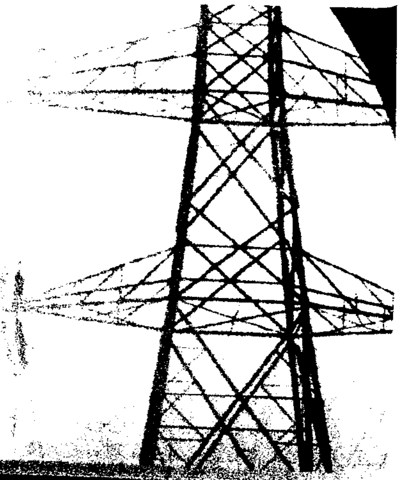
Intervener's Exhibit 17
Docket Nos. PU 06-481
PU 06-482



NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2007 Long-Term Reliability Assessment

2007-2016

October 2007

Progress Since 2006

In its *2006 Long-Term Reliability Assessment*, NERC identified four "Key Findings" that could critically impact long-term reliability unless prompt actions are taken: declining capacity margins, lagging transmission construction, fuel supply and delivery issues (focusing on natural gas), and the aging industry workforce.

The magnitude of these issues necessitates complex solutions, the impacts of which may not be realized for several years. While some progress has been made (as summarized in the chart below), efforts to date have yet to substantially mitigate the risk of these issues to future reliability. Each of the four issues is therefore highlighted again in the 2007 report as a "key finding." A fifth finding is also highlighted in the next section regarding the *integration of wind, solar and nuclear resources.*

Progress on 2006 Findings

Finding 1: Electric capacity margins continue to decline — action needed to avoid shortage

Overall committed capacity margins improved by approximately two percent in the U.S. over the last year, but margins in some areas decreased. Several areas established forward capacity market, which will be relied upon to provide the necessary, new resources to maintain reliability.

Finding 2: Construction of new transmission is still slow and continues to face obstacles

Almost 2,000 miles of transmission were added to U.S. the bulk power system in the past year representing a little over one percent increase. Two draft DOE National Interest Electric Transmission Corridors were identified.

Finding 3: Fuel supply and its delivery to electric generation are vital to maintaining reliability

Organizations in Florida, California and the ISO New England – all representing areas with high dependence on natural gas fuel -- performed studies identifying specific concerns and courses of action to mitigate the risks of supply and delivery interruptions. In ISO New England, 2,300 MW of single-fuel, gas-fired capacity was converted to dual-fuel capability.

Finding 4: Aging workforce presents challenges to future reliability

Industry action is urgently needed to meet the expected 25 percent increase in demand for engineering professionals by 2015. Enhanced recruitment and outreach efforts through consortia, partnerships with local colleges, and increasing R&D support of university programs are vital for developing future industry talent.

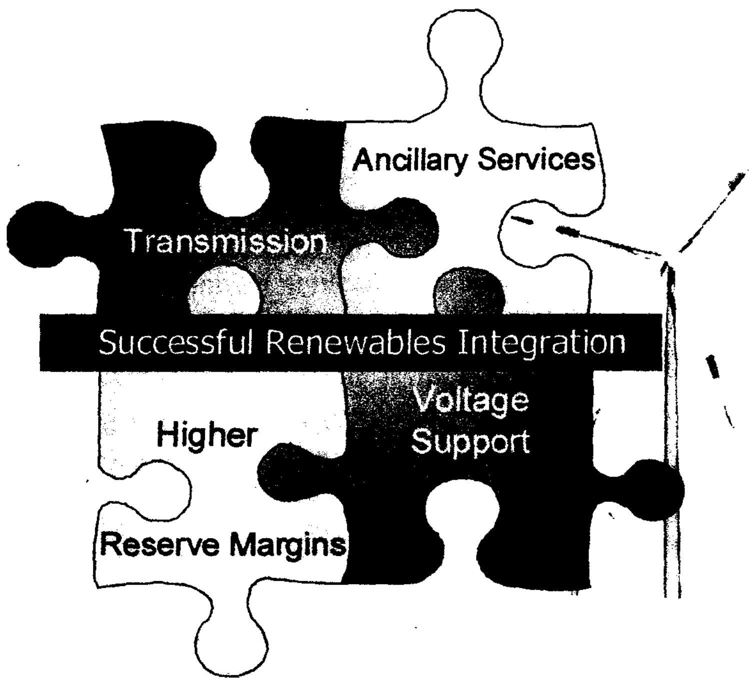
2. Integration of Wind, Solar, and Nuclear Resources Require Special Considerations in Planning, Design, and Operation

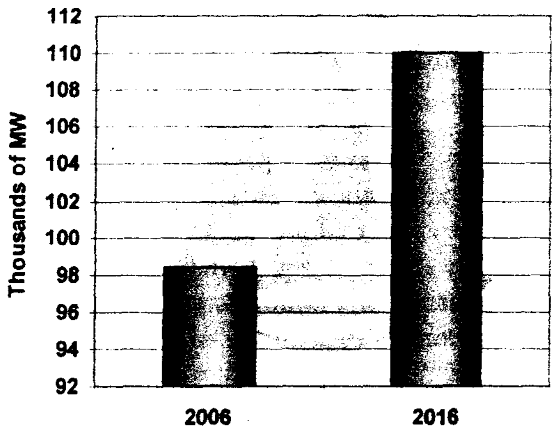
Wind, solar, and nuclear resources have unique characteristics that must be accommodated in the planning, design and operation of the bulk power system. Transmission infrastructure must be developed to reliably integrate these resources, while maximizing their potential to meet resource requirements and reduce greenhouse gas emissions.

Wind and Solar

Regulatory trends, coupled with the increasing viability of renewable resources, have resulted in greater planned use of non-carbon emitting generators. With the potential for federal CO_2 legislation increasing, the trend toward renewable resources is expected to continue and increase.

Much new emphasis is being placed on wind and solar resources in long-term resource planning, especially in ERCOT, SPP, WECC, and MRO where some states have mandated Renewable Portfolio Standards. This proposed level of commitment to renewables offers many benefits (new generation resources, fuel diversification, greenhouse gas reductions), as well as challenges. The unique characteristics and attributes of renewables require special considerations for planning. For example, they are often remotely located, requiring significant transmission links often over challenging terrain. Wind and solar resource variability requires ancillary services such as voltage support, frequency control, increased base-load unit dispatch flexibility, and spinning reserves. In addition, many times their available generating capacity at time of peak is significantly less than their nameplate capacity varying with location. Those entities responsible for bulk power system reliability must take these unique characteristics and attributes into account to ensure wind and solar are reliably integrated into the system.





The NRC predicts to receive applications for 32 new nuclear units by 2009 – proposed as 12,000 additional MW coming online in 2015-2016.

Nuclear

A total of 12,000 MW of new-build nuclear capacity[8] is proposed in 2015–2016. The design specifications for some of these units are large (over 1,600 MW). Significant investment in transmission is vital to support these large units — including their larger safety loads following reactor trips -- and ensure that they are reliably integrated into the system. Because of the long-lead times for major transmission development and siting, and the considerably shorter lead-time[9] for new nuclear units, transmission must be initiated sufficiently far in advance to ensure that the transmission system will be ready to accommodate these units when they are licensed for operation.

Recommendations and Conclusions

- Mandates for aggressive RPS must be accompanied by active support for the development of, and investment in, the transmission infrastructure required to reliably integrate those resources into the bulk power system.

NERC Actions

- NERC will evaluate the operational requirements to reliably integrate intermittent resources into the bulk power system and provide recommendations for draft standards as necessary.
- NERC will develop a consistent approach to rate intermittent resources, such as wind and solar, according to their available capacity at time of system peak.
- NERC will monitor the integration of new nuclear generation to ensure the transmission resources needed to reliably integrate proposed new units into the bulk power system are available, and the coordinated development of needed transmission reinforcements with transmission planners and planning coordinators.

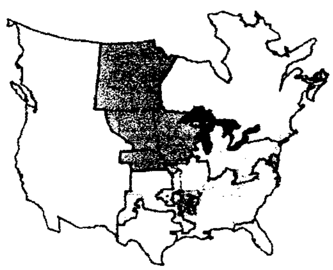
More information on the integration of wind, solar and nuclear resources can be found in the *Scenario Analysis* section.

[8] ERCOT: 6,176 MW, FRCC: 1,125 MW and SERC: 4,320MW

[9] Recent NRC Workshop: Current expectations are that it may take 78 months to complete nuclear plant construction.

future generation siting and corresponding transmission expansion to support future generation and load growth. All Florida utilities are required to meet the Florida Public Service Commission reserve margin requirements. Therefore, even if future generation plans are not firm, the utilities must show they plan to maintain these reserve margin levels throughout the planning horizon. Many of the large generating units planned in the six — ten year timeframe are not sited and may require additional transmission sensitivity assessments.

