FIRMING RENEWABLE ELECTRIC POWER GENERATORS: OPPORTUNITIES AND CHALLENGES FOR NATURAL GAS PIPELINES

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Executive Summary

The increased use of renewable electric power generation, particularly wind, will require electric power systems to provide back-up power to firm the generation from these intermittent sources of electricity. Natural gas-fired generation is a logical, low-cost choice for providing this back-up firming capability. This study evaluates the implications of the increased use of natural gas-fired generation for firming renewable resources for natural gas transportation infrastructure planning and pricing. Firming capacity in this study is the amount of non-wind generating capacity needed to meet shortfalls in actual wind output with respect to *forecast* wind output, that is, to compensate for the *forecast uncertainty*.

To date, there has been little formal analysis of this subject. This study provides a systematic review of the issues in order to inform policy makers and other stakeholders about the operational and regulatory issues raised by deploying significant natural gas fired generators to back-up intermittent power sources. The study raises several questions, including:

- What is the level of natural gas pipeline infrastructure that will be needed to firm intermittent generation while still meeting the needs of other gas transportation customers?
- How do industry and regulators ensure that natural gas pipelines can meet the operational needs of these back up gas-fired generators?
- How can industry and regulators ensure that these generators contract for the appropriate natural gas transportation service?
- Who will pay for necessary gas transportation infrastructure expansions and other added costs?

The utilization of a gas-fired generator for firming and, in turn, the utilization of pipeline infrastructure and services to support a generator for such purposes, will be sporadic and relatively infrequent. The challenge for natural gas system planners is accommodating the rapid ramp-up and ramp-down of gas-fired firming generation which can cause major changes in gas requirements within minutes. (In the case studies detailed in Appendix 2, ramp rates in Wyoming/California ranged between + 173 MW/min. to -210 MW/min.) Making sure gas will be there when needed, and having an alternative home for gas when it is not needed, will require a combination of new natural gas facilities and management systems.

Moreover, the cost of serving these backup generators, which may call on the pipeline system with little or no notice, will be higher on a unit-cost basis than traditional firm transportation service. This is because the pipeline may need to dedicate firm capacity to provide such service—even though the capacity is used infrequently. Thus, the per-unit costs of the infrastructure are likely to be very high. Cost recovery of such lightly utilized assets is complicated because the users of the assets typically are unwilling to pay relatively high unit costs if they are uncertain that such costs can be recovered in the price of their product or service.

This study highlights issues that policy makers should be consider and address if intermittent renewables generation is to become a reliable portion of electric power supply. A clear policy on how and by whom the increased costs are to be borne is necessary for the natural gas industry to have the appropriate incentives to invest in providing the services necessary for back-up gas-fired generators.

The issues highlighted in this study are fully corroborated by the recently released white paper: *Natural Gas in a Smart Energy Future* (Gas Technology Institute, 2011). This white paper provided an independently developed industry-wide vision that highlighted the strategic value of integrating multiple sources of natural gas and electricity.

PRINCIPAL CONCLUSIONS:

1. In the next 15 years, 105 gigawatts (GW) of renewable power generation are forecast to be constructed; of which 88 GW could be new intermittent wind generation. The natural gas-fired generation needed to firm up wind generation could be approximately 33 GW generating some 45,500 gigawatt-hours (GWh) of electricity.

2. Almost 5 billion cubic feet per day (Bcfd) of incremental delivery capability could be required over the next 15 years to provide the new gas-fired firming generation with firm natural gas supply. The total annual gas use associated with firming intermittent generation could grow to about 440 Bcf by 2025. This is roughly about 2 percent of current annual U.S. gas use.

3. The total capital cost of the natural gas infrastructure to support firming requirements could range from about $2 billion to $15 billion. This is equal to about 10 percent of the total investment in midstream pipeline infrastructure (including gathering, transmission and storage) reported in the INGAA Foundation's 2009 report: *Natural Gas Pipeline and Storage Infrastructure Projections Through 2030*. On a regional and especially on a local basis, such requirements can be significant, especially in terms of the natural gas transportation infrastructure required to make such deliveries.

4. The expanded use of wind generation will be felt more in some regions than in others. The analysis reviews the forecasts for future renewable generation by Census Region, and evaluates the need for gas-fired firming generation to support this expansion along with the potential impact on natural gas infrastructure. The regions expected to see the most renewable generation development with concomitant demands on the natural gas infrastructure include East North Central, Middle Atlantic, Mountain 1 (Northern Rockies states), Pacific 1 (Pacific Northwest), West North Central, and West South Central.

5. Utilization of the new gas pipeline infrastructure is expected to be quite low, around 15 percent or less. The implied unit cost of firm transportation capacity ($/MMBtu) at a

low 15 percent utilization rate would be over six times greater than the cost at a full rate of utilization. (Transportation costs are additive to the commodity cost). While natural gas-generation is the least costly of the options for firming renewable energy, ensuring that the costs are correctly identified and allocated appropriately are important regulatory concerns.

6. The natural gas pipeline system has considerable operational flexibility for managing intermittent demands for supplying natural gas reliably to firming generators at their required pressures. Nevertheless, at some locations in some regions, incremental facilities may need to be constructed to guarantee reliable on-demand service to support firming power generators.

7. Gas transportation services needed for firming intermittent renewable generation may include enhanced line pack, applications of new no-notice and gas storage services, increasing the number of nomination cycles, and reducing the length of nomination cycles. The costs of providing these services will affect the cost of gas transportation for intermittent firming power.

8. Regulators should adopt policies that: 1) identify generation units that are providing firming service; 2) provide a mechanism for cost recovery for generators, including the recovery of firm pipeline transportation and storage costs, and; 3) support tariffs that ensure the recovery of costs of pipeline services that meet the needs of the firming generation. Without such policies, there may be inadequate back-up generation capacity and therefore risk to electric system reliability.

9. Natural gas facilities supporting firming generation should be placed on equal footing with other firming facilities with respect to the manner in which costs are reflected in electricity rates. If costs associated with either intermittent renewable generation or costs associated with other options for firming intermittent renewable generation are recovered by the electric utility or RTO/ISO, then the cost of ensuring that the pipeline can deliver gas reliably to the gas-fired generator – the cost of firm pipeline transportation and storage services – also should be incorporated in the cost of firming generation. Unless all costs incurred in connection with firming generation are recognized, the costs related to firming intermittent renewables generation will be understated.

STUDY APPROACH AND HIGHLIGHTS

As part of examining the impact of intermittent renewables generation on gas-fired generation and natural gas infrastructure, ICF first analyzed impacts of renewable generation on the electric system. This analysis includes projections of the growth in renewables generation over time on both a national and regional basis. In addition, the analysis provides seasonal and daily patterns for renewable generation to understand the degree of intermittency of renewable generation. Further, the analysis considers both the known variability of renewable generation and the inherent forecast uncertainty for intermittent renewables generation. The study also evaluates the alternative approaches for firming up intermittent renewables generation—different electric storage technologies and gas-fired generation—analyzing both costs and technical viability.

The study forecasts the amount of gas-fired generation and corresponding gas use that could be needed to firm up intermittent renewables generation. The study investigates some of the resulting impacts on natural gas transportation infrastructure, including potential impacts on system operation. The study next projects the amount and cost of gas transportation infrastructure that may be needed and the resulting unit costs of natural gas transportation services needed to support this infrastructure expansion. This section of the report also addresses regulatory cost recovery issues.

The study distinguishes between expected variability of renewable generation, specifically wind generation, and unexpected variability. Wind power forecasts bid into the electric grid take into account the expected variability in wind generation. Beyond this, however, there is forecast error, or the variability of wind that cannot be readily accounted for when the wind generation is bid into the electric system. When industry observers and analysts refer to intermittency, they are referring to this forecast error. Thus, forecast error must be backed up, or firmed up to create a reliable electric system.

The intermittent generation may be firmed up by various means. Historically, intermittent generation has been firmed by relying on various forms of back-up generation, most notably gas-fired generation. Gas-fired generation has been a reliable and cost-effective means of firming intermittent renewables generation. Therefore, it has been the most widely used means to back up intermittent generation to date.

Electric storage also has been applied in some instances. To date, pumped hydroelectric storage has been the most widely applied electric storage technology. Other forms of electric storage, such as compressed air electric storage (CAES), flywheels, and battery technologies, are being applied on a limited basis. Pumped storage is one of the more technically viable and cost-effective forms of electric storage. Other technologies have not been proven from an operational standpoint, and generally are more expensive. Electric storage technologies are likely to firm up some portion of intermittent renewables generation in the future. Even so, gas-fired generation will continue to have a prominent role in the firming process.

More work, including site and system-specific analysis will be required to understand fully the natural gas system requirements and costs to integrate intermittent renewables generation sources into a reliable energy system.

Other factors, including operating conditions, should be examined in connection with assessing the required gas transportation infrastructure. Laterals to firming facilities and compression associated with maintaining adequate operating pressures on supporting pipelines must be sized sufficiently to maintain reliable operating ranges for line pack and pressure on gas transmission systems. To serve these generators, a pipeline may need to run its compressors more frequently and with less notice. This may increase compressor fuel consumption, and hence fuel costs, and could result in the need for added maintenance on such compressors. The issue of who pays for compressor fuel and line pack and how those costs are recovered needs to be addressed.

Current pipeline transportation services and nominating cycles for natural gas transportation may not be adequate to meet the needs of firming generators. Back-up generators will have to secure reliable natural gas supply and transportation capacity to meet generating demands on short notice. Traditional interruptible transportation service may not be adequate in most cases. Pipelines may develop new storage and on-demand delivery services (similar to existing no-notice service) that are tailored to meet the generators' needs. However, there is no certainty that generators will subscribe to such typically higher-cost services unless they are required to do so. Whether pipelines develop firming gas delivery services or rely on existing tariff rate schedules, the costs of providing additional flexibility for a subset of customers will raise questions with other customers about cost sharing and allocation.

Finally, there is the policy question of whether the regional transmission organizations (RTO) should provide dispatch preferences or incentives for the firming generators to secure reliable gas supply by holding firm pipeline capacity and other on-demand delivery services. In short, there are many implications for the gas infrastructure associated with supporting firming services, all of which need to be considered thoroughly as intermittent generation continues to grow.

Additional gas transportation infrastructure will be required to serve the gas units providing firming services for intermittent renewable generation firmly and reliably. There are no apparent technical obstacles to constructing and operating additional pipeline and compressor facilities to meet the needs of firming generators. As long as pipeline capacity is sized appropriately and compression is adequate to maintain sufficient line pack, gas transportation facilities can be designed to provide reliable transportation service to the firming power plants. The pressure transient examples provided in this report demonstrate that pipeline diameter and the amount of compression are key variables in pipeline facilities design. The issue is whether the firming electric generator contracts sufficiently with the pipeline, both under the appropriate type of service and for an appropriate length of term, to support these additional demands on the pipeline. Further, since annual utilization of the gas facilities providing firming services could average only about 15 percent of annual capacity, the challenge will be to find a way to encourage firming generators to pay for the needed pipeline infrastructure. This would include, at a minimum, any pipeline lateral or mainline expansion that extends to the power plant.

It remains a question how natural gas pipeline rates would be established for services provided for firming generators. The costs to be recovered by such services might include incremental pipeline capacity, compression, and storage, and expanded use of line pack. Allocating the costs to the services used for firming generation could be complicated and ultimately contentious.

Also unresolved is how all of the costs associated with firming generation will be recovered in the prices charged in power and electric transmission markets. Electric power pricing should be structured in a way that ensures such costs can be recovered as a part of the price of electricity and in a manner that does not put gas-fired backup at a disadvantage with other firming options. Gas pipeline transportation and storage costs required to assure the availability of the generation units should be reflected in capacity payments made to the firming generators as a part of the total cost associated with managing the intermittency of renewable generation.

Introduction and Background

In the preliminary work for this project, ICF made regional projections of both renewable and natural gas generation, analyzed firming technologies, and evaluated the need for fast-ramp generation and its associated system costs. This analysis is presented in Appendix 2. ICF used the findings of the latest major research efforts, comments from key industry stakeholders, and projections from two of ICF's modeling platforms, the Integrated Planning Model (IPM©) and the Firming Intermittent Renewables Model (FIRM™) in this investigation of the impact of intermittent renewable resources upon power market operations. The objective of the preliminary work in Appendix 2 was to identify the issues that affect the requirements for firming service and the options that are likely to exist to fill the requirements from the power market perspective. This report uses the extensive analysis in Appendix 2 to focus on the impact that intermittent renewable generation can have on gas-fired generation and natural gas infrastructure.

Renewable generation — specifically wind energy — is the fastest growing segment of new electricity generation in percentage terms. Fostering this growth is a desire to meet the future electricity needs with environmentally responsible and sustainable generation sources. The adoption of increasingly stringency state-level Renewable Portfolio Standards (RPS) will continue to encourage this expansion. Moreover, various federal legislative proposals have included federal mandates for minimum levels of renewable generation that may or may not affect the future generation mix. Finally tax credits and other incentives support investment in wind and other renewable technologies.

While wind and other renewable energy have a number of desirable attributes, some of these technologies are inherently intermittent. The wind does not always blow when electric power is needed. Similarly, solar power is also intermittent. The intermittency is relatively easily handled when renewable energy constitutes a small portion of the overall energy supply mix. The electric power industry has always managed dispatch while accommodating the possibility that some portion of the generation mix will experience an unplanned outage. Moreover, while some wind or solar projects are quite large, most individual projects have been considerably smaller than large central station coal or nuclear facilities. As a result, outages at a single renewable facility have been comparatively easier to manage.

Still, projections of the future generation mix indicate that intermittent renewable generation has the potential to grow substantially as a portion of total generation. As intermittent renewable generation grows, managing the intermittent nature of generation will become a more vexing problem that needs careful consideration. Specifically, technologies and/or infrastructure reserved to address the unanticipated variability in generation will need to be financed and constructed.

Based upon the Appendix 2 estimates of the amount of infrastructure required to firm the intermittent generation and analysis of the relative costs of gas-fired generation and electric storage technology, as well as commercial availability of the electric storage options, this report:

- Estimates the amount of gas-fired generation needed to firm the intermittent renewable generation and identifies the operating characteristics of generation used for firming service;
- Describes the operational impact for pipeline facilities that directly serve gas-fired generation. The report uses dynamic flow modeling for an illustrative pipeline segment with traditional delivery requirements including intermediate-load gas-fired generation as well as rapid ramp-up gas-fired generation that provides firming service for wind generation;
- Estimates the magnitude of the costs that would be incurred for the natural gas infrastructure that supports the firming capacity; and,
- Discusses the cost recovery issues for natural gas pipelines, the suitability of typical pipeline services to meet the needs of firming generation, and the possible new services that may be developed by pipelines to serve the market for firming with gas-fired generation.

To date, there has been little formal analysis of these issues. This report is not intended to be the final word on these issues; rather it suggests that considerably more work, including site specific analysis will be required to understand fully the requirements and costs to integrate intermittent renewable generation sources into a reliable system. This report identifies the issues and informs policy makers and energy stakeholders about a number of factors that have yet to be addressed and to identify infrastructure requirements that will generate costs that will need to be recovered if the investment is made.

Structure of the Report

This report is divided into six sections:

- Section 1 summarizes the important findings from the Appendix 2 preliminary analysis identifying renewable generation, its backup and related facility and cost implications.
- Section 2 demonstrates the intermittency of wind generation and introduces the concept of firming wind generation and the methodology for estimating the required gas-fired capacity and utilization for the firming purposes.
- Section 3 presents an analysis of the annual, seasonal, and daily gas requirements for power generation. In addition, this section evaluates the impact of the seasonal and daily variability in gas requirements arising from the intermittent nature of renewable generation.

- Section 4 presents the results of dynamic pipeline flow modeling to illustrate the impacts on the natural gas network of dispatching gas-fired generation firming service to address the deviation between *forecast* wind generation output and *actual* generation output.
- Section 5 presents the cost implications for the firming intermittent generation with rapid ramping gas turbine generation. The section discusses the nature of the services required and the need to develop cost recovery mechanisms in order to assure that the infrastructure required for firming is constructed.
- Section 6 summarizes the major findings and results.
- Appendix 1 provides a complete glossary of terms and acronyms used throughout the report.
- Appendix 2 provides a detailed explanation of the preliminary analysis assessing renewable generation and its backup.
- Appendix 3 provides stakeholder comments provided during the preliminary analysis covered in Appendix 2.
- Appendix 4 provides a more detailed description of how the required level of firming service capacity and generation are calculated.

1. Growth of Renewable and Related Firming Generation, Supporting Facilities, and Costs

This section summarizes the important findings from the preliminary analysis in Appendix 2 that projects renewable generation growth and analyzes the firming requirements for future intermittent generation. The major focus of the preliminary analysis was to understand the complexities of matching generation with electricity load as the market penetration of intermittent renewable resources grows. Based on the preliminary analysis, this report proceeds to evaluate the impact of intermittent renewable generation on natural gas industry infrastructure and operations since gas-fired generation plays a critical role in accommodating fluctuations in output from intermittent renewable resources.

Renewable generation—primarily wind energy—is among the fastest growing forms of new electricity generation in the U.S. Fostering this growth is a desire to meet the future electricity needs with sustainable generation in an environmentally responsible manner. The adoption and increasing stringency of state-level Renewable Portfolio Standards (RPS) will continue to encourage this expansion. Moreover, federal legislative proposals include mandates for minimum levels of renewable generation.

Renewable resource intermittency is managed relatively easily when renewable energy constitutes a small portion of total energy supply. Grid operators have always accommodated the possibility that some portion of available generation resources will experience an unplanned outage. Moreover, while some wind and solar projects are quite large, most individual projects are considerably smaller than large central station coal or nuclear facilities and therefore loss of load or variability in output has not been problematic.[1] Nevertheless, the complexity of managing intermittency rises as more intermittent resources are added to a system. In regions home to a large amount of wind capacity, wind resources may be unavailable across a wide geographic area due to large scale weather patterns. Wind forecasts can diverge considerably from actual wind generation, which will affect unit commitment, dispatch, and ramp rate requirements. The variability and uncertainty associated with wind resources may increase the amplitude of sustained load ramps (both up and down) and the frequency of generation starts and stops. System operators rely mostly on gas-fired generators to compensate for unforeseen wind variability, because these units have fast ramp rates and other beneficial operating characteristics.

Findings of the Preliminary Analysis

ICF projects that by 2025 over 105 GW of new renewable capacity could be built in the United States, of which 88 GW could be new wind generation capacity. Nearly 70 GW of new gas-fired combustion turbine (CT) and combined cycle gas turbine (CCGT) capacity also could be added through 2025.

[1] While we include a limited discussion of solar resources as another form of intermittent renewable generation, we do not concentrate on solar resources because they currently have very low market penetration.

The most significant period for the development of new renewable capacity will occur between 2010 and 2015 as developers take advantage of expiring federal incentives such as the production tax credit (PTC) and investment tax credit (ITC).

The majority of new renewable capacity additions are located in regions with high quality renewable resources and/or stringent RPS, such as Pacific 2 (California, Hawaii),[2] Mountain 1 (Colorado, Idaho, Montana, Nevada, Utah, and Wyoming), and Middle Atlantic (New York, New Jersey, Pennsylvania).

Three regions were selected for intensive study based on their potential for significant impacts on natural gas pipelines and infrastructure. These were California (Pacific 2) and Wyoming (Mountain 1), Texas/Oklahoma (West South Central), and New England.

As renewable generation increases, the need for demand response (DR) and system reliability services will grow. System operators will likely expand firming capabilities beyond those typically provided by fossil fuel-fired generation to increase system flexibility and reduce system costs. Demand response programs and energy storage technologies may become key renewable firming resources as DR programs increase and storage technologies mature and costs decline.

The literature on wind integration reviewed for this study does not provide a consensus view of the impacts of intermittent generation on natural gas markets and infrastructure requirements; however, several imply that large area balancing and other options such as demand response could make infrastructure additions less likely.

Previous wind integration studies identify fast-ramp generation as a critical component of any integration strategy. Hydro and combustion turbines are two key sources of fast ramp capacity but hydro is limited by water availability and environmental constraints. Combustion turbines such as the GE class 7E or 7F machines or aeroderivatives such as GE's LM-class machines or their equivalent often serve as preferred fast-ramp generation providers.

The detailed analysis of the three regions where growth in wind resources could affect natural gas systems operations analyzed the firming requirements (in terms of ramp up of firming generation resources) arising from changes in load and changes in output from wind generation.

> In each of the cases, wind variation required significant ramping capacity to meet load changes when wind is also changing. At times, this can mean rapid increases in conventional generation and at other times rapid decreases in conventional generation.
>
> In each of the regions studied, the required ramp rates vary significantly and are much more "spiky" when more wind generations is added into the region.

[2] ICF only models the continental U.S. for this report, thus there are no projections for Hawaii or Alaska

The largest swings in ramp rates tend to occur in the summer.

For the forecast year 2025, ramp rates in Wyoming/California ranged between +173 MW/min. to -210 MW/min.; in Oklahoma/Kansas between +125 MW/min. to -200 MW/min.; and in New England between 65 MW/min. to -101 MW/min. New England showed the lowest level of impact due to the lack of wind resource.

The volatility in ramping has a direct effect on natural gas units and the natural gas pipelines and infrastructure to meet these swings in demand. When gas generating units need to ramp up, they have immediate demands on gas supply and transportation deliverability. Similarly, when units need to ramp down, something needs to be done with the natural gas that was nominated and scheduled on the pipeline. Managing these swings in natural gas use can require significant modifications of natural gas pipelines and infrastructure.

Other potential ways of managing this volatility include cross regional coordination, provided there is adequate transmission capacity. Also included are batteries, fly-wheels, and compressed air energy storage (CAES). These technologies, however, may have only niche applications.

2. Summarizing the Concept of Firming Intermittent Generation

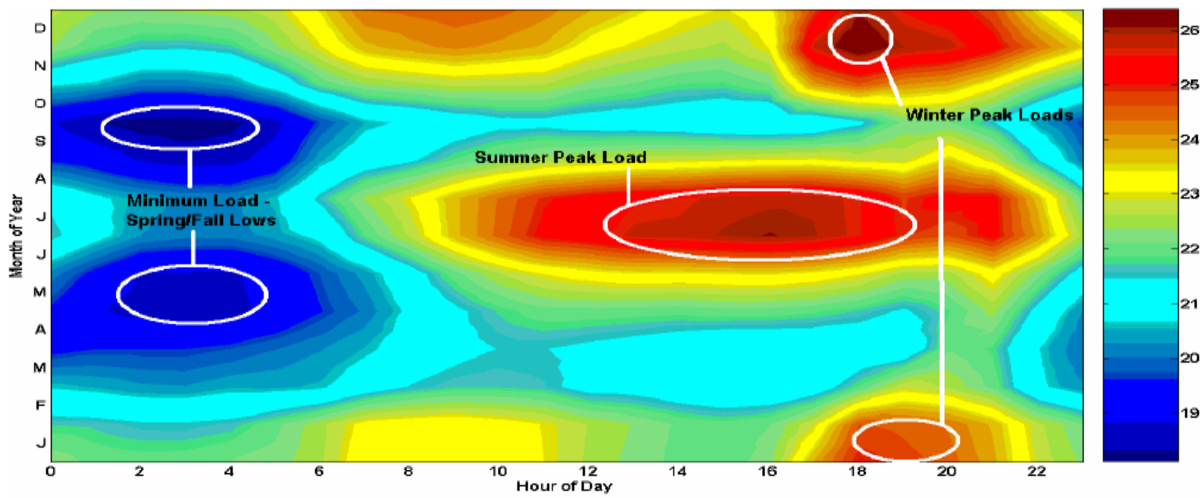
As long as wind energy constitutes a relatively small portion of the overall energy mix, the intermittent nature of wind power is relatively easy to manage. Moreover, because individual wind energy projects tend to be considerably smaller than a large central station coal or nuclear facility, an outage of a single wind facility is more easily managed than an outage of a large power plant.

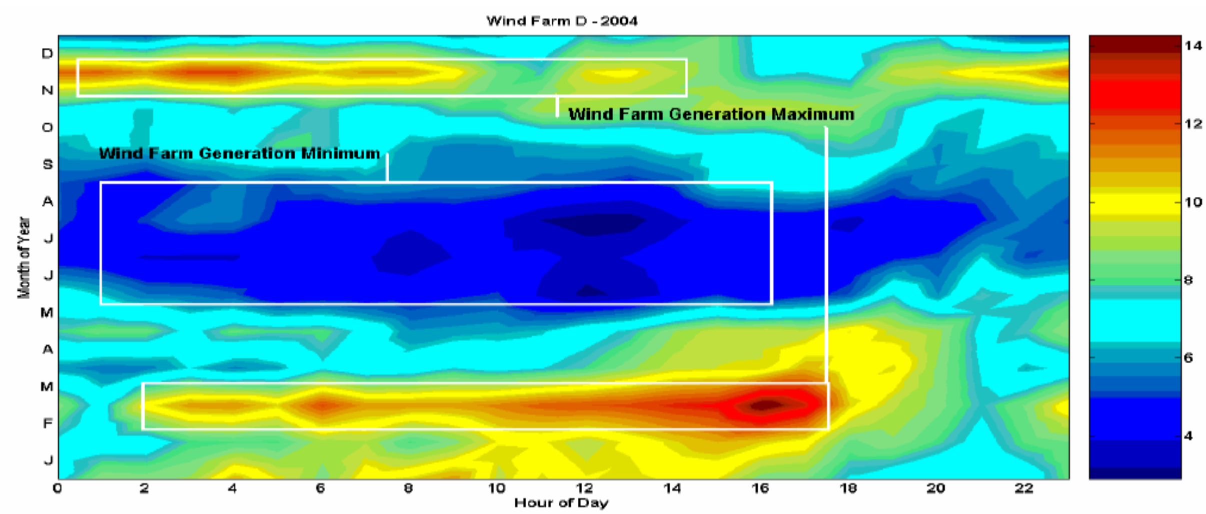
A wind facility can also differ from a large central station plant in terms of the availability of generation. A large central station plant is generally available for dispatch at or near the nameplate capacity after a start-up period, usually a few hours. Central station plants often are less efficient if operated at partial load. By contrast, the operation of wind resources varies throughout the day as wind speeds rise and fall. Moreover, most wind resources will continue to operate into the early morning hours when electricity demand is typically at its lowest point during most days.

The inherent mismatch between power demand and electricity supply from wind generators is illustrated by Exhibit 2-1, next page. This figure shows the intensity of electric load (top chart) and wind generation (bottom chart). The y-axis for each chart represents months of the year from January at the bottom up to December at the top. The x-axis shows each hour of the day. Level of intensity is indicated by colors from dark blue (least intense) to dark red (most intense).

The electric intensity chart at the top shows that summer peak demand occurs during the months of June, July and August (shown as the red portion in the middle of the chart). The wind intensity chart at the bottom shows that the maximum wind generation occurs during the winter months (shown as the red portions in the chart). Therefore, the challenge of integrating wind power into the system occurs not only within days, but across seasons as well. In short, wind does not necessarily blow when electricity demand is at its peak.

Exhibit 2-1: Power Generation Load and Wind Generation Supply





Source: Western Area Power Administration, Wind Production Summary Overview, October 2006.

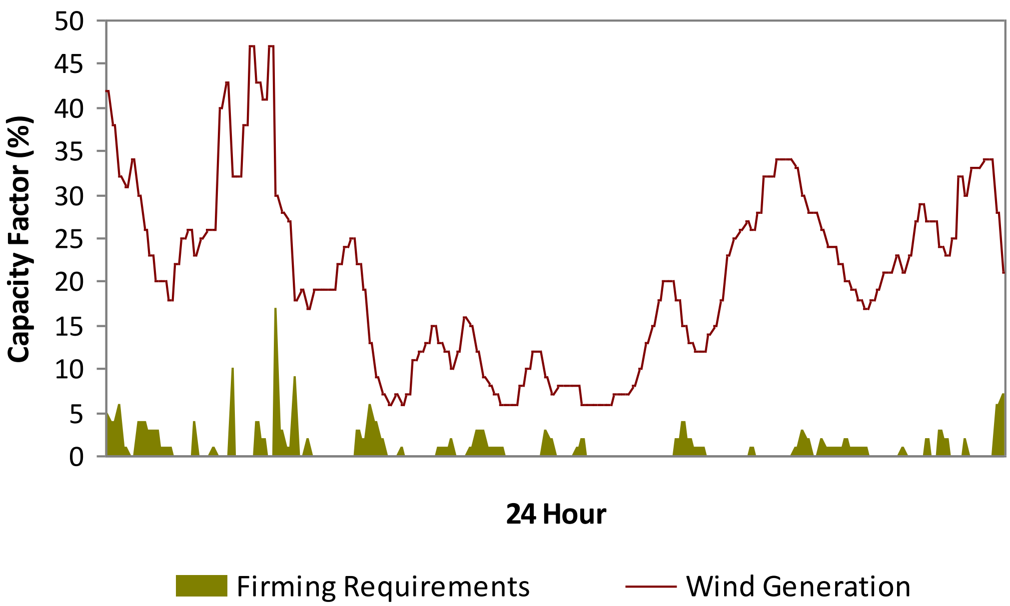
2.1 Compensating for Intermittency in Wind Generation

While analyzing the intermittency of wind generation, it is important to differentiate the variability of wind that is known (with a reasonable degree of certainty) and unknown. Understanding these differences is a key to designing appropriate strategies to compensate for the intermittency of wind. Usually, the amount of wind generation at each instant (and hence its variability) is more certain closer to the actual instant. Therefore, when the variability of wind becomes more certain, power system operators can take specific actions to compensate for this known variability. The variability of wind is less certain (hence more unknown) farther away from the actual instant (such as four hours ahead or a day-ahead). The power system operator has a larger time window to respond to the variations, but the magnitude of variations is more uncertain. This section distinguishes between these two types of variability inherent in wind generation. The two types are denoted as *actual variability* and *forecast uncertainty*.

A significant amount of production data is available for wind generation, because a large amount (> 40 GW) of wind power has been built over the past decade. Since wind generation is dependent on the speed of the wind, which is something that changes continuously, the exact amount of wind power at any instant is not known with 100 percent accuracy. Within 10 to 15 minute intervals, however, a persistence forecast is assumed reasonably accurate. This approach uses the wind speed of the past interval as the forecast for the following interval. Firming generation is required to meet the declining wind output over the 10–15 minute intervals (in this case, the *forecast error*).

Error! Reference source not found. below illustrates this process. Firming generation is needed when wind generation drops within the interval. The amount of firming generation required within an interval is the difference between wind generation at the start and end of the interval. Firming generation is not needed when wind generation rises within the interval. While the maximum drop in wind output can be significant, the majority of such drops are far smaller in magnitude. This suggests that using the persistence forecast for scheduling gas firming generation may result in very high gas load within several intervals throughout the day, even if there is relatively low average daily gas use for firming wind generation. Changes in wind speeds from one interval to the next are referred to as *actual variability* throughout this report.

Exhibit 2-2: Persistence Forecast to Estimate Wind Generation and Firming Requirements



This variability affects natural gas suppliers and pipelines in significant ways. Natural gas supply for delivery is first nominated and scheduled at specific times each day, with one or more modifications allowed during the course of the day. Unexpected large changes from scheduled volumes for specific locations on a pipeline require pipeline operators to adjust pressures and flows rapidly to operate systems reliably. Some variability in hourly requirements from power generation can be planned for and managed with system resources. But the unforeseen changes in wind and wind generation resulting in fast ramp ups and ramp downs that can characterize some regions can create serious problems for pipelines in those regions of the country as well as for many pipelines at certain locations on their systems. When ramping up, additional gas from line-pack or another source must be made available; when ramping down, gas that was scheduled for delivery must be redirected elsewhere on short notice.

Also, to meet power system operational constraints such as conventional unit commitment and dispatch, wind speeds need to be forecast over a much longer timeframe. A study by National Renewable Energy Laboratory (NREL), known as the *Eastern Wind Integration and Transmission Study* (EWITS)[1], applied a four-hour-ahead forecast of wind speed in its analysis. The difference between this four-hour ahead forecast and the actual wind speed for a specific instant in time is not known beforehand, and therefore, is referred to as the *forecast uncertainty* throughout this report.

Exhibit 2-3: Hourly Wind Generation and Four-hour Ahead Forecast

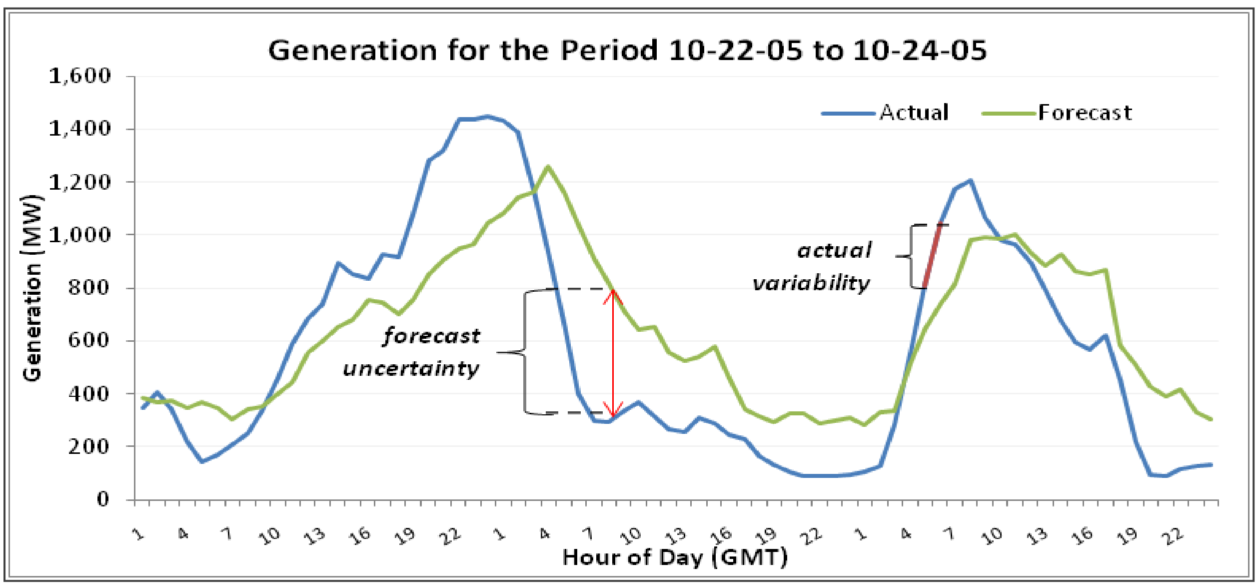


Exhibit 2-3 shows actual variability and forecast uncertainty as defined above. The figure shows the aggregate of actual generation versus forecast generation for 16 wind sites. The forecast uncertainty is shown as the difference between the forecast and actual wind generation. Actual variability is also shown in the chart as the variation in actual wind generation from one hour to the next. As observed, wind generation rarely matches the four-hour-ahead forecast.

[1] "Eastern Wind Integration and Transmission Study", January 2010, Prepared for NREL by: EnerNex Corporation Knoxville, Tennessee, NREL Technical Monitor: David Corbus, Prepared under Subcontract No. AAM-8-88513-01.

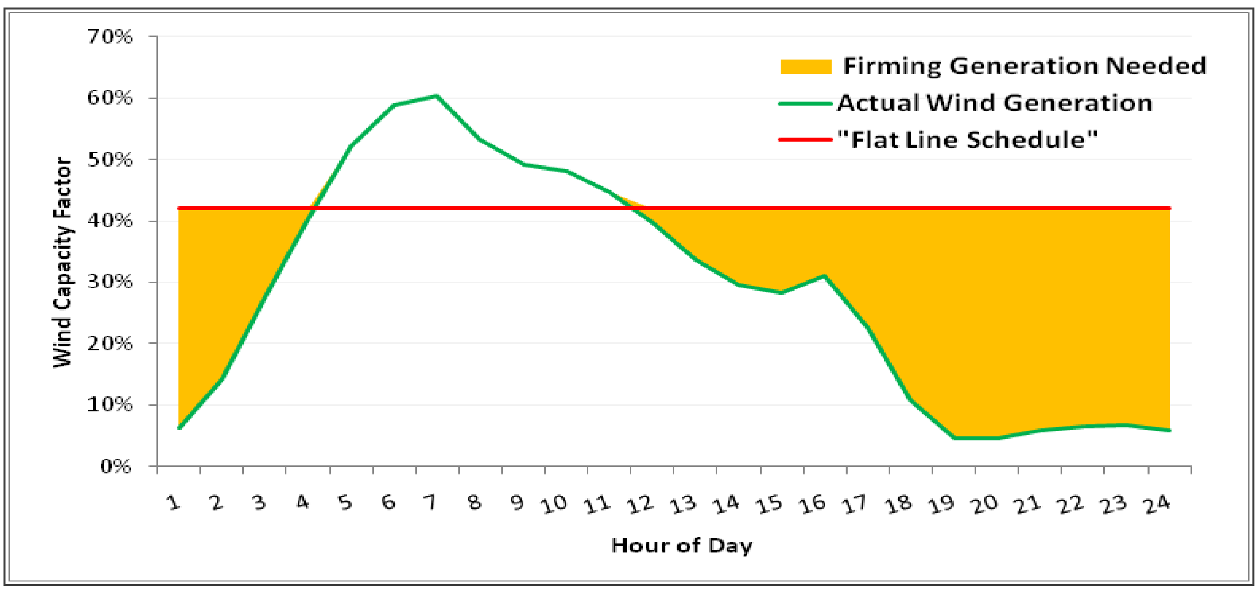
2.1.1 Firming Wind Generation

As described earlier, wind speeds and wind power generation vary significantly from one moment to the next. The concept of firming wind generation is to compensate for some of that variability by providing power from conventional generation or electric storage such that the net power profile (i.e., the sum of power generation from wind and conventional generation or electric storage at each time interval) is equal to a scheduled or expected pattern. **Therefore, *firming capacity* in this analysis is equal to the amount of non-wind generating capacity needed to meet shortfalls in actual wind output with respect to forecast wind output in order to compensate for the forecast uncertainty.**

As wind becomes a larger portion of the generation in regions across the U.S., more power system operators are beginning to require that wind generators submit hourly forecasts for the following day's output. Any shortfalls or surpluses are met with penalties, and avoidance of these penalties is a primary economic motivation for the firming requirements described in this analysis. Further, wind generators that enter a Power Purchase Agreement (PPA) may need to provide a reasonably firm schedule for the purchasing utility to schedule its own generation and load, and therefore may require firming capacity to meet the set power supply schedule.

