development of wind power in the US.

Wind Source Remoteness

Many windy areas are geographically remote from load centers. On average, strong wind sites are located a far distance from major metropolitan centers. For example, the Dakota states, often called the "Saudi Arabia of Wind" for their significant wind resources, are far from the heavy population and commercial centers of the Twin Cities of Minneapolis and St. Paul, Milwaukee, Chicago and Denver. In many cases, there are no transmission lines between the wind resources and the markets. And even where transmission lines are available, they often do not have enough regional capacity to move new sources of power to where they are needed.[33]

The current US transmission system was built primarily to ensure reliable and generally local electric service on a utility-by-utility footprint basis. It was not built to support competitive regional wholesale markets that require moving large quantities of power across long distances, nor is it currently sufficient to integrate planned and potential wind generation. Additional transmission infrastructure will be needed.

At present, there are several barriers to needed transmission investment. These include lack of comprehensive regional planning criteria that effectively capture the benefits of wind power and other new generation sources, unworkable cost allocation rules for transmission investment, inadequate financial incentives for transmission developers, siting challenges, and uncertainties over when and how costs are recoverable in wholesale and retail rates. These issues can become more challenging when transmission upgrades are needed to move renewable power from a wind-rich state into another state that has an RPS requirement or green market opportunities.[34] Some regional planning processes do exist, but their ability to overcome these barriers is limited in their current form. More needs to be done to improve regional planning and reduce regulatory barriers to needed transmission infrastructure improvements necessary to facilitate the delivery of new remote generation sources to load centers.

33 "Transmission investment simply hasn't kept up with the pace of network resource additions and network load additions over the last 20 years. The result has been particularly problematic for wind resources. They are located in remote areas with little load," remarks of John Krajewski on behalf of Transmission Access Policy Group, FERC Technical Conference Transcript, December 1, 2004 p.113.

34 Green market opportunities exist for load-serving entities that are interested in adding clean sources of power to their generation portfolio, regardless of whether their states have an RPS or not, and can result in the trading of Renewable Energy Certificates (RECs). Consumers in a number of states have the option of purchasing RECs, which offset less clean energy use in one location with cleaner energy generated elsewhere.

35 "Wind Transmission, Innovations in State Policy," Matthew H. Brown, director, National Conference of State Legislatures Energy Project, July 2005.

The current US transmission system was not built to support competitive regional markets; additional infrastructure will be required to bring customer savings.

Micrositing

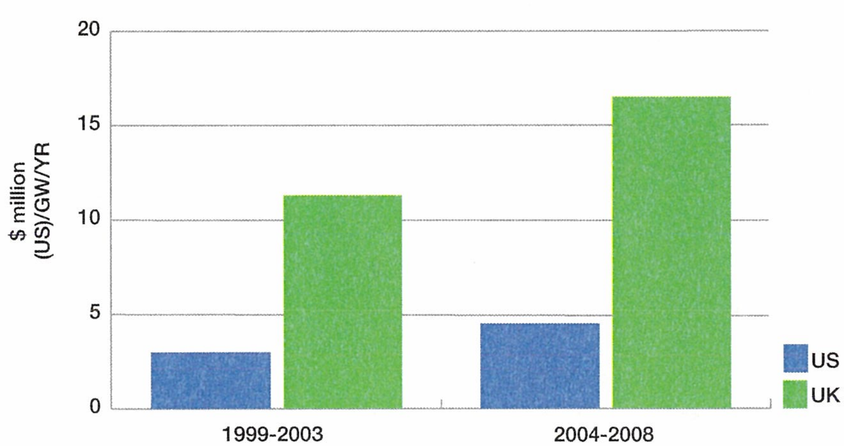
The problems associated with wind development may be amplified by the issue of "micrositing." Micrositing refers to the particular placement of turbines within a wind farm site to optimize electricity production. The particular location of the wind turbine is critical because the energy output of a wind turbine increases exponentially with the increase in wind speed; a 20% increase in average wind speed from 10 mph to 12 mph increases the electrical output of a wind turbine by around 80%.[35] Thus, it is imperative that a wind turbine be placed at exactly the right place on a site for wind. Developers measure wind resources at highly specific locations; moving a turbine a few hundred feet or less may significantly affect the wind speed. Micrositing issues can put additional constraints on siting transmission to interconnect wind generation.

Status of the US Transmission Infrastructure

There is ample evidence that the nation's transmission system is significantly underinvested, with associated troubling reliability and economic effects. Although there has been a recent upturn in US planned transmission investment,[36] transmission investment has not kept up with load growth or generation investment, nor has transmission been sufficiently expanded to accommodate the advent of regional power markets. Transmission investment declined in real dollar terms during the 23-year period from 1975 to 1998, and over the same time period transmission capacity relative to load declined in every NERC region.[37] The Edison Electric Institute (EEI) estimates that capital spending must increase by 25%, from $4 billion to $5 billion annually, to assure system reliability and to accommodate wholesale electric markets, and describes the current growth rate in transmission mileage as insufficient to meet the expected 50% growth in consumer demand for electricity over the next two decades.[38]

The US has a long way to go to catch up with international investment levels. Figure 5 shows high-voltage transmission (>230 kV) investment levels in the US versus the UK. New Zealand, Spain, the Netherlands and Poland also have significantly higher transmission investment levels than the US on a historical and future basis.[39]

Figure 5: Normalized Transmission Capital Investment[40]