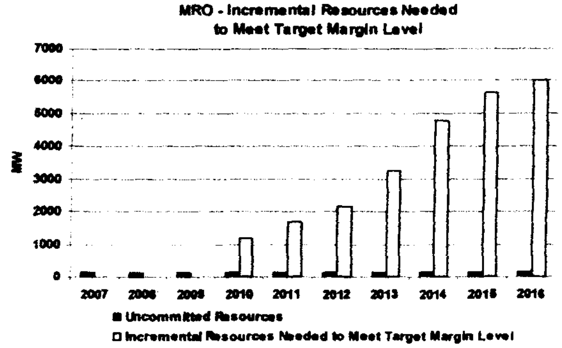
The FRCC transmission system is evaluated to identify possible emerging concerns, monitor known concerns, monitor the effects of planned projects and identify major projects that may require long lead times. The remedies developed for this section take into consideration the uncertainty of the generation expansion plan and the location and timing of projected loads. In addition, the transmission expansion plans representing the years six — ten of this study are typically under review by most transmission owners still considering multiple alternatives for each project.



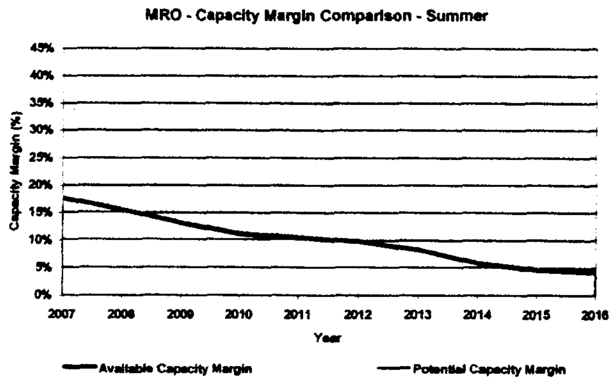
MRO

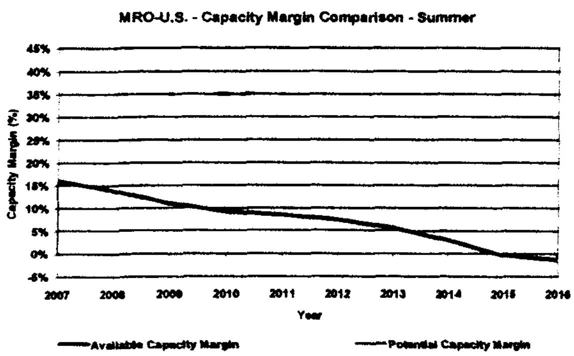
The data submitted by the Midwest Reliability Organization (MRO) indicates reduced capacity margins during the timeframe of this study. MRO-Canada has adequate generating capability throughout the assessment period, but currently planned capacity reported in the MRO-U.S. portion of the region is below MRO targets for reserve margins from 2010–2016.

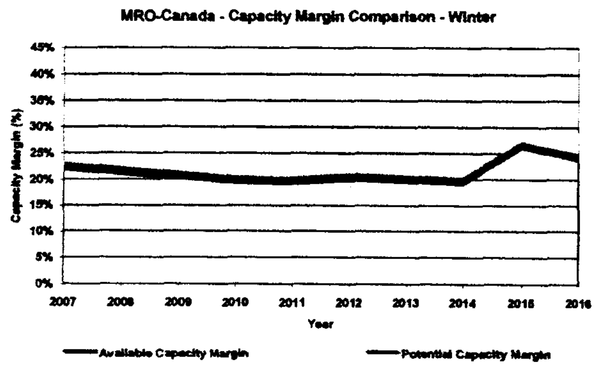
For the 2007–2016 period projected capacity margins are expected to be higher than reported by the regional entity to NERC based on past experience and the contractual enforcement mechanism for reserves within a large part of the MRO region. MRO members are accountable for meeting the planning reserve margins that apply to them. The MRO region is comprised of non-retail access jurisdictions (except the upper peninsula of Michigan) where MRO members have an "obligation to serve load" or "Provider of Last Resort". In addition, the MRO is proposing a resource adequacy assessment standard that requires an annual load and capability assessment. Typically these members assess how best to meet their required margins by considering self-built generation, merchant generation, demand-side management, and firm power purchases with firm deliverability. In the six — ten year timeframe, the location and magnitude of future generation is less certain as lead-times are short for a number of generation types, including wind and gas turbines.

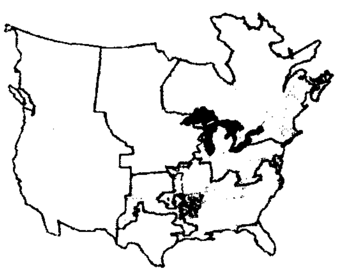


In this assessment, MRO projects only include committed generation projects (from Load and Capacity reports) that have a reasonable amount of certainty. Using only committed projects may lead to conservative predictions of reserve margin/criteria, especially in years six — ten. Historically MRO members have consistently met their reserve margins. To meet NERC's TPL Standards, a ten-year model is built with assumptions made for future generation location using the best knowledge available including generation interconnection queues and engineering judgment. Through the 2016 planning horizon, the MRO expects its transmission system to perform reliably assuming proposed reinforcements are completed on schedule. Power market activity will continue to fully use the capability of the system, which may not meet all market needs.





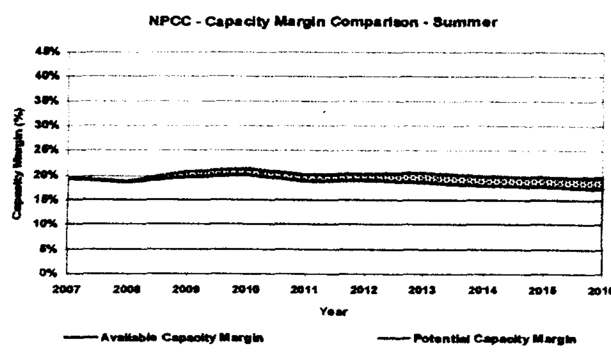




NPCC

To effectively conduct an assessment of resource adequacy, it is necessary to consider individually the five large Northeast Power Coordinating Council (NPCC) subregions: the Maritimes, New England, New York, Ontario and Québec, three of which are summer peaking and two of which are winter peaking. If one considers only the U.S. entities in NPCC (New York and New England), a significant drop in capacity margins over the assessment period is seen. NPCC-Canada (Maritimes, Québec and Ontario) shows a capacity margin growth until the year 2011, leveling at over 20 percent.

In New England, to meet NPCC criteria, approximately 170 MW are needed in 2009, increasing annually and requiring a total of 4,300 MW by the 2015/2016 time period. This amount is to be purchased by ISO-NE in the Forward Capacity Auction. Beginning in 2010, New York will require additional capacity to meet the NPCC adequacy criteria.



Scenario Analyses Development for 2008

To prepare for and support the *2008 Long-Term Reliability Assessment*, NERC is developing two critical scenarios. These initial explorations are outlined below to provide a baseline of information that will be built upon to create specific, detailed "what if" scenarios for the 2008 assessment. In future years, this process will be expanded and will involve analysis from the regional entities. Much of the background for these scenarios can be found in the *Emerging Issues* section of this report. The two scenarios considered are:

- A Generation Fuel Mix Re-Defined by Federal CO_2 Legislation
- An Industry Facing New Levels of Natural Gas Demand

Scenario 1: A Generation Fuel Mix Re-Defined by Federal CO_2 Legislation

One of the key new findings presented in this assessment report is the industry's increased interest in providing infrastructure to support a resource mix (generation, transmission, and demand-side) affected by climate change regulation. Analysis[33] conducted by the U.S. Department of Energy's (DOE) Energy Information Administration (EIA) of current proposals from the U.S. federal government (cap-and-trade[34], carbon tax, renewable mandates[35], etc.), the Ontario Power Authority, and others, forecasts the following generation fuel mix changes to meet CO_2 goals:

- Reduction of existing coal resources (i.e., Canada)
- Proposed coal plant additions in the U.S.
- Higher reliance on
  - nuclear
  - renewable energy sources (most notably, wind)
- Increased demand-side management opportunities

The EIA analysis of a bill introduced by Senators Joseph Lieberman and John McCain (S. 280)[36] projects an increase in nuclear generating capacity from the current level of 100 GW to 245 GW by 2030, or an increase of 145 GW. If unrestrained nuclear unit construction is not supported in areas seeking increased non-emitting generation, biomass fuels could be a candidate for new generation, especially in those areas where wind and solar power are not available. Additional study by the National Gas Council[37] indicates that if unrestrained construction of nuclear plants

[33] http://www.eia.doe.gov/oiaf/service_rpts.htm
[34] http://www.eia.doe.gov/oiaf/servicerpt/csia/pdf/sroiaf(2007)04.pdf
[35] http://www.eia.doe.gov/oiaf/servicerpt/prps/pdf/sroiaf(2007)03.pdf
[36] *Energy Market and Economic Impacts of S. 280, the Climate Stewardship and Innovation Act of 2007*, issued July 2007 by EIA; Report #: SR-OIAF/2007-04
[37] http://www.ngsa.org/docs/GHG_NEMS_FINAL_Report_9-28.pdf

marketplace. Just like supply alternatives, careful planning is required to support its integration and ensure reliable operation.