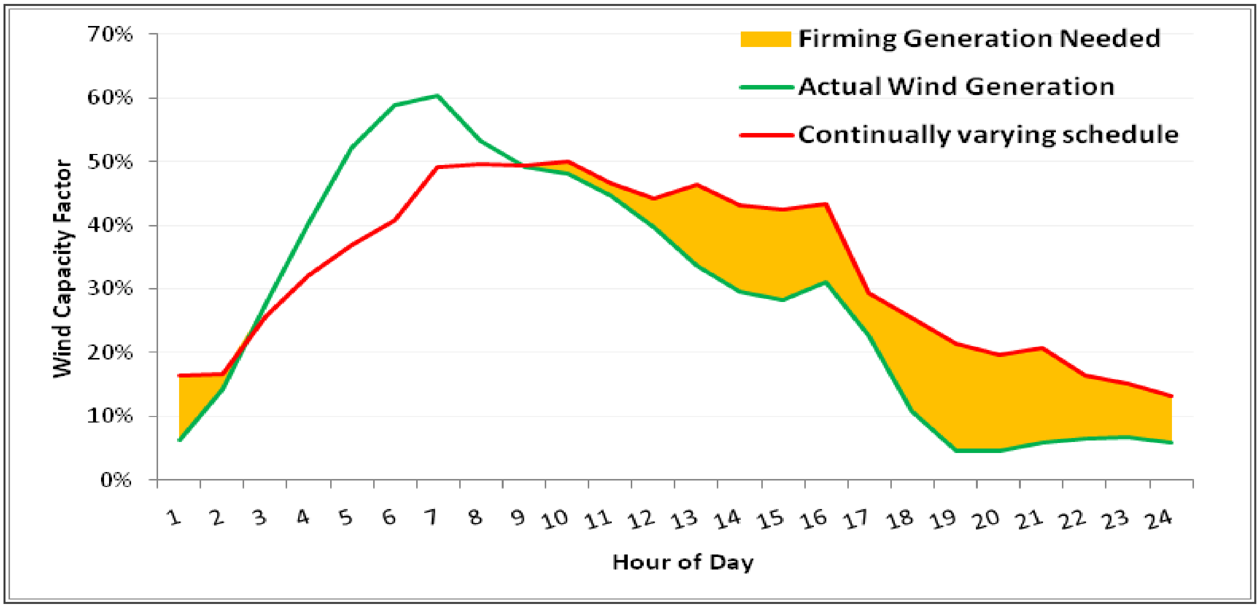
A question then arises as to what exactly is the nature of the firm power schedule provided by the wind generators. The firm power schedule could be a flat line that is a constant amount of power for each hour of the day, or a continually varying amount of power for each hour of the day, or for any other predetermined schedule. Exhibit 2-4 and Exhibit 2-5, respectively, illustrate the flat line and continually varying power schedule concepts.

Exhibit 2-4: Firming to Create a "Flat Line" Schedule[2]



[2] This figure shows the firming generation needed to compensate for shortfalls in wind generation.

Exhibit 2-5: Firming to Create a "Continually Varying" Schedule[3]



In general, the flat line power schedule would require considerably more gas-fired generation for firming when compared to the continually varying schedule. Further, as shown in Exhibit 2-4, a significant amount of wind curtailment could occur, if the wind generation increases far beyond the level assumed in the flat line case, and the excess wind generation cannot be used elsewhere. This result would not be operationally efficient.

The de-regulated wholesale power markets have developed market-based services to deal with the varying nature of wind. These include services from providers of fast response generating reserves (such as spinning reserves) and regulation (load following) capabilities who are compensated for their services to the system. As such, power system operators are more tolerant of known variations than they are of unknown and unexpected variations. Therefore, the key issue is the *forecast uncertainty* of wind generation rather than its actual variability. Assuming it is known, forecast uncertainty may be addressed by ensuring that other conventional generation (such as gas-fired generation) can provide power to compensate for the difference between forecast and actual wind generation. Since the forecast uncertainty can be determined (or at least estimated), a continually varying but known power profile from wind generation is assumed in this study. Such a wind profile would generally be acceptable to power system operators and buyers of PPAs.

In building a large amount of new wind generation to supply power to the grid, there will be a need for either utility scale electricity storage or backup generation capacity for firming. Utility scale electricity storage could store excess electricity during hours in which actual generation exceeds the forecast and supply that stored power back to the grid during hours in which

[3] This figure shows the firming generation needed to compensate for shortfalls in wind generation.

generation falls short of the forecast. Alternatively, quick start/fast response generation capacity may be used as a backup to compensate for variations in wind generation.

This analysis examines the implications of gas-fired generation as the primary source used to firm wind generation in the future, since the preliminary work (Appendix 2) demonstrated that gas-fired generation is the least costly option to backup wind generation.

2.1.2 Determining the Required Level of Firming Service Capacity and Generation

Once the type of firming (flat-line or continually varying) is determined, the next step is to estimate the level of firming service required in terms of back-up capacity and how much it should be expected to operate. In a separate study, ICF examined the level of firming capacity required to support large scale wind generation in Wyoming.[4] Below we summarize the results. (For more detail see Appendix 4.)

The Wyoming analysis showed how site-specific intermittency in wind generation can be mitigated by aggregating wind generation from different locations, since across a large area; off-setting fluctuations tend to even out, reducing the problem somewhat. Intermittency remains however, and a critical factor in managing it depends on the time interval for scheduling power. Four-hour forecasts are the lowest publicly available and introduce less forecast error than day-ahead forecasts. ICF's analysis in Appendix 4 shows that the distribution of forecast errors is symmetrical so that 99.7 percent of the errors will fall within three standard deviations of the mean error. Applying this to the problem of how much back-up generation should be available for intermittent power generation, ICF estimates that for every 1 GW of wind generation, a reserve capacity of 259 MW, or 25.8 percent of the wind capacity is required for firming.

Applying this analysis to a regional or national level is not expected to change the capacity requirements significantly. As the footprint for developing wind generation is expanded to include larger blocks or areas, the multitude of forecast errors are expected to offset, rather than compound. A firming requirement of 25.8 percent of installed wind capacity is reasonable and is used in the subsequent analysis.

To determine the sufficiency of existing natural gas supply infrastructure for handling the changes in gas demand that may be needed due to firming requirements for wind generation, it is necessary to estimate the utilization of gas-fired generation for compensating wind forecast uncertainties. ICF applied similar statistical analysis to estimate how much of the time the forecast error would have required back-up generation. Using the three standard deviation approach to the time intervals, we estimate that the average capacity factor (percent of the year a gas-fired generator would be expected to operate in firming mode) would be about 15.6 percent. We use this estimate for our gas infrastructure requirements.

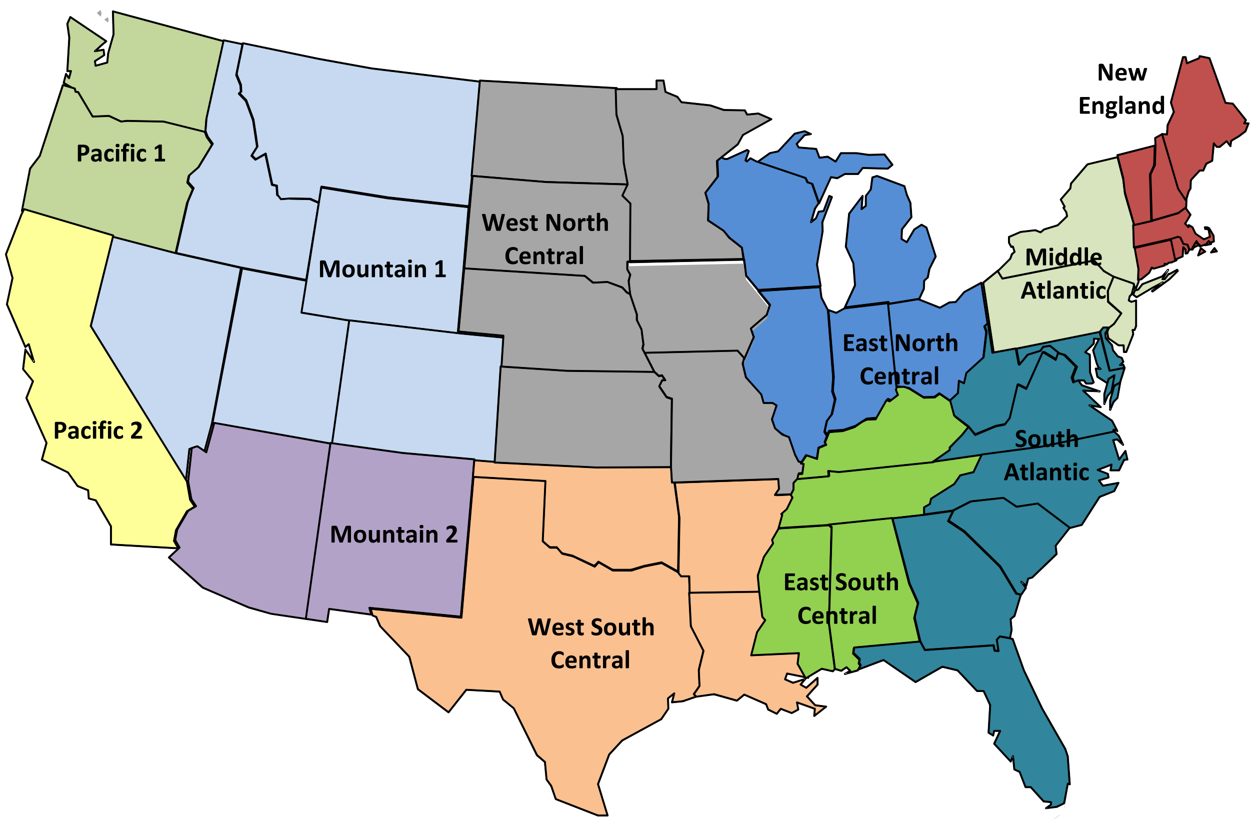
[4] Wyoming Wind Collector System and Integration Study, forthcoming, January 2011

3. Natural Gas Demand Projections and Gas Requirements for Electric Generation, Including Gas Needed for Firming Purposes

This section presents regional projections of natural gas demand from the ICF Gas Market Model (GMM®) based on ICF Expected Case analysis from the preliminary work on renewable generation growth presented in Appendix 2. It also provides analysis of the impacts of intermittency of wind generation on natural gas required for firming generation.

Key assumptions for the ICF Expected Case can be found in Exhibit A2-1-1 in Appendix 2. Regional results are reported in U.S. Census regions, Exhibit 3-1.

Exhibit 3-1: U.S. Census Regions



Important findings from the gas demand analysis are provided below:

- National - The non-power sectors have higher monthly gas demand variability than the power sector, a trend that holds throughout the projection. Gas demand variability over time is likely to be much more sensitive to trends for non-power uses of gas, and not by trends in the power sector. Temperature-sensitive loads in the residential and commercial sectors are much more variable than any other gas loads.

Gas turbine capacity for firming wind generation in the U.S. could grow from about 12 GW in 2010 to more than 33 GW in 2025.

In some of the regions, the share of firming gas use could reach about 4 to 6 percent of total gas demand by 2025. The firming gas use across the entire U.S. will remain less than 2 percent of total gas demand throughout the projection.

- East North Central - The East North Central region is expected to experience significant wind development through 2025 requiring substantial expansion of gas-fired firming generation and associated natural gas infrastructure. The pivotal natural gas issue in connection with wind development is expected to be cost recovery for firming service infrastructure rather than the impact of wind intermittency on the overall gas load variability.

- East South Central - The region is expected to experience robust growth in gas-fired generation, with power sector gas demand quadrupling from less than 1 Bcfd in 2010 to almost 4 Bcfd by 2025. This rapid growth is attributed to the expected large number of gas-fired capacity additions in the region as gas-fired generation displaces other forms of generation. With a flat projection of non-power gas demand, the power sector's share of regional end-use gas demand will increase significantly to more than 60 percent in 2025 from less than 30 percent in 2010. The region currently has a relatively small quantity of installed wind capacity and will continue to have very limited wind development in the foreseeable future. Thus, the share of power gas use for firming wind generation will remain low, and the region should not require significant firming infrastructure for wind generation.

- Middle Atlantic - ICF forecasts strong growth of power gas demand with significant additions of gas-fired capacity required to meet rising peak and energy demand in natural gas-dominated urban markets. Wind generation and intermittency could have a large impact on the total gas load variability, compared to other regions.

- Mountain 1 - Large wind capacity builds in the near term may require a large development of firming service infrastructure in relatively short order. This may require changes to the existing infrastructure to increase line pack and enhanced flexibility in the regional pipeline system.

- Mountain 2 - This is the only region where with power sector natural gas use is the dominant source of monthly natural gas demand variability. Power gas use as a share of the region's total gas demand is the highest in the nation. This region will see more solar development than wind, and some firming generation may be required as back-up.

- New England - The region is expected to develop a modest amount of wind capacity, reflecting the region's limited wind resource. Gas demand attributed to firming wind generation in the region will remain small.

- Pacific 1 - Oregon and Washington will not develop much new gas-fired capacity for base load and intermediate load purposes. Variability of gas demand in the power sector in the area is very high. Power gas demand in the region peaks in the winter at almost double the annual average demand. The winter peak month ratio for this sector is the highest in the U.S. Wind intermittency in this region is expected to have a significant impact on the total gas load variability. Thus, there will be significant need of gas-fired generation for firming intermittent wind generation.

- Pacific 2 - Monthly variability of gas demand is high across all sectors in California. Detailed analysis of firming wind generation shows growing variability of firming gas use that may have a significant impact to the overall gas load variability for the region. However, since the growth is from a relatively low base value, gas use for firming wind generation as a share of total gas demand in the region will continue to remain relatively low.

- South Atlantic - ICF forecasts robust growth in gas demand for power generation. The average annual power gas use is projected to increase significantly from about 3 Bcfd in 2010 to almost 9 Bcfd by 2025. The region will develop only a moderate amount of wind capacity, due to limited resources and the absence of robust REC markets in the area. Wind intermittency in the region is not expected to have a significant impact on total gas load variability since wind development in the area will be relatively low.

- West North Central - There will be 5 GW of incremental wind capacity developed in the region by 2015. Gas use for firming wind generation is expected to increase significantly during this period. Since the region currently has limited gas infrastructure for gas-fired generation, the rapid increase in gas use for firming wind generation may have a significant impact on the area's gas infrastructure. Gas use for firming wind generation is expected to be significant. While the growth of gas use for firming is significant, it will be from a relatively low base value, so the absolute value of gas used for firming will continue to remain relatively small over time.

- West South Central - Gas use for firming intermittent wind generation in the region has been greatest in the U.S. and will continue to be greatest over time. Continued development of the area's wind resources will to present challenges for gas-fired generation and the gas infrastructure required to provide reliable gas transportation to the gas-fired power plants over time.

Appendix 2 presents a more detailed analysis of three regions where there was a possibility of more intermittent generation having an impact on the natural gas system. These detailed analyses examined actual wind patterns, wind generation build forecasts, and ran simulations to understand the impact of the expanded wind generation on the need for firming gas-fired power plants and hence a potential impact on natural gas infrastructure. These findings follow:

- New England – As it turned out, gas firming variability will not have a significant impact on daily gas demand variability in New England.

- Wyoming-California - The highest variability attributable to firming gas use occurs during the shoulder period. Assuming that firming facilities are located close to conventional gas-fired generation units and are interconnected, it may be possible to maintain relatively high line pack in the pipeline system during the shoulder months.

- Oklahoma-Kansas - The region is expected to experience large wind penetration with wind capacity growing at a pace that is more than double the growth in Wyoming-California. Assuming that firming facilities are located close to conventional gas-fired generation units and are interconnected, it may be possible to maintain relatively high line pack in the pipeline system during the shoulder months.

3.1 Demand for Natural Gas

Annual projections of natural gas demand from the GMM® have been provided in Appendix 2. This section summarizes the annual results and presents more detailed seasonal and monthly natural gas demand projections, including natural gas required for firming wind generation.

3.1.1 Annual Projections of Natural Gas Demand

Annual natural gas demand projections are summarized in Exhibit 3-3, Exhibit 3-4, and Exhibit 3-4 for total gas demand, non-power sector gas demand, and power sector gas demand, respectively. Both national and regional gas demand projections are provided. The natural gas demand trends across the Lower-48 are summarized directly below and the regional trends are summarized in the seasonal/monthly gas demand section that follows. Total natural gas demand in the Lower-48 is projected to grow from 2010 to 2025 at a rate of nearly 2 percent per year.

Exhibit 3-2: Total Natural Gas Demand (Bcf)

	2010	2015	2020	2025	Growth 2010–25 (%/yr)
East North Central	3,544	3,695	3,737	4,389	1.4%
East South Central	1,319	1,727	1,985	2,334	3.9%
Mid-Atlantic	2,639	2,974	3,184	3,652	2.2%
Mountain 1	1,399	1,532	1,612	1,705	1.3%
Mountain 2	665	792	876	920	2.2%
New England	856	933	992	974	0.9%
Pacific 1	491	514	527	582	1.1%
Pacific 2	2,136	2,147	2,106	2,074	-0.2%
South Atlantic	2,561	3,571	4,172	4,611	4.0%
West North Central	962	1,086	1,156	1,269	1.9%
West South Central	5,728	6,567	7,052	7,162	1.5%
U.S. Lower-48	**22,301**	**25,538**	**27,399**	**29,672**	**1.9%**

The non-power sector gas demand in Exhibit 3-3 represents gas demand in the residential, commercial, and industrial sectors, as well as gas used in lease and plant[1] and pipeline fuel applications. These sectors will only grow by only 0.5 percent per year from 2010 to 2025.

Exhibit 3-3: Natural Gas Demand in the Non-Power Sectors (Bcf)

	2010	2015	2020	2025	Growth 2010–25 (%/yr)
East North Central	3,261	3,321	3,338	3,379	0.2%
East South Central	966	936	958	984	0.1%
Mid-Atlantic	2,070	2,160	2,192	2,218	0.5%
Mountain 1	1,105	1,156	1,173	1,195	0.5%
Mountain 2	253	270	275	276	0.6%
New England	465	488	498	508	0.6%
Pacific 1	304	320	333	345	0.8%
Pacific 2	1,469	1,489	1,491	1,503	0.2%
South Atlantic	1,351	1,404	1,425	1,447	0.5%
West North Central	958	970	967	983	0.2%
West South Central	4,299	4,830	5,026	5,050	1.1%
U.S. Lower-48	**16,503**	**17,343**	**17,676**	**17,890**	**0.5%**

[1] Lease and plant fuel refers to natural gas used in well, field, and lease operations (such as gas used in drilling operations, heaters, dehydrators, and field compressors) and as fuel in natural gas processing plants.

The power sector gas demand shown in Exhibit 3-4 will grow at a rate of nearly 5 percent per year. The level of power generation gas use will more than double from about 6 Tcf in 2010 to nearly 12 Tcf in 2025.

Exhibit 3-4: Natural Gas Demand for Power Generation (Bcf)

	2010	2015	2020	2025	Growth 2010–25 (%/yr)
East North Central	283	373	399	1,009	8.9%
East South Central	353	791	1,026	1,350	9.4%
Mid-Atlantic	569	814	992	1,434	6.4%
Mountain 1	294	376	439	510	3.7%
Mountain 2	413	523	601	644	3.0%
New England	391	446	494	466	1.2%
Pacific 1	187	194	194	237	1.6%
Pacific 2	666	659	615	571	-1.0%
South Atlantic	1,209	2,167	2,747	3,163	6.6%
West North Central	4	116	189	286	32.4%
West South Central	1,430	1,737	2,026	2,112	2.6%
U.S. Lower-48	**5,798**	**8,196**	**9,723**	**11,783**	**4.8%**

In terms of a share of total gas demand, gas use in power will grow from 26 percent in 2010 to 40 percent in 2025 (Exhibit 3-5). The robust growth of gas use in power is driven by electric load growth and environmental policies that favor gas over other forms of generation.

Exhibit 3-5: Power Gas Demand as a Share of Total Gas Demand (%)

	2010	2015	2020	2025
East North Central	8%	10%	11%	23%
East South Central	27%	46%	52%	58%
Mid-Atlantic	22%	27%	31%	39%
Mountain 1	21%	25%	27%	30%
Mountain 2	62%	66%	69%	70%
New England	46%	48%	50%	48%
Pacific 1	38%	38%	37%	41%
Pacific 2	31%	31%	29%	28%
South Atlantic	47%	61%	66%	69%
West North Central	0.4%	11%	16%	23%
West South Central	25%	26%	29%	29%
U.S. Lower-48	**26%**	**32%**	**35%**	**40%**

3.1.2 Seasonal/Monthly Natural Gas Demand

This section presents monthly variability and peak season natural gas demand in the power sector as well as in the non-power sectors (i.e., residential, commercial, and industrial (R/C/I) sectors) from the GMM® monthly gas demand results. Annual average gas demand is also provided for comparison. The results are presented for both the U.S. and the Census regions.

In this report, the monthly gas demand variability in the end-use sectors is defined as the difference between the highest and lowest monthly average gas demand in that sector throughout the course of a year. Peak season natural gas demand is provided for the winter months (January through March and October through December) and for the summer months (from April to September). Winter and summer peak months are selected based on peak natural gas demand for all gas use during the season. The peak winter month is usually January, but some regions have peak winter end-use gas demand in December. The peak summer months for most regions are either July or August. However, since shoulder months are also included among the summer months, some of the northern regions have peak summer demand in May or September. Ratios of gas demand in the peak summer and winter months to annual average gas demand are provided as measures of the strength or intensity of the seasonal variability.

3.1.2.1 National Trends

Exhibit 3-6 shows the demand measures discussed directly above for the Lower-48. ICF projects a modest growth of gas demand in the non-power sectors between 2010 and 2025. Annual average natural gas demand in the non-power sectors will only increase by 3 Bcfd to 43 Bcfd in 2025. Annual average power gas demand in the Lower-48 represents only 28 percent of total end-use gas demand in 2010. That share is expected to grow significantly to 43 percent in 2025 as power gas demand more than doubles from 15.9 Bcfd in 2010 to 32.2 Bcfd in 2025.

The power sector includes gas use for firming wind generation. As reported in the Appendix 2, there will be significant development of wind capacity in the U.S., mostly brought about by the state-level RPS requirements. Currently, the gas use for firming wind generation makes up a relatively small portion of total gas demand in the U.S. Our analysis suggests that the significant increase of wind capacity, especially in the central regions, is expected to increase the gas use for firming significantly. In most of the regions, however, the gas use for firming wind generation will remain a very small fraction of total gas demand. Detailed analysis of gas use for firming wind generation will be provided later in this section.

Lower-48 gas demand in the non-power sectors is greatest in the winter, driven by heating gas load in the residential and commercial sectors, and lowest in summer when there is very little need of space heating. Monthly variability of gas demand in the non-power sectors is about equal to the size of annual average gas usage in the non-power sectors and is roughly constant throughout the forecast period. Lower-48 power gas demand peaks in the summer for space cooling. The power sector has much less seasonal variability than R/C/I demand, and the monthly variability of power gas demand is much lower than its average annual gas demand.

Exhibit 3-6: End-Use Natural Gas Demand (Bcfd) in Lower-48

	2010			2015			2020			2025		
	R/C/I End-Use	Power	All End-Use	R/C/I End-Use	Power	All End-Use	R/C/I End-Use	Power	All End-Use	R/C/I End-Use	Power	All End-Use
Annual Average	40.3	15.9	56.2	42.1	22.5	64.5	42.6	26.6	69.2	43.1	32.3	75.3
Monthly Variability	40.6	10.7	38.5	40.8	13.2	39.1	40.7	15.0	39.7	39.9	16.6	41.4
Winter Peak Month	65.2	17.1	82.3	66.8	22.7	89.5	67.7	27.1	94.8	67.4	33.5	100.9
Summer Peak Month	26.0	22.3	48.3	27.2	30.4	57.6	27.0	35.9	62.9	27.5	42.7	70.3
Ratio to Annual Average Gas Demand (Scalar)												
Winter Peak Month	1.62	1.08	1.46	1.59	1.01	1.39	1.59	1.02	1.37	1.57	1.04	1.34
Summer Peak Month	0.64	1.40	0.86	0.65	1.36	0.89	0.63	1.35	0.91	0.64	1.32	0.93

Exhibit 3-6 also shows that gas demand in the non-power sectors peaks in the winter and gas demand in the power sector peaks in the summer. The exhibit further indicates that, in 2010, the winter peak month ratio for the non-power sectors is 1.62 (i.e., winter peak gas demand in these sectors is 62 percent higher than its annual average). In the same year, the summer peak month ratio for the power sector is 1.4. This shows that the non-power sectors have higher monthly gas demand variability than the power sector, a trend that holds throughout the projection. **This leads to an important observation: demand variability over time is likely to be much more sensitive to trends in non-power uses of gas, and not to trends in the power sector. Temperature-sensitive loads in the residential and commercial sectors are much more variable than any other gas loads.**

3.1.2.2 Regional Trends

East North Central

The East North Central region includes Illinois, Indiana, Michigan, Ohio, and Wisconsin. End-use natural gas demand in the East North Central region is summarized in**Error! Reference source not found.** Power sector gas demand in the East North Central region is currently a small portion of total end-use gas demand. The share is projected to grow to about 25 percent of the total end-use gas demand by 2025. Non-power sector gas demand also grows, but at a very slow rate.

Exhibit 3-7: End-Use Natural Gas Demand (Bcfd) in East North Central

	2010			2015			2020			2025		
	R/C/I End-Use	Power	All End-Use	R/C/I End-Use	Power	All End-Use	R/C/I End-Use	Power	All End-Use	R/C/I End-Use	Power	All End-Use
Annual Average	8.7	0.8	9.5	8.9	1.0	9.9	8.9	1.1	10.0	9.0	2.8	11.7
Monthly Variability	12.3	0.8	11.9	12.4	0.5	11.9	12.3	0.7	11.8	12.3	1.1	12.3
Winter Peak Month	16.0	0.7	16.7	16.1	0.9	17.0	16.1	1.0	17.1	16.2	2.9	19.1
Summer Peak Month	5.7	0.6	6.3	5.8	1.0	6.8	5.8	1.0	6.9	5.9	2.4	8.3
Ratio to Annual Average Gas Demand (Scalar)												
Winter Peak Month	1.84	0.94	1.76	1.82	0.86	1.72	1.81	0.95	1.72	1.80	1.05	1.63
Summer Peak Month	0.65	0.76	0.66	0.66	0.98	0.69	0.66	0.92	0.69	0.66	0.86	0.71

Monthly variability of gas demand in the power sector is very small because power sector gas use is a relatively small mix of total end-use gas demand. Moreover, the summer peak month ratio is much lower than the national average reflecting a much more stable monthly load profile for gas use in the power sector. We do not expect wind intermittency in the East North Central to have a significant impact on the total gas load variability.

The East North Central region is expected to experience significant wind development through 2025. As reported Appendix 2, there will be significant wind capacity constructed through 2015 that will double the wind capacity in the region, and total wind development will roughly triple capacity by 2025. Relatively high wind penetration in this region will increase the need for firming capacity from gas turbines. **Rapid development of wind capacity in the future may require significant capital-intensive investments in gas-fired generation and the associated gas transportation infrastructure. The pivotal natural gas issue in connection with wind development in the East North Central is expected to be cost recovery for firming service infrastructure rather than the impact of wind intermittency on the overall gas load variability**. Cost recovery for firming service infrastructure is discussed later in Section 5.

East South Central

The East South Central region includes Alabama, Kentucky, Missouri, and Tennessee. Exhibit 3-8 shows annual average, monthly variability, and peak season gas demand in the East South Central region. Robust growth in gas-fired generation is projected, with power sector gas demand quadrupling from less than 1 Bcfd in 2010 to almost 4 Bcfd by 2025. This rapid growth is attributed to the expected large number of gas-fired capacity additions in the region as gas-fired generation displaces other forms of generation with greater emissions over time. With a flat projection of non-power gas demand, the power sector's share of regional end-use gas demand will increase significantly to more than 60 percent in 2025 from less than 30 percent in 2010.

Exhibit 3-8: End-Use Natural Gas Demand (Bcfd) in East South Central

	2010			2015			2020			2025		
	R/C/I End-Use	Power	All End-Use	R/C/I End-Use	Power	All End-Use	R/C/I End-Use	Power	All End-Use	R/C/I End-Use	Power	All End-Use
Annual Average	2.3	1.0	3.2	2.2	2.2	4.3	2.2	2.8	5.0	2.2	3.7	5.9
Monthly Variability	2.6	1.3	3.7	2.3	1.8	3.5	2.3	2.1	3.6	2.4	2.5	3.8
Winter Peak Month	4.1	1.7	5.8	3.7	2.6	6.3	3.7	3.4	7.1	3.8	4.2	8.0
Summer Peak Month	1.5	1.7	3.2	1.4	3.1	4.5	1.4	4.0	5.4	1.4	5.1	6.5
Ratio to Annual Average Gas Demand (Scalar)												
Winter Peak Month	1.79	1.80	1.80	1.72	1.22	1.47	1.70	1.21	1.43	1.71	1.12	1.35
Summer Peak Month	0.65	1.74	0.98	0.64	1.43	1.04	0.64	1.42	1.08	0.63	1.37	1.10

Monthly gas demand variability in the power sector is almost as high as the variability in the non-power sectors, and is relatively higher than the national average. In 2010, power gas demand peaked at almost the same level in the summer and winter. The summer/winter gas power demand mix will change in the future as a greater portion of gas-fired capacity will be directed towards summer peak electric loads.

The region has a relatively small quantity of installed wind capacity and will continue to have very limited wind development in the foreseeable future. Thus, the share of power gas use for firming wind generation will remain low, and the region will not require significant firming infrastructure for wind generation.

Middle Atlantic

The Middle Atlantic region includes Pennsylvania, New Jersey, and New York. It is expected to experience strong growth of power gas demand with significant additions of gas-fired capacity required to meet rising peak and energy demand in natural gas-dominated urban markets. By

2025, average gas demand for power generation will approach 4 Bcfd, compared to only 1.6 Bcfd in 2010 (Exhibit 3-6).

Exhibit 3-9: End-Use Natural Gas Demand (Bcfd) in Mid-Atlantic

	2010			2015			2020			2025		
	R/C/I End-Use	Power	All End-Use	R/C/I End-Use	Power	All End-Use	R/C/I End-Use	Power	All End-Use	R/C/I End-Use	Power	All End-Use
Annual Average	5.5	1.6	7.0	5.6	2.2	7.9	5.7	2.7	8.4	5.7	3.9	9.6
Monthly Variability	7.1	1.8	7.6	7.5	2.3	8.3	7.6	2.2	8.4	7.7	2.8	8.9
Winter Peak Month	9.8	1.9	11.7	10.3	2.7	13.0	10.3	3.2	13.5	10.4	4.5	15.0
Summer Peak Month	2.7	2.6	5.3	2.7	3.5	6.2	2.7	4.1	6.8	2.8	5.4	8.1
Ratio to Annual Average Gas Demand (Scalar)												
Winter Peak Month	1.79	1.20	1.66	1.82	1.22	1.65	1.82	1.19	1.62	1.83	1.15	1.55
Summer Peak Month	0.49	1.66	0.75	0.49	1.55	0.79	0.48	1.50	0.81	0.48	1.36	0.84

Monthly variability of gas demand in the Mid-Atlantic will be dominated by variability of gas demand in the non-power sectors. Variability will remain much the same throughout the forecast because the non-power sector demand barely changes. Variability of gas demand in the power sector will increase along with the increase of gas use in the power sector. The summer peak month represents the highest level for power gas demand in the Middle Atlantic and the ratio representing summer peak use to annual average use is among the highest in the U.S., indicating a relatively high variability of gas demand in the power sector. **Wind intermittency in this region is expected to have a relatively large impact on the total gas load variability, compared to other regions.**

The Middle Atlantic will develop significant wind capacity over the forecast period because of relatively aggressive RPS and robust renewable energy credit markets. As reported in Appendix 2, there will be large wind capacity additions between 2010 and 2015, and wind capacity in 2015 is expected to triple from the current level. The robust wind capacity additions will require a significant increase in firming wind generation capacity in the near future. Nevertheless, the analysis in the following section suggests that while the growth of gas use for firming is significant, it will be from a relatively low base value, and the gas requirement for firming wind generation is expected to remain a relatively small portion of the overall gas use in the region.

Mountain 1

Mountain 1 includes Colorado, Idaho, Montana, Nevada, Utah, and Wyoming. The region has excellent wind resources and is expected to develop significant wind resources through 2025, totaling up to 20 percent of the national total for wind capacity. Although no new gas-fired capacity will be developed in the future, average power gas demand in the region is expected to increase from 0.8 Bcfd in 2010 to 1.4 Bcfd in 2025, reflecting increased utilization of existing units.

Exhibit 3-6 provides an overview of the seasonal and monthly variability of end-use natural gas demand in Mountain 1. Power gas demand is not the dominant source of gas load variability in this region, but the magnitude of the monthly variability in this sector is expected to increase by 50 percent from 2010 to 2025. Monthly gas demand variability in the non-power sectors will remain relatively unchanged throughout the projection. Power gas demand peaks in both the summer and winter at almost the same level, implying similar gas-fired generation requirements for cooling and heating loads. The ratios for the winter and summer peak months versus the annual average continue to indicate that variability in gas load in Mountain 1 will be much more sensitive to residential and commercial trends in gas use than to trends in power sector gas use over time.

Exhibit 3-10: End-Use Natural Gas Demand (Bcfd) in Mountain 1

	2010			2015			2020			2025		
	R/C/I End-Use	Power	All End-Use	R/C/I End-Use	Power	All End-Use	R/C/I End-Use	Power	All End-Use	R/C/I End-Use	Power	All End-Use
Annual Average	1.9	0.8	2.7	1.9	1.0	2.9	1.9	1.2	3.1	2.0	1.4	3.4
Monthly Variability	2.2	0.4	2.2	2.2	0.5	2.3	2.3	0.7	2.4	2.3	0.8	2.5
Winter Peak Month	3.1	0.9	4.0	3.2	1.2	4.4	3.2	1.4	4.6	3.3	1.7	4.9
Summer Peak Month	1.3	0.7	2.0	1.0	1.3	2.3	1.0	1.6	2.6	1.0	1.8	2.8
Ratio to Annual Average Gas Demand (Scalar)												
Winter Peak Month	1.68	1.15	1.52	1.67	1.17	1.49	1.68	1.19	1.49	1.66	1.19	1.47
Summer Peak Month	0.70	0.90	0.76	0.52	1.27	0.78	0.53	1.30	0.82	0.53	1.27	0.84

Analysis in the Appendix 2 suggests that by 2015 wind capacity will increase by three to four times the current level in Mountain 1. Total wind capacity is expected to reach more than 17 GW by 2025. **Large wind capacity builds in the near term may require a large development of firming service infrastructure in relatively short order. This may require changes to the existing infrastructure to increase line pack in the pipeline system within the area.** Gas use for firming wind generation in Mountain 1 is expected to increase significantly but will remain relatively low compared to the total gas use in the region. It is not expected to have a significant impact to the overall gas demand.

Mountain 2

The Mountain 2 includes Arizona and New Mexico. The region is projected to experience modest growth in power sector gas demand. Exhibit 3-11 provides an overview of the end-use natural gas demand in the region. Mountain 2 is expected to experience robust solar development, and by 2025 the region could account for almost 20 percent of the total solar capacity across the U.S. The increase in power gas demand from 1.1 Bcfd in 2010 to 1.8 Bcfd in 2025 is partly attributed to the addition of gas-fired capacity to backup the area's solar capacity.

Mountain 2 is the only region in the U.S. with power sector gas use as the dominant source of monthly gas demand variability. Power gas use as a share of the region's total gas demand is the highest in the nation. So, gas use in the power sector will continue to be an important driver of gas load variability in this region.

Exhibit 3-11: End-Use Natural Gas Demand (Bcfd) in Mountain 2

	2010			**2015**			**2020**			**2025**		
	R/C/I End-Use	**Power**	**All End-Use**	**R/C/I End-Use**	**Power**	**All End-Use**	**R/C/I End-Use**	**Power**	**All End-Use**	**R/C/I End-Use**	**Power**	**All End-Use**
Annual Average	0.5	1.1	1.7	0.6	1.4	2.0	0.6	1.6	2.2	0.6	1.8	2.4
Monthly Variability	0.5	0.6	0.6	0.5	0.7	0.6	0.5	0.7	0.7	0.5	0.7	0.7
Winter Peak Month	0.8	1.1	2.0	0.9	1.5	2.3	0.9	1.7	2.6	0.9	1.8	2.7
Summer Peak Month	0.4	1.5	1.9	0.4	1.8	2.3	0.4	2.1	2.5	0.4	2.2	2.6
Ratio to Annual Average Gas Demand (Scalar)												
Winter Peak Month	1.52	1.01	1.17	1.48	1.03	1.16	1.49	1.03	1.15	1.50	1.03	1.15
Summer Peak Month	0.72	1.30	1.12	0.73	1.29	1.12	0.72	1.27	1.12	0.72	1.25	1.11

New England

New England includes Massachusetts, Maine, New Hampshire, Vermont, Rhode Island, and Connecticut. In 2010, natural gas demand in the power sector is somewhat lower than the gas demand in the non-power sectors. However, the projected modest growth in the power gas demand and anemic growth in the other sectors will bring power and non-power sector gas demand to about the same level after 2015 (Exhibit 3-12).