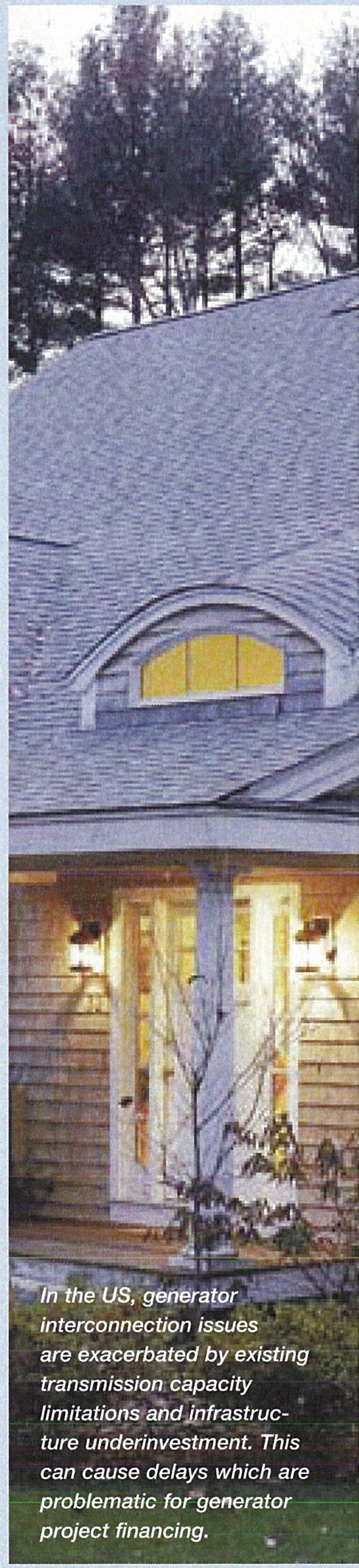
36 Some recently announced major planned projects include: American Transmission Company's Arrowhead-Weston 220-mile 345 KV line from Wisconsin to Minnesota, Allegheny's 210-mile 500 KV transmission expansion project from Pennsylvania to Virginia, and AEP's 550-mile 765 KV transmission line from West Virginia to New Jersey. National Grid's US investment levels are expected to increase, from $85M in 2004 to $294M in 2009, and will include high voltage reinforcements to southeastern New England.

37 Brendan Kirby, U.S. Department of Energy, Oak Ridge National Laboratory, FERC Technical Conference, "Transmission Independence and Investment," Docket No. AD05-5-00, April 22, 2005.

38 Thomas R. Kuhn, Testimony on Behalf of the Edison Electric Institute before the House Subcommittee on Energy and Air Quality Committee on Energy and Commerce, February 10, 2005.

39 Based on a National Grid analysis of planned investment in high voltage transmission through 2008. Investments were adjusted for market size. "Transmission: The Critical Link" June 2005, p.19. (http://www.nationalgridus.com/non_html/transmission_critical_link.pdf). Also see "Transmission Independence and Investment Pricing Policy for Efficient Operation and Expansion of the Transmission Grid," testimony of Nick Winser at FERC Technical Conference, "Transmission Independence and Investment," Docket No. AD05-5-00, April 22, 2005.

40 National Grid analysis on investment levels >230 kV normalized for market size. US investment data derived from Edison Electric Institute Survey of Transmission Investment, May 2005, and National Grid UK investment figures.



In the US, generator interconnection issues are exacerbated by existing transmission capacity limitations and infrastructure underinvestment. This can cause delays which are problematic for generator project financing.

The Energy Policy Act of 2005 puts the issue of needed transmission infrastructure squarely before FERC, the US Department of Energy, and states through provisions for incentives for new investment and independent industry business models (e.g., RTOs and Transcos). The provisions are meant to foster non-discriminatory and adequate access to transmission.

Interconnection Process and Queue Issues

The challenge facing a wind developer, and indeed any new generation resource, of whether it can interconnect to the grid in a timely and economic manner can be critical for project financing. FERC Order 2003 outlines the interconnection process for all generators greater than 20 MW and Orders 661 and 661-A provide specific interconnection requirements for reliable operation of wind generation. These orders represent action by FERC to establish interconnection standards that facilitate generation development, including wind development. However, a number of issues remain that can result in delays in timely interconnection for new projects. As explained below, the current interconnection processes can be an obstacle. However, facilitating improved transmission access and adequacy, including implementing more robust regional planning, can help to mitigate many of the problems seen in current interconnection processes.

In the current interconnection process, the generator developer applies to the transmission provider for an interconnection after identifying a proposed site. The transmission provider must then perform a system impact study to determine what interconnection facilities and system upgrades would be necessary to connect that generator to the electric system. To manage requests for interconnection, a transmission provider has an intake process referred to as a queue. The interconnection queue provides for orderly management of requests under a first-come first-served approach, and serves as the basis for assigning cost responsibility to generation developers for transmission upgrades.

Ideally, all generator applications would be processed in a timely manner. However, the queue process can become burdensome particularly if significant transmission upgrades are required for a project. Queue position can have real commercial significance; a long wait in the interconnection queue can have serious consequences for the financial viability of projects, particularly renewable projects if they are dependent on the recently extended federal PTC.

Project-by-Project Approach

Under the current standard US approach, a proposed generation project is held responsible for the reliability effects and costs of all transmission upgrades associated with its particular interconnection. These effects are determined by the transmission provider's studies of each project, based on assumptions made with regard to the timing of the projects ahead of it in the queue. However, final reliability requirements and cost responsibility depend on which projects are ultimately built. As these often may not be the same projects assumed in the study, further uncertainty and possible delays exist for siting, financing, equipment procurement, and meeting deadlines for eligibility for the PTC in the case of wind and other renewable projects.[41]