Large Nuclear Unit Integration — New nuclear unit designs have significantly increased capacity over older designs (up to 1,600 MW versus 600–1,000 MW). This increased single unit capacity impacts both planning and operational reserves as the sudden unavailability (forced outage) of large units can reduce reliability to a greater extent than smaller units. Additional supply and/or demand-side resources may be needed to support planning reserve requirements, while for operations, increased hot-start and spinning reserve resources (supply or demand-side) might be required to support the reliability requirements of the bulk power system.

Nuclear units are base-load units and traditionally not load following (cycling, starting/stopping, etc.) Though this flexibility may be increasing somewhat with advanced designs, they are generally considered base-load. Significantly increasing the number of the newly designed units may reduce the overall flexibility of the bulk power system, and therefore, its future design would need to accommodate resources that support load-following requirements. Significant bulk transmission system reinforcements would also be required to ensure reliable integration.

Conclusion — To accommodate a shift in resource allocation resulting from CO_2 legislation, the bulk power system will require changes in system design, operating margins and ancillary service requirements to maintain reliability. Furthermore, to manage the expected high integration of demand response, the predictability of these resources must be better understood to ensure that the bulk power system design reliably captures their potential benefits.

Scenario 2: An Industry Facing New Levels of Natural Gas Demand

Natural gas generation, because of its relative ease-of-siting, lower construction costs, and comparative lower CO_2 emissions continues to be a popular fossil-fuel throughout North America, representing up to 19 percent of capacity in the U.S. in 2007. A study by the National Gas Council[39] indicates that if unrestrained construction of nuclear plants was not possible to meet federal CO_2 legislation, and biomass is not fully deployable, higher levels of natural gas fired generation might be needed.

Federal or local environmental policies may encourage the construction of natural gas-fueled generation, and investors as well as Load Serving Entities are attracted to natural gas plants, for these same reasons. However, increased dependency on a single fuel supply increases vulnerabilities in two areas.

Supply — There may be insufficient supply available to support natural gas demand. Domestic consumption of natural gas continues to rise, and is expected to take up much of the domestically available natural gas. Yet domestic natural gas supplies are not increasing. Natural gas imports into the U.S. from Canada are expected to level off and begin declining in 2010, as Canadian domestic consumption increases. Liquefied natural gas (LNG) imports from around the world are

[39] http://www.ngsa.org/docs/GHG_NEMS_FINAL_Report_9-28.pdf

was not possible, and biomass is not fully deployable, higher levels of natural gas fired generation might result (see *Scenario 2*). Further, given the uncertainty associated with foreign gas supplies even with LNG terminal construction and the environmental limits that affect unconventional gas production, new conventional sources of natural gas should be developed.

A significant change in resource mix affects bulk power system reliability. This scenario investigates the impact of increasing three specific technologies: wind, demand-response and nuclear.

Penetration of Wind Energy — Wind generation is projected to become a significant portion of the generation mix. The technology has matured and can enable generation owner/operators to meet federal, state and provincial renewable energy mandates.

The intermittent nature of wind constitutes the major challenge to planning and operating bulk power systems with large amounts of wind generation. Wind generation's total capacity is not available at full output throughout the day and is unavailable most often mid-day when the peak internal demand occurs. In the 2007–2016 timeframe, wind is projected to serve three percent of peak demand. Therefore, to offset the impact of the intermittent nature of wind resources, higher planning/operation capacity margins are required to include supplemental generation (quick-start, gas-fired, or increasingly flexible and dispatchable base-load units) providing load and wind-following flexibility.

Considerable bulk power system upgrades and design modifications are required to provide the ancillary services to deliver new wind energy and to support overall operational reliability, including:

- Load following, frequency response, voltage regulation, and other ancillary services
- Increased reactive support accommodating remotely located wind resources.

High Integration of Demand Response — Demand response is increasingly viewed as an important option to meet the growing electricity requirements in North America, while at the same time addressing green-house gas and CO_2 legislation. Demand response supports operational and long-term planning margins. According to a recent FERC report[38], demand response and the advanced metering programs that enable it have grown significantly over the past year. The report notes major demand response developments in wholesale markets, including its use in forward-capacity markets and ancillary services markets, as well as the development of new reliability-based demand response programs. Demand response lowered the consumption of electricity by 1.4 percent to 4.1 percent during periods of peak demand on the system in 2006, the report states.

A significant amount of demand response resources may reduce the need for planning and operating generation capacity margins, increases bulk power system flexibility, reduces the impact of fuel supply and delivery interruptions, and can be used to enhance renewable integration. Certainty of their availability is vital to ensure demand response provides verifiable reliability benefits. Further, it brings the user of electricity closer to the

[38] FERC Staff Report, *Assessment of demand Response and Advanced Metering*, September 2007, http://www.ferc.gov/legal/staff-reports/09-07-demand-response.pdf

expected to increase, off-setting the decline of the domestic natural gas supply. But LNG requires substantial investment in terminals that convert the LNG into natural gas. If construction of these LNG terminals is delayed, it will impact the nation's ability to rely more on LNG imports to meet natural gas supply needs.

Delivery — Without firm commitments to pipeline owners from suppliers, new pipeline construction cannot proceed as FERC looks upon the degree to which capacity is contracted firm as an indicator of need for capacity. Operators of natural gas-fired generation tend to sign limited firm fuel transportation contracts (release-firm) that have low contractual rights to natural gas pipeline and storage capacity.

Conclusion — To ensure reliability, federal and state/provincial authorities should support industry efforts aimed at diversifying fuel sources and mitigating risks: increased natural gas storage, dual fuel capability addition, LNG terminal construction, and increased firm contracts for gas supply and delivery. Increased construction of transmission lines could also be part of the solution by facilitating the delivery of power to areas where the potential for gas supply/pipeline disruptions exists.

Review of Regulatory & Business Issues

Four of the most significant trends or issues influencing bulk power system reliability are explored in this section.

Green House Gas (CO_2) Regulation and Renewable Energy Mandates

The drive to reduce green house gases, including CO_2, is gaining momentum throughout North America. Demand-side options can play a significant role in reducing CO2 emissions, but will not be enough. Supply-side options that meet green house gas regulations need to be explored, including:

- Non-fossil-fuel-based generation (renewables or nuclear power)
- Fossil-fired fuel technologies that can ultimately prevent CO_2 build-up in the atmosphere, or significantly reduce it compared to existing fossil-fired technologies.

Regulations on Green House Gas emissions, notably CO2, are being promulgated by individual states and provinces throughout the U.S. and Canada. Under mandates in 25 states, clean energy, such as wind, solar and biomass, must be up to 30% of a utility's energy portfolio in five to 15 years. In 2003, just ten states had such requirements.

As states and provinces begin adopting varying approaches to green-house gas emission regulation, the prospect grows that both federal governments will become more engaged and nation-wide legislation result. Renewable energy, mostly from wind farms, is expanding 30% a year.[40]

A few examples of state- and provincial-sponsored regulations are:

- California — Bill AB 32 entitled *The Global Warming Solutions Act of 2006* requires a 25 percent cut in the state's greenhouse gas emissions by 2020, to reduce them to 1990 levels. As defined in the bill, "greenhouse gases" include all of the following gases: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). These are the same gases listed as GHGs in the Kyoto Protocol. Further, as part of rulemaking[41] for Executive Order S-3-05, the California Public Utilities Commission describes a GHG emissions performance standard that would limit the GHG emissions levels for all new utility-owned

[40] http://www.usatoday.com/money/industries/energy/environment/2007-10-03-clean-energy_N.htm

[41] California Public Utilities Commission, Rulemaking 06-04-009, "Order Instituting Rulemaking to Implement the Commission's Procurement Incentive Framework and to Examine the Integration of Greenhouse Gas Emissions Standards into Procurement Policies"

generation and all procurement contracts that exceed three years in length to "no higher than the GHG emissions levels of a combined-cycle natural gas turbine."