The power sector is not a major contributor to gas demand variability in New England. Variability of gas demand in the power sector is about 30 to 40 percent of that in the non-power sectors. Power gas use peaks in both summer and winter with slightly higher gas demand in the winter period, driven by heating electric load in the residential and commercial sectors.

Wind generation constitutes a smaller proportion of renewables in New England. ICF expects only a modest amount of wind capacity will be developed there. Gas demand attributed to firming wind generation in the region should remain insignificant.

Exhibit 3-12: End-Use Natural Gas Demand (Bcfd) in New England

	2010			2015			2020			2025		
	R/C/I End-Use	Power	All End-Use	R/C/I End-Use	Power	All End-Use	R/C/I End-Use	Power	All End-Use	R/C/I End-Use	Power	All End-Use
Annual Average	1.3	1.1	2.3	1.3	1.2	2.6	1.4	1.4	2.7	1.4	1.3	2.7
Monthly Variability	1.6	0.4	1.9	1.8	0.5	2.1	1.8	0.6	2.2	1.8	0.7	2.2
Winter Peak Month	2.2	1.2	3.5	2.4	1.4	3.8	2.5	1.5	4.0	2.5	1.5	4.0
Summer Peak Month	0.6	1.2	1.8	0.7	1.4	2.0	0.7	1.5	2.1	0.7	1.4	2.1
Ratio to Annual Average Gas Demand (Scalar)												
Winter Peak Month	1.77	1.13	1.48	1.81	1.15	1.50	1.82	1.13	1.47	1.82	1.16	1.50
Summer Peak Month	0.50	1.11	0.78	0.49	1.11	0.78	0.49	1.08	0.78	0.49	1.09	0.78

Pacific 1

Pacific 1 includes Oregon and Washington. Power gas demand is expected to be relatively flat throughout the projection with only a slight growth through 2025 (Exhibit 3-13). As mentioned in the Appendix 2, this region has a large quantity of existing hydroelectric capacity which has been used extensively for firming renewable generation. It also has excellent wind resources, and developers in the area are expected to develop large wind power capacity through 2025. As a result, Pacific 1 will not develop much new gas-fired capacity for base load and intermediate load purposes.

Variability of gas demand in the power sector in the area is very high. Power gas demand in the region peaks in the winter with a relatively high ratio for peak use versus the annual average, almost double the annual average demand. The winter peak month ratio for this sector is the highest in the U.S. Wind intermittency in this region could have a significant impact on the total gas load variability depending on how much hydroelectric capacity is available for firming. Thus, there could be significant need of gas-fired generation for firming intermittent wind generation.

Exhibit 3-13: End-Use Natural Gas Demand (Bcfd) in Pacific 1

	2010			2015			2020			2025		
	R/C/I End-Use	Power	All End-Use	R/C/I End-Use	Power	All End-Use	R/C/I End-Use	Power	All End-Use	R/C/I End-Use	Power	All End-Use
Annual Average	0.8	0.5	1.3	0.8	0.5	1.4	0.9	0.5	1.4	0.9	0.6	1.5
Monthly Variability	0.9	0.7	1.5	1.0	0.7	1.6	1.0	0.8	1.8	1.1	0.9	1.9
Winter Peak Month	1.3	0.9	2.3	1.4	1.0	2.4	1.5	1.1	2.5	1.5	1.3	2.8
Summer Peak Month	0.4	0.7	1.1	0.5	0.6	1.1	0.5	0.6	1.1	0.5	0.7	1.2
Ratio to Annual Average Gas Demand (Scalar)												
Winter Peak Month	1.71	1.84	1.76	1.69	1.84	1.75	1.68	2.04	1.82	1.70	1.95	1.81
Summer Peak Month	0.56	1.34	0.87	0.55	1.21	0.81	0.55	1.22	0.80	0.54	1.12	0.78

Pacific 2

Pacific 2 covers the state of California, which has the most significant RPS and some of the best renewable resources in the country (wind, solar, geothermal). Gas power demand in California will decline slightly from the current level of 1.8 Bcfd to 1.6 Bcfd by 2025, and is the only region with declining gas use for power over time (Exhibit 3-14).

Exhibit 3-14: End-Use Natural Gas Demand (Bcfd) in Pacific 2

	2010			2015			2020			2025		
	R/C/I End-Use	Power	All End-Use	R/C/I End-Use	Power	All End-Use	R/C/I End-Use	Power	All End-Use	R/C/I End-Use	Power	All End-Use
Annual Average	3.8	1.8	5.7	3.9	1.8	5.7	3.9	1.7	5.6	4.0	1.6	5.5
Monthly Variability	1.9	1.3	1.8	1.8	1.4	2.3	1.8	1.5	2.4	1.8	1.5	2.4
Winter Peak Month	4.7	2.0	6.6	5.0	2.1	7.2	5.0	2.0	7.1	5.1	2.0	7.0
Summer Peak Month	3.2	2.5	5.7	3.2	2.6	5.8	3.2	2.5	5.7	3.3	2.3	5.6
Ratio to Annual Average Gas Demand (Scalar)												
Winter Peak Month	1.22	1.08	1.18	1.30	1.17	1.26	1.29	1.20	1.26	1.28	1.26	1.28
Summer Peak Month	0.83	1.38	1.01	0.83	1.43	1.02	0.83	1.46	1.02	0.83	1.50	1.02

Monthly variability of gas demand in the power sector is high in California. Variability is high across all gas used within the state. Detailed analysis of firming wind generation in the following sections shows growing variability of firming gas use that may have a significant impact to the overall gas load variability for the region. The analysis also shows that gas used for firming wind generation in the region is expected to increase significantly. However, since the growth is from a relatively low base value, gas use for firming wind generation as a share of total gas demand in Pacific 2 will continue to remain relatively low.

South Atlantic

The South Atlantic includes Delaware, the District of Columbia, Georgia, Florida, Maryland, North Carolina, South Carolina, Virginia, and West Virginia. The region is projected to experience robust growth in gas demand for power generation. **The average annual power gas use is projected to increase significantly from about 3 Bcfd in 2010 to almost 9 Bcfd by 2025 (**Exhibit 3-15**). The region will develop only a moderate amount of wind capacity, due to limited resources and the absence of robust REC markets in the area.**

Exhibit 3-15: End-Use Natural Gas Demand (Bcfd) in South Atlantic

	2010			2015			2020			2025		
	R/C/I End-Use	Power	All End-Use	R/C/I End-Use	Power	All End-Use	R/C/I End-Use	Power	All End-Use	R/C/I End-Use	Power	All End-Use
Annual Average	3.5	3.3	6.8	3.6	5.9	9.6	3.7	7.5	11.2	3.7	8.7	12.4
Monthly Variability	4.6	2.1	5.2	4.0	2.7	4.6	4.1	3.5	4.6	4.0	4.0	5.2
Winter Peak Month	6.6	3.8	10.5	6.3	5.9	12.2	6.3	7.6	13.9	6.3	8.8	15.1
Summer Peak Month	2.1	4.5	6.6	2.2	7.5	9.8	2.3	9.5	11.7	2.3	11.0	13.3
Ratio to Annual Average Gas Demand (Scalar)												
Winter Peak Month	1.90	1.16	1.54	1.73	1.00	1.27	1.73	1.01	1.24	1.70	1.01	1.22
Summer Peak Month	0.61	1.35	0.97	0.61	1.27	1.02	0.62	1.26	1.05	0.62	1.27	1.07

Seasonal variability of gas demand in the power sector is relatively low. Variability for all gas use is much lower than the annual average. Power gas demand in the South Atlantic is highest in the summer. The ratio of the summer peak to the annual average is lower than the national average, reflecting a relatively stable monthly profile power gas use. **Wind intermittency in the region should not have a significant impact on total gas load variability since wind development in the area will be relatively low.**

West North Central

The West North Central includes Iowa, Kansas, Minnesota, Montana, Nebraska, North Dakota, and South Dakota. Currently, the region has a limited amount of gas-fired capacity and relatively little power gas use. Gas-fired capacity is expected to grow, with power gas demand increasing to 0.8 Bcfd by 2025 (Exhibit 3-16).

Exhibit 3-16: End-Use Natural Gas Demand (Bcfd) in West North Central

	2010			2015			2020			2025		
	R/C/I End-Use	Power	All End-Use	R/C/I End-Use	Power	All End-Use	R/C/I End-Use	Power	All End-Use	R/C/I End-Use	Power	All End-Use
Annual Average	2.4	0.0	2.4	2.5	0.3	2.8	2.4	0.5	3.0	2.5	0.8	3.2
Monthly Variability	3.7	0.0	3.7	3.6	0.2	3.4	3.5	0.3	3.4	3.5	0.6	3.4
Winter Peak Month	4.8	0.0	4.8	4.7	0.3	4.9	4.6	0.5	5.1	4.7	0.8	5.4
Summer Peak Month	1.5	0.0	1.5	1.5	0.3	1.8	1.5	0.5	2.0	1.1	1.2	2.4
Ratio to Annual Average Gas Demand (Scalar)												
Winter Peak Month	1.96	1.70	1.96	1.90	0.85	1.78	1.90	0.94	1.73	1.90	0.98	1.67
Summer Peak Month	0.60	0.49	0.60	0.61	0.91	0.64	0.61	0.94	0.67	0.46	1.59	0.73

Gas demand variability in the area is almost entirely attributed to variability in non-power uses for gas. This is generally because non-power uses for gas dwarf power gas use, and because the area has a significant amount of temperature-sensitive load in the residential and commercial sectors. The area also experiences significant temperature swings in the wintertime.

The West North Central has excellent wind resources, and the area's wind developers are projected to develop over 10 GW of new wind capacity through 2025**. As reported in Appendix 2 there could be 5 GW of incremental wind capacity developed by 2015. Gas use for firming wind generation is expected to increase significantly during this period. Since the region currently has limited gas infrastructure for gas-fired generation, the rapid increase in gas use for firming wind generation could have a significant impact on the area's gas infrastructure.** The region will require developing new firming service infrastructure such as gas-fired generation and new gas transportation capacity. Gas use for firming wind generation is expected to be significant. While the growth of gas use for firming is significant, it will be from a relatively low base value, so the absolute value of gas used for firming will continue to remain relatively small over time.

West South Central

The West South Central includes Arkansas, Louisiana, Texas, and Oklahoma. Power gas demand is projected to grow from the current level of about 4 Bcfd to about 6 Bcfd in 2025 (**Error! Reference source not found.**). The share of power gas demand in the region will continue to remain at about one-third of the total end-use gas demand.

Exhibit 3-17: End-Use Natural Gas Demand (Bcfd) in West South Central

	2010			2015			2020			2025		
	R/C/I End-Use	Power	All End-Use	R/C/I End-Use	Power	All End-Use	R/C/I End-Use	Power	All End-Use	R/C/I End-Use	Power	All End-Use
Annual Average	9.7	3.9	13.6	10.8	4.8	15.5	11.2	5.5	16.7	11.2	5.8	17.0
Monthly Variability	3.9	3.8	3.9	3.7	4.0	3.4	3.6	4.4	3.2	3.7	4.7	4.9
Winter Peak Month	11.9	3.5	15.3	12.8	3.9	16.7	13.6	4.6	18.2	13.4	4.6	18.0
Summer Peak Month	9.2	6.3	15.5	10.1	7.4	17.5	10.0	8.4	18.4	10.1	8.9	19.0
Ratio to Annual Average Gas Demand (Scalar)												
Winter Peak Month	1.22	0.88	1.13	1.19	0.82	1.08	1.22	0.84	1.09	1.20	0.80	1.06
Summer Peak Month	0.95	1.60	1.14	0.94	1.56	1.13	0.90	1.51	1.10	0.91	1.54	1.12

Monthly variability of power gas demand is very high and is expected to dominate the overall gas demand variability in the region. The variability in the non-power sectors is not significant since the area's winters are relatively mild; gas used directly for space heating is a small portion of the area's gas load. The span of the variability is much lower than the annual average non-power gas demand. The area's power gas demand is highest in the summer and the summer peak month ratio for the power sector is one of the highest in the U.S., indicating relatively high seasonal gas demand variability.

The West South Central is expected to develop a significant amount of wind capacity in the foreseeable future. Wind development is limited to Texas, Oklahoma, and a small portion of Arkansas. The region currently has more than 10 GW of installed wind capacity with more than 90 percent of the capacity in Texas. As reported in Appendix 2, the area's wind developers are projected to build more than 20 GW of additional wind capacity over the next 15 years. The vast wind development, together with high gas demand variability in the power sector may have significant impacts on the area's gas use over time.

The West South Central is the area in the U.S. where gas use for firming intermittent wind generation has been and will continue to be greatest over time. This is because the area has a significant amount of wind resources that are being developed, and because of the area's heavy reliance on gas-fired generation to backup that intermittent source of electricity. **Continued development of the area's wind resources will present challenges for gas-fired generation and the gas infrastructure required to provide reliable gas transportation to the gas-fired power plants.**

3.2 Daily Variability of Gas Demand and 10-Minute Variability of Gas Use for Firming Wind Generation

There is already significant variability in daily gas use. Gas demand in the residential and commercial sectors fluctuates with changes in temperature. Electric load also fluctuates with weather and by time of day, which in turn drives fluctuations in gas demand for power generation. Currently, renewable intermittency accounts for a relatively small portion of total gas load variability. As renewable capacity is expected to increase significantly in the future, gas load variability attributable to renewable intermittency also is likely to increase significantly. Still, gas load variability connected with renewable intermittency is likely to remain a small percentage of total load, as will be discussed below.

This section projects daily variability of gas use in three illustrative regions: New England, Wyoming-California, and Oklahoma-Kansas. These regions have been selected for the potential impact of renewable generation on natural gas infrastructure. Since the focus of the study is primarily on wind energy, only gas demand variability due to wind generation is considered here. Furthermore, it is assumed that power generation for firming requirements is met entirely using gas turbines, either at existing power plants or from new gas power plants built solely to backup the wind generation. The gas-fired generation for firming is converted to gas consumption assuming an average gas turbine heat rate of 10,000 Btu/kWh. The gas demand variability is presented for three periods: the winter (January, February, November, and December), the summer (June, July, and August), and shoulder months (March, April, September, and October). The shoulder month period is separately considered, because in some regions, such as California, wind variability is relatively high during the shoulder months.

In this study, daily gas demand forecasts for the end-use sectors have been estimated based on GMM® monthly gas demand forecasts and ICF's Daily Gas Load Model (DGLM).[2] Gas demand variability in the power sector includes variability of gas used for firming wind generation. As discussed earlier when the concept of firming wind generation was introduced, the exact amount of wind power at any instant is not known with 100 percent accuracy, because the speed of the wind changes continuously. Still, within 10 to 15 minute intervals, a persistence forecast[3] is assumed reasonably accurate. In this analysis, variability of gas use for firming wind generation is estimated based on a 10-minute persistence forecast which represents the difference between the highest and the lowest 10-minute gas use for forming wind generation within a day. The persistence forecast for scheduling gas firming generation may result in very high gas load within several intervals throughout the day, even if the average daily gas use for firming wind generation is relatively low. In the following subsections and figures we present the 10-minute variability of gas use for firming generation to show wind intermittency affects power gas demand variability.

[2] ICF's Daily Gas Load Model (DGLM) is used to project daily load profiles, including peak day gas demand.

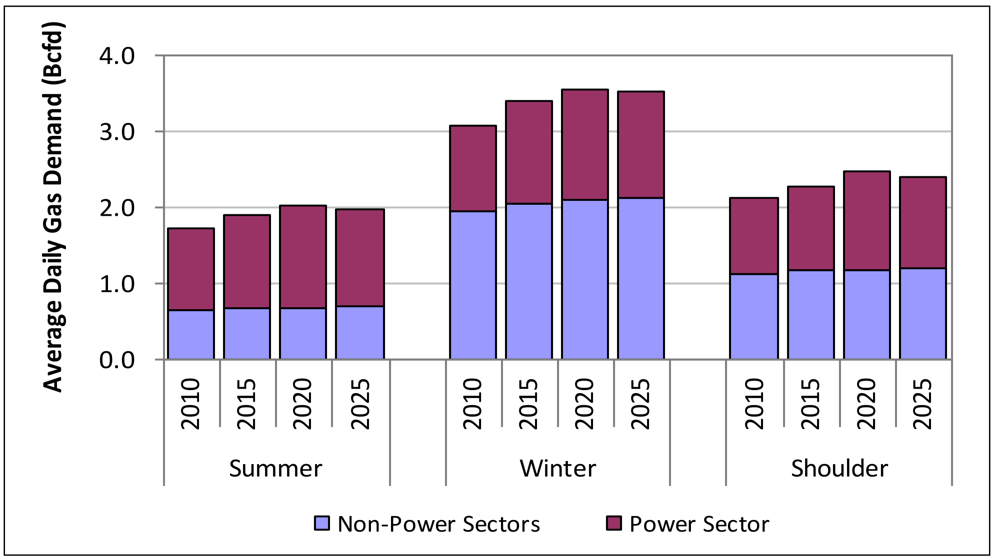
[3] The persistence forecast is used to forecast wind speeds within a very short duration, such as 5, 10 or 15 minutes. This method assumes that the forecast of wind speed for the next interval is equal to the actual value of wind speed in the present interval.

In this analysis, daily gas demand variability refers to the difference between the highest and the lowest daily end-use gas demand in a season. The 10-minute variability of gas use for firming wind generation is the difference between the highest and the lowest 10-minute gas use for firming wind generation within a day.

3.2.1 New England

A forecast of average daily gas demand for New England is shown in Exhibit 3-19. Exhibit 3-19, Exhibit 3-20 and Exhibit 3-21 present a forecast of average daily gas demand for the end-use sectors in New England in the summer, winter, and shoulder periods along with the daily gas demand variability and the 10-minute variability for firming wind generation.

Exhibit 3-18: Average Daily Gas Demand (Bcfd) in New England



In New England, daily variability of end-use gas demand in the summer will be dominated by variability in the power sector. This reflects relatively flat natural gas demand in the residential and commercial sectors in the same period. The daily variability of power gas demand is quite large when compared to the average power gas demand. The variability is about 110 percent of the average power gas demand. In the winter and shoulder periods, the daily gas demand variability is much higher in the non-power sectors, driven by fluctuating residential and commercial gas demand due to changes in weather. Power gas demand variability is lower in the winter and shoulder periods than in the summer. Daily gas demand variability in the power sector is about 70 percent of the average power gas demand in the winter and 85 percent of the average power gas demand in the shoulder period.

While New England currently has limited wind generation, the area's wind developers are expected to develop significant wind capacity in the future. Wind capacity in the region is expected to increase by more than eight times over the current level by 2025. Since the firming gas requirements will increase proportionally to the increase of wind capacity, the magnitude of the variability of gas use for firming wind generation will also grow significantly in New England. In Exhibit 3-19, Exhibit 3-20 and Exhibit 3-21, the 10-minute variability of firming gas use is shown to grow from less than 0.05 Bcfd in 2010 to more than 0.2 Bcfd in 2025. Even within the 10-minute intervals, however, this variability is much lower than the average daily variability of total power gas demand throughout all seasons. This suggests that gas firming variability will not have a significant impact on daily gas demand variability in New England.

Exhibit 3-19: Gas Demand Variability (Bcfd) in New England – Summer

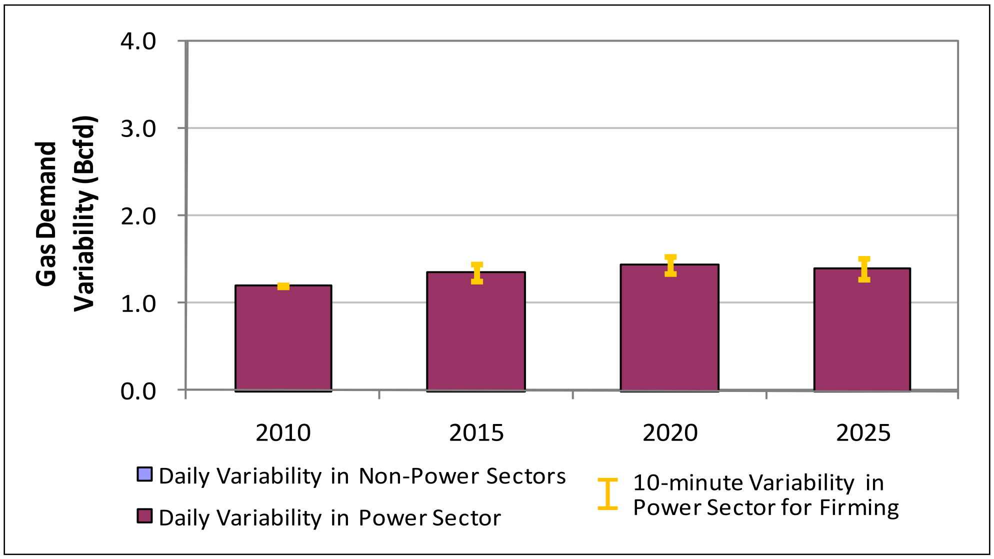


Exhibit 3-20: Gas Demand Variability (Bcfd) in New England – Winter

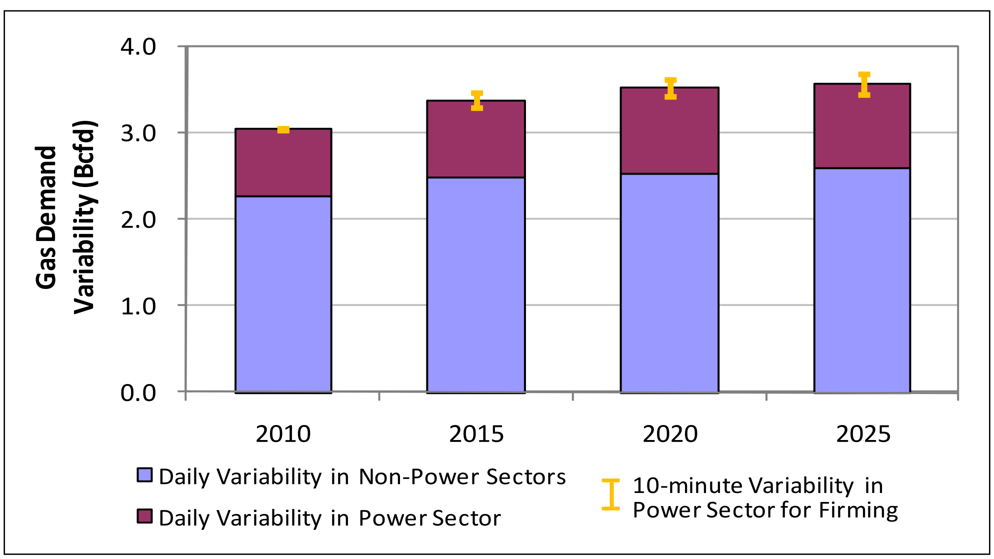
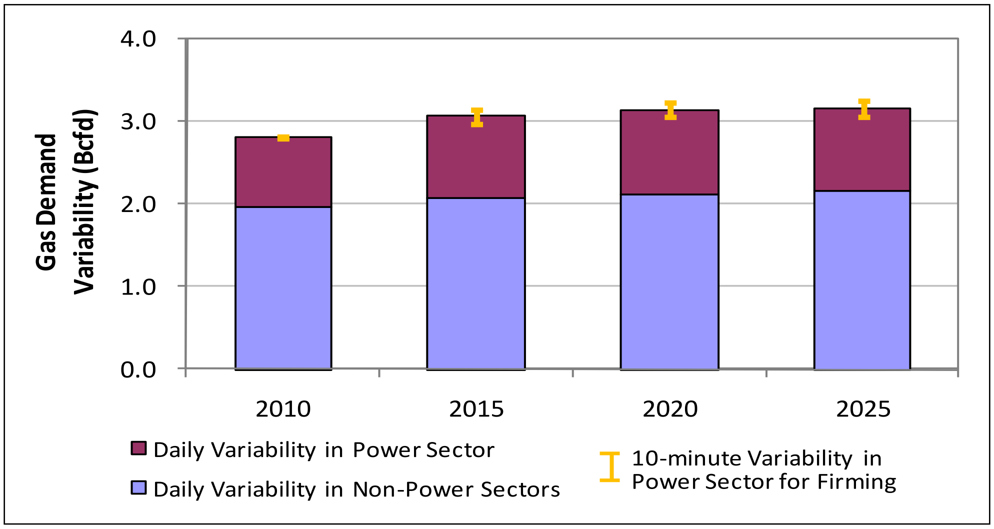


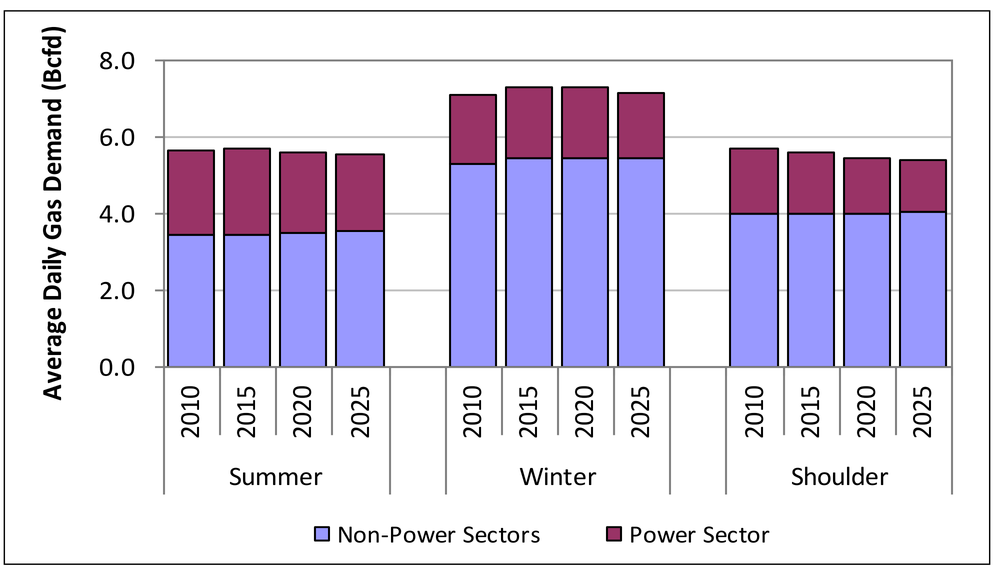
Exhibit 3-21: Gas Demand Variability (Bcfd) in New England – Shoulder



3.2.2 Wyoming-California

Exhibit 3-22 shows the average daily end-use gas demand in Wyoming-California. This region has the highest end-use gas demand among the three focus regions studied here. Wyoming-California currently has the greatest wind capacity among the three focus regions, and the area is expected to maintain its position due to the stringent renewable portfolio standard in California and the large potential for additional renewable resources.

Exhibit 3-22: Average Daily Gas Demand (Bcfd) in Wyoming-California



Gas demand variability in Wyoming-California is shown in Exhibit 3-23, Exhibit 3-24, and Exhibit 3-25. In this region, the lowest total end-use gas demand variability is during the summer.

However, daily gas demand variability in the power sector is highest in this period, corresponding to higher gas load to satisfy space cooling. The variability of power gas demand in summer is about 85 percent of average power gas demand. The 10-minute variability of gas use for firming wind generation in the summer is also relatively high, growing from 0.2 Bcfd in 2010 to more than 0.5 Bcfd in 2025. Although the total end-use gas demand variability is lowest in the summer, the impact of wind intermittency will be more pronounced during this period due to the cumulative effect of demand created by firming units and by air conditioning load met with gas-fired generators.

Exhibit 3-23: Gas Demand Variability (Bcfd) in Wyoming-California – Summer

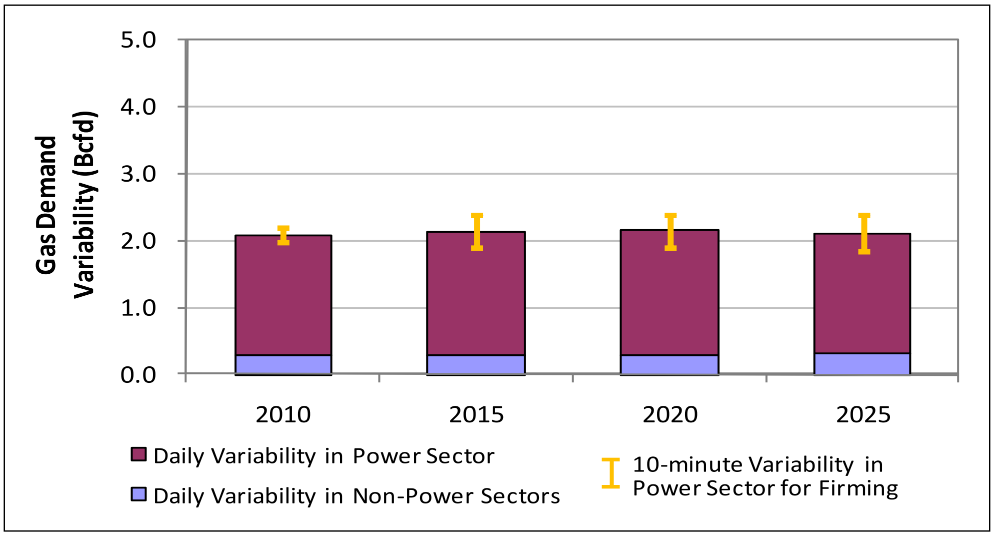


Exhibit 3-24: Gas Demand Variability (Bcfd) in Wyoming-California – Winter

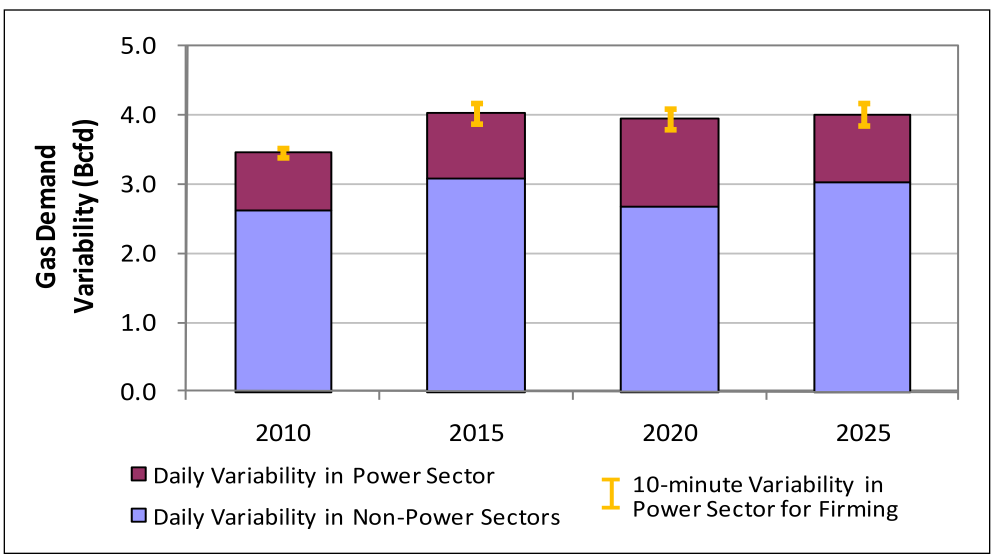
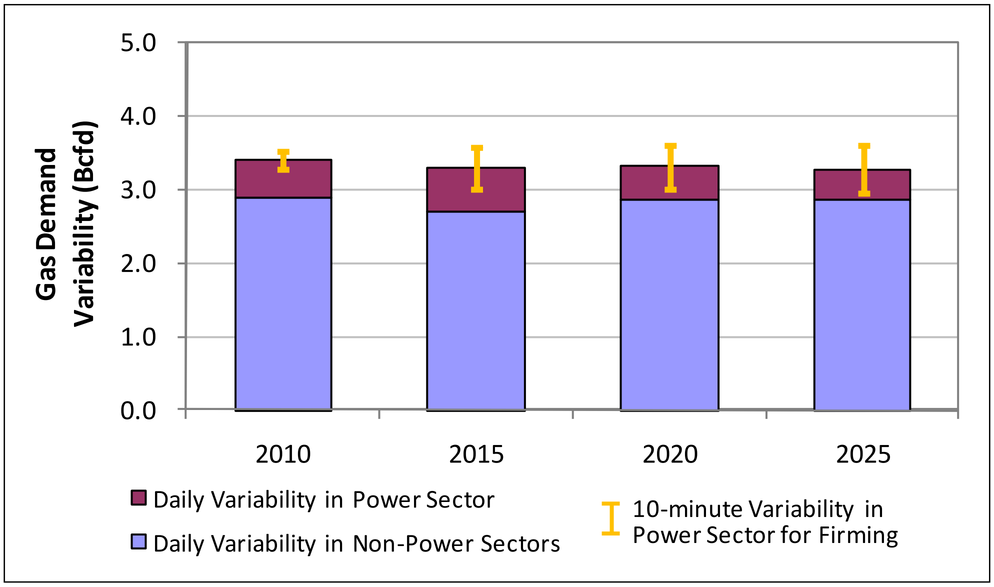


Exhibit 3-25: Gas Demand Variability (Bcfd) in Wyoming-California – Shoulder



End-use gas demand variability is highest during the winter. However, since the 10-minute variability in the firming gas use is lowest in this period, the impact of wind intermittency will not be as strong as in the summer. The variability of power gas use in the winter ranges from 45 to 70 percent of the average daily power gas level.

The highest variability attributable to firming gas use occurs during the shoulder period. The 10-minute variability of gas use for firming is expected to grow from 0.25 Bcfd in 2010 to nearly 0.7 Bcfd in 2025. This large gas firming variability may have a significant impact on gas infrastructure. Still, due to lower utilization of conventional gas-fired generation units and lower variability in overall power gas demand; the impact of firming variability is expected to be lower than in the summer. Assuming that firming facilities are located close to conventional gas-fired generation units and are interconnected, it may be possible to maintain relatively high line pack in the pipeline system during the shoulder months.

3.2.3 Oklahoma-Kansas

The Oklahoma-Kansas region has the lowest natural gas use among the regions studied here. Exhibit 3-26 shows average daily gas demand in the region. Exhibit 3-27, Exhibit 3-28, and Exhibit 3-29 present gas demand variability for the area. The region is expected to experience large wind penetration with wind capacity growing at a pace that is more than double the growth in Wyoming-California.