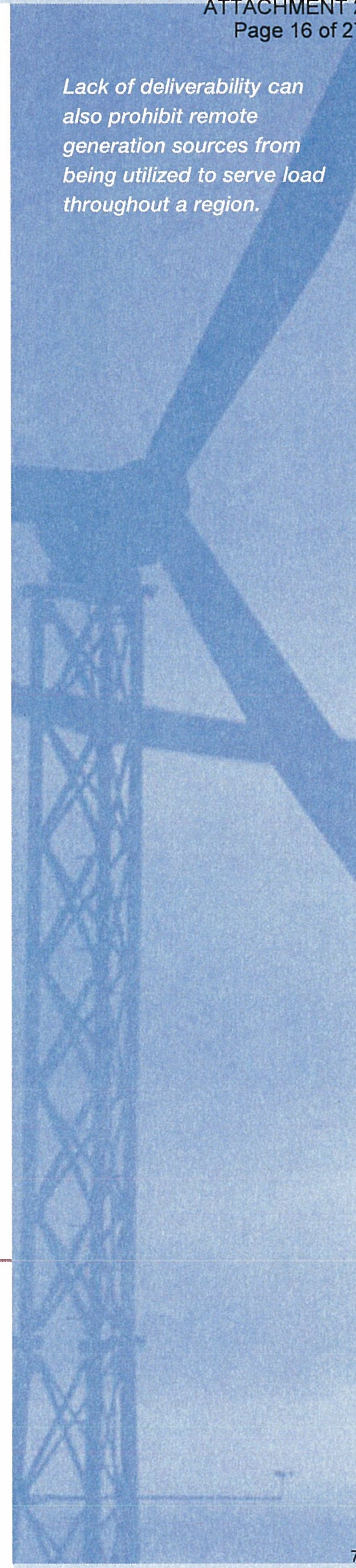
Uncertainty with respect to ultimate cost responsibility and timing delays can prevent a project from proceeding. Some queuing management improvements, such as clustering, class-year studies, and subordination processes[42] aim to mitigate the problems caused by the project-by-project queue approach, but have only achieved a certain degree of success. Developers continue to indicate that the current interconnection processes are problematic.[43]

The current interconnection process approach can also be cost-prohibitive to a developer

41 For instance, in PJM almost 50% of generator interconnections were withdrawn from the queue since 1997 (www.pjm.com/planning/project-queues).

42 Clustering or Class Year approach refers to generator interconnections grouped with other proposed generating projects into a periodic open season, which is six months in PJM and one year in New York. The projects are studied collectively to determine the necessary transmission upgrades, the costs of which may be shared by multiple new generation projects. The subordinate process, such as offered in New England, allows a developer the option to accelerate the construction and operation of its facilities ahead of other projects in the queue if the developer assumes the risks associated with building their facilities in a sequence different from the study order of the queue. These risks include additional uncertainties for ultimate reliability requirements and cost responsibility for transmission upgrades, including the continuing obligation to update studies as relevant projects with higher standing in the queue advance through the process.

43 "Comments of the American Wind Energy Association, the Renewable Northwest Project, the Center for Energy Efficiency and Renewable Technologies, Wind on the Wires, and West Wind Wires," FERC Docket No. RM06-4, "Promoting Transmission Investment through Pricing Reform," January 11, 2006.



because interconnection and transmission upgrade costs can be very large, particularly when regions are starting with an underinvested transmission system. Furthermore, the practice of assigning cost responsibility for transmission upgrades to the next project or projects in the queue fails to take into account what may be broad benefits to system users from such upgrades. Consequently, when these costs are assigned to only one or a few generators, they can present a significant obstacle to needed transmission expansion.

Deliverability

Across the US there are differences in regional approaches to requiring the deliverability of generation. Deliverability refers to the ability of generation sources to reach aggregate load in the region. New England and New York do not require that generation meet a regional deliverability standard and that can result in locked-in generation pockets. PJM has required that generators fulfill regional deliverability requirements to be eligible to receive installed capacity (ICAP) market revenues. However PJM's recently proposed modifications to its capacity market, the Reliability Pricing Model, with its creation of localized deliverability areas may lead it to re-examine its deliverability requirements. Lack of deliverability in a region can lead to the balkanization of market areas into smaller and less competitive local areas which can significantly raise costs to customers and undermine the reliability of the network. Lack of deliverability can also prohibit remote generation sources from being used to serve load throughout a region.

The current interconnection process is unlikely to work well to integrate needed new remote sources of generation into the electric system. The interconnection process alone is insufficient to provide for the robust transmission system that will meet the needs of generation developers and customers. Because the transmission system in many areas of the country is insufficient, the problems with the current interconnection and queuing processes are magnified and can become essentially "show stoppers" for new generation projects. While the queue process can provide for an orderly management of interconnection requests, robust regional planning and effective transmission policies are also needed to address the significant transmission investment required to meet growing customer load, accommodate new and diverse generation sources, and to facilitate competitive markets.

Need for Effective Regional Planning and Transmission Policies

Interconnection and queue issues are exacerbated by existing transmission capacity limitations and infrastructure underinvestment. The wind generation industry recognizes that a more robust transmission grid will enhance the ability to tap our country's vast wind potential and develop other renewable energy resources.[44] Looking abroad, we see that countries with a large wind generation sector have put into place supporting transmission planning and policies to accompany wind and other new generation development.

Currently, Denmark has the highest market penetration in the world. Subsidies granted through government policies, which since the late 1990s have helped renewable development in privately owned wind turbines (farms and industrial factories), have decreased over time due to the advances of wind technology and its growing competitiveness with conventional generation.