- In an effort to reduce green house gases, many states (about 23) are mandating renewable energy levels:

    - Minnesota has mandated 25 percent of the states energy come from renewable sources. All Minnesota utilities except Xcel Energy Inc. would be bound by the 25 percent-by-2025 standard. Xcel, which delivers half of Minnesota's electricity, is mandated by 2020 to meet 30 percent of energy generated by renewable resources
    - New York has a 25 percent mandate by 2013.
    - Colorado is moving toward a standard of 20 percent by 2020.
    - New Jersey has a "20-20" initiative that calls for 20 percent of its electricity to be generated with renewables within 13 years.
    - Prince Edward Island has a target of achieving 15 percent of its electricity from renewables by 2010.
    - Nova Scotia mandated 20 percent of 2013 electricity will be generated by renewable energy — wind, tidal, biomass, solar and hydro.
    - Florida has a 16 percent target by 2020 by a governor's executive order.

For the U.S., a number of additional regional and state activities are being pursued to develop renewable portfolios (Figure 3[42]). Federal legislation is under consideration, including carbon tax, cap-and-trade, and renewable portfolio standards.

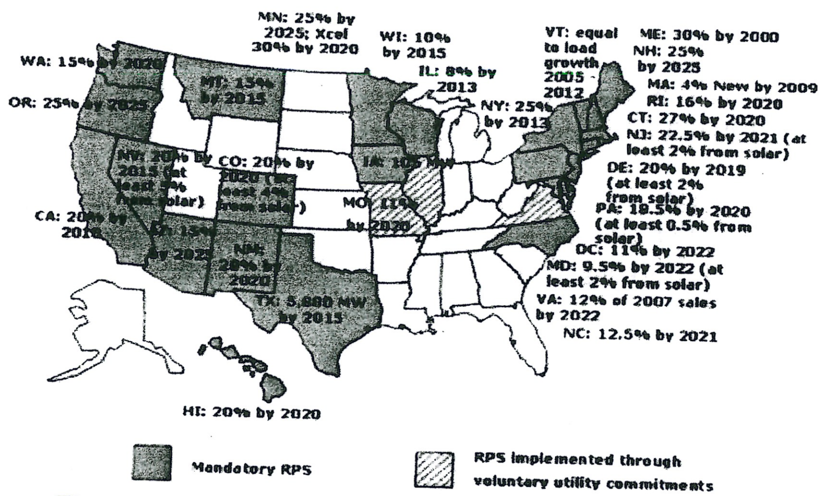


Figure 3: Snapshot of Renewable Portfolio Standards

All of these advancements require intense coordination and integration with the existing system, in order to fully capture their benefits while ensuring system adequacy. These greenhouse gas initiatives can impact the bulk power system in ways including the following.

- Investment risks caused by regulatory variability can delay construction of adequate generation.

42 http://www.pewclimate.org/what_s_being_done/in_the_states/rps.cfm or more detailed resource maps at: http://www.pewclimate.org/what_s_being_done/in_the_states/nrel_renewables_maps.cfm

- Increased investment in Combined Heat and Power (CHP) applications could reduce transmission loading in some areas, thereby improving transmission reliability.

  - Integrating newly sited, non-emitting generation, including small distributed energy projects which serve local loads as well as power the grid, may require construction/upgrading/rejuvenation of the grid.

  - As learned from the recent disturbance in Europe (November 4, 2006), harmonized operations during emergencies is critical to ensure that non-emitting sources are dispatched to support system reliability goals.

  - Large numbers of new generating units replacing retiring plants could temporarily influence system adequacy. Once understood, synchronized action can be taken to ameliorate the effects until balance is realized.

  - If fuel options become limited, energy security and fuel supply vulnerability risks are increased. A balanced fuel-mix must be available to withstand supply disruptions.

  - Generation can become unavailable due to environmental emission limitations impacting system adequacy during years where higher then expected availability of emission-limited units is required. Unavailability of Reliability Must Run (RMR) units can reduce real and reactive power supplies exasperating system conditions.

  - Some non-emitting sources provide energy, but may not be available, at full capacity, to serve peak load requirements, unless coupled with storage technologies. Study of their characteristics can help planners understand how to best site and take advantage of the capacity and develop system/technology strategies increasing their reliability benefits.

Energy Policy Act of 2005: Transmission Related Provisions

Several specific areas of EPACT are intended to improve reliability through enhanced transmission infrastructure siting and enforcement:

1. National Electric Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors (NIETCs) (Section 1221a)

   Section 1221 of EPAct 2005 requires the Secretary of Energy to publish an electric transmission congestion study by August 8, 2006. Further, the Act provides that after receiving and considering public comments, the secretary may designate selected areas as NIETCs. Designation as a NIETC gives the FERC backstop authority under

Demand Issues

Internal demand or load is a fundamental component of adequacy assessment. Influence of a variety of important emerging parameters are discussed below.

DEMAND RESPONSE

Introduction

Demand response is increasingly viewed as an important option to meet the growing demand for electricity in North America, while at the same time addressing green house gas and CO_2 legislation. Demand response is a subset of the broader category of end-use customer energy solutions known as Demand-Side Management (DSM). In addition to demand response, DSM includes energy efficiency programs. This DSM evaluation is concentrated on the influence of demand response on reliability assessment and; therefore, focused on peak demand reduction rather than overall energy efficiency.

Demand response benefits reliability by reducing customer demand for power, which in turn alleviates somewhat the demand on supply-side and transmission resources. Demand response becomes a resource supplementing reserves, along with operational reliability benefits providing operating reserve and flexibility. Demand response can support the management of operational reserves as well as long-term planning reserves.

Demand response programs require substantial investment in measurement technologies, including advanced metering to enable two-way customer communications, measurement of actual response, and validation of participation. This investment must be recognized along-side other investments as part of overall bulk power system rejuvenation. Increased certainty regarding customer participation, especially for voluntary programs, is required as part of the justification of these investments.

For purposes of this report, NERC will embrace the definition of demand response as proposed by the U.S. Department of Energy in its February 2006 report to Congress[58pp.viii] and adopted by the FERC in its August 2006 *Assessment of Demand Response and Advanced Metering*[59]:

[58] FERC Staff August 2006 Report: *Assessment of Demand Response & Advanced Metering* http://www.ferc.gov/legal/staff-reports/demand-response.pdf#xml=http://search.atomz.com/search/pdfhelper.tk?sp_o=1,100000,0

[59] U.S. Department of Energy, *Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them*: A report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005, February 2006 (February DOE EPAct Report). http://www.oe.energy.gov/DocumentsandMedia/congress_1252d.pdf

> *"Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale prices or when system reliability is jeopardized.*

FERC noted that demand response, using this definition, can be divided into two categories: incentive-based demand response and time-based rate programs. Each of these programs has unique aspects influencing the electric utility industry's ability to reliably plan and operate the bulk power system.

The FERC suggests *"The potential immediate reduction in peak electric demand that could be achieved from existing demand resources is between three and seven percent of peak demand in most regions."* This represents a significant resource for meeting demand. Expanding the penetration of these programs or designing new ones may result in an even greater resource impact.

NERC Data

NERC collects two quantities for on-peak megawatts (MW) for seasonal and long-term (ten years) reliability assessment reports: direct control load management and interruptible demand.

As NERC's reports are forward-looking, the remainder of utility DSM programs is captured as part of the internal demand, defined as:

> **Internal Demand**[60]: is the sum of the metered (net) outputs of all generators within the system and the metered line flows into the system, less the metered line flows out of the system. The demands for station service or auxiliary needs (such as fan motors, pump motors, and other equipment essential to the operation of the generating units) are not included. (Note: integrated hourly demand values are requested.)
>
> *Internal demand includes adjustments for utility indirect demand-side management programs such as conservation programs, improvements in efficiency of electric energy use, rate incentives, and rebates*(**emphasis added**). Internal demand should not include stand-by demand and should not be reduced by direct control load management or interruptible demand.

Respondents to NERC's seasonal and long-term reliability assessment data requests modify the demand curve to accommodate a variety of demand response programs (such as time of use, real-time pricing, etc.) which is specifically helpful when forecasting future internal demand. To afford comparative analysis, these

[60] NERC: *Instructions for NERC Summer Assessment Data Reporting*

same quantities are also collected as part of the forecasted seasonal summer/winter reliability assessment data requests.

Demand Response Taxonomy

As the industry's use of demand response changes, NERC's data collection and impact assessment of these programs will change, highlighting those that have an impact on bulk power system reliability. Figure 5 provides a graphic illustration of demand response programs followed by a brief description of the demand response subcategories categorized as described in FERC's report[61].