Exhibit 3-26: Average Daily Gas Demand (Bcfd) in Oklahoma-Kansas

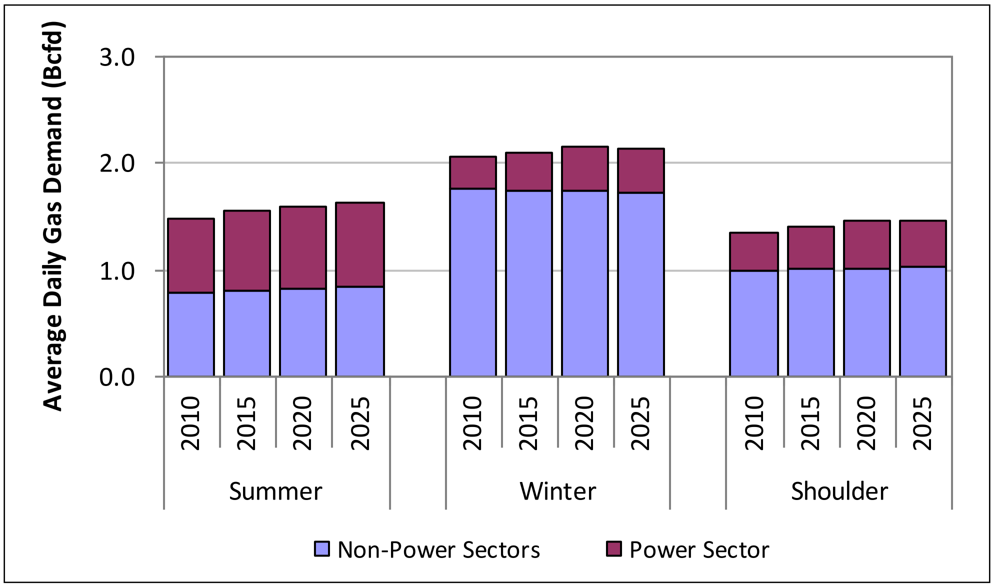


Exhibit 3-27: Gas Demand Variability (Bcfd) in Oklahoma-Kansas – Summer

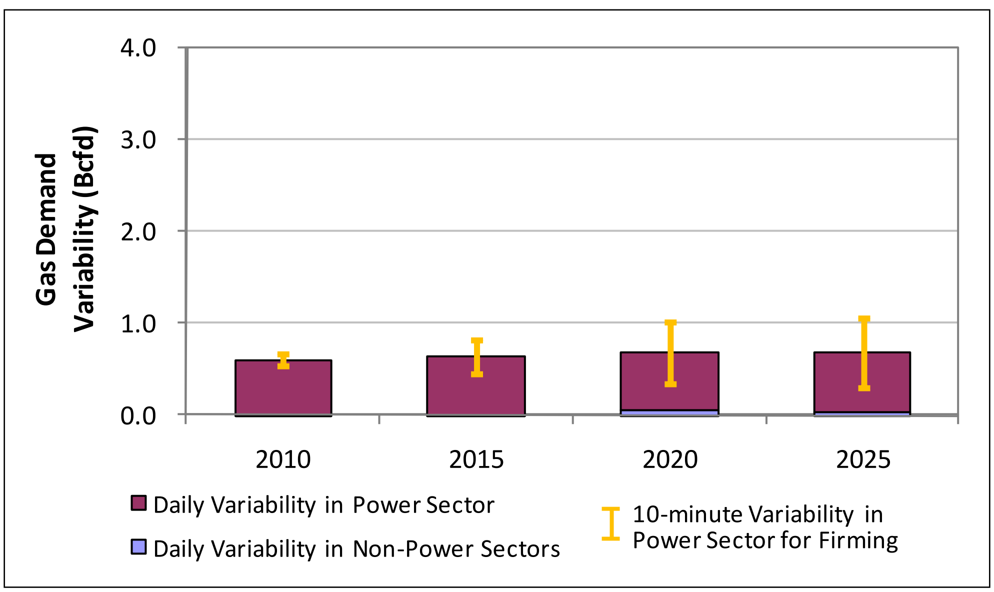


Exhibit 3-28: Gas Demand Variability (Bcfd) in Oklahoma-Kansas – Winter

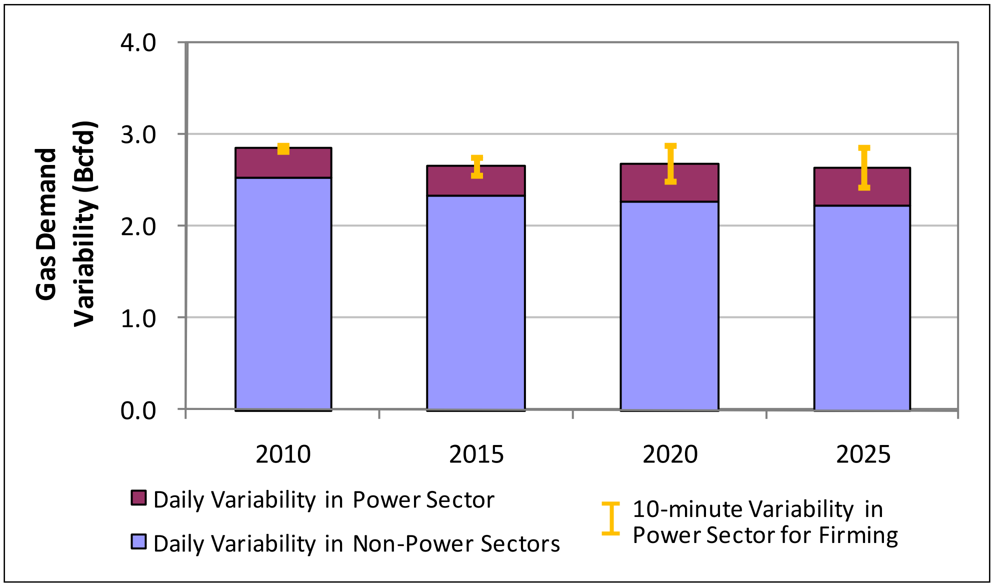
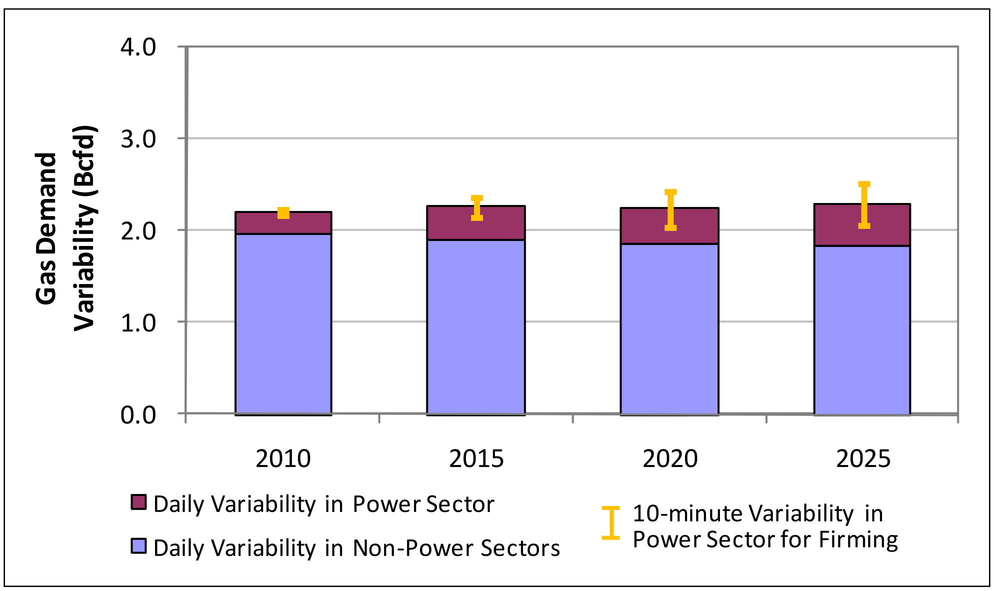


Exhibit 3-29: Gas Demand Variability (Bcfd) in Oklahoma-Kansas – Shoulder



Oklahoma-Kansas will experience significant impact from wind intermittency during the summer. This will be somewhat similar to Wyoming-California, but with a greater impact due to very high firming variability. The 10-minute variability of gas use for firming wind generation in the region is expected grow to as high as 0.75 Bcfd in 2025, up from less than 0.15 Bcfd in 2010. Daily power gas demand variability is also high, at about 85 percent of the average power gas demand. The impact of wind intermittency in Oklahoma-Kansas region will be more pronounced in the summer due to the cumulative effect of demand created by firming units and by air conditioning load met with gas-fired generators.

The winter and shoulder periods have similar patterns of end-use gas demand and variability. The 10-minute variability of gas use for firming is the same in both periods, and is expected to grow from less than 0.1 Bcfd in 2010 to 0.45 Bcfd in 2025. Average daily use in the power sector in the two periods is about half of the corresponding level in the summer due to lower utilization of conventional gas-fired generation units. Due to these expected conditions, firming variability will have less impact on overall gas infrastructure than during the summer. Also, assuming that firming facilities are located close to conventional gas-fired generation units and are interconnected, it may be possible to maintain relatively high line pack in the pipeline system during the shoulder months.

3.3 Intermittency in Wind Generation and Its Impacts on Gas Demand

As discussed above, wind generation can vary significantly within minutes and create a need for firming generation from gas turbine power plants. This section summarizes an analysis of how the intermittency of wind generation and its impact on the dispatch of firming generation will affect natural gas demand across the entire U.S.

3.3.1 Gas Turbine Capacity and Generation Needed for Firming Wind Generation

As discussed above in Section 2, the required gas turbine capacity for firming wind generation has been found to be 25.8 percent of the installed wind capacity and the average annual utilization of gas turbines for firming purposes is 15.6 percent. It is important to note, however, that the two factors may vary by region depending on the level of wind variability intermittency in the region. For providing a first-order estimate of gas use and gas infrastructure requirements for firming wind generation, the two factors are broadly applied across the entire U.S in this analysis.

Exhibit 3-30 shows regional projections of wind capacity in the U.S. The capacity numbers have been derived from ICF's multi-client analysis performed using the IPM® energy market simulation software. This analysis simulated the entire U.S. power market to determine the most economically attractive generation (type and amount) subject to various environmental, fuel, and transmission policies and constraints. The numbers shown here are total wind generation, inclusive of existing wind generation, which is about 41 GW.

Exhibit 3-30: Projected Wind Capacity (GW)

	2010	2015	2020	2025
East North Central	4.2	8.1	10.3	14.2
East South Central	0.0	0.1	0.1	0.2
Mid-Atlantic	5.0	8.3	8.4	9.3
Mountain 1	5.7	15.3	18.3	21.0
Mountain 2	0.7	2.7	2.7	3.3
New England	0.4	3.1	3.1	3.5
Pacific 1	5.0	7.3	7.3	9.5
Pacific 2	4.1	7.9	9.2	9.2
South Atlantic	0.6	2.8	2.9	2.9
West North Central	9.4	14.4	17.9	22.0
West South Central	11.8	21.7	27.2	34.0
U.S. Lower-48	**46.9**	**91.5**	**107.4**	**129.2**

Note: Totals include existing plus new additions. See Exh. A2-1-2.

Exhibit 3-31 shows the projections of generation capacity needed for firming, assuming the 25.8 percent value referenced above. Gas turbine capacity for firming wind generation in the U.S. will grow from about 12 GW in 2010 to more than 33 GW in 2025. Some of the firming generation is expected to come from increased dispatching of existing installed generation units. Renewable resources are going to displace some existing generation units that are installed today, but those units might be dispatched in different ways to provide firming generation in the future.

Exhibit 3-31: Projected Gas Turbine Capacity Needed for Firming (GW)

	2010	2015	2020	2025
East North Central	1.1	2.1	2.7	3.7
East South Central	0.0	0.0	0.0	0.0
Mid-Atlantic	1.3	2.1	2.2	2.4
Mountain 1	1.5	3.9	4.7	5.4
Mountain 2	0.2	0.7	0.7	0.9
New England	0.1	0.8	0.8	0.9
Pacific 1	1.3	1.9	1.9	2.5
Pacific 2	1.1	2.0	2.4	2.4
South Atlantic	0.2	0.7	0.7	0.7
West North Central	2.4	3.7	4.6	5.7
West South Central	3.0	5.6	7.0	8.8
U.S. Lower-48	**12.1**	**23.6**	**27.7**	**33.3**

3.3.2 Gas Power Generation and Gas Use for Firming Wind Generation

The annual gas-fired generation and the associated gas consumption for firming wind generation are summarized in Exhibit 3-32 and Exhibit 3-33, respectively. Gas-fired generation is estimated based on the assumption of 15.6 percent average annual utilization of gas turbines for firming wind generation referenced above. The associated gas use for firming generation is estimated assuming an average gas turbine heat rate of 10,000 Btu/kWh and natural gas heat content of 1,030 Btu per cubic foot.

Exhibit 3-32: Projected Annual Gas-Fired Generation for Firming Wind Generation (GWh)

	2010	2015	2020	2025
East North Central	1,468	2,847	3,646	5,007
East South Central	10	23	23	59
Mid-Atlantic	1,776	2,935	2,967	3,293
Mountain 1	2,020	5,385	6,439	7,409
Mountain 2	232	936	954	1,171
New England	146	1,092	1,110	1,245
Pacific 1	1,762	2,566	2,566	3,354
Pacific 2	1,451	2,790	3,243	3,243
South Atlantic	208	990	1,021	1,021
West North Central	3,297	5,067	6,294	7,767
West South Central	4,162	7,643	9,590	11,988
U.S. Lower-48	**16,532**	**32,275**	**37,853**	**45,558**

Exhibit 3-33: Projected Gas Use for Firming Wind Generation (Bcf)

	2010	2015	2020	2025
East North Central	14.3	27.6	35.4	48.6
East South Central	0.1	0.2	0.2	0.6
Mid-Atlantic	17.2	28.5	28.8	32.0
Mountain 1	19.6	52.3	62.5	71.9
Mountain 2	2.3	9.1	9.3	11.4
New England	1.4	10.6	10.8	12.1
Pacific 1	17.1	24.9	24.9	32.6
Pacific 2	14.1	27.1	31.5	31.5
South Atlantic	2.0	9.6	9.9	9.9
West North Central	32.0	49.2	61.1	75.4
West South Central	40.4	74.2	93.1	116.4
U.S. Lower-48	**160.5**	**313.3**	**367.5**	**442.3**

Gas use for firming wind generation across the U.S. will remain a small portion of total gas demand. It is expected to account for less than 0.5 Tcf out of almost 30 Tcf of total gas demand through 2025.

Exhibit 3-34 shows gas use for firming wind generation as a percentage of total gas demand. Because of low gas firming requirements, the impact of wind development on the overall U.S. gas demand will not be significant. This will vary by region, however**. In some areas such as Mountain 1, Pacific 1, and the West North Central, the impact of gas use for firming wind generation on total gas demand will be more significant.** The share of firming gas use in these regions will reach about 4 to 6 percent of total gas demand by 2025. The firming gas use across the entire U.S. will remain less than 2 percent of total gas demand throughout the projection.

Exhibit 3-34: Gas Use for Firming Wind Generation as a Share of Total Gas Demand (%)

	2010	2015	2020	2025
East North Central	0.4%	0.7%	0.9%	1.1%
East South Central	0.0%	0.0%	0.0%	0.0%
Mid-Atlantic	0.7%	1.0%	0.9%	0.9%
Mountain 1	1.4%	3.4%	3.9%	4.2%
Mountain 2	0.3%	1.1%	1.1%	1.2%
New England	0.2%	1.1%	1.1%	1.2%
Pacific 1	3.5%	4.8%	4.7%	5.6%
Pacific 2	0.7%	1.3%	1.5%	1.5%
South Atlantic	0.1%	0.3%	0.2%	0.2%
West North Central	3.3%	4.5%	5.3%	5.9%
West South Central	0.7%	1.1%	1.3%	1.6%
U.S. Lower-48	**0.7%**	**1.2%**	**1.3%**	**1.5%**

4. Dynamic Flow Modeling of Gas Pipeline Facilities Incorporating Intermittent Dispatch of Gas-Fired Generation

Because wind generation can be extremely variable, the gas-fired generation and the gas use associated with that generation to back-up this intermittency (firming) will be extremely variable as well. Such variability potentially creates different pipeline flow requirements over relatively short periods of time and very different pressure transients[1] across a pipeline system.

This section provides transient pipeline flow modeling to demonstrate how the operation of gas-fired firming generators may affect the operation of natural gas pipeline system. It assesses the potential flow impacts on pipelines that may be created by the intermittency of gas dispatch to support wind generation. The transient flow modeling is an important part of this study as it can help in designing proper pipeline system to better handle the variability of pipeline flow due to wind intermittency.

4.1 Pipeline Configuration for Transient Analysis

ICF subcontracted Gregg Engineering for pipeline flow modeling in order to have the benefit of Gregg's steady state[2] and transient flow models for pipeline systems and their expertise in these matters. For this work, Gregg Engineering's WinTran[3] was used to model the flows and pressure transients across a pipeline system. The modeled pipeline system does not represent any single company's actual pipeline, but is realistic because it includes a number of different delivery points that represent gas utilities, power plants, and industrial customers.

[1] Pressure transient refers to fluctuations of pipeline pressure due to variations of gas flow (or transient flow) over time.

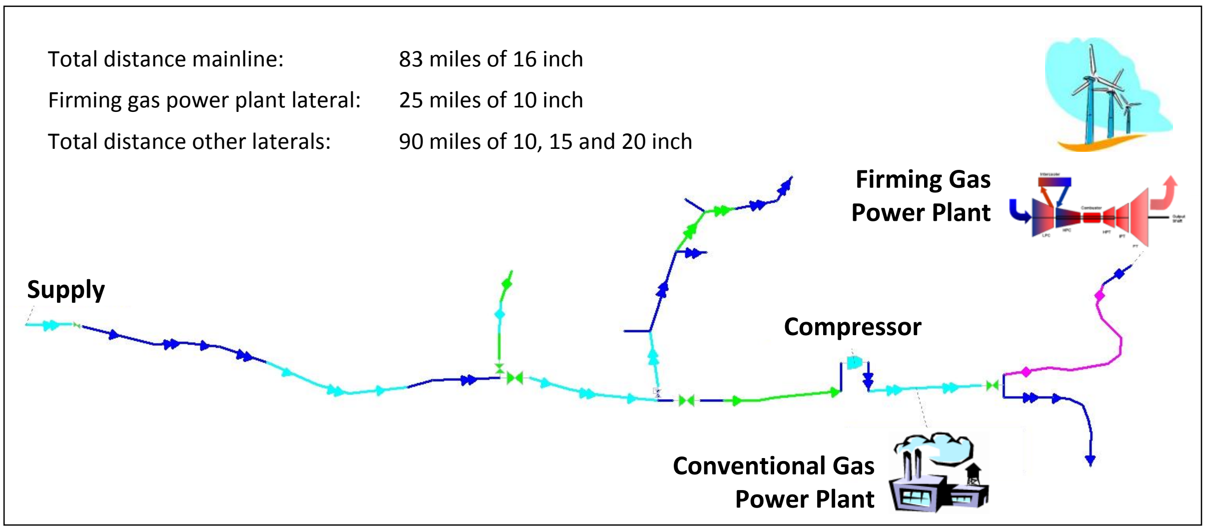
[2] Under steady state condition the gas flows in the pipeline do not vary with time.

[3] Gregg Engineering's WinTran model is a transient pipeline simulator that takes into consideration changing flow or pressure conditions over

time. This unsteady or changing flow or pressure condition can be considered "on" or "off" line simulation that considers dynamic fluid flow characteristics over a specified time span. Detailed information regarding Gregg Engineering and the pipeline flow models are available at www.greggengineering.com.

The system that was modeled, as shown in Exhibit 3-32, includes two gas power plants, a gas turbine to provide firming services for a wind power plant and a conventional gas power plant. The firming gas turbine is a two-block GE LMS100[4] with 200 MW to support wind farm capacity of about 800 MW. The gas turbine heat rate is assumed to be 10,000 Btu/kWh. The left most point of the pipeline system is the only natural gas supply source to meet gas demand for the two gas power plants and for gas utilities and industrial customers along the mainline and pipeline laterals. There is a compressor located upstream of the two power plants that can be turned on to maintain minimum requirement pressure into the gas power plants. Initial steady state pressure of the pipeline system is 720 psia and the minimum requirement for pressure into the power plants is assumed to be 550 psia.

Exhibit 4-1: Pipeline Configuration for Transient Analysis



The base pipeline configuration in Exhibit 4-1 has been designed such that it can handle adequate delivery for firm usage and average gas use for firming wind generation. Under steady state conditions using Modified Panhandle[5] flow correlation, the capacity of the mainline is calculated to be roughly 130 MMscfd for pressure ranges from 550 psia to 850 psia.

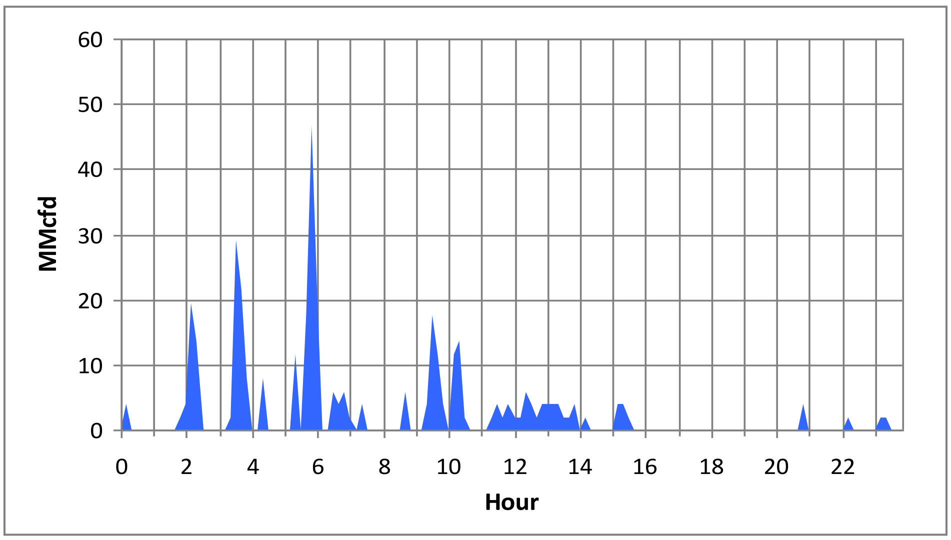
[4] As a part of GE Energy's ecomagination portfolio, the LMS100 offers 100MW of electricity at 44% thermal efficiency with a wide range of operating flexibility for peaking, mid-range and base-load operation with lower start-up emissions and 10-minute starts, www.gepower.com/corporate/ecomagination_home/lms100.htm.

[5] Modified Panhandle correlation is a steady state flow correlation to estimate gas pipeline capacity based on gas physical properties, pipeline dimensions, and pressure range.

4.2 Transient Modeling Scenarios

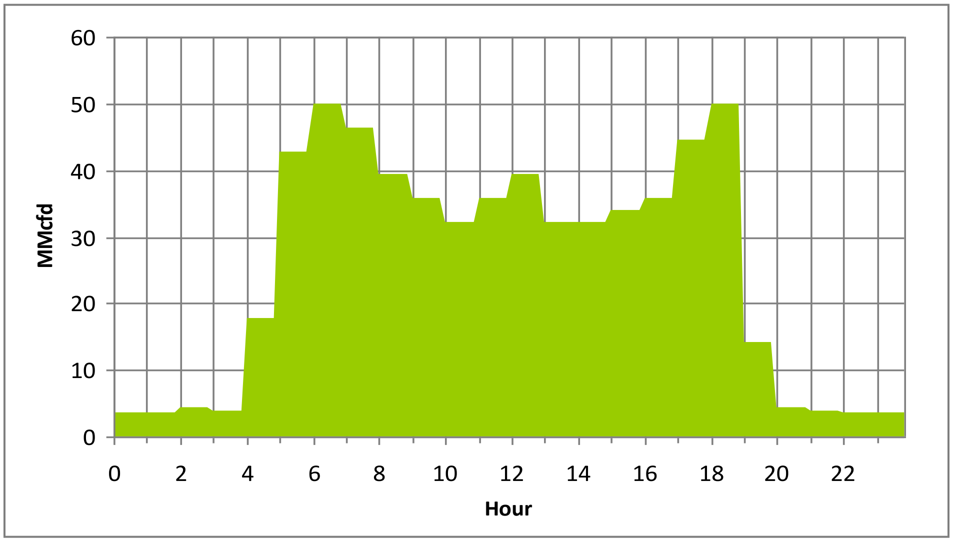
Several transient scenarios have been developed to investigate the feasibility and impact of supplying natural gas to power plants during certain demand periods. A 24-hour WinTran transient simulation was conducted for each of the scenarios. Exhibit 4-2 and Exhibit 4-3 show gas demand profiles for the firming power plant and conventional power plant, respectively. The gas demand profile for firming generation is based on actual historical wind data from the Oklahoma-Kansas region and is constructed using the *10-minute persistence forecast* described in Section 2. The gas demand for the gas utilities and industrial customers along the mainline and pipeline laterals is assumed constant, within the 24-hour simulation period, at a rate of 83 MMscfd.[6]

Exhibit 4-2: Gas Use Profile for the Firming Power Plant



[6] Actual gas demand for the gas utilities and industrial customers may vary throughout the day but it is assumed to be constant to focus the analysis on the intermittency of the wind generation.

Exhibit 4-3: Gas Demand Profile for the Conventional Power Plant



The transient scenarios include two supply nomination schedules at the supply point, a standard 4-nomination window with a 6-hour nomination cycle and an enhanced service with a 1-hour nomination cycle. Because of the unpredictable nature of the wind generation, the supply nomination for the firming gas turbine is set to lag one cycle (or nomination window) where the nomination for the current cycle is set to the average of gas use for firming services from the previous cycle. The one-day forecast of gas demand for the conventional power plant is based on expected electric load for the plant and is assumed relatively accurate. Therefore, no time lag is applied and the gas nomination for the conventional plant is set to average of gas demand forecast for the same cycle. Exhibit 4-4 and Exhibit 4-5 show the supply and demand levels for the 6-hour and 1-hour nomination cases, respectively. The gas supply in the two exhibits represents total nomination for all gas customers which average around 110 MMscfd or 85 percent of the pipeline capacity.

Exhibit 4-4: Natural Gas Supply and Demand for the Standard 4-Nomination Window (6-hour Nomination Cycle)

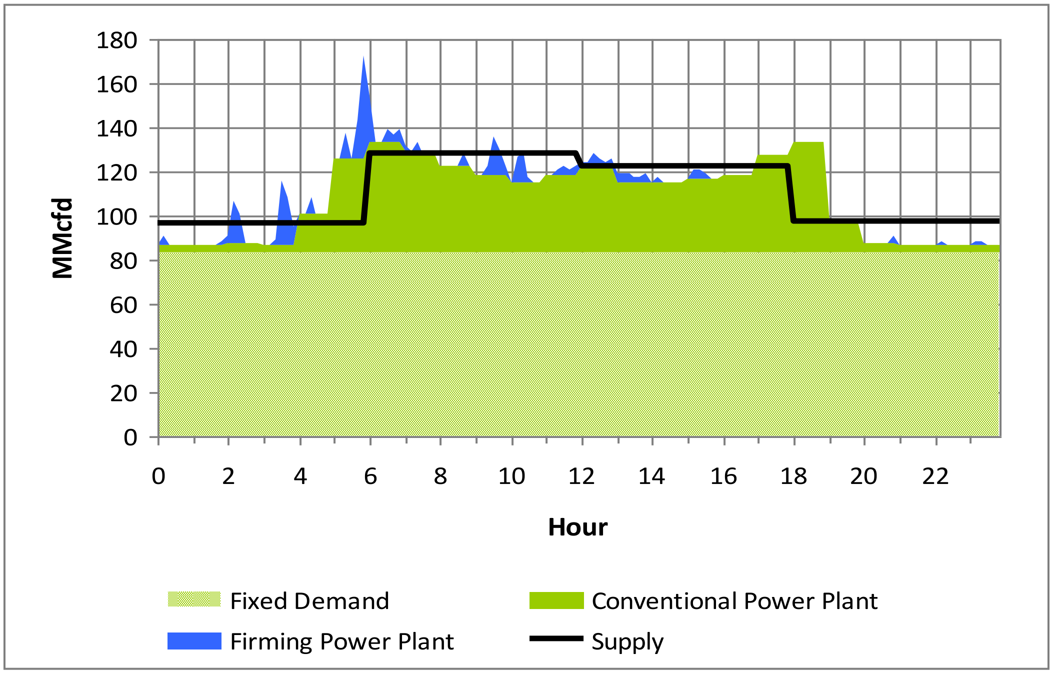
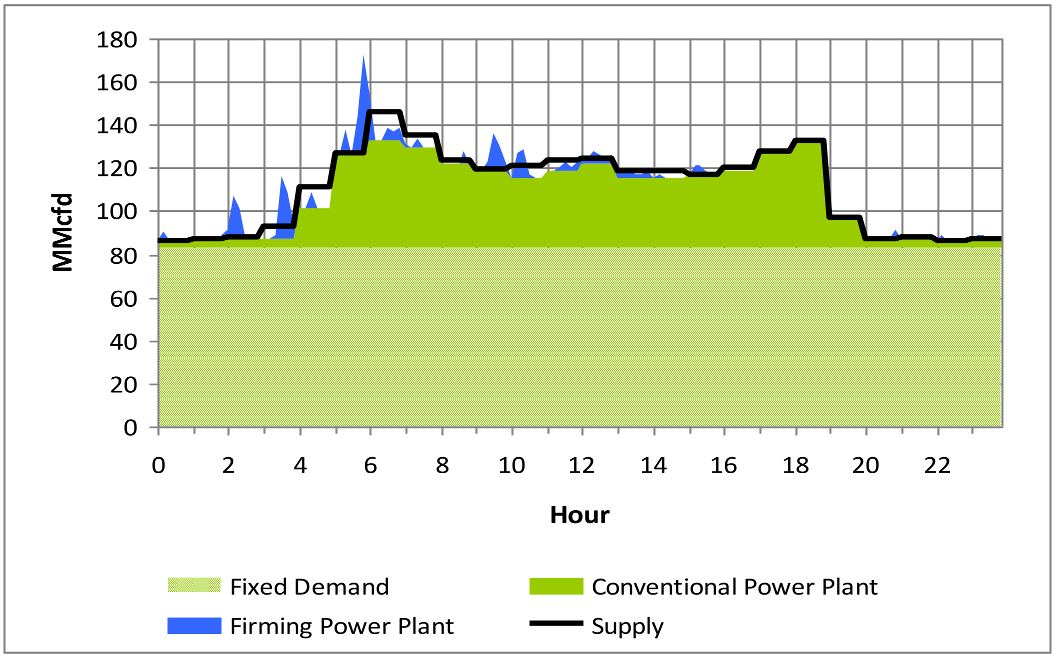


Exhibit 4-5: Natural Gas Supply and Demand for the Enhanced Service (1-hour Nomination Cycle)



Six scenarios have been developed for the pipeline transient analysis based on the natural gas supply and demand profiles in Exhibit 4-4 and Exhibit 4-5, and using the pipeline configuration shown in Exhibit 4-1. The scenarios begin with *survival analysis* to examine the feasibility of the base pipeline configuration under the most extreme conditions. As noted earlier, minimum pressure requirement of 550 psia at the firming gas turbine has been imposed in this feasibility study. The term survival analysis in this context refers to a condition at which the pressure at the firming gas turbine is maintained above 550 psia throughout the simulation. The base pipeline configuration has been designed with the capability of handling flows of natural gas supply and average gas demand including gas use for firming wind generation. The system is expected to be able to maintain pressure within the acceptable ranges for the majority of the firming generation levels. However, the system may not be able to maintain pressure at the firming gas turbine above 550 psia under the most extreme conditions such as at the peak of firming generation.

The survival scenario is followed by five other scenarios. Each scenario requires changes in infrastructure to ensure that the system operates within acceptable pressure ranges. **The infrastructure changes include the use of a larger pipeline lateral connecting the mainline to the firming power plant and the use of compression to support load swings due to intermittency of the firming generations.**

The impacts of employing a shorter nomination cycle to the base pipeline configuration and with changes in the infrastructure are also analyzed. The assumptions for the scenarios are provided in Exhibit 4-6. A 24-hour WinTran transient simulation has been conducted for each of the scenarios and the transient results have been reviewed to determine whether the system can maintain minimum requirement pressure at the firming gas turbine.

Exhibit 4-6: Transient Scenarios

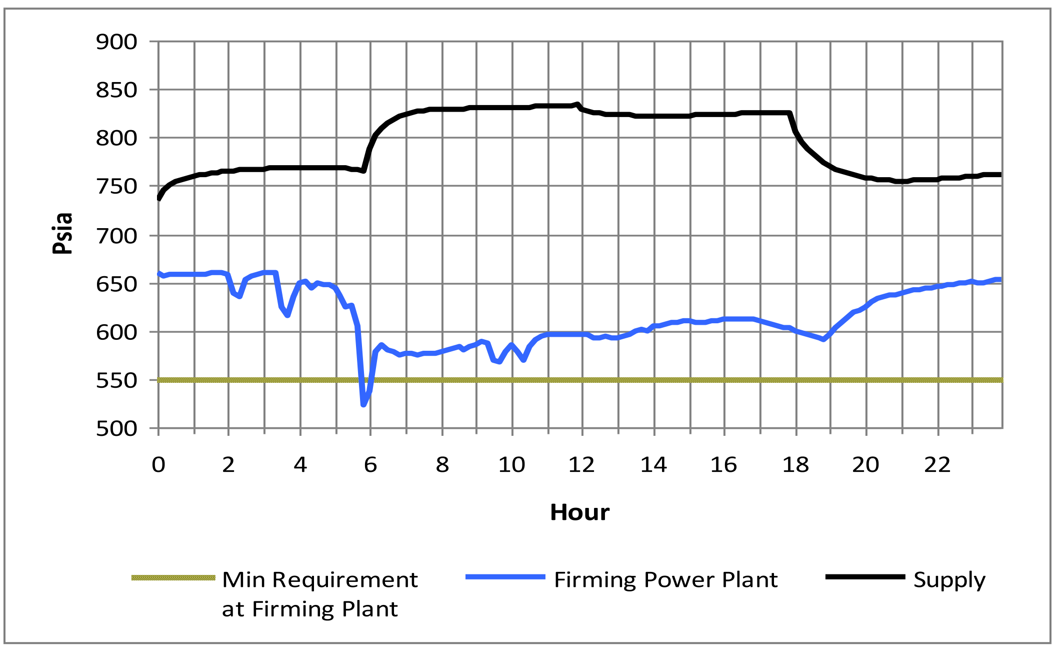
No	Nomination	Lateral Diameter	Compression
1	Standard, 6-hour nomination cycle	10 inch	None
2	Standard, 6-hour nomination cycle	14 inch	None
3	Standard, 6-hour nomination cycle	10 inch	With compression
4	Enhanced Service, 1-hour nomination cycle	10 inch	None
5	Enhanced Service, 1-hour nomination cycle	14 inch	None
6	Enhanced Service, 1-hour nomination cycle	10 inch	With compression

4.2.1 Scenario 1: Survival Analysis (6-hour Nomination Cycle and 10-inch Lateral without Additional Compression)

This scenario is designed for survival analysis for the base pipeline configuration without additional compression. The 10-inch lateral is expected to be large enough to handle gas flow for the firming gas turbine as shown in Exhibit 4-2. However, it may not be large enough to hold sufficient line pack to maintain the minimum pressure requirement at the firming gas power plant when gas demand at the plant spikes to its peak of 47 MMscfd at around hour 6.

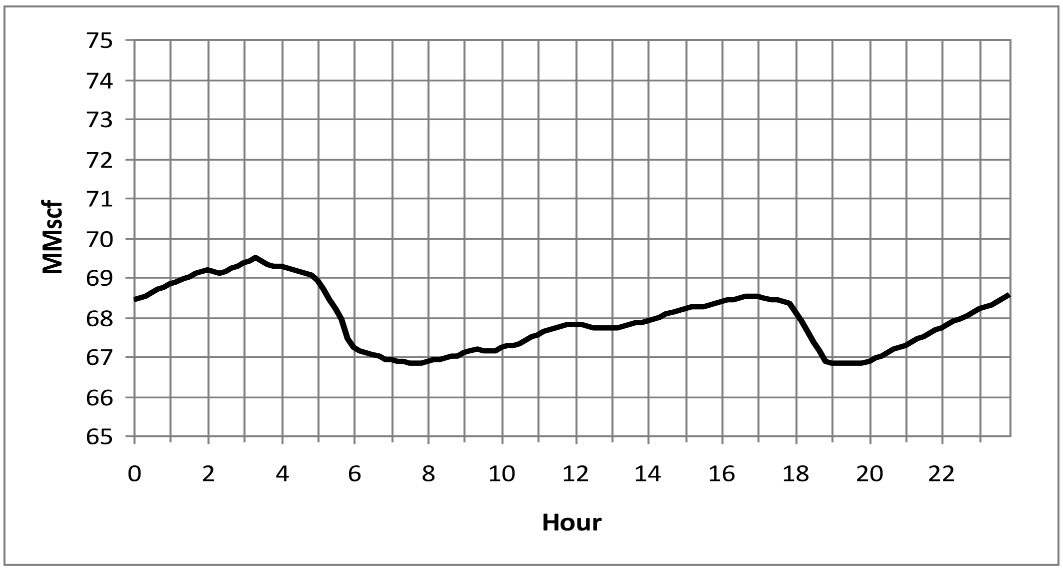
Pressure transient results at the supply point and at the inlet to the firming gas turbine are shown in Exhibit 4-7. Pressure at the firming gas turbine is stable in the first few hours at around 660 psia because no firming generation is required during the period. Firming generation around hours 2 and 4 reduces the pressure by about 25 psia and 45 psia, respectively, but pressure remains well above the minimum pressure requirement of 550 psia.

Exhibit 4-7: Pressure Transient for Scenario 1



The line pack volume profile for the whole pipeline system is shown in Exhibit 4-8. Pressure at the supply point increases in the first few hours due to higher gas supply to the system than total gas consumption, and is reflected in line pack buildup during the period. The total line pack starts to drop after firming generation around hour 3 and drops significantly between hours 3 and 6 due to peak gas consumption at firming plant and large increase of gas consumptions at the conventional gas plant. The system fails to maintain pressure at the firming gas turbine above the minimum requirement at around hour 6 with pressure dropping below 550 psia at the firming plant because line pack is insufficient to support the peak firming gas consumption.

Exhibit 4-8: Total Line Pack Volume for Scenario 1



4.2.2 Scenario 2: Larger Pipeline to Support Load Swings (6-hour Nomination Cycle and 14-inch Lateral without Additional Compression

This scenario is designed to increase the capacity of the system to hold more line pack to support load swings from the firming gas plant. For this purpose, the diameter of the lateral to the firming plant is increased to that of a 14 inches pipeline (from 10 inches). In practice, this can be done by building a loop[7] to provide more line pack capacity. This exercise, however, is assumed to be a design analysis of a new firming infrastructure (pipeline lateral, gas turbine, etc.) and this scenario is modeled by simply changing the lateral size to 14 inches.

[7] Pipeline loop is a parallel pipeline along existing pipeline, or along just a section of it, to increase capacity.

Pressure transient results in Exhibit 4-9 show that increasing the lateral size from 10 inches to 14 inches can reduce the amount by which pressure drops during the periods of high firming generation. This scenario significantly reduces the large pressure drop in Scenario 1 during the peak generation around hour 6. Larger line pack volume as shown in Exhibit 4-10 is able to maintain the pressure at the firming plant above the minimum required pressure of 550 psia. Increasing the lateral size from 10 inches to 14 inches increases the total line pack volume by about 3.4 MMscf.