The majority of Danish wind plants are less than 100 MW in size and located on-shore. These are connected to the electric system mainly at voltages up to 100 kV. The wind developer is responsible only for the cost of its interconnection to the nearest 10 kV point of the electric system. Any upgrades or reinforcements resulting from a wind plant connection are paid for through transmission rates to customers. In the case of wind plants larger than 100 MW,

44 Ibid.

Danish system operator rules generally provide for connection at voltages above 100 kV, in which case the cost of the interconnection line along with upgrades are included in transmission rates to customers, including off-shore installations.[45]

Following the Kyoto protocol, the UK government set a target of 10% of electricity requirements in England and Wales to be sourced from renewable technologies by 2010, and 15% by 2015. An aspirational target of 20% has been set for 2020. In Great Britain, renewable generation is encouraged by additional payments to generators who supply "green energy" through the issue of Renewable Obligation Certificates (ROCs).

To date, most of the development in England and Wales has been on-shore wind plants of 50 MW or less, although this is starting to change in favor of larger projects, particularly off-shore wind farm projects. In Scotland there are naturally favorable on-shore wind resources and geographic characteristics, which have resulted in significant interest for developing on-shore sites. Wind projects in England, Wales and Scotland could result in some 14.8 GW of wind projects being connected by 2016, although it is recognized that not all of these projects are likely to materialize.[46]

National Grid in the UK operates under regulatory arrangements, including performance-based incentive programs, to provide for a reliable and economically efficient transmission system to support the electricity market. In the UK, generators enjoy firm access to the system, with the ability to be compensated by the system operator if system constraints restrict their generation output, the costs of which are usually incorporated into the incentive programs. This arrangement strengthens the incentives for the utility to plan effectively for needed transmission investment as part of providing a reliable and economically efficient transmission infrastructure.

Costs of the transmission system are generally paid for through system usage charges, and get allocated 73% to load and 27% to all interconnected generators based on the regulator's view of benefits and obligations associated with the transmission system upgrades. Under regulatory rules, National Grid requires financial security from the interconnecting generator developer(s) before proceeding with construction. This security is to provide reassurance that the transmission facilities will not be constructed only to find that the expected new generation sources never materialize. Security from generation developers is required until the new transmission construction is complete and the new sources of generation are operational. From that point on, the costs of the transmission are included in system usage charges to load and generators. The UK regulator is currently assessing the security requirements to ensure they are not prohibitive to new sources of generation.

In North America, both the ERCOT (Texas) and Alberta, Canada regions have implemented beneficial transmission policies to integrate new generation sources. These regions employ economic analysis in their planning processes to reduce congestion and integrate new generation sources. They also each employ a cost allocation methodology that broadly assigns the economic costs of transmission system improvements to system users, without attempting to assign transmission upgrades to specific generator developers.

45 Currently, two off-shore installations exist in Denmark, Horns Rev in the west (160 MW) and Nysted in the east (165 MW).

46 For more information on wind development in the UK, see Department of Trade and Industry's Final Report, The Transmission Issues Working Group, June, 2003; and "Transmission Investment for Renewable Generation, Final Proposals," OFGEM, December 2004.

The development of a robust transmission infra-structure should also include consideration of renewable "trunk lines."

Problems with Existing US Transmission Planning

Inadequacies in existing US transmission planning exacerbate the problems facing wind and other generators seeking access to the transmission system. These inadequacies include planning processes that are not geared to comprehensive regional needs, failure to accommodate long transmission lead times, and a narrow focus on minimum reliability requirements. Moreover, policymakers and planners often fail to recognize transmission as the essential infrastructure which enables competitive wholesale electricity markets and mistakenly view transmission as a market product.

National Grid described the solutions to these problems in its recent paper, *Transmission: The Critical Link*, outlining the critical components of effective regional planning. They include sufficient geographic scope, transparency, independence, comprehensive planning criteria that address both reliability and economic needs, obligation to construct, and clear cost allocation and recovery mechanisms. These problems and their solutions are summarized in greater detail in Appendix A.

Key Considerations for Renewables

Regional planning issues of particular importance to renewable energy resources such as wind include consideration of renewable trunk lines, linkage to state RPS programs, and cooperation among states.

Renewable trunk lines

The development of a robust transmission infrastructure should also include consideration of "trunk lines." Trunk lines refer to radial high-capacity transmission lines that link the interconnected transmission system to remote areas of generation resource development. A shortcoming of relying on an interconnection request-driven process, such as the generator queue, to expand the transmission system is that it creates a catch-22 situation – one in which the initiation of transmission infrastructure is driven only by a request from a new entrant, yet the absence of sufficient transmission capacity represents a significant obstacle to the participation of new entrants. Moreover, this approach can produce a sub-optimal transmission system expansion through its necessarily piecemeal study of the system. Planning studies should incorporate metrics that assess the value of building new trunk line facilities to areas of potential generation development including wind generation and other clean and/or economic generation technologies.

Moreover, cost allocation and recovery mechanisms should include provisions for addressing the costs of such projects to facilitate their development and the eventual benefits they can provide to customers. For example, trunk lines may be integrated into the system as multi-use facilities, or even become networked, non-radial facilities as the system evolves.

Recently, FERC struggled with appropriate cost treatment for Southern California Edison's proposed three-segment transmission project for potential wind development in the Tehachapi region. FERC accepted that costs for the two networked line segments should be rolled into transmission rates for all customers. However, FERC denied such treatment for the radial trunk line segment intended to facilitate wind development without evidence from Southern California Edison that the line would benefit all customers.[47] The California Public Utilities Commission is currently coordinating with the California ISO to develop a new ratemaking approach to accommodate renewable trunk lines.[48]

47 See 112 FERC ¶ 61,014, Order on Petition for Declaratory Order, (2005).

48 "Order instituting investigation to facilitate proactive development of transmission infrastructure to access renewable energy resources for California," CPUC Investigation 05-09-005, July 13, 2006.59 Resolution of the Organization of PJM States, Inc. Regarding Electric Transmission System Planning and Investment, December 15, 2005.