Where data is collected for NERC's seasonal and long-term reliability assessments, the program description is modified to reflect NERC's nomenclature. Comments are provided on each program's influence on bulk system reliability.

[61] FERC Staff August 2006 Report: *Assessment of Demand Response & Advanced Metering* Chapter IV, Existing Demand Response Programs and Time-Based Rates

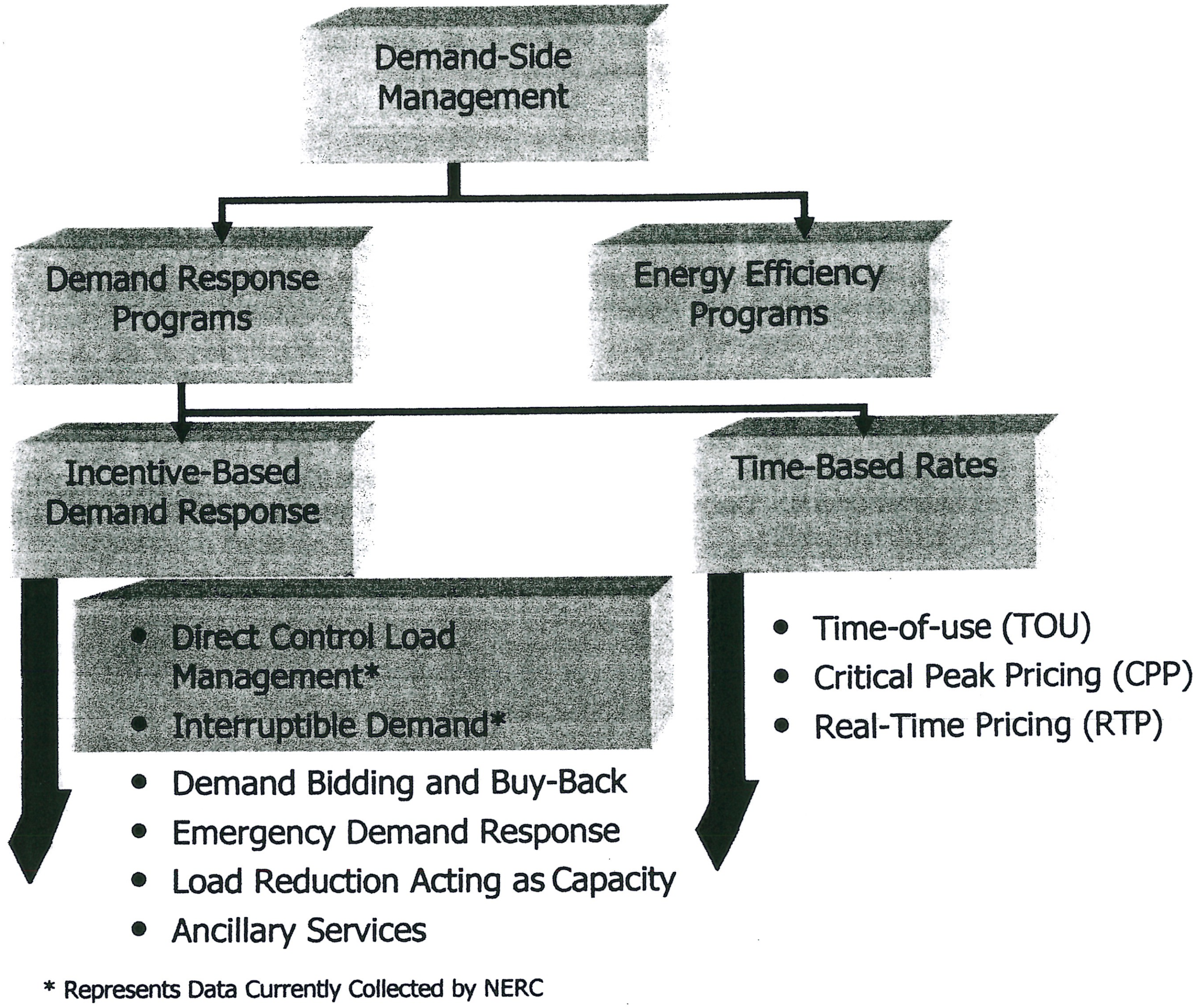


Figure 5: Demand Response Programs and NERC's Data Collection

Data NERC collects on direct control load management and interruptible demand are used to modify the peak internal demand condition. The influence of these programs, which are directly controlled by the operator, is accounted for in the modified internal demand.

As with any demand-side management program, experience is needed to determine program requirements and the expected demand resource available to manage the balance of transmission, supply, and demand. In some cases, the demand response programs are helpful for short-term reliability measures, though unclear in regards to the long-term impacts on reliability. The influence of demand response on this balance and bulk power system reliability requires further study.

Many of the programs are not unique to organized markets and can be applied in most electric utility settings.

Incentive-Based Demand Response Programs

These programs include an inducement or incentive for customer participation and they provide an active tool for load-serving entities, electric utilities, or grid operators to manage their costs and maintain reliability. Some existing incentive-based programs are:

- Direct Control Load Management
- Interruptible Demand
- Demand Bidding/Buyback
- Emergency Demand Response
- Load Reduction Acting as Capacity
- Ancillary-Service Market

Each is described below with their associated reliability benefits.

Direct Control Load Management[62]

Direct control load management refers to programs where the utility or system operator remotely terminates or cycles a customer's equipment on short notice to address system or local reliability contingencies in exchange for an incentive payment or bill credit[63]. These programs have been in place for many years and utilities and system operators have gained sufficient experience to reflect them in both operating procedures and resource plans. The actual benefits vary by customer type, geography and climate. As existing programs are expanded or new programs created, their actual characteristics should be factored into planning and operating activities.

Interruptible Demand[64]

NERC's seasonal and long-term reliability assessments also collect data interruptible demand, defined as:

The magnitude of customer demand that, in accordance with contractual arrangements, can be interrupted at the time of the

[62] NERC: *Instructions for NERC Summer Assessment Data Reporting*

[63] FERC Staff August 2006 Report: *Assessment of Demand Response & Advanced Metering* chapter IV, Existing Demand Response Programs and Time-Based Rates

[64] NERC: *Instructions for NERC Summer Assessment Data Reporting*

Regional Council's seasonal peak by direct control of the system operator or by action of the customer at the direct request of the system operator. In some instances, the demand reduction may be effected by direct action of the system operator (remote tripping) after notice to the customer in accordance with contractual provisions. For example, demands that can be interrupted to fulfill planning or operating reserve requirements normally should be reported as interruptible demand. Interruptible demand does not include direct control load management.

Customers on interruptible demand programs receive a discount or bill credit in exchange for agreeing to reduce load during system events. If customers do not curtail, they can be penalized. Note that interruptible demand programs are different than emergency demand response and load reduction acting as capacity program alternatives as reduction is not always optional. The application of interruptible demand programs is frequently, though not exclusively, used by customers who do not have obligations to provide service (hospitals, schools, etc.) or 24/7 continuous process operations. Though interruptible demand programs have been in place for decades, there is concern about the sustainability and reliability of the resource. For example, the expected participant loss is three percent–five percent each time interruptible demand programs are exercised, influencing long-term assumptions on program participation.

Emergency Demand Response Programs

Emergency demand response programs provide incentives for customers to reduce loads during reliability events, though the curtailment is voluntary. No penalty is assessed if customers do not curtail, and the rates are pre-specified, though no capacity payments are received. This program is typically offered by ISO/RTO, though they are also offered by electric utilities. They are voluntary and part of emergency procedures. Generally, emergency demand response is not included in internal demand data and NERC does not collect this data. Operators can not predict with certainty load curtailment amounts, and planners do not attempt to forecast their influence when developing future system alternatives.

Load Reduction Acting as Capacity

Customers commit to providing specific load reductions during events in return for payments and are penalized if they do not comply. These programs offer a firm, quickly deployed resource (both emergency operating procedure and a mid- to long-term supply option) which can be forecasted for operations and planning. Operating experience is needed to forecast the affect on short-term and long-term bulk power system reliability.

Demand Bidding/Buyback Programs

Demand bidding/buyback programs enable large consumers to offer specific bids or posted prices for specified load reductions. Customers stay at fixed rates, but receive higher payments for load reductions when the wholesale prices are high. There is ongoing discussion to determine which entities should be responsible for paying successful customer bidders. Until this review is complete, it is difficult to determine the operational and planning reliability benefits.