Exhibit 4-9: Pressure Transient for Scenario 2

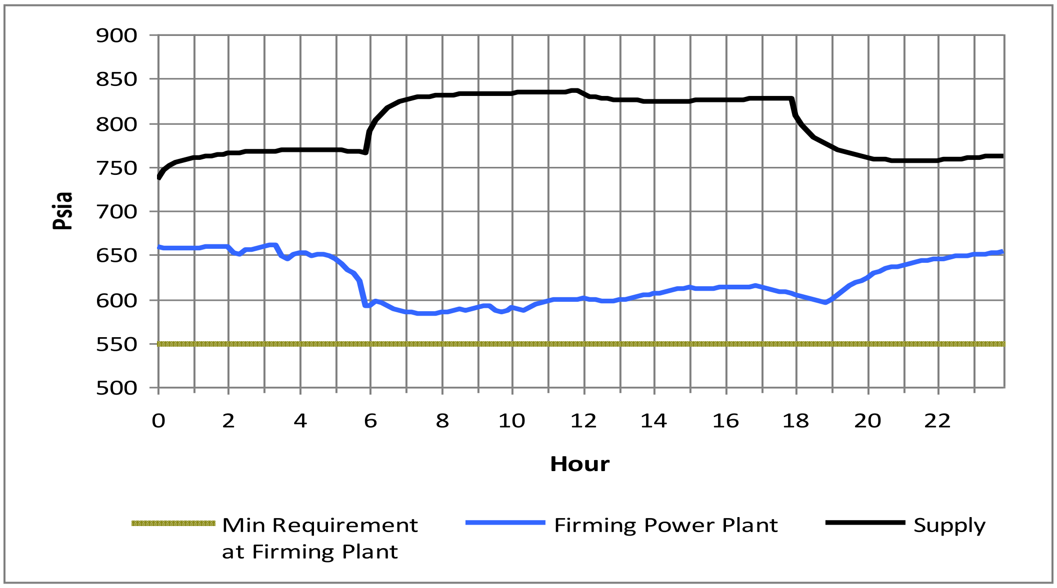
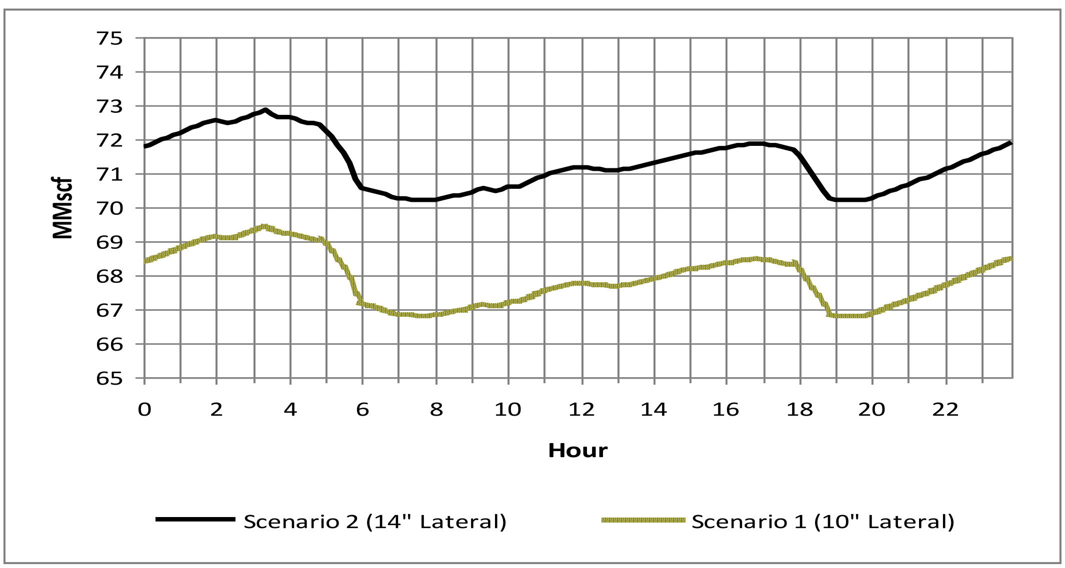


Exhibit 4-10: Total Line Pack Volume, Scenario 2 vs. Scenario 1



4.2.3 Scenario 3: Use of Compression to Maintain System Operating Pressure (6-hour Nomination Cycle and 10-inch Lateral)

This scenario is designed to increase upstream pressure for the two power plants using compression. The pipeline configuration is similar to that in Scenario 1 but with additional compression located upstream of the two power plants that can be turned on and off to maintain minimum requirement for pressure into the power plants. Since the firming gas turbine is connected to the downstream end of the mainline with a 25 miles lateral (Exhibit 4-1), maintaining minimum requirement pressure at the firming gas turbine will ensure adequate pressure to other gas customers located downstream of the compressor. In this scenario, the compressor is scheduled to be activated between hours 4 and 8 in anticipation of the large pressure drop during the peak firming generation period around hour 6. In actual operation, the compressor activation can be automated based on pressure levels at the firming gas turbine. For example, the compressor can be set to turn on when the pressure at the firming plant drops below 575 psia and to turn off when the pressure stabilizes above 650 psia.

Results for this scenario indicate that the use of compression will keep the pressure above the minimum pressure requirement in the firming power plant. As shown in Exhibit 4-11, the pressure drop during the peak firming generation period is reduced to about half of that without compression (Scenario 1.

Exhibit 4-11: Pressure Transient for Scenario 3

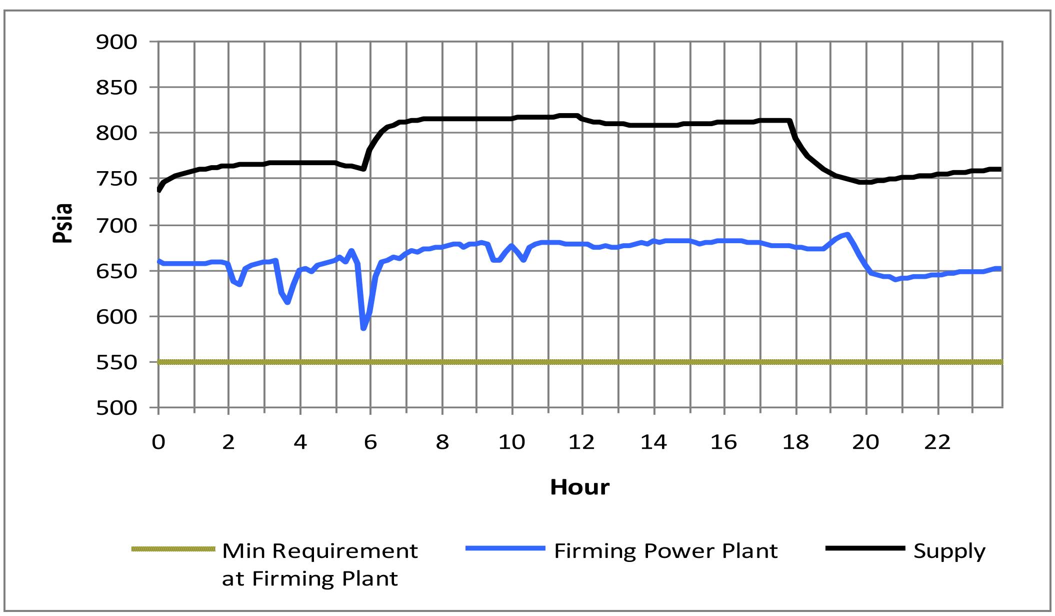
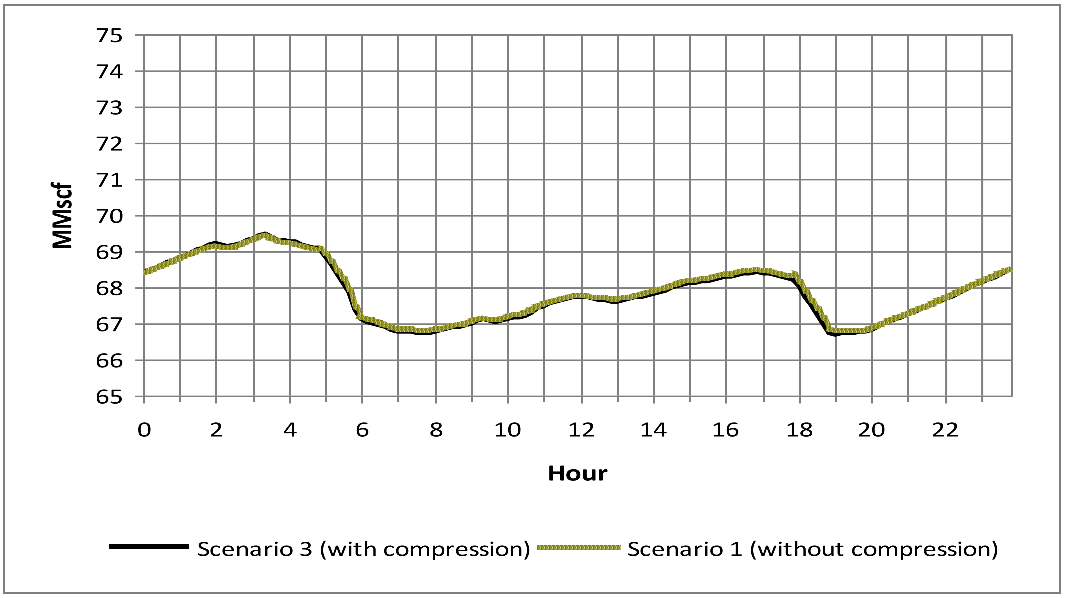


Exhibit 4-12 compares total line pack volume when the system is running with compression and without compression (Scenario 1). The total line pack profiles are roughly the same between the two scenarios because there is no change in total volume in the pipeline system. However, the line pack volume within the 25-mile lateral connecting the mainline to the firming power plant is expected to be larger in Scenario 3 (with additional compression) than in Scenario 1 (no additional compression). This is sufficient for maintaining downstream system pressure above the minimum required.

Exhibit 4-12: Total Line Pack Volume, Scenario 3 vs. Scenario 1



4.2.4 Scenario 4: Shorter Nomination Cycle (1-hour Nomination Cycle and 10-inch Lateral without Additional Compression

This scenario is designed to examine whether shorter nomination cycle can better manage pressure drops during peak firming generations. This appears to be the case because the supply profile of shorter nomination cycle can tightly follow the demand profile for the firming plant shown in Exhibit 4-2. This scenario is similar to Scenario 1, but with an extended 1-hour nomination cycle replacing the standard 6-hour nomination cycle.

The pressure transient results presented in Exhibit 4-13 below, however, suggest that employing shorter nomination cycle does not necessarily provide better pressure management for the firming power plant. The pressure profile is very similar to that in Scenario 1, which has a longer nomination cycle. In fact, the pressure drops during the firming generations between hours 2 and 6 are somewhat higher than those in the 6-hour nomination cycle case due to the way line pack is accumulated or drained according to changes in the supply and demand balance in the system.

Exhibit 4-13: Pressure Transient for Scenario 4

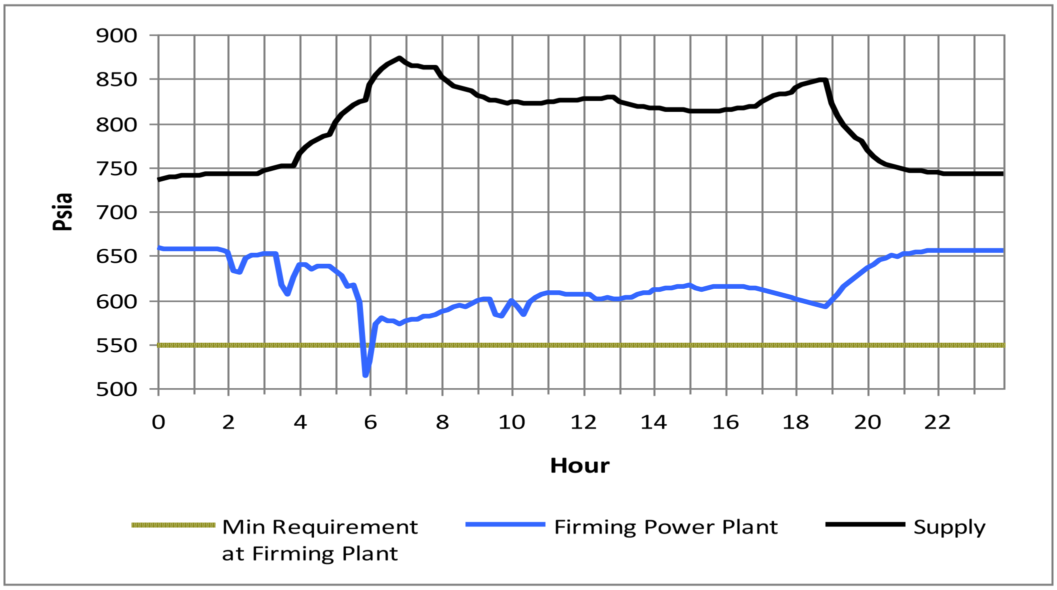


Exhibit 4-14: Total Line Pack Volume, Scenario 4 vs. Scenario 1

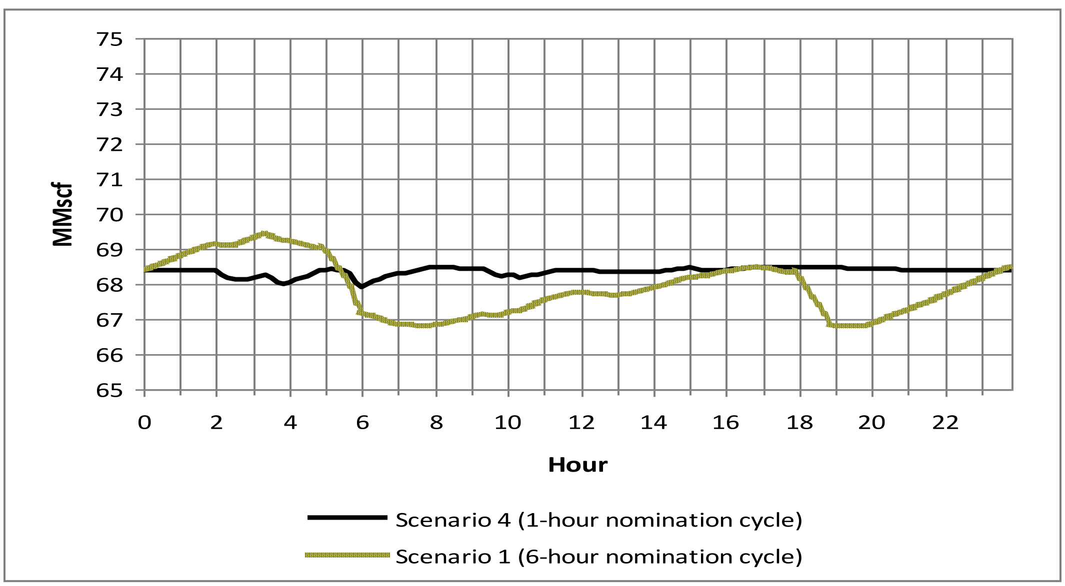


Exhibit 4-14 compares total line pack volume for the two nomination cases. The shorter 1-hour nomination cycle provides more stable line pack compared to that in the longer 6-hour nomination cycle due to the more immediate supply responses in the 1-hour nomination cycle case. However, the condition of oversupply during the first few hours in the 6-hour nomination cycle case (Exhibit 4-4) builds up the line pack does not hold in the 1-hour nomination case. More line pack in the 6-hour nomination cycle case (Scenario 1) during the first 5-hour period is the reason for the lower pressure drops in the same period.

4.2.5 Scenario 5: Shorter Nomination Cycle with Larger Pipeline to Support Load Swings (1-hour Nomination Cycle and 14-inch Lateral without Additional Compression)

This scenario is designed for the same purpose as in Scenario 2, which specified increased system capacity to hold more line pack to support load swings from the firming gas plant. The size of the 25-mile lateral connecting the mainline to the firming plant was increased from 10 inches to 14 inches. This scenario uses the shorter 1-hour nomination cycle instead of the 6-hour nomination cycle used in Scenario 1.

Results for this scenario indicate that increasing the lateral size for the firming power plant will keep the pressure above the minimum requirement (Exhibit 4-15) because of larger volume of line pack (Exhibit 4-16). The pressure drop during the peak generation is significantly reduced. Increasing the lateral size from 10 inches to 14 inches increases the total line pack volume by about 3.4 MMscf.

Exhibit 4-15: Pressure Transient for Scenario 5

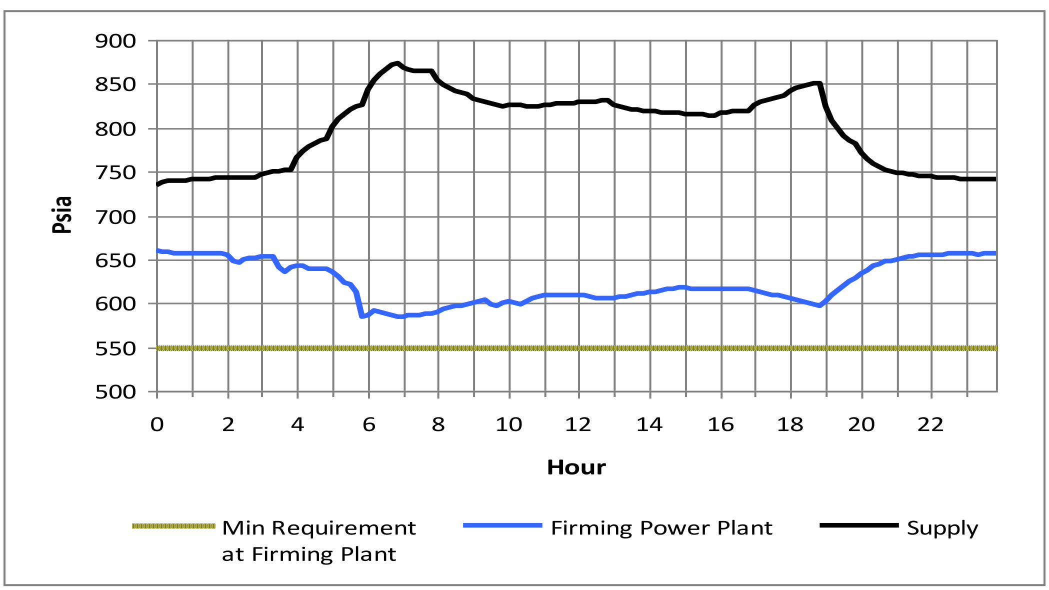
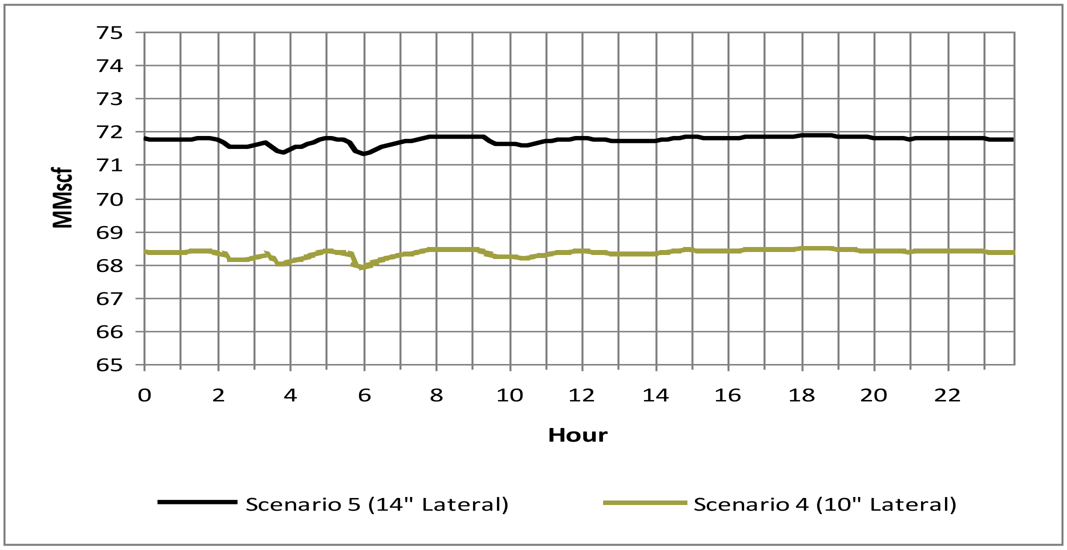


Exhibit 4-16: Total Line Pack Volume, Scenario 5 vs. Scenario 4



4.2.6 Scenario 6: Shorter Nomination Cycle with Compression to Maintain System Operating Pressure (1-hour Nomination Cycle and 10-inch Lateral)

This scenario repeats the Scenario 3 with shorter nomination cycle. The compressor located upstream of the two power plants is scheduled to activate between hours 4 and 8 in anticipation of a large pressure drop during the peak firming generation period around hour 6.

In results similar to Scenario 3, the use of compression is found to be able to keep the pressure above the minimum requirement in the firming power plant (Exhibit 4-17).

Exhibit 4-17: Pressure Transient for Scenario 6

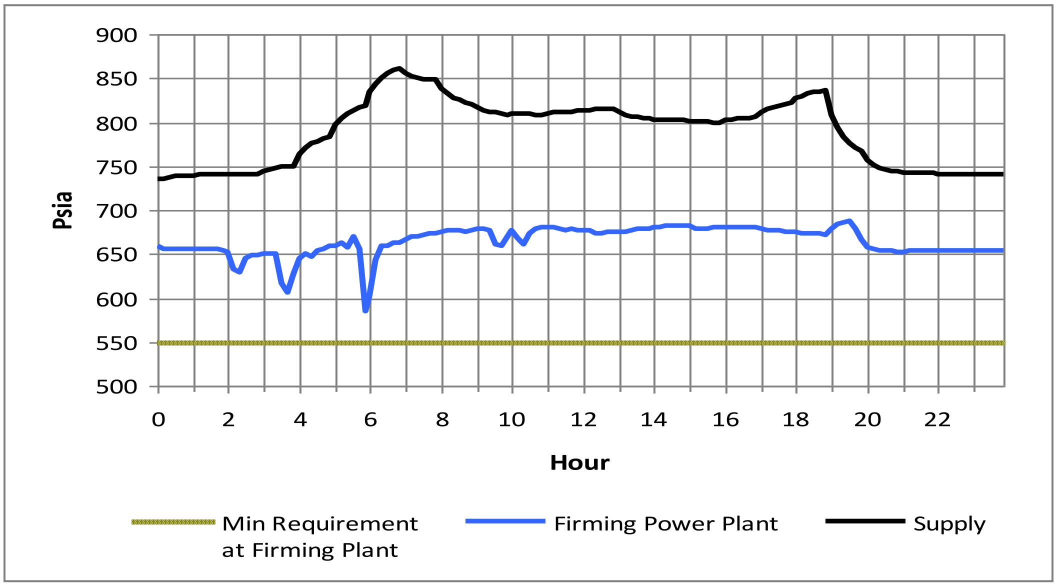
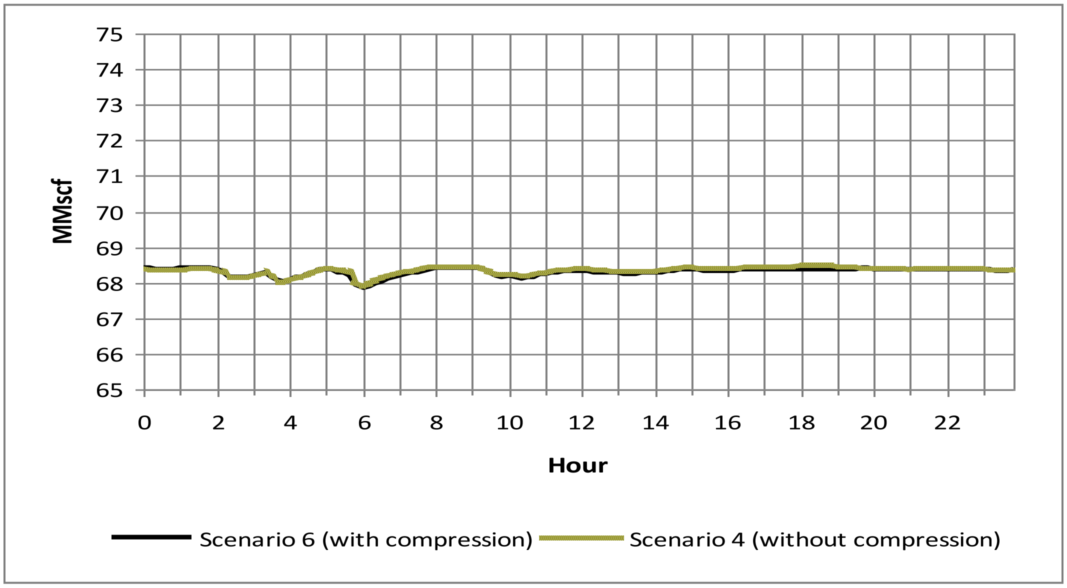


Exhibit 4-18 compares total line pack volume when the system is running with compression and without compression (Scenario 4). The total line pack profiles are roughly the same between the two scenarios because there is no change in total volume in the pipeline system. However, the line pack volume within the 25-mile lateral connecting the mainline to the firming power plant is expected to be larger due to compression and is able to maintain downstream system pressure above the minimum pressure requirement.

Exhibit 4-18: Total Line Pack Volume, Scenario 6 vs. Scenario 4



4.3 Use of Natural Gas Storage to Support Load Swings

Natural gas storage can also be used to support load swings due to intermittency of the firming generation. There is a lot of relatively high deliverability storage being built in California and in other places. This type of natural gas storage acts like natural shock absorbers and can be used to manage gas supplies, especially for intra-hour fluctuations. Having the storage in proximity, however, cannot guarantee or require a shipper to withdraw from storage rather than use flowing gas according to the tariff (this issue will be discussed in further detail in Section 5). In order to make storage more useful to manage short-term system changes, the storage tariffs might need to be modified.

4.4 Summary of Transient Modeling Findings

The results of the transient flow modeling demonstrate that there are engineering solutions to address the local pressure stability challenges associated with the unanticipated variability in the dispatch of gas-fired turbines used to firm wind and other intermittent generation. At the same time, the analysis demonstrates that natural gas pipeline design must be robust in a manner that manages the gas line pack in the vicinity of the plants that are providing firming services. Larger diameter lateral and increased compression can be used, as well as other design changes. Engineering a solution to provide reliable service at a facility will require coordination between the firming generator and the natural gas pipeline company.

Analysis on nomination cycles shows that the shorter 1-hour nomination cycle provides more stable line pack compared to that in the longer 6-hour nomination cycle due to the more immediate supply responses. Having more nomination cycles, shorter than 1-hour, are possible and are expected to provide better line pack stability because the supply profile can closely follow the variation of gas use for firming wind generation.

In addition, various measurement sensors and information management tools can assist management of pressure on the gas pipeline segment. Sensors and information management can alert the operators quickly about changing conditions. Currently, pipelines operate such systems, but in proximity to plants with rapid cycling and less predictable operation, additional systems may be appropriate.

5. Costs of Gas Transportation Infrastructure Needed to Firm Wind Generation and Associated Cost Recovery Issues

This section provides an assessment of natural gas infrastructure that could be needed to support the firming of wind generation. The section begins with a brief review of the natural gas infrastructure requirements needed over the next 20 years, as projected in a 2009 INGAA Foundation report, prepared by ICF, *Natural Gas Pipeline and Storage Infrastructure Projections Through 2030* (Infrastructure Report).[1] This section next examines the incremental amount of natural gas infrastructure that could be needed for firming requirements of wind generation during the next 15 years and potential cost recovery issues associated with that infrastructure.

5.1 Base Line Natural Gas Infrastructure Requirements

In the 2009 Infrastructure Report, ICF determined that gas consumption in U.S. and Canadian natural gas markets would grow from near 27 Tcf in 2008 to between 31.8 and 36.0 Tcf by 2030, largely driven by growth in gas-fired power generation. While that study considered many different factors that would affect gas use in power generation over time, it did not include a detailed investigation of the intermittent nature of wind generation and the impacts that it could have on gas use and gas infrastructure requirements over time.

Nonetheless, the study projected significant need for additional midstream infrastructure in natural gas markets in the foreseeable future. In the study, 2009 transmission pipeline capacity between major regions throughout the U.S. and Canada was found to be approximately 130 Bcf per day. The study further found that, by 2030, the need for new interregional natural gas transport would likely increase by between 21 and 37 Bcf per day.

Some other key results from the study are as follows:

- 28,900 to 61,600 miles of new gas transmission pipeline would be needed from 2009 through 2030,
- 6.6 to 11.6 million HP of new gas transmission pipeline compression would be needed,
- 371 to 598 Bcf of new working gas storage capacity would be needed,
- 15,000 to 26,000 miles of new gathering pipeline would be needed,
- 20 to 38 Bcf per day of new natural gas processing capacity would be needed, and
- 3.5 Bcf per day of new LNG import terminal capacity would be needed.

[1] *Natural Gas Pipeline and Storage Infrastructure Projections Through 2030*, provided by ICF International to the INGAA Foundation, September 25, 2009.

The projected midstream infrastructure will have a cumulative capital expenditure ranging from $133 to $210 billion from 2009 through 2030, equating to annual expenditures ranging from $6 to $10 billion. This need for new infrastructure would be driven predominately by a shift in production from mature basins to areas of unconventional or frontier natural gas production and the growth in gas-fired power generation.

5.2 Additional Gas Transportation Requirements

The projected changes in wind generating capacity documented in Appendix 2 and Section 4 suggests that there could be significant additions in natural gas infrastructure to accommodate firming generation, particularly adding new or increasing capacity on laterals to gas plants in some regions and locales. These estimates are shown in Exhibit 4-18.

Exhibit 5-1: Incremental Gas Transportation Capability Needed for Deliveries to Firming Plants, 2010–25

Region	Incremental Gas Power Plant Capacity for Firming (GW)	Incremental Transport Capability Required to Support Deliveries to Firming Plants (Bcfd)	Estimated Capital Costs for Incremental Transport Capability (Billion $)		
			Low Assuming $100/kW	Average Assuming $400/kW	High Assuming $700/kW
East North Central	2.6	0.6	0.3	1.0	1.8
East South Central	0.0	0.0	0.0	0.0	0.0
Mid-Atlantic	1.1	0.3	0.1	0.4	0.8
Mountain 1	3.9	0.9	0.4	1.6	2.8
Mountain 2	0.7	0.2	0.1	0.3	0.5
New England	0.8	0.2	0.1	0.3	0.6
Pacific 1	1.2	0.3	0.1	0.5	0.8
Pacific 2	1.3	0.3	0.1	0.5	0.9
South Atlantic	0.6	0.1	0.1	0.2	0.4
West North Central	3.3	0.8	0.3	1.3	2.3
West South Central	5.7	1.3	0.6	2.3	4.0
U.S. Lower-48	**21.2**	**4.9**	**2.1**	**8.5**	**14.9**

As noted earlier, the need for reliable backup for renewable generation will require development of some form of electricity storage or gas-fired generation and its supporting infrastructure. Since electric storage applications are generally more expensive and less commercially proven when compared with gas-fired generation as a means of firming intermittent renewables generation, ICF assumed for purposes of this report that gas-fired generation would be relied on exclusively for firming wind generation.

ICF estimates that about 33 GW of new gas-fired generation could be needed across the U.S. to back up wind generation over the next 15 years and almost 5 Bcfd of new delivery capability could be needed to support gas transport to these firming power plants over the same time period.[2]

The total capital expenditure for gas transportation infrastructure associated with these gas-fired generation plants is estimated to range from about $2 billion to nearly $15 billion with an average capital outlay approaching $9 billion. Annual expenditures will range from $100 million to $1 billion, with an average annual expenditure of about $600 million.[3]

The gas transportation infrastructure will include pipeline laterals directly to each power plant; any needed mainline pipeline expansion including additional compression, and any new gas storage facilities that could be used to support the plant. Much of the uncertainty over the range of infrastructure capital costs is due to cost differences among projects including regional land and construction cost differences and differences in the size and specifics of the projects needed to support the power plants. For example, some laterals may need to be sized larger and/or longer than other laterals, which will increase costs, due to the specific location of the firming power plant vis-à-vis the location of the pipeline's existing infrastructure. The pipeline's existing design and operating conditions will also determine whether the incremental deliveries to the firming generator could be supported without substantial upgrades to the existing pipeline facilities.

These costs range between 1 and 10 percent, and average about 5 percent, of the total midstream infrastructure costs identified in INGAA's 2009 report. Since firming of renewables generation was not considered in that report, these costs should be viewed as *incremental* expenditures above and beyond the costs provided in that report. This level of incremental costs is not insignificant and should not be dismissed as trivial.

5.3 Cost Recovery Issues for Infrastructure Relied on for Firming Services

Long-lived, capital-intensive investments such as gas-fired generation, gas pipelines, and gas storage need to have cost recovery mechanisms that foster sufficient investment in all the required elements of the system. For merchant generation, cost recovery is achieved through a competitive position in the market where the generator's capital investment and return is recovered by generating electricity below the marginal cost of electricity in the market. Contractual relationships such as purchase power agreements between buyers and sellers of firming power can be used to manage market risk.

[2] The regional estimates in this exhibit have been derived by assuming that the heat rate of all gas plants providing firming services is 10,000 Btu/kWh, as mentioned in Appendix 2.

[3] These values have been determined by assuming a range of $100 up to $700 per kW with an average value of $400 per kW of gas capacity for the capital outlay needed for gas transportation infrastructure required to provide reliable gas transportation service to each power plant.

With the growth of gas-fired generation that has occurred over the past decade, pipeline operators have worked to address the challenges associated with meeting the pressure, ramping, and volume requirements of gas turbines and combined cycle facilities. As the amount of gas fired-generation increases on a pipeline, the ability to use line pack and manage pressure variations will become significantly more difficult. Communications between the pipeline, generators, and the operators of the electric grid about when the generator will be dispatched, for example, will become even more essential and compliance with the nomination, scheduling, confirmation, and imbalance provisions of the pipeline tariff will become an even more essential component of operation.

On most pipelines, the pipeline tariff requires shippers to take service on a ratable 1/24 hour take, subject to a margin of error of 1 to 4 percent. Some pipelines have enhanced tariff services to provide for additional flexibility to address the changing intraday requirements of these shippers. Most pipelines serve gas-fired generation shippers under standard firm and interruptible transportation tariff services and have maintained the North American Energy Standards Board (NAESB) nomination cycles. Pipelines often provide their customers, including generators, the ability to take gas on a non-ratable basis (i.e., at an hourly rate of take greater or less 1/24th of the daily contract quantity specified in the tariff) or at enhanced pressures when pipeline operations permit. Pipelines can provide such flexibility, if not unduly discriminatory, and as long as it doesn't affect the pipeline's other delivery obligations. Flexibility has its limits, however, and there are times when a pipeline cannot accommodate a shipper's special requirements. Despite the operational flexibility embedded in the pipeline system, the rapid ramp up and ramp down of firming generators can create major challenges to pipeline operations, particularly when the generator ramps up or down with little or no notice to the pipeline.

Gas-fired generators often utilize a mix of firm and interruptible gas transportation services. In addition, gas-fired generators participate in the secondary market as both buyers and sellers of released pipeline capacity and gas. In more constrained regional markets, gas-fired generators that have obligations to generate through purchase power agreements or reliability-must-run obligations rely principally on firm service. Many peaking gas-fired generators only subscribe for interruptible capacity since they are called on only when needed and do not want to commit to pipeline reservation charges which must be paid regardless of how often the customer uses the pipeline system. Since peaking gas-fired generators typically generate power during the summer months when pipeline capacity is more available, they take the chance that the less-costly pipeline interruptible transportation will be available. By definition, interruptible transportation service is interruptible. A pipeline cannot guarantee that a generator relying on interruptible transportation service will have gas deliverability when a plant is called upon with little notice. As a result, firming generation will likely require firm gas transportation service to fill the role reliably.

Unlike the electric network where generation capacity is constructed to maintain reserve margin, natural gas pipeline transportation capacity is constructed to serve firm requirements with no additional reserve capacity available to provide interruptible transportation service when firm shippers are utilizing their firm rights. As a result, a gas-fired generator, or any shipper, is never assured that interruptible transportation or capacity release will be available on call, particularly during high demand periods.

The key aspect of firming generation is its ability to respond on short notice. In effect, the firming capacity must be an incremental investment above and beyond base, intermediate, or peaking units that are deployed to meet normal diurnal electricity demand. As a result, the costs of these units – both the capital cost of the generation units and the capital cost of pipeline facilities and the cost associated with contracting for the appropriate amount of transportation service that meets the generator's operational needs, including possibly storage – may need to be directly associated with the cost of the wind generation itself. For the system to operate, the firming capacity must be a reserve that can be called upon when needed. There are at least two models whereby this can be achieved.

- A requirement could be placed upon the wind generator to obtain directly a sufficient quantity of firming capacity to meet a calculated reserve requirement. The wind generator would be responsible for negotiating a capacity payment for the firming service sufficient to cover the cost of the generation and any fuel procurement costs (including any gas pipeline and storage costs).

- The responsibility for investment in firming infrastructure could be socialized through the electric transmission and distribution network, either through the Regional Transmission Organization (RTO), Independent System Operator (ISO), or the electric utility. Once again, the cost associated with fuel procurement including any gas pipeline facility and storage costs should be considered a key component of the firming infrastructure.

In each of the models suggested, cost allocation follows the basic principle that cost recovery should follow cost causation. The firming pipeline infrastructure is a necessary component to back up the intermittent generation. There is a need for the firming service that is inherent to the renewable generation itself. Omission of the costs of firming in the cost of wind and other intermittent renewable generation is an understatement of the actual cost of the generation choice.

5.4 FERC Notice of Proposed Rulemaking to Integrate Variable Energy Resources

On November 18, 2010, FERC issued a Notice of proposed Rulemaking (NOPR) to reform the *pro forma* electric utility Open Access Transmission Tariff (OATT) to address issues presented by variable electric energy resources (VERs) such as wind and solar renewable generation.[4] The proposed rule would do the following:

(1) Require public utility transmission providers to offer intra-hourly transmission scheduling;

(2) Incorporate provisions into the pro forma Large Generator Interconnection Agreement requiring interconnection customers whose generating facilities are variable energy resources to provide meteorological and operational data to public utility transmission providers for the purpose of power production forecasting; and

(3) Add a generic ancillary service rate schedule through which public utility transmission providers will offer regulation service to transmission customers delivering energy from a generator located within the transmission provider's balancing authority area.

In the NOPR, FERC finds, on a preliminary basis, that "requiring transmission customers to adhere to hourly schedules may be unduly discriminatory and result in the inefficient use of transmission and generation resources to the detriment of customers." The Commission also finds that "a lack of VERs power production forecasts may unnecessarily increase the volume of regulated reserves that are required" for reliability and provides transmission providers with tools required to obtain such forecasts.

While not yet a final rule, the NOPR indicates that FERC understands that intermittent generation presents a series of dispatch issues that are different from other generation sources and that there are inherent deviations between forecasted output and actual output, even within short time periods. Importantly, the NOPR provides for a rate schedule that allows a public utility transmission provider "the opportunity to recover reserve service costs associated with the management of supply side variability." Moreover, the NOPR states that, "as a general matter, the Commission agrees that regulation reserve costs should be allocated consistent with cost causation principles," but the Commission does not "propose to mandate a particular method for apportioning" the costs.

While the NOPR does not discuss gas-fired generation, specifically, or use the terminology of "firming service" in the manner used in this report, the "regulation reserve service" described in the NOPR is similar in concept. The use of gas-fired generation or any other technology used to manage supply reliability will be affected by the ultimate outcome of the design of these tariffs, which the NOPR envisions will be developed by the individual electricity transmission providers. Accordingly, this report suggests that the Commission, state public utility commissions, RTOs and others consider gas-fired firming generation and all the costs associated with it including the necessary natural gas transportation costs as a cost of regulation reserve service just as other supply side management costs and these costs should be allocated to those receiving the natural gas service consistent with cost causation principles.