It may be appropriate to distinguish between trunk lines planned for and designed to serve multiple users and trunk lines that start off as sole-use interconnection facilities but evolve over time to become multi-use facilities. Where a generator seeks to interconnect through a sole-use facility, participant funding or direct assignment may be appropriate, provided that rates are structured in a manner that facilitates construction of the project and does not create a barrier to new entry. One way to bridge the gap between initially sole-use and then later multi-use facilities may be to assign costs to the generator, and credit back costs as other developers or users share in the use of the trunk line over time. It may even be appropriate to roll into transmission rates some costs of the trunk line if it can be shown to broadly benefit system users as a whole. Similar treatment could be afforded to smaller projects interconnecting to local distribution facilities.

Linking State RPS Programs with Comprehensive Transmission Planning

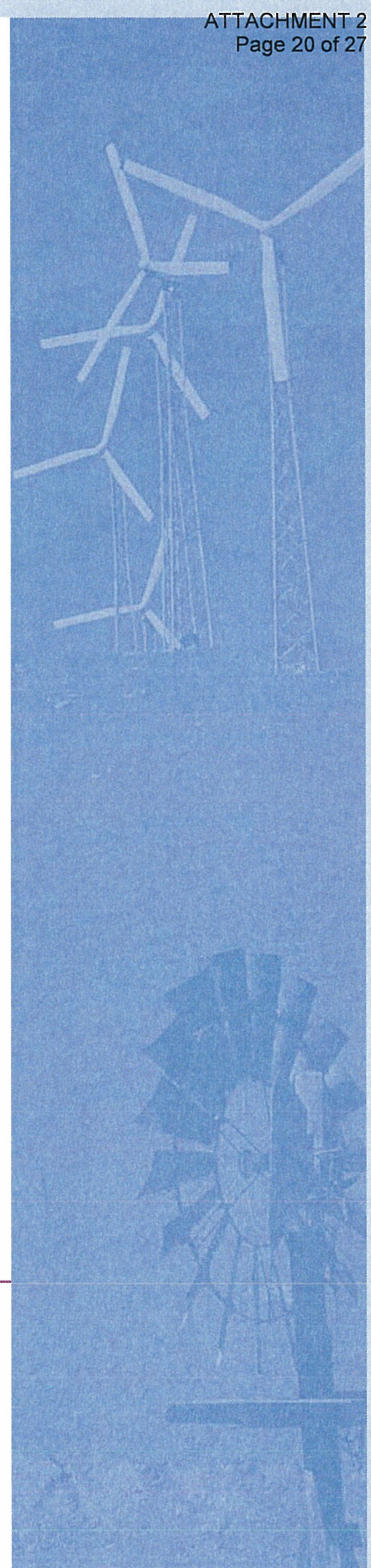
By the end of 2005, 22 states had RPS or similar programs. In order to optimally and efficiently expand the nation's transmission system, these RPS programs should be factored into regional planning as inputs to likely future system needs and conditions. A number of states such as Texas, Minnesota, and California have begun adopting new rules and regulations related to their state renewables initiatives that provide state legal and regulatory support for building transmission improvements for renewable power development.

- Pursuant to recently enacted Texas law, the Public Utility Commission of Texas must designate sufficient land areas as renewable energy zones throughout the state and develop transmission capacity construction plans necessary to deliver the output from renewables in the competitive renewable energy zones.
- Minnesota requires the state commission to approve energy development tariffs to promote wind projects throughout the state.
- On June 15, 2006, the California Public Utilities Commission decided to allow utilities in that state to charge ratepayers under retail rates for upfront transmission costs of building major transmission facilities in areas to support expected development of renewable energy, especially wind projects. The decision is a departure from FERC policy in which developers pay the costs to connect their projects to the grid and recover these costs over time from customers.

Cooperation Among States

The problem of aligning transmission infrastructure benefits with funding and siting reveals itself at the state level. Regulatory policies that do not allow for certain and prompt recovery of costs at the retail level for transmission investment to meet regional reliability and economic needs are a further obstacle to that investment. State cooperation for transmission cost recovery and for prompt siting approvals, along with support for robust regional planning processes, is paramount to achieving necessary levels of transmission investment. A good example is the resolution that the regional states committee in the PJM region established in December 2005. The resolution recognized the importance of regional state cooperation regarding the operation and improvement of the interconnected transmission system and encouraged investment in the electric transmission network to ensure the economic vitality of the region.[49]

49 Resolution of the Organization of PJM States, Inc. Regarding Electric Transmission System Planning and Investment, December 15,2005.



Incentives for Transmission Investment and Independence Can Help Wind Development

Transmission Incentives

FERC's recently issued transmission pricing rule offers a wide range of incentives and pricing reforms to stimulate needed investment in new transmission facilities to projects that qualify in both RTO/ISO and non-RTO/ISO regions.[50] Additionally, FERC offers incentives to encourage further independence in the operation and ownership of transmission, based on the record of investment by independent entities and the value such entities, particularly for-profit Transcos, offer consumers.

Transcos, particularly those independent of market interests and sufficiently wide in geographic scope, focus on delivering low-cost, reliable energy to consumers by facilitating robust and fuel-diverse electricity markets and providing non-discriminatory transmission access to all generation. The advantage of the Transco structure is that it can cut through thorny issues that may be associated with fragmented and vertically integrated transmission ownership, such as potential conflicting business priorities, market interests, differences in business approach, and even skill sets. Because of its for-profit structure, a further advantage is that Transcos can be held firmly accountable by the public and regulators for system performance and operating costs, particularly through performance-based rate structures.

FERC's continued encouragement of Transco formation will:

- Provide the most effective method of ensuring non-discriminatory and adequate transmission access to new, less costly, and diverse sources of generation including clean coal, renewables, and wind;
- Promote effective regional system planning processes that provide for new generation, including remote renewables, and demand-side participation in electricity markets;
- Facilitate the closure of old, dirty, and uneconomic generating sources by allowing newer, cleaner regional generation sources to be delivered to load centers.