Ancillary Services

In some organizations, these programs are called Load Acting as a Resource (LaaR). Consumers bid load curtailment for operating (i.e. spinning) reserves. Successful bids are paid as standby reserves and if required are paid spot market energy prices to curtail. To participate, customers are pre-qualified having under-frequency relays set by the electric utility, include integral demand recorders and must be able to curtail load quickly when events occur typically in minutes rather than hours. This is juxtaposed to longer duration response for peak-shaving or price signal responses. Ancillary services are focused on operational reliability as a high probability resource, though planners can deploy similar concepts measuring long-term and seasonal reliability when evaluating standard criteria (i.e. N-1, etc.) and reserves. ERCOT considers its LaaR program as an interruptible demand service when determining net internal demand for the NERC LTRA data submittal.

Time-Based Rate Programs

This category of demand response programs, which can link retail and wholesale markets, has recently received a high level of attention. Retail consumers obtain a price signal reflecting the costs of production and delivery which guides them in how to deploy resources more efficiently. This characteristic, as the programs are generally tailored for mass markets, has the potential to reduce or shape electricity use and overall costs. There are three prevalent time-based rate programs:

- Time of Use Rates (TOU)
- Critical Peak Pricing (CPP)
- Real-Time Pricing (RTP)

Time-of-Use Rates (TOU)

The most widespread time-varying program for residential electric consumers, Time-of Use (TOU) demand response are pre-set offerings for a wide variety of time-periods: from seasons to time-of-day depending on the desired application. The pre-set offering reflects the underlying costs for production in hopes that consumers will reduce/curtail their use during the higher priced time-periods. Many utilities now require their larger customers to use TOU demand response. To deploy TOU, investment in meters is required to enable time-stamped billability. Consumers can change their electricity use behavior if price differentials are substantial. There is a multifarious experience with TOU rates with varying levels of success, as results can be hard to predict. Load reduction associated with TOU programs are reflected in actual load recordings and embedded in load forecasts.

Critical Peak Pricing (CPP)

A new form of TOU relies on very high prices during critical peaks rather than average TOU. The offerings are pre-set, but dispatched dynamically on short notice when needed. Data indicates customers do react to reduce/curtail load during the system stress events if appropriate price signals are sent through the CPP. As most proposed CPP programs are currently voluntary, more operating experience is needed. Currently the character of penetration and customer churn rate uncertainty makes it difficult to determine their long-term reliability benefits.

Real-Time Pricing (RTP)

Prices in this program continuously vary reflecting wholesale prices. RTP are not pre-set and are provided hourly and/or day-ahead for pre-planning. RTP provides a direct link between wholesale and retail markets supplying a price-responsive calibration to the electricity market. Further, RTP programs can also enable reduced unit construction as planners and operators can depend on reductions of demand during high-priced hours. As with CPP rates, RTP programs are currently voluntary, again making the impact uncertain until further experience is gained by system operators.

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Demand Response Influence on Reliability

There is significant potential for demand reduction to provide reliability benefits as noted in FERC's report[65]. Advanced applications of electricity such as Plug-in Hybrid Electric Vehicles (PHEV), which can act both as a load and mobile storage element (demand and supply), will add new requirements to the bulk power system, as well as offering supportive capacity. Clearly, more load control for planners and operators is required to support the multifarious applications and wisely manage load growth, while at the same time meeting the regulatory requirements promulgated by society.

For example, as demand grows, utilities are beginning to mandate implementation of load control abilities to improve not only the reliability/adequacy of the power system, but also as a first response to large-scale disruptions promulgated by events such as large storms, earthquakes, and terrorist attacks. Many of these events can result in long-term electric disruptions. The ability to differentiate between essential and non-essential demand is critical so utilities can serve essential loads that provide security and health services, while system repairs take place.

It is upon this platform that additional services can be provided to serve reliability concerns, integration of new supply-side options, and economic benefits. In the mean time, more operating and planning experience is needed with demand response programs to fully appreciate their potential and clarify the uncertainty associated with potential reliability benefits. As significant infrastructure investment is required, planners need to understand the scalability of pilot projects reflecting reliability improvements.

Demand response incorporation into resource adequacy assessment should be better understood by the industry. It is important to forecast their growth over the next decade and the influence of customer choice on program participation. In some cases, it may be best to categorize some programs as committed resources, and others as uncommitted. These are key characteristics required to ensure that the reliability benefits can be assessed, and reflected appropriately, without double-counting both as internal demand and potential resource.

IMPACT OF EXTREME WEATHER ON PEAK DEMAND FORECASTS

The behavior of system demand or load is largely correlated to weather. Forecasting system peak demands for the long-term is, therefore, highly dependent on weather-related assumptions, especially the normal temperature and humidity. Normal temperature and humidity are obtained through an averaging process of the last ten to thirty years of temperature data. Other weather conditions such as wind speed, dew

[65] FERC Staff August 2006 Report: *Assessment of Demand Response & Advanced Metering*

Supply Issues

A number of supply issues face the industry, including integration of renewable resources and planned large nuclear plants, fossil fuel availability, and weather impacts on fossil-fired power plant capacity.

INTEGRATION OF RENEWABLES

Almost 50 percent of North American generation relies on fossil-fuels such as coal, oil, and natural gas. Fossil fuels are *nonrenewable*, that is, they draw on finite resources. In contrast, *renewable energy* resources — such as wind, solar, bio-fuels, biomass, hydro, etc. can be replenished at a generally predictable rate, assuming average climate.

As mentioned in the discussion of Green-House Gas (including CO_2 reduction), state/provincial mandates and targets are being set as a way to drive desired reductions in greenhouse gases. Renewable resources quantity and type vary considerably from one geographic location to another. Siting of renewable energy systems therefore requires knowledge of the specific resource characteristics — availability, magnitude, and variability — at any given location. In some cases, especially wind and solar power, these "fuel" concerns emulate those of other generation technologies, though fossil-fuels and biomass can have greater portability and predictability. The lack of portability/predictability of these renewable resources poses greater challenges for the electric delivery system, than generation fueled by other transport systems. Bulk transmission system construction/modernization is a key element to realize the potential reliability benefits of renewable energy resources.

Wind Energy Resources

As wind renewable energy resources are expected to grow substantially (in some locations targeted over 30 percent of overall capacity) throughout North America, understanding how to integrate intermittent resources into the bulk power system and assess their impact on reliability/adequacy becomes increasingly important. In some cases, traditional tools focused solely on capacity, and simplified dynamic models may not be sufficient to gauge that impact.

Around the world, wind generation has become a significant portion of the generation mix. The technology has matured and can enable generation owner/operators to meet federal, state, and provincial renewable energy mandates. The maximum penetration of wind power into a bulk power system before it becomes operationally difficult to control is system dependent. For example, weather patterns of the region, the variety of wind turbine installed, the existing generation mix, and the bulk power system transfer capability with neighboring organizations all influence this saturation limit. The identification of maximum penetration boundaries is system dependent and opaque[66].

Until recently[67], in the province of Alberta[68] of Canada, the Alberta Electric Service Operator temporarily set a "threshold" of 900 MW for wind power production concerned that amounts above that level could destabilize the power grid. With general acceptance of the *Market and Operational Framework for Wind Integration in Alberta* (published March 2007[69]) outlining the rules, obligations and costs of wind integration, this limit was eliminated.

A number of factors are considered when assessing the potential reliability benefits of wind resources:

1. The annual capacity factor of wind generators (the average actual output as a percentage of rated output) is typically about 25–35 percent[70]. The probability that wind generators are available at their rated value during the annual peak period is between 5–20 percent varying greatly from year to year and region to region. Therefore, barring substantial use of storage technologies, wind generation is often considered an energy source rather than a capacity resource.
2. Transmission systems using significant amounts of wind generation must be designed for economical delivery of wind energy and to support a multitude of wind generation patterns. Traditional peak period analysis of transmission requirements does not represent the variable generation patterns modeling all hours of the year. Full year, hourly simulations of generation variations with the transmission systems modeled is required to ensure transmission system designs will deliver the renewable resources when they are available.

    a. Power systems designed to operate when wind resources are not available may deploy demand side management and demand response programs to maintain a reliable system (see section on demand response) on peak. In addition, to maintain system reliability, short term interruption (a few hours) of wind resources may be required. These interruptions will not significantly affect the revenue of a wind generator though State/Provincial Resource Portfolio Standards mandates may result in higher costs of curtailment.
    b. Additional transmission ties to neighboring areas or throughout the region may be required to realize the potential wind resource reliability benefits.