[4] Docket No. RM10-11-000

5.5 Cost Recovery of Natural Gas Pipeline and Storage Infrastructure Associated with Firming Intermittent Renewable Generation

5.5.1 Costs Incurred for Facilities in Close Proximity to the Generator

The dynamic flow modeling presented in this report demonstrates that there are engineering solutions to address the local pressure stability challenges associated with the unanticipated variability in the dispatch of gas-fired turbines used to firm wind and other intermittent generation. In order to do so, however, natural gas pipeline design must be robust in a manner that manages the gas line pack near the plants that are providing firming services. This can include larger diameter pipe and increased compression for enhanced flexibility, as well as various measurement sensors and information management tools that can assist management of pressure on the gas pipeline segment in real time. Sensors and information management can alert the operators quickly about changing conditions. Currently, pipelines operate such systems, but adding these capabilities in proximity to plants with rapid cycling and less predictable operation may be appropriate.

The need for additional information regarding the operating conditions can go beyond the pipeline system. This point is also highlighted in the February 3, 2011 report sponsored in part by the INGAAA Foundation entitled *Natural Gas in a Smart Energy Future*. Pipeline operation and the integrity of both the electric and gas network systems can be improved if the pipeline receives more real time information about the operation on the electric grid – including real time notice of when the gas-fired generator will be dispatched. Today, much of this information still relies on phone calls between generating plant operators and pipeline operators and occasionally the regional transmission operators. Additional information systems that are automated could improve the ability to address system changes prior to the development of critical events.

These design and operational changes, however, have cost implications for the pipeline. The incremental cost of larger diameter pipe is substantially higher than the small increase in size might suggest. If the pipeline must install additional compression in proximity to the gas-fired generator, and those costs are allocated to and recovered from the generator, the generator's costs will be even greater.

In the case where a pipeline constructs a new lateral dedicated to a firming power plant, the issue of cost recovery for the incremental physical requirements is greatly simplified. Under the FERC's incremental rate policy, the shipper lateral will be constructed with a clear understanding that the shipper will bear the cost responsibility for that lateral and any related mainline capacity expansions.

Where an existing gas-fired generator contracts with a pipeline for firming requirements, however, the problem is more complicated. First, the operation of the plant may require the pipeline to invest in additional mainline compression or dedicate additional line pack to a portion of the pipeline system in order to serve the generator. The cost of this investment, however, would be harder to assign only to the specific shipper unless there is a specific tariff service category designed for the particular class of service since the benefits of the additional compression may be enjoyed by other or all system customers. It is likely that a firming shipper would argue that there are system-wide benefits in terms of pressure management that should be borne by all of the pipeline's customers.

5.5.2 Illumination on the Unit Cost of Gas Transportation for Gas Used for Firming

One of the inherent problems with gas transportation assets used for firming purposes is that they will be used only sporadically and lightly. They are only used when generation falls below expected or forecast generation. As noted earlier, since gas transportation assets relied on solely for firming wind generation will be used at an average annual load factor of about 15.6 percent (see Section 2 above), unit costs for gas transportation assets dedicated to firming intermittent generation will be quite high relative to higher load factor services.

Consider, for example, a lateral dedicated to a gas-fired power plant that is used solely for firming wind generation. Assume that the lateral is designed to deliver up to 25 MMscfd, sized appropriately, to serve the maximum requirements of the plant at full utilization. Assume also that the incremental annual revenue requirement for service on the lateral is $912,500. If the generator uses its full contractual amount, then the tariff rate would be 10 cents per MMBtu, a value determined by dividing the revenue requirement by the amount of gas transported along the lateral at full utilization over the course of a year (**Error! Reference source not found.**).

Exhibit 5-2: Unit Cost of Gas Transportation on a Lateral Dedicated to a Gas-fired Power Plant Used Solely for Firming Purposes

Gas Plant Daily Requirement	Annual Maximum Volume at 100% Load Factor	Revenue Requirement	100% Load Factor Rate	Unit Cost at 15% Utilization	Unit Cost at 5% Utilization
MMcfd	MMcf per Year	Dollars	$/MMBtu	$/MMBtu	$/MMBtu
25	9,125	$912,500	$0.10	$0.67	$2.00

If, instead, the generator utilizes the lateral only 15 percent, then the unit cost of transport (not the tariff rate but the actual unit cost of transport) along the lateral rises to 67 cents per MMBtu, because the revenue requirement is spread over less units of gas. If the generator utilizes the lateral even less, say to merely 5 percent annually, then the unit cost of transport rises to $2.00 per MMBtu, a value that is 20 times greater than the unit cost at full utilization. In short, the unit cost of transportation on the lateral is inversely proportional to load factor. Admittedly, project developers will do their best to design generation projects to achieve better utilization, which means that plants will be built for multiple purposes, and not just solely for firming purposes. Nevertheless, this unit cost issue further complicates the cost recovery of assets used to any extent for firming purposes. It highlights the issue of whether a low load factor shipper, such as a firming up generator, would contract for sufficient pipeline capacity and pay for the construction of a lateral, at a minimum, in order for a facility to be built.

Furthermore, the unit cost of the transportation upstream of the lateral also would increase for the firming generator shipper. In the case of the upstream capacity, the shipper with low load factor utilization has the ability to release capacity for periods and thus recover some of his costs. It is likely that most firming generator shippers would seek the services of gas marketers or asset managers who can use their asset and supply portfolio to service the firming shipper, for a price. Nonetheless, the cost impact on firming generation shippers remains significant in instances where they need firm pipeline services.

The implications of the load factor effect on gas transportation costs to the cost of intermittent generation are critical. Moreover, to date, these cost elements largely have been ignored. Assuming a $6.00 commodity price for gas at the receipt point of the lateral, an incremental transportation rate of $2.00 will have a noticeable impact on the cost of electricity generated by the unit located along that lateral. Nonetheless, this $2.00 cost is a legitimate cost that should be considered an essential element of the cost to firm up renewable generation.

5.6 Enhancing Line Pack to Manage Variable Deliveries to Gas-fired Generation Used for Firming

The broader issue presented to a pipeline by the firming requirements for intermittent wind and other renewable generation is the overall management of line pack on the system. Pipelines will need to be prepared for the quick ramp-up of a firming generation plant and this typically would be done by increasing the pressure in the vicinity of the power plant in anticipation of the plant coming on-line. Absent this high pressure line pack in the vicinity of the generating plant the gas turbine can trip and drop off the electric grid. If the pressure on the pipeline is compromised by gas requirements from a firming generator that have not been scheduled and confirmed, the pipeline may have to restrict flow to the generator in order to maintain the scheduled and confirmed volumes to other shippers or to protect the integrity of the pipeline system. In either case, the result is the same. The smooth operations and reliability of the electric and gas systems are compromised. In such an instance, the loss of pressure harms all of the shippers in the vicinity, including those that are operating in compliance with the nomination, scheduling and imbalance norms.

Ultimately, the pipeline may be required to maintain additional line pack in the vicinity of a firming gas generator in order to maintain the reliability of both the gas pipeline and the electric grid. To do this, the pipeline would require additional compression to maintain higher pressures locally and a correspondingly larger average volume of gas in the pipeline to serve as line pack. Because additional compression is required, the pipeline's fuel costs will increase.

There are costs associated with maintaining a reliable system. These system costs include:

- Maintaining additional gas for line pack in the pipeline – this gas could either be acquired directly by the pipeline or collected through the same mechanism as fuel and Lost and Unaccounted for gas (LAUF). The latter mechanism, however, could be insufficient on many pipelines under current tariffs and/or settlement rates where these recovery volumes or percentages are set by agreement and are recovered from all shippers. In a sense, the increase in operating line pack can be considered a one-time incurrence of incremental costs.

- Compression to maintain pressure for the line pack – These costs could be associated with increased operation of compressors, which would increase maintenance costs, or with the installation of new compression.

- Compressor fuel – Unlike the addition of the gas for maintaining increased line pack, the increase in compressor fuel use is an ongoing expense. Moreover, the increase in compressor fuel may not be limited to the compression in close proximity to the plant, but may extend system-wide. The fuel used for compression is not linear in relation to throughput. Rather, it takes more compressor fuel to increase pressure in a pipeline that is running at higher load factors than it does when there is slack capacity. On many pipeline systems, all shippers within the rate zone are responsible for the same system average fuel and LUAF volumes. In this instance, the cost of the increase in fuel required to manage the firming load would be borne, in part, by shippers that did not cause the increase in fuel. Regardless, the recovery of these additional fuel costs likely will be contentious among shippers and among shippers and the pipeline.

5.7 Utilizing Storage to Manage Pressure

Natural gas storage capacity in close proximity to the firming generator offers a physical option to manage pressure fluctuation resulting from intermittency. The requirement to manage the pressure in the pipeline in proximity to the plant and throughout the system is the combination of compression and a source of gas. Since the gas is moving at a speed of 15 to 30 miles per hour in the pipeline and the pressure changes (waves) are moving much more quickly, the source of gas must be located close enough to the line segment where pressure may be dropping to fill the line pack. Compression with no source of gas on the inlet side of the compressor is not sufficient to manage pressure.

If gas can be withdrawn from storage close to the firming plant, either directly upstream of the compressor or utilizing compression at the storage facility, pressure can be stabilized and managed as the firming plant ramps up.

The ability to utilize storage, however, relies on several factors:

(1) A suitable geologic site for storage must exist in close proximity to the firming generation

(2) There must be other markets that also can be served by the storage service. Given the relatively small requirements for gas for firming and the economics for storage development, it is unlikely that storage would be developed solely to serve a firming generation plant. If it were, it would be extremely expensive. Alternatively, the imbalance penalties for a generator would have to be so high as to justify storage that is largely dedicated to the management of imbalances or new local, small- scale storage technologies would have to be commercialized.

(3) There must be assurance that gas is withdrawn from the storage facility when it is needed and not delivered by the pipeline to another location, even if the service tariff were to allow such delivery for balancing purposes.

The third point presents particularly difficult issues for a pipeline. Under FERC regulation, a pipeline cannot impose differentiated service conditions to shippers in the same category of service[5]. If the service tariff allows the shippers options for where gas can be delivered to the pipeline, the pipeline would have difficulty requiring a shipper to restrict deliveries to a particular point on a routine basis.[6]

One potential option would be to create a specific tariff rate schedule for the operation of storage used in conjunction firming generation. That would assure that the gas is delivered when and at the point where it is required. Broader changes in the basic tariffs for storage and transportation that restrict the flexibility for receipt and delivery points that shippers receive consistent with FERC Orders 636 and 637 are not a viable option since they would undercut the basic operation of the gas commodity market that exists today.

As a result, the pipeline itself could be the only party that could hold some storage capacity to use to meet firming requirements. Additional storage operated by the pipeline could in some instances be a viable option and greatly assist the management of line pack. This may not be an optimal solution for all pipelines and would certainly present cost recovery and cost allocation issues. These issues are discussed in the broader context of all of the costs of firming below.

[5] While FERC policy allows for the negotiation of rates, the policy explicitly denies the authority to offer negotiated terms and conditions of service that deviate from the tariff.

[6] A pipeline may, under certain critical conditions, direct shippers to use certain points or restrict certain points, but that authority is not designed for daily operation.

5.8 Cost Allocation and Recovery

The allocation of costs associated with the infrastructure needed to provide service to the firming plants may present a number of contentious issues to a pipeline and their shippers in rate and fuel recovery proceedings. A basic tenet in rate design for natural gas pipelines is that cost recovery should follow cost responsibility. In lay terms, that means that the rates charged to a shipper should recover all of the costs that the shipper causes to be incurred. This includes the portion of "joint and common costs" (those shared with other shippers) as well as costs for which the shipper is solely responsible.

In practice, however, cost allocation and cost recovery can be much more complicated. First, with the exception of a new green field pipeline project, there has already been a cost allocation for rates that FERC has found to be just and reasonable. This establishes a benchmark. Shippers that have historically taken service from the pipeline under conditions that did not require the change in operating conditions (which required an investment in additional infrastructure to meet the changed operational needs) will almost certainly argue that it is inappropriate for existing customers to bare any increase. The rate setting process allows all parties to argue that costs should or should not be allocated to individual customers or customer classes, or whether they should be recovered at all.

Second, existing contracts and settlements may not allow for adjustment of rates or recovery of costs incurred for the benefit of the entire system. In these cases, the pipeline might be concerned legitimately that the pipeline itself may not be able to recover costs that were incurred to insure system reliability.

Finally, existing tariffs may be written in a manner, with sufficient flexibility either in imbalance leniency, ability to take non-ratable flow, or the ability for shippers to nominate much more frequently than the NAESB time frames, that a firming generator legitimately believes that it can operate under the terms of the existing firm or interruptible transportation service without subscribing to a premium service. This could occur in instances where the existing tariff was written to provide maximum flexibility to shippers at a time when either the service requirements of a generator providing firming service were not contemplated or at a time when the number of generators on the pipeline system were limited. In this instance and assuming that capacity is available, the pipeline may be required to sell capacity under the tariff service even though the addition of the firming generator would create operational challenges and increase system costs.

The above discussion identifies some of the traditional issues that are likely to arise in a rate case or a fuel recovery proceeding should a pipeline file to recover these costs from its customers. These proceedings are expensive and can be litigious.

5.9 Pipeline Service Options for Firming Generators

There are two basic paths for service options made available to firming generators and the chosen path will be determined by one simple question. Are firming generators a separate customer class for rate purposes or are they the same as any other firm service shipper?

If firming generation is deemed to be a separate class of gas pipeline customer, because they require special services unlike those available to other customers with different operating requirements, then pipeline rates can be designed specifically to recover the costs of managing the system pressure and flow for these firming generators. This may require, however, that an electric transmission operator designate a generator as a firming generation shipper. Currently ISOs and RTOs do not differentiate generating assets on this basis. In the future, however, parties may argue that such differentiation is appropriate and that pipeline rates should reflect the different character of service, and costs, to firming generation.

In a sense, this structure would be a refinement to current capacity payments. In most organized markets, payments are made to generators on the basis of the capacity that is available to the network. In some markets, these payments are made on the basis of the cost of peaking service, but in most the payments are made on the basis of base and intermediate generation capital costs. At this time, however, capacity payments do not include the costs of firm natural gas transportation service, even to base and intermediate load plants.

In the future, however, it may be appropriate to differentiate plants that are providing a dedicated service for firming and to create a payment to those plants that includes the costs of gas transportation and storage service. A market structure of this sort would greatly assist in assuring reliability of both the gas and electric networks and allow for the construction of facilities necessary to allow the networks to work.

If, however, the electricity system operator makes no such designation for cost recovery in electricity prices and rates, it may be unreasonable to expect any generator to elect voluntarily to be designated as a customer that incurs additional costs compared to another gas-fired generator.

If a firming generator is considered to be in the same class as all other firm service shippers, the pipeline will be required to treat the firming generator on a non-discriminatory basis, i.e., with no special consideration beyond the level of service defined in the tariff. On the one hand, if the pipeline limits its service to the letter of the tariff, the firming generator may not receive enough natural gas to meet its rapid ramping demands. On the other hand, in order to meet the firming generator's requirements, the pipeline may need to provide, on a best efforts basis, additional flexibility and related service that, strictly speaking, exceeds its obligations under the tariff. Providing such services could lead to increased operating costs. Eventually, a pipeline will seek to recover such costs in its rates. Customers in the rate class that do not require the degree of flexibility required by the firming generators likely would object to the rate increase. There is no benefit to them from paying higher rates that subsidize the service to firming generators.

Ideally regulatory framework would create a system that: 1) identifies generation units that are providing firming service; 2) creates a mechanism for cost recovery for those generators including the recovery of firm pipeline transportation and storage costs and; 3) creates pipeline services that meet the needs of the firming generation, which are priced in a manner that recovers those costs. In the absence of such a framework, there may be extensive litigation and some level of risk to system reliability.

Even under such a framework, the allocation of costs to the service used for firming generation will be somewhat contentious and complicated. Depending on the individual pipeline system configuration and customer mix, there likely will be some allocation of mainline costs that associated with the firming service that will need to be addressed.

5.10 Implication for the Cost of Integration of Renewable Generation

In the current structure that exists in most regions, costs associated with gas-fired generation have not been related directly to the wind generation itself. Rather, the gas-fired generation is assumed to compete and be dispatched in a manner similar to the process for dispatching merchant gas-fired generation.

By contrast, the more expensive electric storage technologies may be chosen by electric utilities and system operators simply because the existing market structure makes the linkage between the technology and the RPS requirements for renewable generation more easily demonstrated, and, as a result, cost recovery more certain in the electric utility's rates. ***In order to address the firming requirements of intermittent renewable generation in a cost effective manner, all firming options, including natural gas-fired generation and the associated pipeline and storage, should have an equal opportunity to compete to provide firming service and have the cost of the services reflected in electricity rates.***

6. Summary and Conclusions

Renewable wind generation is the fastest growing segment of new electricity generation in percentage terms. Fostering this growth is a desire to meet the future electricity needs with sustainable generation in an environmentally responsible manner. The adoption and increasing stringency of state-level RPS will continue to encourage this expansion. Even without federal legislation, state-level RPS will increase significantly the volume of renewable generation. In the ICF Base Case used in this analysis, about 105 GW of new renewable capacity—approximately 88 GW of which could be wind—is forecast to be added in the United States through 2025.

While wind and other renewable energy technologies have a number of desirable attributes, wind generation is inherently intermittent. The wind does not always blow when electric power is needed. Similarly, solar power also is intermittent. When renewable energy is a small portion of the overall energy supply mix, handling this intermittency is relatively easy. But managing intermittency becomes a more vexing problem as renewable generation grows at forecasted rates and becomes a larger component of the electric generation fleet. Analysis in this report shows that gas-fired generation will be the least costly alternative for firming intermittent renewable generation, even when including the costs of developing natural gas infrastructure to manage the large and fast swings in natural gas requirements to firm up the intermittent generation. The amount of back-up gas-fired capacity and natural gas system infrastructure that will be needed depends on the forecast errors around renewable generation availability and demand fluctuation.

The new gas infrastructure to meet these firming needs should be viewed in the context of a continuing natural gas network expansion to meet the growing demand for gas-fired generation. While renewable generation is being promoted by policy incentives, other changes in policy and regulations also are driving the growth of gas-fired generation, most notably Hazardous Air Pollutants standards (HAPs) that will require the operators of coal-fired generation to install expensive emission controls or retire generation capacity. Between 2010 and 2025, ICF forecasts that gas consumption for power generation will increase by almost 5 percent per year, going from 5.8 Tcf per year to 11.8 Tcf per year. Some regions will see significant expansions as shown in **Error! Reference source not found.** below.

Exhibit 6-1: Natural Gas Demand for Power Generation (Bcf)

	2010	2015	2020	2025	Growth 2010–25 (%/yr)
East North Central	283	373	399	1,009	8.9%
East South Central	353	791	1,026	1,350	9.4%
Middle Atlantic	569	814	992	1,434	6.4%
Mountain 1	294	376	439	510	3.7%
Mountain 2	413	523	601	644	3.0%
New England	391	446	494	466	1.2%
Pacific 1	187	194	194	237	1.6%
Pacific 2	666	659	615	571	-1.0%
South Atlantic	1,209	2,167	2,747	3,163	6.6%
West North Central	4	116	189	286	32.4%
West South Central	1,430	1,737	2,026	2,112	2.6%
U.S. Lower-48	**5,798**	**8,196**	**9,723**	**11,783**	**4.8%**

6.1 Impact of Intermittent Renewable Generation on Natural Gas

The firming capacity estimated in this analysis is equal to the amount of non-wind generating capacity needed to meet shortfalls in actual wind output relative to *forecasted* wind output. As wind becomes a larger portion of generation in regions across the United States, an increasing number of power system operators may require wind generators to submit more detailed forecasts for the following day's output in order to be able to anticipate intermittency firming requirements better.

Because of the intermittent nature and variability of generation output within short periods (10 minute intervals), wind generation will require a firming service to complement the wind output. The firming service will have to be contractually reserved for this specific purpose and cost recovery for the investment will need to be assured by the contract. For every 4 GWs of wind generation installed approximately 1 GW of firming capacity will be required. The utilization of the firming service generally will be low. For natural gas turbines, utilization will be around 15 percent.

ICF considered a number of technologies for firming wind generation, including various electricity storage technologies and natural gas turbine generation. Natural gas combustion turbines have proven they can provide reliable firming capacity, and therefore are a primary option to firm wind generation.

Gas generation capacity to firm wind generation could come from existing underutilized capacity or from new power plants dedicated to support wind generation. In order to fill the role of providing reliable service, ICF concludes that ***gas-fired generation capacity that***

provides firming service must be reserved exclusively for that function and will not be available to compete in ordinary economic dispatch. This is because the firming generation must be on call when the actual output of wind generation is reduced from the level that has been forecasted as available and planned for the electric grid. In the context of the overall requirements for gas infrastructure, firming service will constitute a relatively small portion of the overall investment requirements between 2010 and 2025, approximately $9 billion out of $143 billon, or 6.3 percent. But, the gas pipeline and storage infrastructure required for firming service could be locally significant.

While firming service requires some additional investment, the service has a very small impact on total gas consumption. The variability in wind generation largely will shift the timing of natural gas consumption for electric generation, at times requiring gas to ramp up to firm wind that is not available and at other times backing out gas and other generation when wind output exceeds projected generation. Assuming that natural gas turbines are installed for firming, ICF projects that the total generation from the firming capacity will be roughly 45,500 GWh in 2025. The total volume of gas consumed to provide this generation will be about 440 Bcf per year, or 1.5 percent of projected gas consumption in 2025 (**Error! Reference source not found.**).

Because there will be periods when wind generation exceeds the forecasted availability and that generation would displace other generation, including some gas-fired generation, the net impact of gas-fired firming capacity on natural gas demand will be less than the total natural gas consumed by firming capacity.

Exhibit 6-2: Volume of Gas Needed to Firm All Wind with Gas-Fired Generation (Bcf)

	2010	2015	2020	2025
East North Central	14.3	27.6	35.4	48.6
East South Central	0.1	0.2	0.2	0.6
Mid-Atlantic	17.2	28.5	28.8	32.0
Mountain 1	19.6	52.3	62.5	71.9
Mountain 2	2.3	9.1	9.3	11.4
New England	1.4	10.6	10.8	12.1
Pacific 1	17.1	24.9	24.9	32.6
Pacific 2	14.1	27.1	31.5	31.5
South Atlantic	2.0	9.6	9.9	9.9
West North Central	32.0	49.2	61.1	75.4
West South Central	40.4	74.2	93.1	116.4
U.S. Lower-48	**160.5**	**313.3**	**367.5**	**442.3**

6.2 Cost Recovery of Natural Gas used for Firming Renewable Generation

FERC has issued a Notice of Proposed Rulemaking (NOPR) to reform the pro forma Open Access Transmission Tariff (OATT) to address issues presented by variable energy resources (VERs) such as wind and solar renewable generation.[1] The proposed rule would do three things. First, it would require public utility transmission providers to offer intra-hourly transmission scheduling.[2] Second, it would incorporate provisions into the *pro forma* Large Generator Interconnection Agreement requiring interconnection customers whose generating facilities are VERs to provide meteorological and operational data to public utility transmission providers for power production forecasting. Finally, it would add a generic ancillary service rate schedule through which public utility transmission providers will offer regulation service to transmission customers delivering energy from a generator located within the transmission provider's balancing authority area.

Although the NOPR does not consider gas-fired generation specifically or use the terminology firming service in the manner used in this report, it is clear that the "regulation reserve service" described in the NOPR is similar in concept. The use of gas-fired generation or any other technology to manage supply reliability will be affected by how pricing in power markets is structured or how electricity transmission providers develop transmission tariffs under this rule.

The NOPR indicates FERC's intention to address the unique challenges of VERs. Importantly, the NOPR proposes a rate schedule that allows a public utility transmission provider "the opportunity to recover reserve service costs associated with the management of supply side variability." Moreover, the NOPR states that, "as a general matter, the Commission agrees that regulation reserve costs should be allocated consistent with cost causation principles", but it does not "propose to mandate a particular method for apportioning" the costs.

This analysis shows that there can be significant costs (and facilities) associated with providing firm gas supply to gas-fired generators that firm-up renewable generation. The dynamic flow modeling presented in Section 4 demonstrates that management of line pack in the pipeline system is critical in maintaining reliability of both the gas pipeline and the electric grid. The system costs associated with maintaining line pack include the following:

- Maintaining additional gas for line pack in the pipeline,
- Compression to maintain pressure for the line pack,
- Additional compressor fuel to support line pack, and
- Natural gas storage capacity in close proximity to the firming generator

[1] Docket No. RM10-11-000

[2] ICF has examined wind variability at 10-minute intervals. In the November 18 NOPR, FERC contemplates 15-minute intervals in the intra-hour scheduling requirement.

A basic tenet in natural gas pipeline rate design is that the rates charged to a shipper should recover all of the costs that the shipper causes to be incurred. This includes a portion of joint and common costs (those shared with other shippers) as well as costs for which the shipper is solely responsible. In practice, however, cost allocation and cost recovery can be much more complicated by questions of cost causation, appropriate allocation, and who benefits from the changes pipelines implement to support firming generation.

These complexities highlight the importance designing natural gas pipeline rates for firming generators. Two basic paths exist for service options specifically intended to address the needs of firming generators.

- If firming generation has transportation requirements of such distinguishable characteristics that it constitutes a separate customer class for ratemaking purposes, then rates can be designed specifically to recover the costs of managing the system pressure and flow to ensure reliability for firming purposes. This would require, however, that a generator providing such firming functions be compelled to take pipeline service specifically designed for firming generation shippers.
- If a firming generator, however, is considered to be in the same class as all other firm service shippers, then a pipeline will be required to treat the firming generator on a non-discriminatory basis that may or may not meet the generator's needs. This could result in complications. First, in some cases, a pipeline may not have the operational flexibility to offer its customers, including generators, additional pressure or non-hourly flow on a best efforts basis that exceed the pipeline's obligations under its tariff. In this case, the reliability of the firming generator could be compromised. Second, assuming that a pipeline had the flexibility to offer its customers this additional flexibility on a non-discriminatory, best efforts basis, the operational flexibility is finite and after a certain point does not exist. Further, the pipeline might incur additional costs that ultimately would have to be recovered from all shippers in the rate class if it invests in additional compression or line pack to provide further flexibility under a standard firm transportation tariff schedule. It is reasonable to assume that shippers would object to such rate increases, particularly those that did not need the additional flexibility offered by the pipeline.

Costs associated with gas-fired firming generation have not been related directly to wind generation in most areas under the current wholesale power market system. Rather, the gas-fired firming generators compete in the market and are dispatched in a manner similar to the process for dispatching merchant gas-fired generation.

By contrast, the existing market structure makes it easier to demonstrate the linkage between electric storage technologies and compliance with RPS requirements for renewable generation and, as a result, cost recovery is more certain. Furthermore, it is likely that regulated electric utilities would be permitted to include electric storage facilities in their rate base, which creates a further incentive to select this option. From a cost perspective and ultimately a consumer perspective, this may not be the best choice because these technologies may be more expensive and less proven than gas turbines. ***In order to address the firming requirements of intermittent renewable generation in a cost-effective manner, all firming options, including natural gas-fired generation and the associated pipeline and storage, should be treated the same as electric storage technologies in rates designed to recover the costs of firming generation services.***

Appendix 1: Glossary

Acronym	Term	Description
Bcf	Billion Cubic Feet	Units of measurement of gas volume.
Bcfd	Billion Cubic Feet per Day	Units of measurement of gas flow rate.
CAES	Compressed Air Energy Storage	Technology used to store energy by using it to compress air in an underground cavern
CAISO	California Independent System Operator	
CCGT	Combined Cycle	An electric generating station that uses waste heat from gas turbines to produce steam for conventional steam turbines. For the purposes of this report, we assume that CCGTs are entirely natural gas-fired
CEC	California Energy Commission	
CO2	Carbon dioxide	
CPUC	California Public Utility Commission	
CSP	Concentrated Solar Power	A system of electricity generation that uses lenses or mirrors to concentrate solar energy in order to heat a transfer fluid and run a power generator
CT	Combustion Turbine	A combustion turbine is a power generator that draws in air, compresses it, mixes it with fuel, and ignites it. The resulting hot combustion gases expand through turbine blades that are connected to a generator. As they expand they turn the blades and produce electricity. For the purposes of this report, we assume that CTs are entirely natural gas-fired
DGLM	Daily Gas Load Model	ICF's Daily Gas Load Model (DGLM) is used to project daily load profiles, including peak day gas demand.
DOE	Department of Energy	
DSM	Demand Side Management	A form of load management tool that may be active (demand response) or passive (energy efficiency)
EIA	Energy Information Administration	
EPRI	Electric Power Research Institute	

Acronym	Term	Description
ERCOT	Electric Reliability Council of Texas	
EV	Electric Vehicles	
EWITS	Eastern Wind Integration and Transmission Study	
FERC	Federal Energy Regulatory Commission	
FIRM	Firming Intermittent Renewables Model	
GMM	Gas Market Model	A supply/demand equilibrium model that projects monthly natural gas prices, given different supply/demand assumptions specified by the user. GMM is developed by ICF International.
GW	Gigawatt	A unit of power that equals one billion watts
Hg	Mercury	
HP	Horsepower (compressor)	Units of measurement of power.
HTF	Heat Transfer Fluid	Fluids like synthetic oil, molten salt or water that transfer heat
IAP	Intermittency Analysis Project	
ILP	Integrated Licensing Process	FERC's licensing process for hydro facilities
IPM	Integrated Planning Model	A multi-regional, dynamic and deterministic linear programming model of the U.S. electric power sector developed by ICF Consulting, Inc.
IRC	International Renewables Corporation	
ISO	Independent System Operator	
ISO-NE	New England ISO	

Acronym	Term	Description
ITC	Investment Tax Credit	A 30 percent federal credit available to solar units, distributed wind systems, and geothermal heat pumps
LBNL	Lawrence Berkley National Laboratory	
LFG	Landfill Gas	A renewable energy source produced by the decomposition of organic waste and primarily composed of methane and carbon dioxide.
LNG	Liquefied Natural Gas	
MMBtu	Million British Thermal Unit	Units of measurement of energy.
MMscf	Million Standard Cubic Feet	Units of measurement of gas volume.
MMscfd	Million Standard Cubic Feet per Day	Units of measurement of gas flow rate.
MW	MegaWatt	One million watts
NAESB	North American Energy Standards Board	
NERC	North American Electric Reliability Corporation	
NIST	National Institute of Standards and Technology	
NO_x	Nitrogen oxide and Nitrogen dioxide	
NPCC	Northeast Power Coordinating Council	
NREL	National Renewable Energy Laboratory	
NYISO	New York ISO	

Acronym	Term	Description
NYSERDA	New York State Energy Research and Development Authority	
PEV	Plug-in Electric Vehicle	
PHEV	Plug-in Electric Vehicle	
PHS	Pumped Hydro Storage	Systems that store power produced in off-peak hours by pumping water to a reservoir at a higher-elevation
PPA	Power Purchase Agreements	
Psia	Pound per Square Inch	Units of measurement of pressure.
PTC	Production Tax Credit	A federal credit of 2.2¢/kWh available to wind, closed loop biomass, and geothermal units. The PTC is 1.1¢/kWh for landfill gas and open loop biomass. Under the American Recovery and Reinvestment Act, the PTC for wind was extended through 2012 and through 2013 for other qualified facilities.
PV	Photovoltaic	Technology used to convert light energy directly to electrical energy
REC	Renewable Energy Credit	A financial instrument representing the renewable attributes of power produced by a renewable energy generator. One REC typically represents one MWh of renewable generation.
RPS	Renewable Portfolio Standards	
RRS		Response reserve service
RTO	Regional Transmission Organization	An independent organization established to operate the transmission assets and deliver wholesale transmission services within a defined geographic region
SMES	Superconducting Magnetic Energy Storage	Systems that store energy within the magnetic field of a large coil of material that is super-cooled to become superconducting.
SO_2	Sulfur dioxide	
SPP	Southwest Power Pool	
STH	Solar Thermal	See Concentrating Solar Power (CSP)

Acronym	Term	Description
T&D	Transmission & Distribution	
Tcf	Trillion Cubic Feet	Units of measurement of gas volume.
V2G	Vehicle To Grid	Technology that allows for the bi-directional sharing of electricity between Evs/PHEVs and the electric power grid
WECC	Western Electricity Coordinating Council	
WWSIS	Western Wind and Solar Integration Study	
	Aeroderivatives	A type of gas turbine, similar to an aircraft engine, used in industrial and marine applications
	Ancillary Services	Services that ensure the reliability of transmission and distribution infrastructure and support the delivery of electricity. Such services including regulation and frequency response (regulation or automatic generator control), spinning reserve, nonspinning reserve, replacement reserve, reactive supply and voltage control
	Base load	See Base load Generation
	Base load Generation	Generation from units with comparatively low operating costs and slow ramp-up and ramp-down rates. Base load generation capacity tends to meet the portion of demand that is relatively constant over time.
	Biomass Generation	A form of renewable generation that uses biologically-derived materials
	Capacity Factor	The ratio of the actual output of a power plant over a period of time (usually one year) to the output of the plant if it were generating at full capacity over that period
	Capacity Firming	Using energy provided by generators or energy storage systems to offset fluctuations in output from other generators (such as intermittent renewable capacity)
	Demand Response	The curtailment of energy consumption during periods of high energy demand
	Dispatch stack	The arrangement of generating capacity according to operating cost. The lowest-cost units from the bottom of the stack
	Electric Double Layer Capacitors	See Ultracapacitor

Acronym	Term	Description
	End-Use	A firm or individual that purchases products for its own consumption and not for resale (i.e., an ultimate consumer).
	Expanded Interlinked Transmission Grid	An system of two power grids with transmission links to enable (with development and implementation of appropriate coordination mechanisms) advanced power grid operations such as dynamic scheduling to take place over a wider region, thus enhancing the ability of the power system to absorb the variations in renewable generation output
	Fast Ramp Generation	Generation that can be quickly dispatched to meet short-term load changes.
	Firm Service	A service offered to customers under schedules or contracts which anticipate no interruptions.
	Flywheel	Device to store energy via a rotating cylinder in a near frictionless environment
	Full-load variable cost	The variable cost of an operating unit that is running at full capacity
	Gas Load Variability	Difference between the highest and lowest gas load within a time period.
	Gas Nomination	A request for a physical quantity of gas under a specific purchase, sales or transportation agreement or for all contracts at a specific point.
	GE LMS100	As a part of GE Energy's ecomagination portfolio, the LMS100 offers 100MW of electricity at 44% thermal efficiency with a wide range of operating flexibility for peaking, mid-range and base-load operation with lower start-up emissions and 10-minute starts, www.gepower.com/corporate/ecomagination_home/lms100.htm.
	Heat Rate	A measure of generating station thermal efficiency commonly stated as Btu per kilowatt hour. Note: heat rates can be expressed as either gross or net heat rates, depending whether the electricity output is gross or net generation. heat rates are typically expressed as net heat rates.
	Hydrogen Fuel Cell	Fuel Cells that uses hydrogen as its fuel
	Intermediate Load (electric system)	The range from base load to a point between base load and peak. This point may be the midpoint, a percent of the peak load, or the load over a specified time period.
	Intermittent generation	Generation that varies in magnitude and phase (timing) according to the availability of primary fuel (wind, sunlight and water flow)

Acronym	Term	Description
	Lease and Plant Fuel	Natural gas used in well, field, and lease operations (such as gas used in drilling operations, heaters, dehydrators, and field compressors) and as fuel in natural gas processing plants.
	Line Pack (gas pipeline flow)	Quantity of gas in the pipeline network.
	Liquid Flow Batteries	Device that stores energy within the magnetic field of a large coil of a super-cooled material that becomes superconducting
	Load Leveling	A method of load management using demand response.
	Mid-merit generation	Mid-merit generation is that which falls between base load and peak. Generation.
	Midstream natural gas assets	Midstream includes all assets between the wellhead and the distribution systems and includes gathering systems, processing facilities, interstate and intrastate transmission lines, LNG import and export facilities, and gas storage fields that are operated by the interstate pipelines.
	Modified Panhandle Correlation	Steady state flow correlation to estimate gas pipeline capacity based on gas physical properties, pipeline dimensions, and pressure range.
	Off-Peak	Usually the time period from 11:00 PM through 7:00 A.M., and all day on Saturdays, Sundays and holidays. Power demand is low during this time.
	On-Peak	Usually the time period from 7:00 A.M. through 11:00 P.M. on all non-holiday weekdays, when power demand is high
	Operating Reserves	The capability above firm system demand required for regulation, load forecasting error, and forced and scheduled equipment outages
	Peak Demand	Demand during on-peak hours
	Peaking Generation	Generation provided by expensive inefficient units to meet load needs during periods of high demand
	Persistence Forecast	Method of forecast where the wind speed in the next interval is a function of the wind speeds of previous intervals
	Persistence Forecast	The persistence forecast is used to forecast wind speeds within a very short duration, such as 5, 10 or 15 minutes. This method assumes that the forecast of wind speed for the next interval is equal to the actual value of wind speed in the present interval.
	Pipeline Loop	A parallel pipeline along existing pipeline, or along just a section of it, to increase capacity.
	Pressure Transient (gas pipeline flow)	Fluctuations of pipeline pressure due to variations of gas flow (or transient flow) over time.

Acronym	Term	Description
	R/C/I	Residential, commercial, and industrial gas customers.
	Ramp down rate	See Ramp Rate
	Ramp rate	The rate of change in output of a power plant
	Ramp up rate	See Ramp Rate
	Ramping	The period of escalation or decline in generation
	SNL Financial	Data subscription service
	Spinning Reserves	The portion of operating reserve consisting of either (1) generation synchronized to the system and fully available to serve load within the disturbance recovery period following the contingency event, or (2) load fully removable from the system within the disturbance recovery period following the contingency event
	Steady State (gas pipeline flow)	In steady state condition the gas flows in the pipeline do not vary with time.
	Substation	A high-voltage electric system facility used to switch generators, equipment, and circuits or lines in and out of a system
	Supercapacitor	See Ultracapacitor
	T&D Deferral	The deferral of investment in transmission and distribution lines and substations
	Thermal Energy Storage	Energy storage in mediums such as heated water, ice or heat transfer fluid
	Transient Stability	Voltage stability on the electric grid
	Ultracapacitor	Device used to store energy in an electric charge
	Variable Generation	See Intermittent Generation
	Ventyx	Data subscription service
	Wind Shape	The generation profile of a wind facility

Acronym	Term	Description
	WinTran	Gregg Engineering's WinTran model is a transient pipeline simulator that takes into consideration changing flow or pressure conditions over time. This unsteady or changing flow or pressure condition can be considered "on" or "off" line simulation that considers dynamic fluid flow characteristics over a specified time span. Detailed information regarding Gregg Engineering and the pipeline flow models are available at www.greggengineering.com.