In carrying out its transmission pricing policies, FERC ought not to lose sight of the benefits of transmission independence for achieving efficient energy markets that deliver low-cost power and environmental benefits to consumers. In particular, independent entities that own and operate the transmission system, such as Transcos, are best suited to operate, plan, and invest in the regional system ensuring that consumer benefits, not energy market interests, are the driving force. In fact, AWEA, among others, has recognized the advantages of Transcos for wind development and indicated its support for their development.[51]

50 See 116 FERC ¶61,057, Final Rule, "Promoting Transmission Investment through Pricing Reform," July 20, 2006.

51 "Comments of the American Wind Energy Association, The Renewable Northwest Project, The Center for Energy Efficiency and Renewable Technologies, Wind on the Wires, and West Wind Wires," FERC Docket No. RM06-4, "Promoting Transmission Investment through Pricing Reform", January 11, 2006.

Conclusion

Policymakers have recognized that the US has tremendous opportunities to tap wind power as a cleaner, economic, and domestically available new source of generation. Despite the challenges described in this paper, regulators, consumers and the electricity industry in the US are recognizing the environmental and economic benefits associated with wind and other clean technologies. The challenges to the effective integration of wind power into the grid are not insurmountable; they can be addressed with industry, public, and regulatory commitment.

Robust transmission infrastructure policies in countries outside the US have helped them progress toward achieving their goals of diversifying their generation sources using economical renewable sources of supply, while maintaining system reliability. We can look to these international models for transmission planning approaches, and for transmission cost allocation methods that recognize the broad benefits of a robust infrastructure.

The US has not yet fully implemented aggressive transmission policies to take advantage of additional renewable sources of power. Comprehensive, robust, long-term regional planning that includes both the reliability and economic needs of the system will help ensure adequate transmission infrastructure and non-discriminatory access that can aid renewable energy resource development. The evolution of market rules to facilitate renewable resources within the context of reliable system operation and the further use of wind forecasting tools and techniques will also help the US toward its goal of reliable, low-cost, secure and diverse electricity markets. Further, regulatory encouragement of independent transmission companies, and federal and state regulatory policies and incentives that support needed transmission investment are needed to capture the benefits of renewable generation, such as wind power, for customers.

The challenges to the effective integration of wind power into the grid are not insurmountable; they can be addressed with industry, public, and regulatory commitment.

Appendix A: Problems with Existing US Transmission Planning

There are several issues with current transmission planning in the US.

Not Geared To Comprehensive Regional Needs

The fragmentation of the nation's transmission infrastructure by hundreds of different transmission owners can make it difficult for effective expansion of the regional transmission grid. This is in stark contrast to many other countries that have a single transmission system owner and operator.[52] In much of the US, transmission owners are vertically integrated utilities and may have market interests in their own generation or supply contracts. They may face internal corporate competition for capital versus their generation interests, and the imperative to maximize overall value to shareholders can often lead to a focus on generation. Consequently, such vertically integrated utilities may not make transmission investments that provide the most benefit for the region as a whole.[53]

May Not Facilitate Long Transmission Lead Times

It can take up to five years or longer from the time a proposed transmission project is introduced to the public to the time construction begins.[54] But many regional planning processes do not look sufficiently far into the future to be able to identify needs, analyze solutions, and trigger needed transmission construction in time to meet expected system needs. In the case of new remote generation development, it is critical that transmission infrastructure is addressed ahead of the expected changes in system conditions as much as possible. For instance, wind generation development can occur quickly due the modularity of wind technology designs. In Texas more than 900 MW of wind was brought on-line in 2001, outstripping available transmission capacity.

A regional planning process that takes a long-term view of system needs, looking ahead up to 10 to 15 years, can provide opportunities to anticipate many system needs by performing planning, engineering, and even some siting functions in advance of specific project-by-project interconnection requests. This approach allows regions to monitor actual system needs to ensure that the "trigger is pulled" on transmission construction in a timely manner; neither too soon, nor too late.

Too Narrowly Focused on Minimum Reliability Requirements

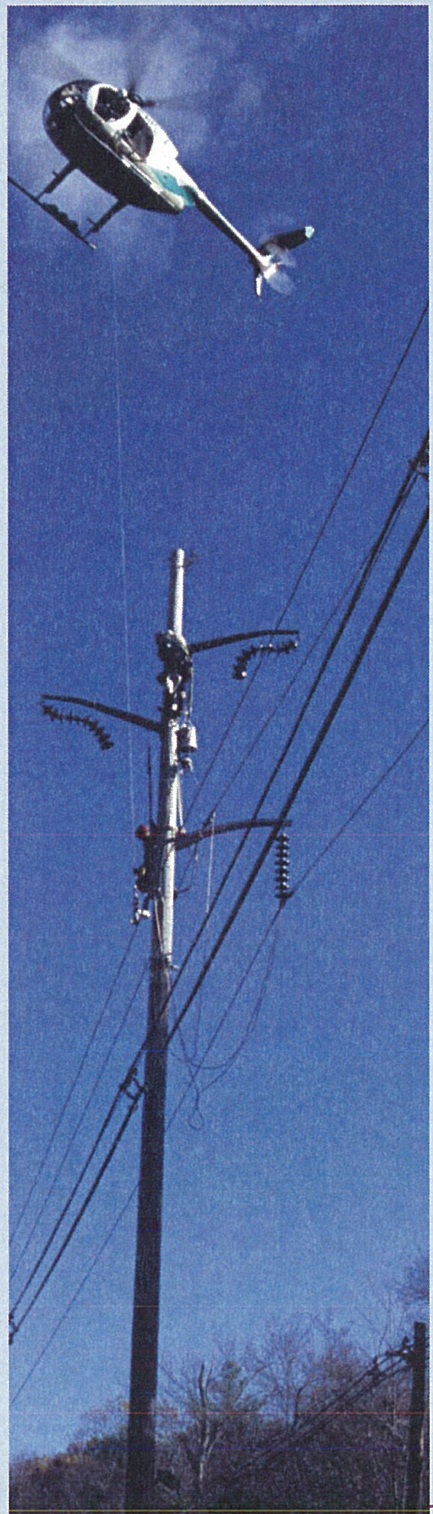
Currently, most planning processes focus on the minimum reliability needs of the system without due consideration to economic efficiency, market facilitation, or other customer benefits of transmission upgrades.[55] Transmission upgrades can help reduce congestion costs, increase customers' options for new generation sources, reduce the need for regulated reliability compensation to existing inefficient generators, and lead to overall lower-cost energy and greater reliability. By focusing exclusively or primarily on minimum reliability standards,