[66] CIGRE Technical Brochure, Working Group 601, of Study Committee C4, *Modeling and Dynamic Behavior of Wind Generation as it Relates to Power System Control and Dynamic Performance*, Final Report, January 2007.
[67] http://www.aeso.ca/files/News_Release_Wind_Announcement_-_September_26.pdf
[68] Alberta Electric System Operator, *Incremental Impact on System Operations with Increased Wind Power Penetration*, Final Reports, Phases I & II, November 2005 and July 2006 respectively.
http://www.aeso.ca/files/Incremental_Effects_on_System_Operations_with_Increased_Wind_Power_Penetration_rev_2_3.pdf, & http://www.aeso.ca/files/AESO_Phase_II__Wind_Integration_Impact_Studies_final_20060718.pdf
[69] http://www.aeso.ca/files/Wind_Framework_7March07.pdf
[70] EPRI Journal, *Putting Wind on the Grid*, Spring 2006.

3. Increased operating reserve margins may be needed in areas where significant wind resources are located. In addition, market structures can also impact the amount of operating reserves required to mitigate wind output uncertainty.

   a. Transmission should be adequate to provide the import/export capability delivering the system regulation and other transfer schedules required.
   b. Geographic diversity greatly reduces the influence of wind resource variability as short term wind energy variability (less than five minutes) is greater than for longer term (one hour). Sufficient transmission capacity is necessary to manage generation variability over a large area.
   c. The Minnesota Wind Integration Study[71] provides an analysis of the cost of wind integration and the amounts of reserves that must be added to ensure 25 percent of the state's energy is wind energy (40 percent capacity). The state of Minnesota enacted a requirement on February 22, 2007 that requires the states utilities to provide 25 percent of their energy requirements from renewable resources by the year 2025 (see section on Green House Gas Regulation).
   d. Current wind technologies do not follow load variations well. Taking up these variations can be challenging, especially if units fueled by different sources are close to their minimum loading.

4. FERC has developed a breakdown of the various renewable energy initiatives across the U.S.[72]

Solar Energy Resources

Currently less popular than wind resources due to their cost/benefit ratio and capital costs, solar energy resources are also being deployed on the grid. Their variability relates to energy availability when its major fuel supply, the sun, is covered either by dense cloud cover or unavailability at night.

Pacific Gas and Electric Company (PG&E) announced in August 2007 it has agreed to buy power from a 553-megawatt solar thermal power plant to be located in California's Mojave Desert. Solel-MSP-1 plans to build the Mojave Solar Park using its parabolic trough technology, which employs long rows of trough-shaped mirrors that concentrate the sun's heat onto a "receiver" tube. The vacuum-insulated tubing carries a fluid that is heated to high temperatures and is then used to boil water. The steam drives a turbine and generator to produce power. The Solel facility will cover about nine square miles, featuring 1.2 million mirrors and 317 miles of vacuum tubing. When fully operational in 2011, the Mojave Solar Park will produce enough electricity to meet the average annual needs of 400,000 homes in PG&E's service territory. The new contract is the largest solar power agreement in the world.

[71] http://www.puc.state.mn.us/docs/windrpt_vol%201.pdf
[72] http://www.ferc.gov/market-oversight/mkt-electric/overview/2007/elec-ovr-rps.pdf

In the past four years the FERC in Washington, DC, has issued preliminary permits for tidal installations at 25 sites, and it is considering another 31 applications.

Biomass Energy Resources

Biomass-based power generation yields little to no net emissions of CO_2 as the emissions are reabsorbed by plants which then can become fuel. Biomass is currently the largest non-hydro renewable source of electricity in the U.S., used most predominantly in industrial combined heat and power (CHP) applications (especially the paper and pulp industries). Utilities generally use biomass in combination with primary fuels.

Feedstock is portable, but may have limited availability. Investigations into liquid biofuels are currently being performed to increase the portability and intensity of the fuel. Overall, this generation type has many characteristics as central stations, though fuel security needs study. Distributed generation can provide challenges, especially for bi-directional feeds and emergency back-up when biomass plants become unavailable.

Ethanol Production: Internal Demand and Water Use

Ethanol production — much of it from corn predominately in the Midwestern U.S. (See Figure 774) — is increasing, mainly to fuel automobiles. Ethanol production capacity in the U.S. is expected to double by 2009 adding 5,730 million gallons/year (mgy). In modern grain ethanol plants, the critical energy cost is the price of natural gas. During the past year a few plants have integrated coal as a primary boiler fuel. Currently, to dry the grain, natural gas is used to reduce the grain moisture content. Due to the potential for energy price volatility, project developers pay close attention to the selection of process energy sources.

Plant sizes range from roughly 50 mgy to 100 mgy, with approximate electrical requirements of 5 MW to 10 MW, respectively. R&D is being performed to use compressed CO_2 for the drying process, which would double the total required electrical capacity (10 MW to 20 MW respectively). Under construction in the United States are an additional 72 refinement plants75 throughout North America, thus creating internal demand of between 573 MW (5,730 mgy* (10 MW/100 mgy) to 1146 MW (5,730 mgy * (20 MW/100 mgy) spatially dispersed. The load factor for these plants are typically 0.85. Capacity/energy requirements along with appropriate supporting bulk power systems will be required to support this growing industry.

[74] Economist, *The Craze for Maze*, May 10, 2007

[75] http://www.ethanol.org/index.php?id=15

address the contingency loading issues associated with the existing two 250 MVA 345/230 kV Grand Island transformers. The recommended plan is to install a third 345/230 kV transformer at the Grand Island substation (2009).

NPPD is planning the construction of the Columbus / Norfolk / Lincoln 345 kV transmission expansion plan to address summer peak load voltage issues and enhance the reliability of the eastern Nebraska regional transmission system. This project is identified as the Electric Transmission Reliability (ETR) Project for east central Nebraska. The project is targeted for completion by 2010 and includes the following facilities:

- New 68-mile 345 kV transmission line from Columbus East to LES NW68th & Holdrege
- New 12-mile 345 kV transmission line from Columbus East to Shell Creek
- 345 kV Conversion of 45 miles of existing 230 kV line from Shell Creek to Hoskins
- New Shell Creek 345/230 kV substation

The Public Power Generation Agency (PPGA) is a non-profit entity formed in the state of Nebraska to plan and construct a new 220 MW coal-fired generating unit at the existing Whelan Energy Center site near Hastings, Nebraska. There are a number of new 115 kV substation and transmission line additions planned to accommodate the interconnection and delivery of the new Whelan Energy Center Unit # 2 (Spring of 2011).

Dakotas Area

Transmission additions associated with the Big Stone Unit 2 in South Dakota, which is planned for a 2012 in-service date, consist of the following 345 kV, 230 kV, and lower voltage additions and upgrades:

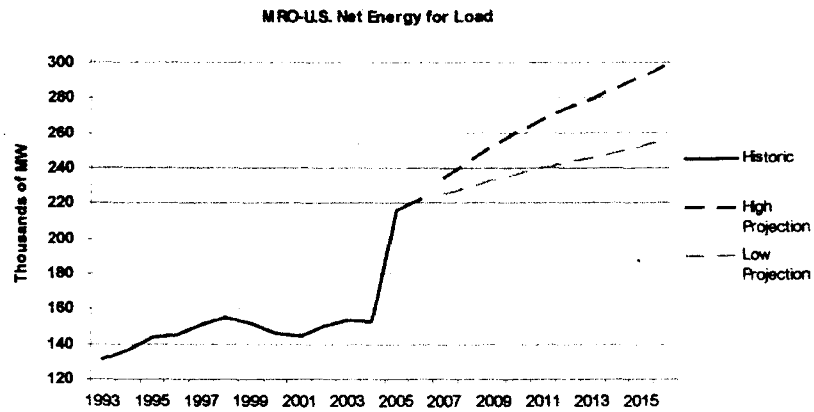
- New 230 kV Big Stone - Ortonville line
- Upgrade the Ortonville - Johnson Junction 115 kV line to 230 kV
- Upgrade the Johnson Junction - Morris 115 kV line to 230 kV
- New 230 kV Big Stone - Canby line
- Upgrade the Canby - Granite Falls 115 kV line to 230 kV

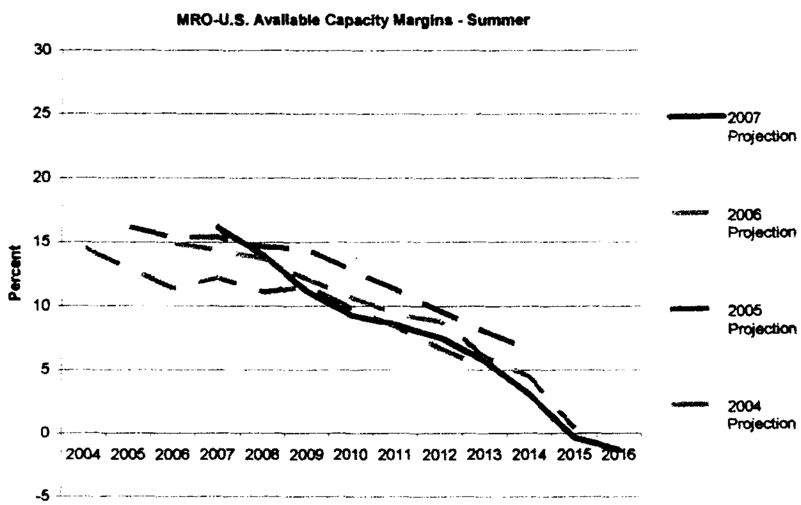
Additional third party voltage and loading issues are being examined, and mitigation may be proposed.