Appendix 2: Analysis of Renewable Generation Growth and Firming Requirements

Introduction and Background

This analysis is the first part of a two-part study of the impact of renewable generation resources on natural gas industry infrastructure and operations in the U.S. In this part, we analyze the implications of increased use of renewable generation, wind in this case, for meeting load requirements under conditions of intermittent generation and changing load characteristics. The analysis uses a quantitative modeling approach to estimating the firming requirements electric systems will need in order to match intermittent generation with electric loads. We also review the recent literature on wind generation management.

Renewable generation—primarily wind energy—is among the fastest growing forms of new electricity generation in the U.S. Fostering this growth is a desire to meet the future electricity needs with sustainable generation in an environmentally responsible manner. The adoption and increasing stringency of state-level Renewable Portfolio Standards (RPS) will continue to encourage this expansion. Moreover, federal legislative proposals include mandates for minimum levels of renewable generation.

Wind energy has a number of desirable attributes but is inherently intermittent. This intermittency is relatively easily managed when renewable energy constitutes a small portion of total energy supply. Grid operators have always accommodated the possibility that some portion of available generation resources will experience an unplanned outage. Moreover, while some wind projects are quite large, most individual projects are considerably smaller than large central station coal or nuclear facilities.[1] Nevertheless, the complexity of managing intermittency rises as more intermittent resources are added to a system. In regions home to a large amount of wind capacity, wind resources may be unavailable across a wide geographic area due to large scale weather patterns. Wind forecasts can diverge considerably from actual wind generation, which will affect unit commitment, dispatch, and ramp rate requirements. The variability and uncertainty associated with wind resources may increase the amplitude of sustained load ramps (both up and down) and the frequency of generation starts and stops. System operators rely mostly on gas-fired generators to compensate for unforeseen wind variability, as these units have fast ramp rates and other beneficial operating characteristics.

Findings and Approach

ICF International used the findings of the latest major research efforts, comments from key industry stakeholders, and projections from two of ICF's modeling platforms, the Integrated

[1] While we include a limited discussion of solar resources as another form of intermittent renewable generation, we do not concentrate on solar resources because they currently have very low market penetration.

Planning Model (IPM©) and the Firming Intermittent Renewables Model (FIRM™) in this investigation of the impact of intermittent renewable resources upon power market operations.

Key Findings

ICF projects that by 2025 over 105 GW of new renewable capacity could be built in the United States, of which about 88 GW could be wind generation. Nearly 70 GW of new gas-fired combustion turbine (CT) and combined cycle gas turbine (CCGT) capacity could be added through 2025.

The most significant period for the development of new renewable capacity will occur between 2010 and 2015 as developers take advantage of expiring federal incentives such as the production tax credit (PTC) and investment tax credit (ITC).

The majority of new renewable capacity additions are located in regions with high quality renewable resources and/or stringent renewable portfolio standards (RPS), such as Pacific 2 (California, Hawaii),[2] Mountain 1 (Colorado, Idaho, Montana, Nevada, Utah, and Wyoming), and Middle Atlantic (New York, New Jersey, Pennsylvania).

Three regions were selected for intensive study based on their potential for significant impacts on natural gas pipelines and infrastructure. These were California (Pacific 2), Wyoming (Mountain 1), Texas/Oklahoma (West South Central), and New England.

As renewable generation increases, demand will grow for demand response (DR) and system reliability services. System operators will likely expand firming capabilities beyond those typically provided by fossil fuel-fired generation to increase system flexibility and reduce system costs.

Demand response programs and energy storage technologies may become key renewable firming resources as DR programs grow and storage technologies mature and costs decline.

The literature on wind integration reviewed for this study do not provide a consensus view of the impacts of intermittent generation on natural gas markets and infrastructure requirements; however, several imply that large area balancing and other options/actions such as demand response could make infrastructure additions less likely.

Previous wind integration studies identify fast ramp generation as a critical component of any integration strategy. Hydro and combustion turbines are two key sources of fast ramp capacity

[2] ICF only models the continental U.S. for this report, thus there are no projections for Hawaii or Alaska

but hydro is limited by water availability and environmental constraints. Combustion turbines such as the GE class 7E or 7F machines or aeroderivatives such as GE's LM-class machines or their equivalent serve as default fast ramp generation providers.

The detailed analysis of the three regions where growth in wind resources could affect natural gas systems operations analyzed the firming requirements (in terms of ramp up of firming generation resources) arising from changes in load and changes in output from wind generation.

> In each of the cases, wind variation required significant ramping capacity to meet load changes when wind is also changing. At times, this can mean rapid increases in conventional generation and at other times rapid decreases in conventional generation.
>
> In each of the regions studied, the required ramp rates vary significantly and are much more "spiky" when more wind generations is added into the region.
>
> The largest swings in ramp rates tend to occur in the summer.
>
> For the forecast year 2025, ramp rates in Wyoming/California ranged between + 173 MW/min. to -210 MW/min.; in Oklahoma/Kansas between +125 MW/min. to -200 MW/min. and in New England between 65 MW/min. to -101 MW/min.
>
> The volatility in ramping has a direct effect on natural gas units and the natural gas pipelines and infrastructure to meet these swings in demand. When gas generating units need to ramp-up, they have immediate demands on gas supply and transportation deliverability. Similarly, when units need to ramp down, something needs to be done with the natural gas that was nominated and scheduled on the pipeline. Managing these swings in natural gas use can require significant modifications of natural gas pipelines and infrastructure.

Other potential ways of managing this volatility include cross regional coordination, provided there is adequate transmission capacity. Also included are batteries, fly-wheels, and compressed air energy storage (CAES). These technologies, however, may have only niche applications.

Approach and Report Organization

The first chapter of this report provides regional projections for renewable and gas-fired capacity expansion and generation.

The second chapter provides illustrative regional renewable and gas-fired generation profiles that are applied later in the modeling analysis described in Chapter 5. The focus regions for this part of the analysis include California (Pacific 2), Wyoming (Mountain 1), Texas/Oklahoma (West South Central), and New England. We focus on these areas in particular due to high local natural gas consumption and high penetration of intermittent renewable generation.

The third chapter provides an analysis of technologies (aside from fossil fuel-fired generation) used to mitigate the potential effects of intermittent renewables.

The fourth chapter reviews the latest studies investigating energy storage options and the impact of renewable intermittency on natural gas-based generation including peaking plants. The reports we evaluated were produced by NERC[3], DOE[4], NREL[5,6], NYISO[7], ISO-NE[8], CAISO[9], CEC[10], and ERCOT[11], all of which agree on several key points:

- Variations in wind and load are uncorrelated with each other.
- Wind output usually varies inversely with load.
- Significant ramp events can occur with wind generation due to both predictable and unforeseen variability in wind speeds. These ramp events require corresponding fast ramp/quick start generation to compensate for wind variability.
- It is important to consider net load (load + wind) when determining ancillary service requirements.
- The magnitude of chronological (time-series) variations increase with higher wind penetration.
- Both statistical and chronological variations can be reduced by geographical diversity and mitigated by larger balancing area operations.

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[3] NERC. Accommodating High levels of Variable Generation. April, 2009.

[4] DOE. 20% Wind Energy by 2030 - Increasing Wind Energy's Contribution to U.S. Electricity Supply. July, 2008.

[5] NREL. Eastern Wind Integration and Transmission Study. January, 2010.

[6] NREL. How do Wind and Solar Power Affect Grid Operations: The Western Wind and Solar Integration Study. September, 2009.

[7] NYISO, NYSERDA. The Effects of Integrating Wind Power on Transmission System Planning, Reliability, and Operations. March, 2005.

[8] ISO-NE. Technical Requirements for Wind Generation Interconnection and Integration. November, 2009.

[9] California ISO. *Integration of Renewable Resources*. November, 2007.

[10] California Energy Commission. Intermittency Analysis Project: Appendix B - Impact of Intermittent Generation on Operation of California Power Grid. July, 2007.

[11] ERCOT. Analysis of Wind Generation Impact on ERCOT Ancillary Services Requirements. March, 2008.

- Energy storage is a promising technology to compensate for variations in wind; however, storage technologies are limited due to high capital costs, low energy storage capability, and low efficiency.
- Aggregation of wind and solar sites could mitigate the relative impacts of the large ramps caused by wind speed variations; however, large photovoltaic (PV) plants can serve as extremely fast ramping resources by altering output by +/- 70% in a timeframe of two to ten minutes, several times per day.

The wind integration studies reviewed in this study do not explicitly address the most cost-effective mechanism of meeting the need for fast response generation. While multiple options for meeting the need for fast-response exist, using natural gas-fired combustion turbines for this purpose could require additional natural gas supply and/or adjustments to natural gas market structures.

Chapter 5 provides a description of the analysis of the impact of intermittent renewable power on the need for fast ramp generation and an estimate of any related system costs. ICF utilized its in-house developed model, Firming Intermittent Renewables Model (FIRM^{TM}), to run sample cases in various regions of the U.S. for several representative simulation years to estimate the impact of additional renewable generation on fast ramp generation and energy storage requirements.[12] We analyzed three representative days in three seasons (summer peak, winter peak and shoulder) for four years (2010, 2015, 2020 and 2025) in the New England (ISO-NE), Wyoming-California (WY-CA) and Oklahoma-Kansas (OK-KS) regions. For each of the three regions we determine the maximum fast ramp capacity needed due to wind and its pattern of variation, the amount of conventional generation curtailed, and the approximate magnitude of energy storage that could be utilized to compensate for wind speed variations. The results from these analyses show that there are considerable swings on required ramp rates due to varying speeds in the region. Quantitative details on how ramp rates vary by simulation year and season are given in the report. For the purposes of this analysis, we assume that a significant portion of the ramp rate requirements is met by natural gas based generation.[13] Therefore, changes in ramp rates translate into changes in natural gas supply requirements.

[12] A description of the model, its assumptions and data sources are provided in the report

[13] We recognize that there are other means by which ramp rate requirements may be met, and this assumption is based on the typical mixture of generators meeting ramping requirements in the three focus regions of the report.

Chapter 1: Regional Projections for Renewable and Gas-fired Capacity Development and Generation

ICF uses a suite of models to provide quarterly projections of developments in fuel, power, capacity, and emissions markets in the U.S. and Canada. These projections constitute ICF's Expected Case analysis. This chapter provides regional projections for renewable and gas-fired capacity expansion and generation through 2025.

The ICF Expected Case is based on a host of assumptions covering energy demand, fuel transportation costs, performance and cost metrics for electric generation capacity, transmission infrastructure, renewable resource availability, regulatory policies, and legislative initiatives. The table below summarizes several of the key assumptions included in the ICF Expected Case.

Exhibit A2-1-1: ICF Expected Case Assumptions

Assumption	Description
SO_2 Program	• 2010-2012: CAIR • 2013: Legislated Program
Annual NO_x Program	• 2010-2012: CAIR • 2013: Legislated Program
Seasonal NO_x Program	• 2010: CAIR Ozone Season
Mercury Program	• 2015: Federal MACT • 90% removal from fuel input • States with existing rules proceed as planned, so long as they meet minimum requirement as defined by federal MACT
CO_2 Program	• 2015: National Multi-sector Cap and Trade
Electricity Demand	• Forecast is based on historical GDP growth and controls for heating and cooling degree-days. • Peak demand is forecast by using historical data to derive a project ratio of energy to peak demand, and this ratio is applied to the forecast energy demand.
Existing Transmission Infrastructure Assumptions	• ICF uses public sources such as NERC and regional reliability councils for total transfer capacity (TTC) assumptions, interface limits published by various Independent System Operators (ISOs), where possible. • In regions where data is unavailable, ICF uses estimates derived from industry contacts and proprietary modeling exercises.

Assumption	Description
Financial Assumptions for New Power Plants	• ICF considers the capital charge rate as the levelized rate of return on an investment. The components of this rate are based on a combination of utility and merchant financing. • Levelized Real Fixed Capital Charge Rate of 10.1-12.5% based on unit type
Greenfield Power Plant Costs	• Based on survey data and internal analysis • Capital costs are regionalized using economic multipliers that account for labor and equipment cost differences across the U.S. • Capital costs are also adjusted to account for interconnection costs as well as interest during construction

ICF's modeling exercise for this report includes a federal renewable energy standard (RES) based on the RES included in the Waxman-Markey (HR 2454) bill. Expected case generating capacity expansion results are presented both for the U.S. and for individual Census regions.

CUMULATIVE RENEWABLE AND GAS-FIRED CAPACITY BUILDS

National

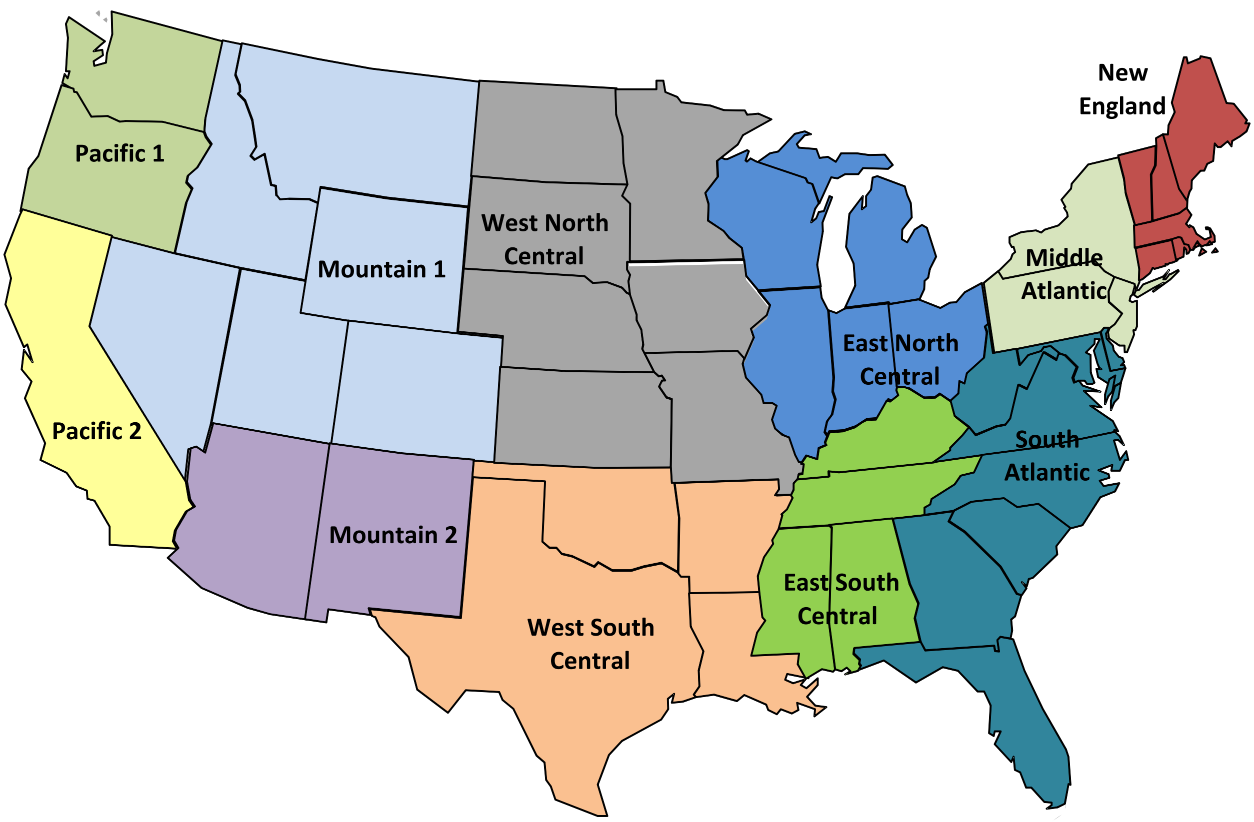
Exhibit A2-1-2 below provides ICF's projections for renewable and gas-fired capacity additions over the forecast period. ICF projects that over 105 GW of new renewable capacity and nearly 70 GW of new CT and CCGT capacity will be added in the U.S. through 2025. The most significant development of new renewable capacity will occur between 2010 and 2015 as developers take advantage of expiring federal incentives such as the production tax credit (PTC) and investment tax credit (ITC). Development continues steadily through the end of the forecast period as renewables become increasingly competitive with fossil fuel-fired generation due to rising CO_2 allowance prices. We project that a large quantity of CCGT and CT capacity will be added between 2020 and 2025 to meet peak and energy demand. In the near-term, ICF projects that CCGT and CT development will remain limited until market conditions such as energy margins and demand growth improve sufficiently to justify new investment.

Exhibit A2-1-2: Cumulative Renewable and Gas-Fired Capacity Additions (MW)

Capacity Type	2010	2015	2020	2025
Wind	6,000	50,651	66,471	88,327
Biomass	-	2,070	3,353	4,323
Geothermal	-	800	1,270	1,726
Landfill Gas	101	1,103	2,102	3,103
Solar PV	20	2,454	4,888	5,951
Solar Thermal	-	1,889	2,156	2,156
Combined Cycle	-	3,686	19,686	59,087
Combustion Turbine	-	636	3,656	9,932

Source: ICF Analysis

Exhibit A2-1-3: U.S. Census Regions



Note: This analysis only covers the contiguous U.S. Neither Alaska, which is part of Pacific 1, nor Hawaii, which is part of Pacific 2, is covered in this analysis.

EAST NORTH CENTRAL

The East North Central region, composed of Illinois, Indiana, Michigan, Ohio, and Wisconsin, will be dominated by wind development through 2025. This development trend reflects the region's significant wind potential coupled with strong renewable portfolio standards, creating high regional demand for renewable generation. Neither geothermal nor solar thermal capacity will be developed in this region because we limit potential geothermal capacity builds to the Pacific 1 & 2 and Mountain 1 & 2 regions, and we limit potential solar thermal capacity builds to the Mountain 1, Mountain 2, and Pacific 2 regions in our model. Nearly 25 percent of the nation's new landfill gas capacity development through 2025 will be concentrated in the East North Central region which has extensive landfill facilities capable of generating power.

The region does not have a large need for new fossil-fired capacity until 2025. As CO_2 prices rise in the outer years of the forecast period, energy prices in this region will increase significantly. As a result, natural gas combined cycle units can capitalize on strong energy margins, leading to a large amount of CCGT builds in the outer years of this study. Exhibit A2-1-4 below provides an overview of the cumulative renewable and gas-fired capacity builds in the East North Central Region.

Exhibit A2-1-4: Cumulative Renewable and Gas-Fired Capacity Builds (MW) in East North Central

East North Central	2010	2015	2020	2025
Wind	-	3,912	6,177	10,038
Biomass	-	194	583	750
Geothermal	-	-	-	-
Landfill Gas	-	49	404	744
Solar PV	-	134	403	524
Solar Thermal	-	-	-	-
Combined Cycle	-	-	305	7,583
Combustion Turbine	-	-	-	90

EAST SOUTH CENTRAL

The East South Central region composed of Alabama, Kentucky, Missouri, and Tennessee, hosts very limited renewable development, which can be attributed to the region's lack of renewable energy standards and limited renewable resources. Nearly 13 percent of the nation's new combined cycle capacity developed through 2025 will be developed in this region. East South Central, like East North Central, also meets a large proportion of its energy requirements with coal-fired generation. As a result, when CO_2 prices start to significantly rise in 2020 and 2025, energy margins will steadily increase for gas-fired generators in this region. These large energy margins, coupled with tightening demand, will prompt the development of new CCGT capacity.

An overview of the cumulative renewable and gas-fired capacity builds in the East South Central Region is given below in Exhibit A2-1-5.

Exhibit A2-1-5: Cumulative Renewable and Gas-Fired Capacity Builds (MW) in East South Central

East South Central	2010	2015	2020	2025
Wind	-	37	37	138
Biomass	-	-	-	-
Geothermal	-	-	-	-
Landfill Gas	-	-	-	71
Solar PV	-	-	-	-
Solar Thermal	-	-	-	-
Combined Cycle	-	-	1,913	7,804
Combustion Turbine	-	-	-	-

MIDDLE ATLANTIC

The Mid-Atlantic region, composed of Pennsylvania, New Jersey, and New York, develops significant renewable capacity over the forecast period. While wind is the dominant renewable technology, ICF projects the region will develop more than 20 percent of the new biomass capacity, more than 20 percent of the new landfill gas capacity, and nearly 20 percent of the new solar PV capacity constructed in the U.S. through 2025. The strength of renewable development in this region can be attributed to stringent renewable portfolio standards and robust REC markets. Rising peak and energy demand will require the addition of new fossil-fired capacity around 2020. New York and New Jersey, unlike the Central regions, is natural gas-dominated, which means that the long-term increase in energy margins available to CCGTs will not be very significant. In order to meet capacity needs, some areas within the Mid-Atlantic will build comparatively less expensive combustion turbines, which can meet capacity requirements at a much lower capital cost. An overview of the cumulative renewable and gas-fired capacity builds is given in Exhibit A2-1-6 below.

Exhibit A2-1-6: Cumulative Renewable and Gas-Fired Capacity Builds (MW) in Middle Atlantic

Middle Atlantic	2010	2015	2020	2025
Wind	2,948	6,237	6,326	7,253
Biomass	-	648	909	909
Geothermal	-	-	-	-
Landfill Gas	73	350	558	627
Solar PV	20	417	1,006	1,105
Solar Thermal	-	-	-	-
Combined Cycle	-	-	844	3,805
Combustion Turbine	-	-	361	3,994

MOUNTAIN 1

The Mountain 1 region, composed of Colorado, Idaho, Montana, Nevada, Utah and Wyoming, also exhibits substantial renewable development. ICF projects that the region, which has excellent wind resources, will develop over 17 GW of new wind capacity through 2025, representing nearly 20 percent of new national wind builds. Within the region, Nevada and Idaho develop much of the nation's projected new geothermal capacity, and Nevada develops much of the nation's projected new solar thermal capacity. Neither landfill gas nor solar PV is developed heavily as the economics of wind are much more appealing in this region. While we recognize that the Langley Gulch CCGT and Mill Creek CT units 1-3 facilities are firm builds that will soon collectively add 450 MW of new gas-fired capacity to the region, we do not do not project that additional CCGT or CT facilities will be developed in the region within the forecast period.[14] Exhibit A2-1-7 below provides an overview of the cumulative renewable and gas-fired capacity builds in the Mountain 1 region.

Exhibit A2-1-7: Cumulative Renewable and Gas-Fired Capacity Builds (MW) in Mountain 1

Mountain 1	2010	2015	2020	2025
Wind	2,052	11,596	14,585	17,337
Biomass	-	-	-	-
Geothermal	-	350	350	350
Landfill Gas	-	27	41	75
Solar PV	-	98	157	167
Solar Thermal	-	333	600	600
Combined Cycle	-	-	-	-
Combustion Turbine	-	-	-	-

MOUNTAIN 2

The Mountain 2 region, composed of Arizona and New Mexico, is home to some of the most robust solar development in the nation over the forecast period. ICF projects the region will develop over one GW of solar PV capacity through 2025, representing nearly 18 percent of total new solar PV capacity developed nationally. Within the region, Arizona will develop nearly 2 GW of CT capacity through 2025, representing nearly 20 percent of new national capacity additions, which can be explained by the state's low energy margins and high demand growth.

[14] The 300 MW Langley Gulch facility will be located in Idaho and has an estimated COD of October 2012. Mill Creek CT units 1-3, located in Montana, are each rated at approximately 50 MW and have a COD of December 2010. A fourth Mill Creek CT unit is planned but not yet firm.

Exhibit A2-1-8: Cumulative Renewable and Gas-Fired Capacity Builds (MW) in Mountain 2

Mountain 2	2010	2015	2020	2025
Wind	-	1,995	2,046	2,662
Biomass	-	-	-	-
Geothermal	-	41	111	158
Landfill Gas	-	-	-	-
Solar PV	-	358	825	1,055
Solar Thermal	-	-	-	-
Combined Cycle	-	-	-	-
Combustion Turbine	-	-	242	1,932

NEW ENGLAND

The New England region, composed of Massachusetts, Maine, New Hampshire, Vermont, Rhode Island, and Connecticut, develops a modest amount of renewables and a substantial amount of new CCGT and CT capacity. The renewable capacity development in the region reflects the region's moderate renewable portfolio standards and limited renewable resource base. Connecticut develops the majority of CCGT additions in New England due to the state's good margins and strong demand growth. New England needs new capacity to meet significant reserve margin requirements sooner than other regions, such as East North Central. In states such as Connecticut, Massachusetts and Rhode Island, energy margins will be high enough to support new CCGT investment. However, Maine, which is largely electrically isolated from the rest of New England, will develop CTs due to the state's low margins coupled with its need to meet its tightening reserve margin. An overview of the cumulative renewable and gas-fired capacity builds in the New England region is given below in Exhibit A2-1-9.

Exhibit A2-1-9: Cumulative Renewable and Gas-Fired Capacity Builds (MW) in New England

New England	2010	2015	2020	2025
Wind	-	2,685	2,734	3,119
Biomass	-	-	-	-
Geothermal	-	-	-	-
Landfill Gas	-	73	99	117
Solar PV	-	51	114	127
Solar Thermal	-	-	-	-
Combined Cycle	-	527	2,684	5,368
Combustion Turbine	-	91	871	1,372

PACIFIC 1

The Pacific 1 region, composed of Alaska, Oregon, and Washington, will develop limited renewable resources and no CCGT or CT capacity through 2025. ICF does not model Alaska, thus projections from this state are not included here. The 4.5 GW of wind developed in the region is evenly split between Oregon and Washington, both of which have moderately stringent renewable portfolio standards and excellent wind resources. ICF expects much of wind generation in these states to be exported to nearby WECC states such as California. This region has a large quantity of existing hydroelectric capacity that provides inexpensive base load power and limits energy margins available to fossil-fired units. The region also has low demand growth. As a result, Pacific 1 will not need to add new fossil-fired capacity during the forecast period. Exhibit A2-1-10 below provides an overview of the cumulative renewable and gas-fired capacity builds in the Pacific 1 region.

Exhibit A2-1-10: Cumulative Renewable and Gas-Fired Capacity Builds (MW) in Pacific 1

Pacific 1	2010	2015	2020	2025
Wind	-	2,281	2,281	4,517
Biomass	-	-	-	-
Geothermal	-	9	9	35
Landfill Gas	-	-	-	50
Solar PV	-	-	-	-
Solar Thermal	-	-	-	-
Combined Cycle	-	-	-	-
Combustion Turbine	-	-	-	-

PACIFIC 2

The Pacific 2 region, composed of California and Hawaii, will develop nearly 12.5 GW of renewable resources through 2025, more than half of which comes from non-wind renewables (since ICF models the continental U.S., Hawaii is not included in this projection). California currently has the most stringent renewable portfolio standard and some of the best renewable resources in the country. As a result, California will develop more than 10 percent of the nation's total new biomass capacity, nearly 70 percent of the nation's total new geothermal capacity, nearly 25 percent of the nation's new landfill gas capacity, over 40 percent of the nation's new solar PV capacity, and more than 70 percent of the nation's new solar thermal capacity. Additionally, California's attractive energy margins (due to the large amount of legacy steam natural-gas units present in the state) and strong demand growth will spur the development of over 4.5 GW of new CCGT capacity. Exhibit A2-1-11 below provides an overview of the cumulative renewable and gas-fired capacity builds in the Pacific 2 region.

Exhibit A2-1-11: Cumulative Renewable and Gas-Fired Capacity Builds (MW) in Pacific 2

Pacific 2	2010	2015	2020	2025
Wind	1,000	4,797	6,082	6,082
Biomass	-	222	353	454
Geothermal	-	400	800	1,183

Pacific 2	2010	2015	2020	2025
Landfill Gas	28	338	528	755
Solar PV	-	1,203	1,906	2,418
Solar Thermal	-	1,556	1,556	1,556
Combined Cycle	-	87	1,070	4,553
Combustion Turbine	-	-	-	-

SOUTH ATLANTIC

The South Atlantic region, composed of Delaware, the District of Columbia, Georgia, Florida, Maryland, South Carolina, North Carolina, Virginia and West Virginia, will develop a moderate amount of renewables and a significant amount of gas-fired generation. Within the region, North Carolina and Virginia will develop over 2 GW of biomass, amounting to nearly 50 percent of national biomass builds through 2025, due to the need for additional base load generation and the availability of significant biomass resources. The total renewable development in this large region is limited by moderate renewable resources (except for biomass), and by the absence of robust REC markets. Several states in the region, including South Carolina, Virginia and Georgia do not have renewable mandates, and the requirements in the states that do have mandates are relatively modest. ICF projects the region will develop over 23 GW of new CCGTs through 2025, more than half of which will be located in Virginia, Maryland, and Delaware and the remainder of which will be located in Florida. These four states exhibit solid margins and strong demand growth in the mid- to long-term. An overview of the cumulative renewable and gas-fired capacity builds of the South Atlantic region is provided in Exhibit A2-1-12 below.

Exhibit A2-1-12: Cumulative Renewable and Gas-Fired Capacity Builds (MW) in South Atlantic

South Atlantic	2010	2015	2020	2025
Wind	-	2,218	2,307	2,307
Biomass	-	1,006	1,508	2,210
Geothermal	-	-	-	-
Landfill Gas	-	92	224	416
Solar PV	-	192	477	556
Solar Thermal	-	-	-	-
Combined Cycle	-	3,071	12,164	23,026
Combustion Turbine	-	414	1,241	1,241

WEST NORTH CENTRAL

The West North Central region, composed of Iowa, Kansas, Minnesota, Montana, Nebraska, North Dakota, and South Dakota, have excellent wind resources. The states in this region with moderate renewable portfolio standards or goals, including all states except Iowa and Nebraska, focus almost exclusively on the development of wind, over 12.5 GW of which is developed through 2025. The region experiences an increase in demand growth and improved margins for gas-fired facilities in the later years of the forecast period, driving the development of nearly 3.5 GW of new CCGT capacity between 2020 and 2025. An overview of the cumulative renewable and gas-fired capacity builds of the West North Central region is provided in Exhibit A2-1-13 below.

Exhibit A2-1-13: Cumulative Renewable and Gas-Fired Capacity Builds (MW) in West North Central

West North Central	2010	2015	2020	2025
Wind	-	5,020	8,501	12,679
Biomass	-	-	-	-
Geothermal	-	-	-	-
Landfill Gas	-	-	-	-
Solar PV	-	-	-	-
Solar Thermal	-	-	-	-
Combined Cycle	-	-	706	4,051
Combustion Turbine	-	131	940	1,304

WEST SOUTH CENTRAL

ICF projects that the West South Central region, composed of Arkansas, Louisiana, Texas, and Oklahoma, will develop a significant amount of wind capacity over the forecast period. Wind development in the region is limited to Texas, Oklahoma, and a small portion of Arkansas. ICF expects no wind will be developed in Louisiana or most of Arkansas due to a scarcity of quality wind resources in these states. ICF projects that Texas will add nearly 3 GW of CCGT capacity between 2020 and 2025 as demand growth increases and margins improve. Exhibit A2-1-14 below provides an overview of the cumulative renewable and gas-fired capacity builds in the West South Central region.

Exhibit A2-1-14: Cumulative Renewable and Gas-Fired Capacity Builds (MW) in West South Central

West South Central	2010	2015	2020	2025
Wind	-	9,873	15,395	22,195
Biomass	-	-	-	-
Geothermal	-	-	-	-
Landfill Gas	-	174	248	248
Solar PV	-	-	-	-
Solar Thermal	-	-	-	-
Combined Cycle	-	-	-	2,897
Combustion Turbine	-	-	-	-

Demand for Natural Gas

Gas demand results generated by the Gas Market Model (GMM®) are presented in total for the contiguous United States and by U.S. Census regions in the following discussion.

NATIONAL

Exhibit A2-1-15 provides ICF's projection for natural gas demand in the Lower-48 states through 2025. GMM® forecasts substantial growth in gas use over time, spurred by the increase in gas-fired power generation. Power sector gas demand nearly doubles during the study period, growing from 6.0 Tcf in 2008 to 11.8 Tcf to 2025, driven by electricity demand carbon regulatory policy. Non-power sector end-use demand will increase during the next five years at 1 percent per year to 17.3 Tcf per year by 2015. Gas demand from the power sector as a share of total gas demand grows from 27 percent in 2008 to 40 percent in 2025.

Exhibit A2-1-15: Lower-48 U.S. Natural Gas Demand (Bcf)

(Billion cubic feet)	2008	2010	2015	2020	2025
Power generation	6,044	5,798	8,196	9,723	11,783
Non-power sector end use	16,531	16,503	17,343	17,676	17,890
Power (% of total gas demand)	27%	26%	32%	35%	40%

Demand growth (% per annum)	2008-10	2010-15	2015-	2020-25
Power generation	-2.1%	7.2%	3.5%	3.9%
Non-power sector end use	-0.1%	1.0%	0.4%	0.2%

East North Central

The East North Central region, composed of Illinois, Indiana, Michigan, Ohio, and Wisconsin, is projected to experience to rapid growth in gas demand by the power generation sector in the period from 2020 to 2025. A large number of CCGT additions are expected in the region (see Exhibit A2-1-4) as carbon prices rise later in forecast period, pushing gas demand for power generation to over 1.0 Tcf by 2025. With non-power sector end-use demand in the region projected to be flat over time, power sector demand will grow to account for 23 percent of regional gas demand by 2025, compared to only 5 percent in 2008. Exhibit A2-1-16 below provides an overview of natural gas demand in the East North Central region.

Exhibit A2-1-16: Natural Gas Demand (Bcf) in East North Central

(Billion cubic feet)	2008	2010	2015	2020	2025
Power generation	168	283	373	399	1,009
Non-power sector end use	3,421	3,261	3,321	3,338	3,379
Power (% of total gas demand)	5%	8%	10%	11%	23%

Demand growth (% per annum)	2008-10	2010-15	2015-	2020-25
Power generation	29.6%	5.7%	1.3%	20.4%
Non-power sector end use	-2.4%	0.4%	0.1%	0.2%

East South Central

The East South Central region, composed of Alabama, Kentucky, Missouri, and Tennessee, is expected to see robust growth in gas-fired generation, with power sector demand quadrupling during the study period, from 0.3 Tcf in 2008 to nearly 1.4 Tcf by 2025. A large number of CCGT additions are expected in the region (see Exhibit A2-1-5) as carbon prices rise in the latter part of the forecast period; this result is similar to the one observed in the East North Central region, but with an earlier onset due to the limited renewable energy resources in the region. With non-power end-use demand projected to be flat over time, the power sector's share of regional gas demand will increase from 25 percent in 2008 to 58 percent by 2025. Exhibit A2-1-17 below provides an overview of natural gas demand in the East South Central region.

Exhibit A2-1-17: Natural Gas Demand (Bcf) in East South Central

(Billion cubic feet)	2008	2010	2015	2020	2025
Power generation	319	353	791	1,026	1,350
Non-power sector end use	967	966	936	958	984
Power (% of total gas demand)	25%	27%	46%	52%	58%

Demand growth (% per annum)	2008-10	2010-15	2015-	2020-25
Power generation	5.1%	17.5%	5.4%	5.6%
Non-power sector end use	0.0%	-0.6%	0.5%	0.5%

Middle Atlantic

Gas-fired generation in the Mid-Atlantic region, composed of Pennsylvania, New Jersey, and New York, is expected to exhibit strong growth during the study period. By 2025, power sector gas demand exceeds 1.4 Tcf, compared to only 0.5 Tcf in 2008. Non-power sector end-use demand is projected to grow modestly, in line with national growth rates. Also consistent with the national trend, gas demand for power generation as a share of total regional gas demand rises from 21 percent in 2008 to 39 percent in 2025. Exhibit A2-1-18 below provides an overview of natural gas demand in the Mid-Atlantic region.

Exhibit A2-1-18: Natural Gas Demand (Bcf) in Middle Atlantic

(Billion cubic feet)	2008	2010	2015	2020	2025
Power generation	543	569	814	992	1,434
Non-power sector end use	2,011	2,070	2,160	2,192	2,218
Power (% of total gas demand)	21%	22%	27%	31%	39%

Demand growth (% per annum)	2008-10	2010-15	2015-	2020-25
Power generation	2.3%	7.4%	4.0%	7.6%
Non-power sector end use	1.5%	0.8%	0.3%	0.2%

Mountain

Power sector demand for natural gas will grow steadily in the Mountain region, which includes Arizona, Colorado, Idaho, Montana, Nevada, New Mexico, Utah, and Wyoming, throughout the study period. Gas demand for power generation will increase from 0.8 Tcf in 2008 to nearly 1.2 Tcf by 2025, fuelled by the recovery and growth of electricity demand and by the addition of CT capacity in Arizona. Non-power sector end-use demand is projected to increase at a modest rate during the forecast period. Gas demand by the power sector as a share of regional total gas demand grows from 37 percent in 2008 to 44 percent in 2025. Exhibit A2-1-19 below provides an overview of natural gas demand in the Mountain region.