52 New Zealand, Denmark, the UK, Spain, and Norway are among the countries that have a single transmission owner/operator.

53 "Vertically integrated utilities do not have an incentive to expand the grid to accommodate new entry or to facilitate the dispatch of more efficient competitors", FERC Notice of Proposed Rulemaking, "Preventing Undue Discrimination and Preference in Transmission Service," p. 31, May 19, 2006.

54 There are several reasons for this: engineering, procurement, analyzing route options, permitting and siting issues, coordination with public and state regulatory approvals, and solving real estate and environmental issues.

55 Some regions such as PJM, New England, and ERCOT incorporate economic needs to varying degrees into planning studies along with reliability needs.



Transmission has an inherent ability to link neighboring regions and expand existing markets that provides reliability and economic benefits to all customers in a way that generation or demand solutions cannot.

existing planning processes often miss opportunities for expansion of the transmission system to bring overall economic benefits to customers. These benefits include customers' access to new sources of generation, including wind technologies, that can reduce their overall electricity costs.

Transmission is Often Mistakenly Considered a Market Product

Oftentimes, transmission is mistakenly viewed as a market product, with transmission expansion to be performed by market participants in response to locational marginal pricing or other market pricing signals. However, this view of transmission has proven ineffective in furthering transmission expansion in the US. Regions that attempt to rely on such mechanisms find that market participants' proposals to expand transmission simply do not materialize.[56]

Further, some claim that transmission is a direct competitor with generation or demand side options. However, while generation or demand solutions can, in certain circumstances, mitigate the need for transmission upgrades, these non-transmission solutions cannot effectively act as substitutes for a robust transmission infrastructure. Transmission has an inherent ability to link neighboring regions and expand existing markets that provides reliability and economic benefits to all customers in a way that generation or demand solutions cannot. These mistaken views often serve as a distraction that can delay or thwart regional planning processes from advancing transmission infrastructure improvements that provide reliability and economic benefits to customers.

Achieving Effective Regional Planning

The effectiveness and scope of existing regional planning processes vary widely across the country. Regional transmission planning processes are more developed in ISO/RTO regions, where regional planning is identified as a key function for RTOs under FERC Order No. 2000 and where the FERC has held RTOs to certain standards. However, there is still considerable room for improvement. The Commission's further leadership is needed to ensure that all transmission is subject to a robust, comprehensive regional planning process in both RTO/ISO and non-RTO/ISO regions.

Critical Components of Effective Regional Planning

There are several minimum critical components that are particularly important for achieving a transmission grid capable of supporting the development of new generation sources, including remote renewable technologies such as wind. They are:

- ***Sufficient geographic scope –*** The planning process must encompass sufficient geographic and electrical scope to serve a broad market area, or area of significant prospective regional power transactions. It is desirable that all transmission owners within a region participate in the planning process. To provide the necessary infrastructure to support the development of generation, including wind and other renewable resources, the geographic and electrical scope should also include both potential generation sources (i.e., where wind resources are plentiful) and load centers.
- ***Open and transparent process –*** The planning process must be timely, well-defined, and well-documented. The process should be carried out in an open manner with the ability for meaningful input by industry and market participants including existing and potential generators, suppliers, and customers at all stages of the process. An open stakeholder process with regular meetings should review planning assumptions, criteria, and results in sufficient detail to facilitate meaningful understanding of and input into the

56 PJM has relied primarily upon participant funding to prompt economic transmission development, however congestion costs are currently around 9% of the total market, nine times that of ERCOT (scaled to market size) whose well developed transmission system has helped lower congestion costs to about 1% of its market. The absence of meaningful market response in the face of stubbornly high PJM congestion costs has prompted the region to undertake a reform initiative to further facilitate reliability and economic transmission upgrades.

planning process. With respect to wind, the planning process should provide an opportunity for consideration of the comprehensive needs of renewable resources and the needs of the system to handle resource characteristics such as intermittency.

- ***Independent entity –*** The process must be led and administered by an independent entity. In order to ensure a regional perspective, this entity should have the authority and responsibility to identify needs and proposals for consideration without being limited to simply consolidating plans submitted by incumbent utilities. This authority should be independent of market participants, and may be an ISO/RTO, an independent entity formed by participating states, or an independent transmission entity such as an ITC, Transco, or other appropriate entity as long as the planning authority and process have the requisite characteristics.