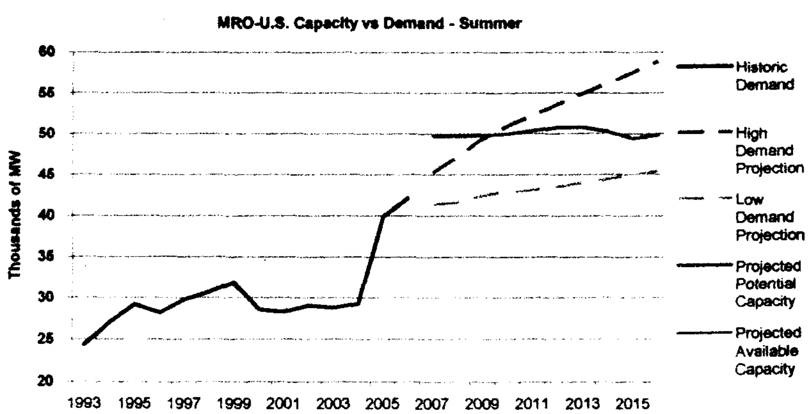
Additional facilities in the Dakotas area associated with new planned generation will consist of 230 and 345 kV additions from the coal fields of North Dakota to the Red River Valley in Western Minnesota, and 345 kV and 230 kV additions in South Dakota to south western Minnesota. Specific transmission facilities for these generation projects have not yet been finalized.

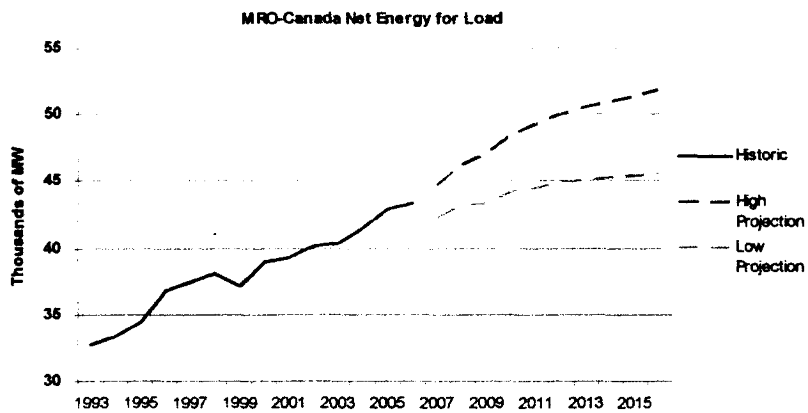
Queued projects for wind generation total several thousands of megawatts. Currently facilities committed or under construction number in the low hundreds of megawatts. In the last several years, several hundred megawatts of wind generation have been installed in the Dakotas. Wind generation typically has a very fast planning and construction period, and it is anticipated that wind generation will continue to be installed in the Dakotas at 100-200 MW per year.

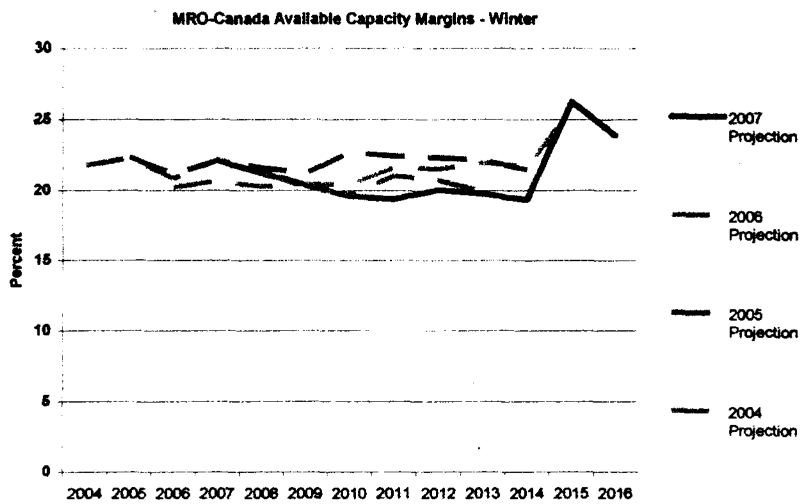
MRO Capacity and Demand

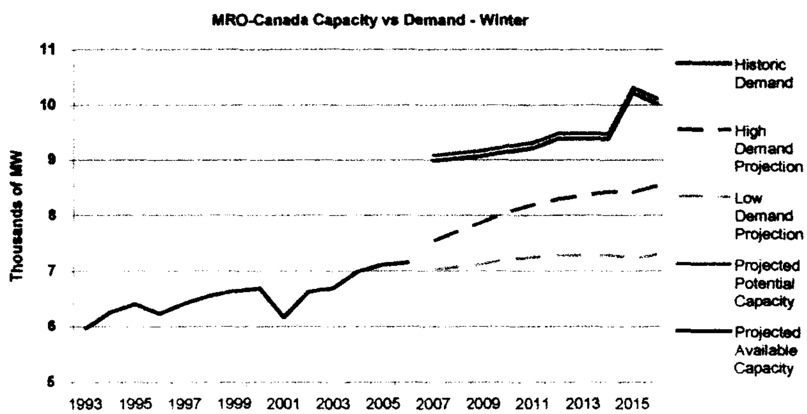




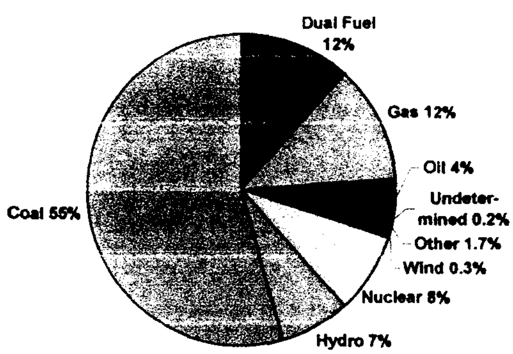



MRO-Canada Net Energy for Load
Thousands of MW
55
50
45
40
35
30
1993 1995 1997 1999 2001 2003 2005 2007 2009 2011 2013 2015
Historic
High Projection
Low Projection

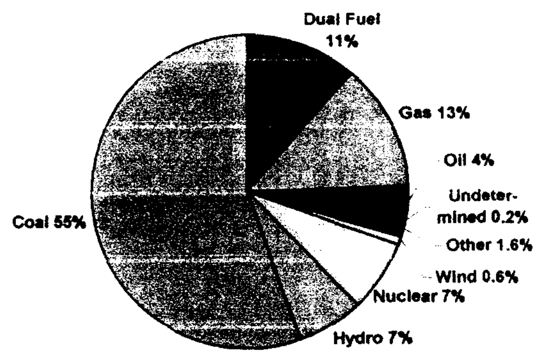

MRO-Canada Available Capacity Margins - Winter
Percent
30
25
20
15
10
5
0
2004 2005 2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016
2007 Projection
2006 Projection
2005 Projection
2004 Projection


MRO-Canada Capacity vs Demand - Winter
Thousands of MW
11
10
9
8
7
6
5
1993 1995 1997 1999 2001 2003 2005 2007 2009 2011 2013 2015
Historic Demand
High Demand Projection
Low Demand Projection
Projected Potential Capacity
Projected Available Capacity

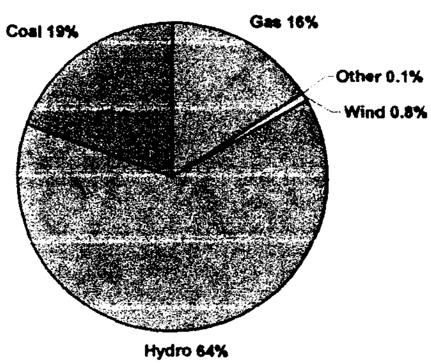
MRO-U.S. Capacity Fuel Mix 2006



MRO-U.S. Capacity Fuel Mix 2012



MRO-Canada Capacity Fuel Mix 2006



MRO-Canada Capacity Fuel Mix 2012