- ***Comprehensive planning criteria –*** The planning process should include explicit criteria to identify regional system needs to ensure both reliability and economic efficiency.[57] The comprehensive regional process should include:

  1) Transmission service and interconnection requests

  2) Upgrades needed for reliability standards

  3) Market facilitation and reduction to barriers to trade

  4) Access to economic power supply alternatives

  5) Reduction of need for market mitigation or generator reliability compensation

  6) Economic reduction of congestion

  7) Deliverability of resources

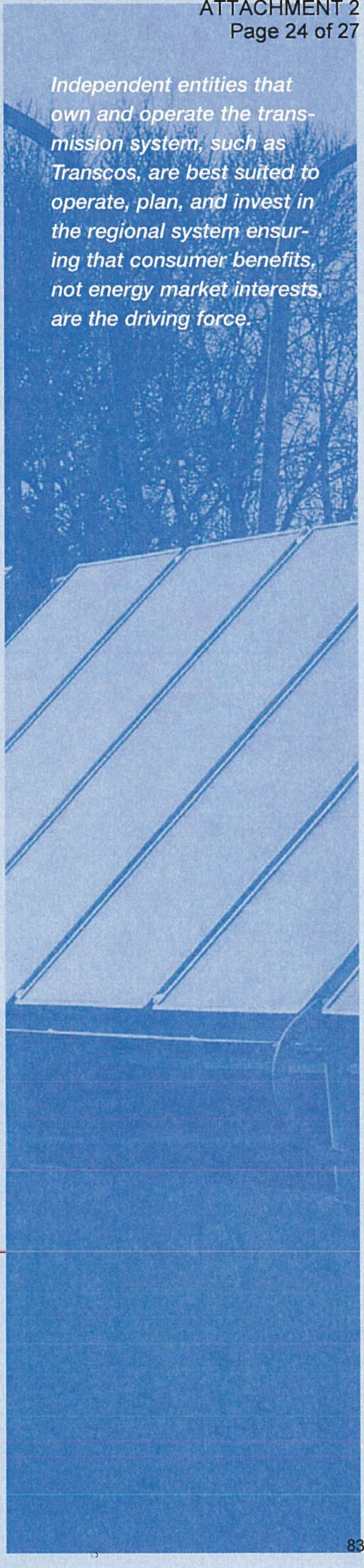
  8) Consideration of fuel diversity, including facilitation of renewable sources of generation

  9) Environmental performance and RPS programs

  Given the often long lead times for transmission construction, the regional planning process should have a sufficiently long time horizon (e.g., from 10 to 15 years) to ensure that transmission projects can be identified and constructed prior to the need date. The process should take a broad view of the system and include areas for potential new generation development, particularly where such development depends on location-specific resources such as wind. Specifically, the regional planning process should actively study a wide range of future scenarios in order to effectively manage uncertainty with respect to new generation, availability of generation including retirements,[58] demand growth, advanced technologies, fuel prices and availability.

- ***Authorization for construction –*** The planning process should outline roles and responsibilities for constructing all new transmission identified pursuant to the regional plan. The process should include provisions for construction of regulated transmission if merchant or market-driven projects have not addressed needs in a timely manner, for example after a predefined window for market response.[59] The regional planning authority should be able to order that transmission enhancements be undertaken to meet reliability and economic needs, and to authorize third parties to construct if incumbent utilities do not commence work in a timely fashion.

Independent entities that own and operate the transmission system, such as Transcos, are best suited to operate, plan, and invest in the regional system ensuring that consumer benefits, not energy market interests, are the driving force.



57 FERC has confirmed that, "[i]n order to fully meet the planning and expansion function for an RTO," an RTO's planning process must "identify expansions that are needed to support competition." PJM Interconnection, LLC., et al., 101 FERC ¶ 61,345 (2002), p. 24.

58 Reinforcing the network in anticipation of generation deactivations/retirements would avoid the need for reliability must run contracts and other forms of so-called "reliability compensation."

59 PJM provides for a one-year "market window" in its regional planning process. PJM Regional Transmission Expansion Plan, February 2006.

- ***Cost allocation and recovery –*** No matter how compelling the case may be for a particular transmission project in the regional transmission planning process, projects are likely to face substantial resistance if the rules for how and which customers will pay for investments are not clear. The planning process should include upfront practical transmission cost allocation rules for regulated transmission built pursuant to the regional plan. Ideally, there should be a commitment and a clear path to ultimate cost recovery through wholesale and retail rates, including allowance for abandoned plant associated with the regional plan. Cost allocation rules should recognize the broad benefits that are associated with an upgrade, and could incorporate a mix of regionally spread (postage stamp), license plate, and participant funding mechanisms (for sole-use facilities). While New England has settled on a clear, easily administered cost allocation mechanism for new transmission projects,[60] cost allocation continues to be debated in other regions.[61]

60 See New England Power Pool and ISO New England, Inc.; Maine Public Utilities Commission v. New England Power Pool and ISO New England, Inc., 105 FERC ¶ 61,300 (2003), Order on Complaint.

61 PJM has been challenged by many parties regarding its current cost allocation rules. On May 26, 2006, FERC ruled that the allocations on some projects may be unjust and unreasonable and has set the matter for hearing (FERC Docket ER06-456). See also Midwest Independent Transmission System Operator, Inc., PJM Interconnection, LLC., et al,; Ameren Services Company, et al., 109 FERC ¶ 61,168 (2004) - recognizing that the Midwest ISO and PJM stakeholders were unable to agree on a long-term transmission pricing methodology for the super-region, but ordering the parties to develop a proposal for allocating to the customers in each RTO the cost of new transmission facilities that are built in one RTO but provide benefits to customers in the other RTO. See also FERC's Order on New York planning encouraging NYISO and New York stakeholders to move beyond high level cost allocation principles to a "full cost allocation methodology," FERC Docket ER04-1144, p. 29. Although the NYISO planning process is incomplete with respect to planning for economic reasons and the inclusion of a full-cost allocation methodology, it should be noted that the New York planning process does provide a cost recovery mechanism for transmission owners that must build planned projects.

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