Exhibit A2-1-19: Natural Gas Demand (Bcf) in Mountain

(Billion cubic feet)	2008	2010	2015	2020	2025
Power generation	808	707	899	1,040	1,154
Non-power sector end use	1,388	1,358	1,425	1,448	1,472
Power (% of total gas demand)	37%	34%	39%	42%	44%

Demand growth (% per annum)	2008-10	2010-15	2015-	2020-25
Power generation	-6.4%	4.9%	3.0%	2.1%
Non-power sector end use	-1.1%	1.0%	0.3%	0.3%

New England

The New England region, composed of Massachusetts, Maine, New Hampshire, Vermont, Rhode Island, and Connecticut, is projected to experience modest growth in gas demand over the study period. Gas demand for power generation is forecast to increase incrementally from 0.4 Tcf in 2008 to about 0.5 Tcf in 2025. End-use gas demand remains steady throughout the projection from significant space-heating requirements during winter months. Gas demand for power generation as a share of regional demand for gas remains within a narrow range over the forecast period. Exhibit A2-1-20 below provides an overview of natural gas demand in New England.

Exhibit A2-1-20: Natural Gas Demand (Bcf) in New England

(Billion cubic feet)	2008	2010	2015	2020	2025
Power generation	382	391	446	494	466
Non-power sector end use	457	465	488	498	508
Power (% of total gas demand)	46%	46%	48%	50%	48%

Demand growth (% per annum)	2008-10	2010-15	2015-	2020-25
Power generation	1.2%	2.7%	2.1%	-1.2%
Non-power sector end use	0.9%	0.9%	0.4%	0.4%

Pacific (contiguous)

The contiguous Pacific region, composed of California, Oregon, and Washington, is projected to experience a decline in natural gas demand. Regional gas demand for power generation is not expected to return to its 2008 level (1.0 Tcf) for the remainder of the forecast period. Non-power end-use gas demand in the region is also forecast to decline over the study period. For the period from 2010 to 2025, however, non-power sector gas demand exhibits moderate growth over time, indicating a gradual recovery in end-use demand following the recession. The contiguous Pacific region is the only U.S. Census region in which power generation demand for gas as a share of total regional gas demand is forecasted to decline over the study period (see Exhibit A2-1-21 below).

Exhibit A2-1-21: Natural Gas Demand (Bcf) in Pacific (contiguous)

(Billion cubic feet)	2008	2010	2015	2020	2025
Power generation	1,022	853	853	809	808
Non-power sector end use	1,857	1,774	1,809	1,823	1,848
Power (% of total gas demand)	36%	32%	32%	31%	30%

Demand growth (% per annum)	2008-10	2010-15	2015-	2020-25
Power generation	-8.7%	0.0%	-1.0%	0.0%
Non-power sector end use	-2.3%	0.4%	0.2%	0.3%

South Atlantic

The South Atlantic region, composed of Delaware, the District of Columbia, Georgia, Florida, Maryland, North Carolina, South Carolina, Virginia, and West Virginia, is projected to see robust growth in gas demand for power generation, with strongest growth expected to take place during the next five years. Gas demand for power generation is forecast to increase from 1.0 Tcf in 2008, to 2.2 Tcf in 2015, to 3.2 Tcf by 2025. Non-power sector end-use gas demand in the region will exhibit moderate growth, with 1.0 Tcf of incremental demand expected over the next 15 years. Gas demand for power generation as a share of total regional gas demand increases from 45 percent in 2008 to 69 percent by 2025. Exhibit A2-1-22 below provides an overview of natural gas demand in the South Atlantic region.

Exhibit A2-1-22: Natural Gas Demand (Bcf) in South Atlantic

(Billion cubic feet)	2008	2010	2015	2020	2025
Power generation	1,042	1,209	2,167	2,747	3,163
Non-power sector end use	1,286	1,351	1,404	1,425	1,447
Power (% of total gas demand)	45%	47%	61%	66%	69%

Demand growth (% per annum)	2008-10	2010-15	2015-	2020-25
Power generation	7.7%	12.4%	4.9%	2.9%
Non-power sector end use	2.5%	0.8%	0.3%	0.3%

West North Central

The West North Central region, composed of Iowa, Kansas, Minnesota, Montana, Nebraska, North Dakota, and South Dakota, is projected to triple its gas demand for power generation during the study period. In absolute terms, however, the increased power sector demand for gas is not substantial. With non-power end-use demand in the region projected to be flat over time (at around 1.0 Tcf per year), power sector demand will grow to account for 23 percent of regional gas demand by 2025, compared to only 7 percent in 2008. Exhibit A2-1-23 below provides an overview of natural gas demand in the West North Central region.

Exhibit A2-1-23: Natural Gas Demand (Bcf) in West North Central

(Billion cubic feet)	2008	2010	2015	2020	2025
Power generation	78	4	116	189	286
Non-power sector end use	1,008	958	970	967	983
Power (% of total gas demand)	7%	<1%	11%	16%	23%

Demand growth (% per annum)	2008-10	2010-15	2015-	2020-25
Power generation	-76.7%	93.9%	10.2%	8.6%
Non-power sector end use	-2.5%	0.2%	-0.1%	0.3%

West South Central

The West South Central region, composed of Arkansas, Louisiana, Texas, and Oklahoma, is expected to exhibit gas demand growth that decelerates over the forecast period. Gas demand for power generation is projected to grow from 1.4 Tcf in 2010 to 2.1 Tcf in 2025. Although Texas and Oklahoma have some of the best wind resources in the U.S. and over 22 GW of wind capacity is expected to be built in the region during the study period, demand growth and improving margins will support the development of additional CCGT capacity beyond 2020 (see Exhibit A2-1-14). End-use gas demand is forecast to grow from 4.1 Tcf in 2008 to 4.8 Tcf in 2015, and 5.0 Tcf by 2025. Gas demand for power generation as a share of regional demand for gas remains within a narrow range over the forecast period. Exhibit A2-1-24 below provides an overview of natural gas demand in the West South Central region.

Exhibit A2-1-24: Natural Gas Demand (Bcf) in West South Central

(Billion cubic feet)	2008	2010	2015	2020	2025
Power generation	1,681	1,430	1,737	2,026	2,112
Non-power sector end use	4,136	4,299	4,830	5,026	5,050
Power (% of total gas demand)	29%	25%	26%	29%	29%

Demand growth (% per annum)	2008-10	2010-15	2015-	2020-25
Power generation	-7.8%	4.0%	3.1%	0.8%
Non-power sector end use	1.9%	2.4%	0.8%	0.1%

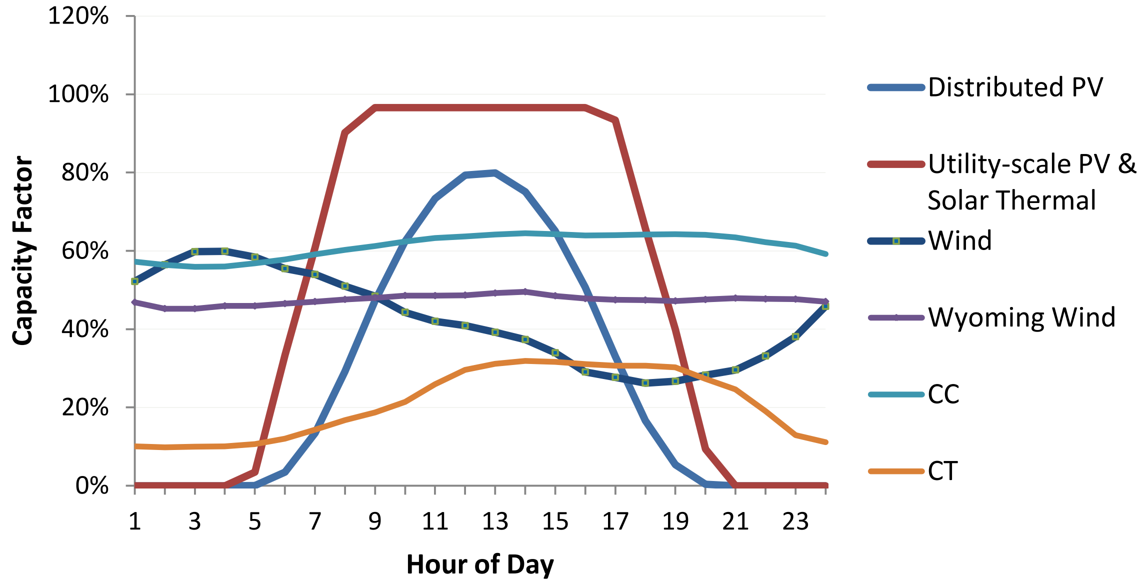
Chapter 2: Typical Regional Generation Profiles for Intermittent Renewable and Gas-fired Capacity

This chapter provides illustrative regional renewable and gas-fired generation profiles that are applied later in modeling work discussed in Chapter 5. The focus regions for this part of the analysis include Pacific 2 (California), Mountain 1 (Wyoming), West South Central (Texas/Oklahoma), and New England. We focus on these regions in particular due to their high natural gas consumption and high penetration of intermittent renewable generation.

Pacific 2 and Mountain 1

The generation profile discussion below pertains to the focus states, California and Wyoming, within these two census regions. The two exhibits below provide illustrative generation profiles of intermittent renewable and gas-fired facilities in these states. Both California and Wyoming have excellent renewable resources. Average hourly and monthly irradiance in both states is comparable, giving rise to similar peak-coincident solar generation profiles. However, wind generation differs noticeably between states as Wyoming wind is much more consistent on an hour-to-hour basis. Wyoming wind resource intermittency can contribute to capacity factors swings of five to 10 percent, while capacity factor changes can be as high as 30 percent in California. Wyoming wind may prove much more reliable during peak hours than California wind, which tends to drop-off leading into peak hours. Wyoming wind capacity factors are highest in winter months and lowest in summer months while California wind capacity factors tend to be highest in mid-to-late winter and drop off in the summer through the early winter. Typical combined cycle units and combustion turbine units in California have approximate average annual capacity factors of 75 and 50 percent, respectively.

Exhibit A2-2-1: Illustrative Avg. Hourly Capacity Factor of Pacific 2 Renewable and Gas Units

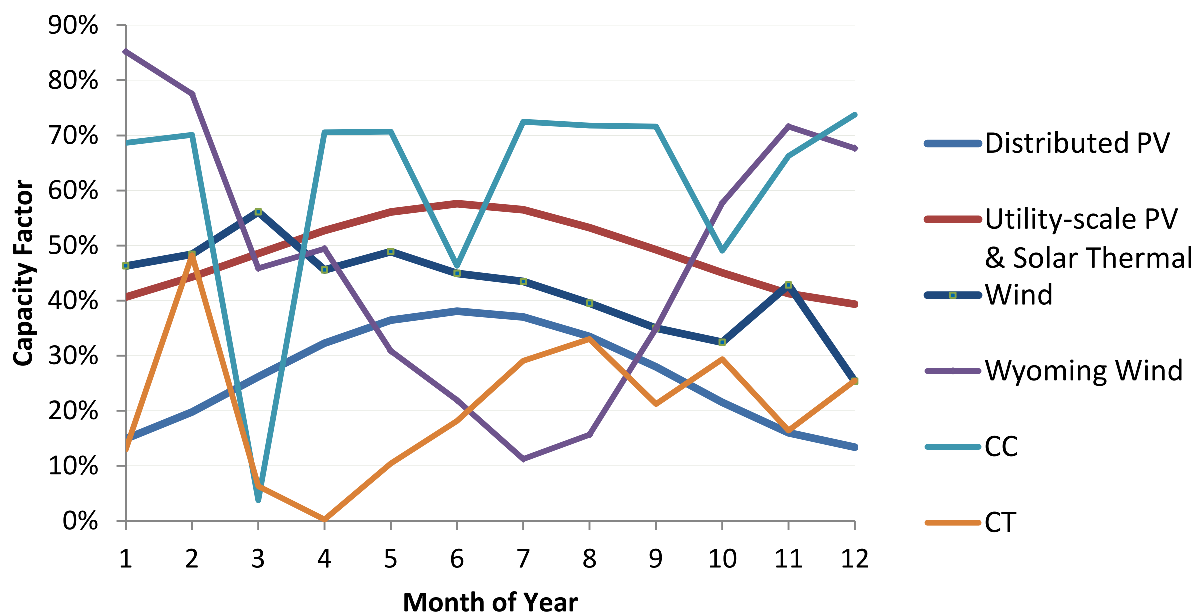


Sources: ICF Analysis, National Renewable Energy Laboratory (NREL), SNL Financial

Note: i) CC = Combined Cycle, CT = Combustion Turbine

ii) Capacity factors are relative for Distributed Solar PV, Utility-Scale Solar PV and Solar Thermal.

Exhibit A2-2-2: Illustrative Avg. Monthly Capacity Factor of Pacific 2 Renewable and Gas Units



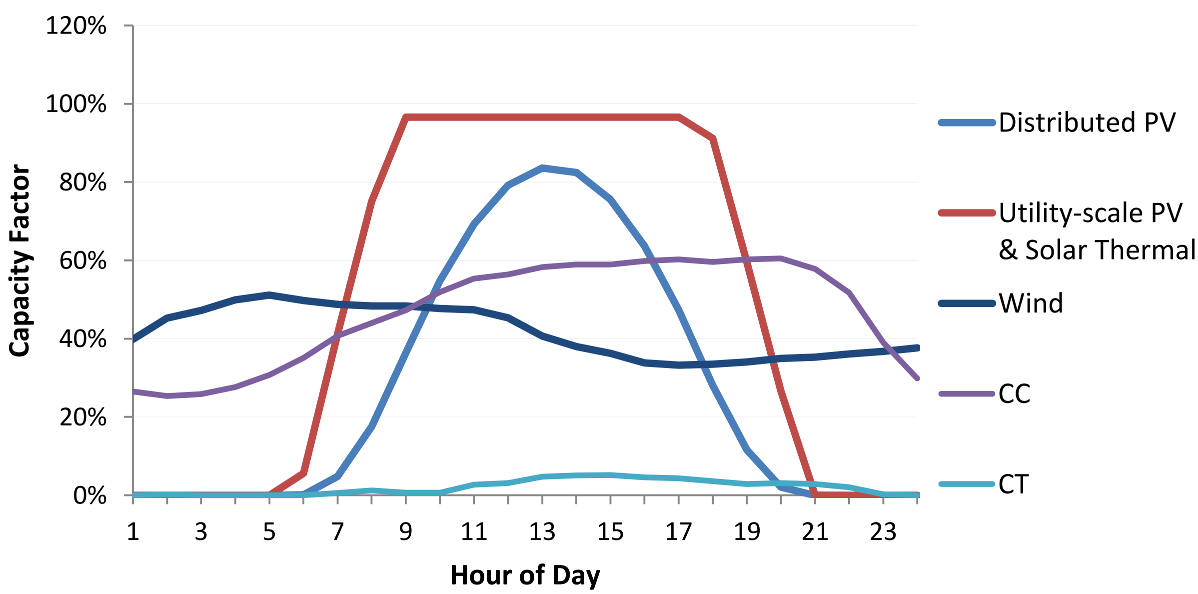
Sources: ICF Analysis, NREL, SNL Financial

Note: Capacity factors are relative for Distributed Solar PV, Utility-Scale Solar PV and Solar Thermal.

West South Central

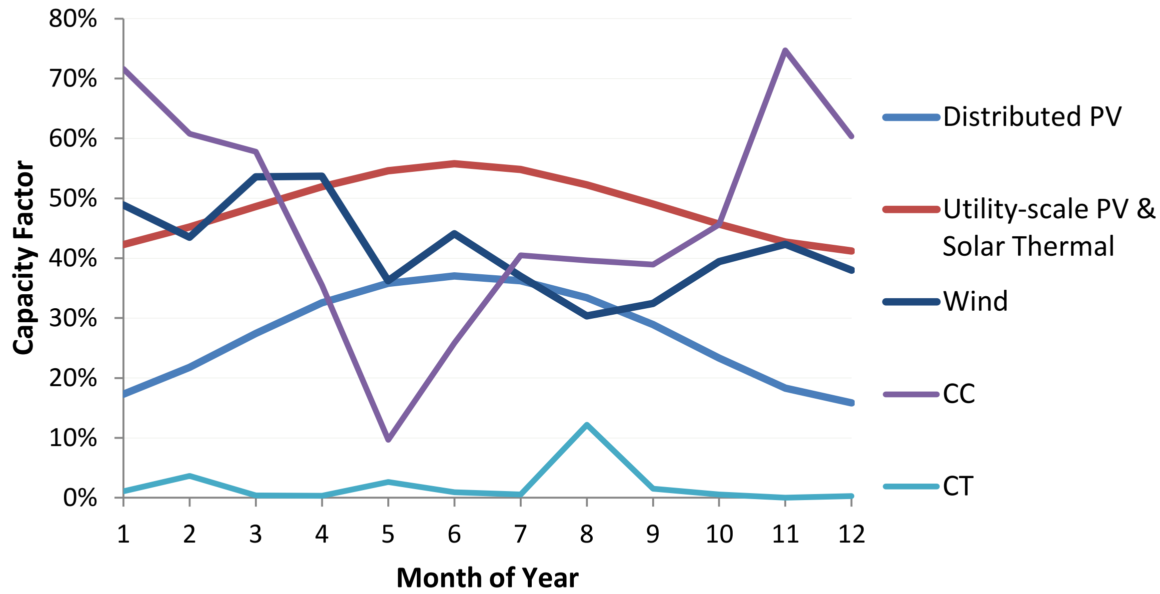
Much of the West South Central region, excluding Louisiana and most of Arkansas, has excellent solar and wind resources. The following generation profiles are representative of the SPP portions of Texas and Oklahoma within the West South Central region. The two exhibits below provide illustrative generation profiles of intermittent renewable and gas-fired facilities in these areas. A typical distributed solar facility in the region has a peak-coincident generation profile and an annual average capacity factor of approximately 23 percent. Typical utility scale solar PV and solar thermal facilities also have peak-coincident generation profiles and have an annual average capacity factor of approximately 31 percent. A typical wind facility in the region has an annual average capacity factor of 42 percent and has a generation profile that rises in the early hours of the day and falls for much of the remainder of the day. The daily and monthly average capacity factors of a wind facility may range from approximately 30 to 50 percent. Dramatic drop-offs in regional wind generation are very low frequency events. A typical CCGT has an annual average capacity factor of approximately 32 percent but may serve as base load in some winter and summer months during which it may have a monthly average capacity factor of up to 70 percent. A typical CT provides generation during peak hours and has an annual capacity factor of approximately 3 percent.

Exhibit A2-2-3: Illustrative Avg. Hourly Capacity Factor of West South Central Renewable and Gas Units



Sources: ICF Analysis, NREL, SNL Financial
Note: Capacity factors are relative for Distributed Solar PV, Utility-Scale Solar PV and Solar Thermal.

Exhibit A2-2-4: Illustrative Avg. Monthly Capacity Factor of West South Central Renewable and Gas Units

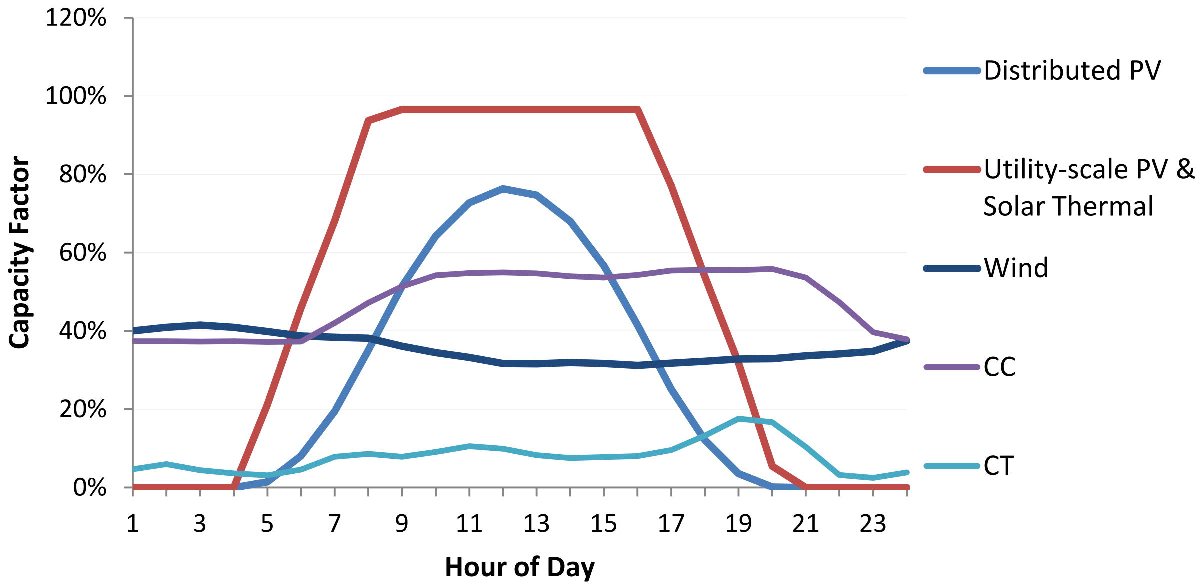


Sources: ICF Analysis, NREL, SNL Financial
Note: Capacity factors are relative for Distributed Solar PV, Utility-Scale Solar PV and Solar Thermal.

New England

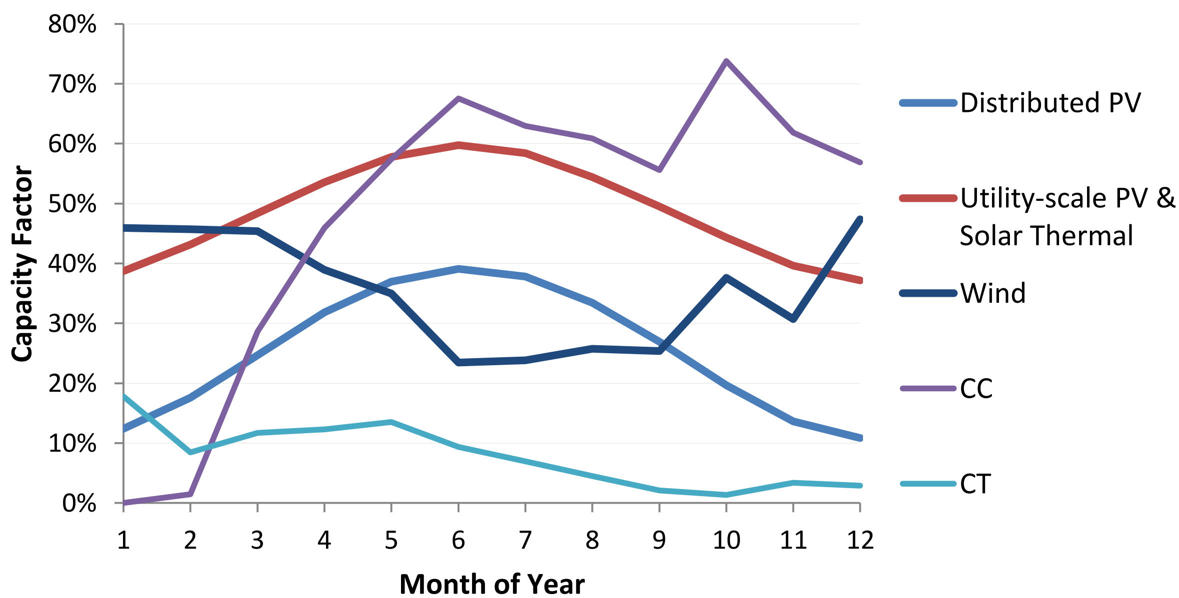
New England has average quality solar resources and medium to high quality wind resources. The two exhibits below provide illustrative generation profiles of intermittent renewable and gas-fired facilities in this area. Typical solar facilities in the region have peak-coincident generation profiles and have the highest average monthly capacity factors during the summer months. Distributed PV systems and utility scale PV systems have annual average capacity factors of approximately 17 percent and 22 percent, respectively. The region's non-peak-coincident wind resources are strongest in the winter and weakest in the summer, ranging from roughly 23 percent to 47 percent. A typical combined cycle unit in the region has an annual average capacity factor of about 50 percent and a typical combustion turbine unit has an annual average capacity factor of 8 percent.

Exhibit A2-2-5: Illustrative Avg. Hourly Capacity Factor of New England Renewable and Gas Units



Sources: ICF Analysis, NREL, SNL Financial
Note: Capacity factors are relative for Distributed Solar PV, Utility-Scale Solar PV and Solar Thermal.

Exhibit A2-2-6: Illustrative Avg. Monthly Capacity Factor of New England Renewable and Gas Units

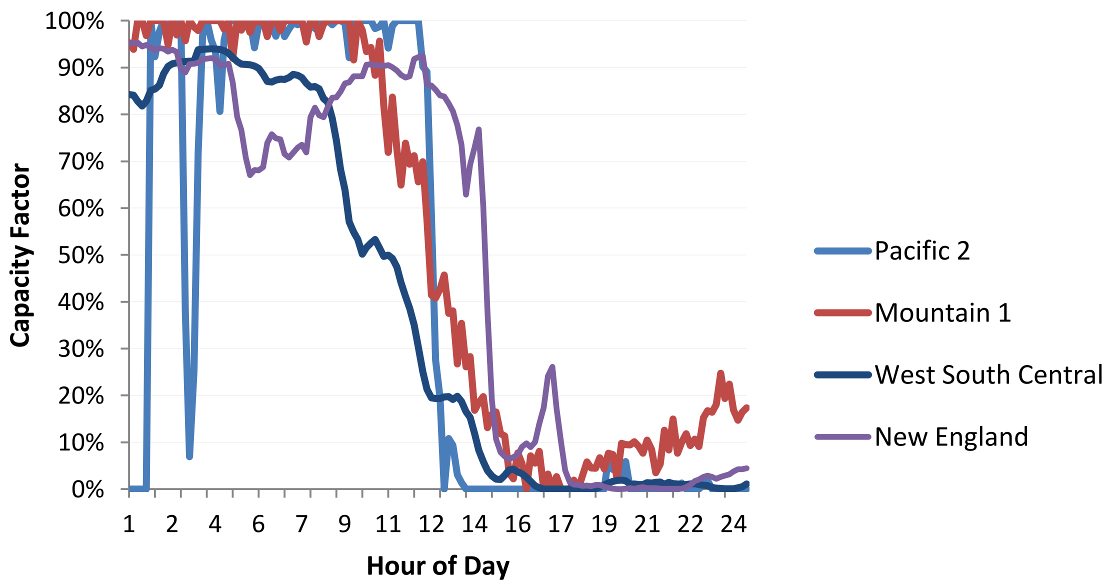


Sources: ICF Analysis, NREL, SNL Financial
Note: Capacity factors are relative for Distributed Solar PV, Utility-Scale Solar PV and Solar Thermal.

Wind Variability and the Scale of Wind Generation Relative to Gas-Fired Generation

Unforeseen extreme wind variability puts significant strain on a power system and may create a need for firming resources. Exhibit A2-2-7 below displays the extent of wind generation variation on days with the greatest wind resource variability in the focus regions of this study. A few dozen days a year may have comparable variability though only a handful are unanticipated and even fewer occur on low load days when systems are typically at the greatest risk of experiencing instability.

Exhibit A2-2-7: Illustrative Wind Generation Profile on a High Variability Day by Region



Source: NREL Wind and Solar Integration Project

The total system impact of such low frequency wind days may be minimal as wind penetration levels in many regions are not yet significant enough to warrant large-scale investment in resources designed solely to provide firming capacity. The following three exhibits provide a comparison of ICFs projected annual wind generation and annual gas-fired generation (CCGT and GT). These charts highlight the small scale of total wind generation relative to total gas-fired generation in the focus regions in across the forecast period. Significant new wind and gas-fired capacity is added in these focus regions over the forecast period, though the growth of gas-fired generation outpaces that of wind generation.

Exhibit A2-2-8: ICF Projected Annual Wind Generation v. Natural Gas-fired Generation[15] in Pacific 2 (CA) and Mountain 1 (WY)

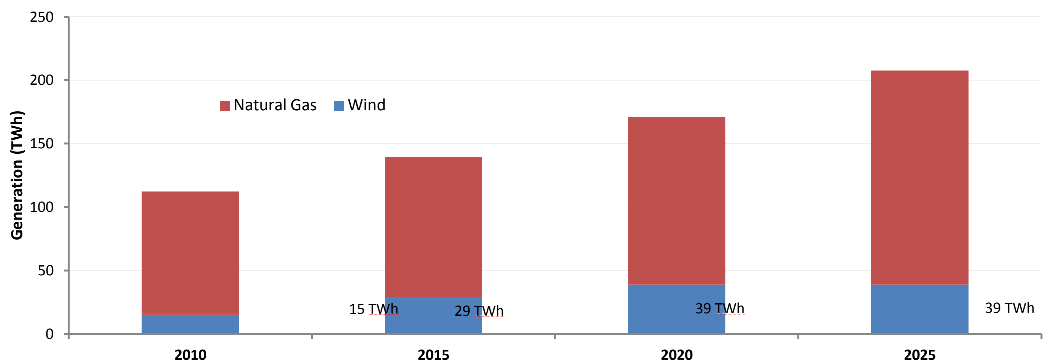
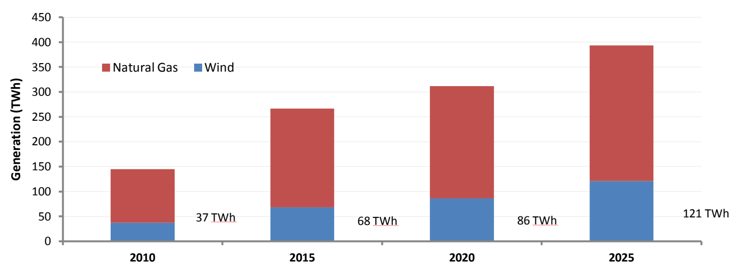
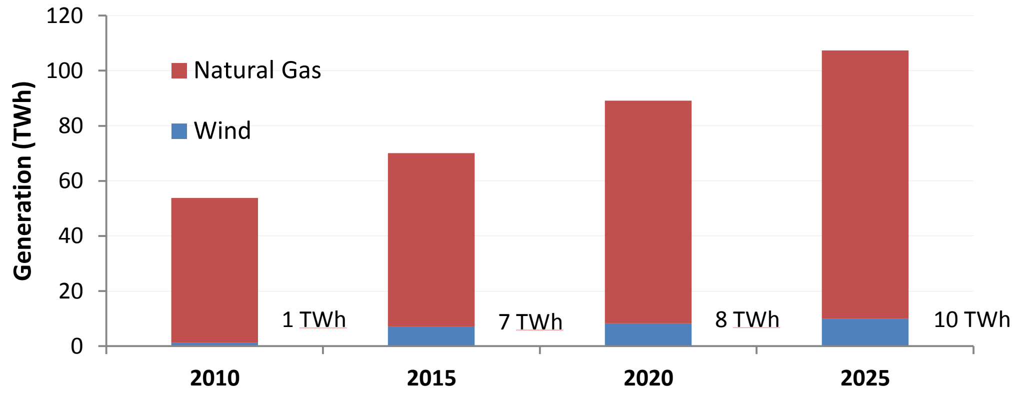


Exhibit A2-2-9: ICF Projected Annual Wind Generation v. Natural Gas-fired Generation in West South Central



[15] Just CCGT and GT gas-fired generation

Exhibit A2-2-10: ICF Projected Annual Wind Generation v. Natural Gas-fired Generation in ISO-NE



Chapter 3: Analysis of Technology Alternatives

This chapter provides an analysis of technologies besides fossil fuel-fired generation that may be used to mitigate the potential effects of intermittent renewables. Presently, most system reliability services[16] in the U.S. are provided by gas-fired (CT and CCGT) and coal-fired (steam turbine) facilities.[17] The exhibit below provides a brief overview of the advantages and disadvantages of relying on these conventional generation technologies to provide system reliability services.

Exhibit A2-3-1: Overview of Conventional Providers of System Reliability Services

Prime Mover	Advantages	Disadvantages
CT and CCGT	• Fast response time • Fast ramp rate • Capable of providing a wide range of reliability services • Less emissions intensive than coal	• May be prohibitively expensive to develop if limited additional reliability services are needed • Requires transmission and fuel • Siting difficulty in some regions
Steam Turbine	• Large capacity to provide reliability services • Capable of providing a wide range of reliability services	• Prohibitively expensive to develop if limited additional reliability services are needed • Slow response time from cold start • Very emissions intensive • Requires transmission and fuel • Siting difficulty in some regions

The exhibit below provides illustrative ramp rates for conventional generation technologies. Faster ramp rates indicate greater ability to quickly respond to and meet system operator requests for certain reliability services. Natural gas-fired facilities offer noticeably faster ramp rates from cold start (from 0 percent load) than do coal-fired facilities though both types of facilities have comparable ramp rates from 50 percent load. Coal-fired facilities are much more emissions intensive than a gas-fired facility when increasing or decreasing output.

[16] We provide an overview of the range of system reliability services later in the chapter.

[17] Hydro facilities also provide system reliability services. We discuss hydro resources later in the chapter.

Exhibit A2-3-2: Illustrative Ramp Rates of Conventional Providers of System Reliability Services

Prime Mover	Startup Type	Capacity (MW)	Time to 100% Load (minutes)	Ramp Up (MW/Min)
CT	Cold Start	165	30	6
	From 50% Load	83	12	7
CCGT	Cold Start	250	145	2
	Hot Start	250	45	6
	From 50% Load	125	20	6
Steam Turbine	Cold Start	-	-	n/a for the first 9-12 hours
	From 50% Load	-	-	4 to 6

Given their technological maturity and known costs of providing reliability services, CTs, CCGTs and steam turbines will most likely continue to provide the majority of reliability services for the foreseeable future. However, as intermittent renewable generation increasingly penetrates energy markets, system operators will likely require more reliability services and require that a more dynamic resource mix provide those services. Demand response (DR) programs and energy storage technologies will likely add to the diversity of this resource mix as both offer greater flexibility and potential cost savings. These non-traditional providers of system reliability services and may become key renewable firming resources as their technologies mature and costs decline.

Demand Response Overview

Demand response (DR) programs pay electricity users (typically large users like industrial facilities) to curtail energy consumption during periods of high energy demand. DR programs may greatly mitigate the demand for some reliability services by allowing a system operator to make short-term load adjustments to compensate for unforeseen changes in energy supply and demand. Demand response resources may be used to directly mitigate the system impact of sudden and substantial decreases in generation from renewable resources.

Many existing large-scale demand response programs have proven to be very effective system management tools and are quickly growing in size. DR resources play a major role in many markets such as California and New England, representing 4.3 percent[18] and six percent[19] of

[18] California ISO. 2010 Summer Loads and Resources Operations Preparedness Assessment. May, 2010.

[19] ICF Analysis of ISO-NE forecasts and ISO-NE Forward Capacity Market (FCM) results.

peak load, respectively. FERC recently found that if existing programs were to expand to other states, peak load could be reduced between 9 and 20 percent by 2019.[20]

While existing demand response programs rely primarily on industrial and commercial customer participation, smart grid and smart appliance technologies will allow a much larger portion of residential customers to participate. These technologies enable two-way communication between end-users and suppliers, making it possible for consumers and their appliances to adjust consumption behavior based on real-time price signals. Given that residential electricity sales represent more than a third of total annual electricity sales in the U.S., significantly boosting residential participation in demand response programs could greatly expand program flexibility and improve the ability of program operators to mitigate the impacts of intermittent renewables.[21] In addition to providing load shedding service, demand-side resources may also provide spinning reserve reliability service in the near future. DR resources successfully provided spinning reserve reliability services in a recent California-sponsored demonstration project.[22]

Some industry experts have expressed concern regarding the reliability of demand response resources because in some areas, such as ISO-NE, program participants who fail to meet curtailment commitments incur minimal penalties. As DR programs grow and reduce the need for new supply-side resources, program participant reliability will become increasingly important to maintain system reliability. Nevertheless, given the success of current programs, demand response resources may likely play a major role in mitigating the effects of intermittent renewable generation.

Energy Storage Systems Overview

Demand response programs will provide system operators with some but not all the tools needed to address the low frequency, high impact issues associated with intermittent renewable generation. System operators will still experience a growing need for reliability services like transient stability, contingency reserves, and ramping. While traditionally provided by thermal generators, these services will increasingly be provided by energy storage systems. The system benefits that energy storage systems may provide fall under the following reliability service classes: power quality, bridging power, and energy management. Exhibit A2-3-3 below provides an overview of these classes. Although most energy storage systems are not yet cost-effective, they offer faster response times and significantly smaller carbon footprints than traditional thermal providers of reliability services such as combined cycle facilities. In the future, energy storage systems will also provide system operators with more flexible system reliability service options as the most flexible of the traditional thermal providers become increasingly displaced in supply schedules by intermittent renewables. Additionally, storage

[20] FERC. A National Assessment of Demand Response Potential. June, 2009.

[21] EIA. Table 5.1 Retail Sales of Electricity to Ultimate Customers: Total by End-Use Sector. March, 2010.

[22] LBNL. Demand Response Spinning Reserve Demonstration Project. 2006.

systems may permit system operators to defer substation and transmission investments. While the potential reliability service market penetration of these technologies will be limited in the near-term, it will likely grow rapidly in the mid-to-long term. The remainder of this discussion will examine the major energy storage technologies and assess the potential timing and extent of their development.

Exhibit A2-3-3: Overview of Energy Storage Classes

Energy Storage Class	Example Applications	Discharge Time	Best Suited Technologies*
Power Quality	• Frequency Regulation • Transient Stability	Seconds – Minutes	• Flywheel • Ultracapacitor • Superconducting Magnetic Energy Storage (SMES)
Bridging Power	• Contingency Reserves • Ramping	Minutes – Hours	• Liquid Flow Batteries • Advanced Batteries • Electric Vehicle to Grid (V2G)
Energy Management	• Load Leveling • Firm Capacity • T&D Deferral	Hours	• Compressed Air Energy Storage (CAES) • Hydrogen Fuel Cell • Thermal Energy Storage

Source: NREL, ICF Analysis
*Note: Many storage technologies are capable of providing services in multiple classes; however, a technology's class assignment reflects which services they would best be suited to provide in a world in which a wide range of specialized storage systems are available and given current cost estimates.

Power Quality Overview

Power quality services, including transient stability and frequency regulation, require very fast response times, short-term dispatch, and continuous cycling. To maintain transient stability is to ensure that a system can quickly return to stable operation following a voltage disruption. Frequency regulation is a service that quickly increases or decreases grid frequency to smooth out small, unpredictable variations in supply and demand.[23] Load forecast error is the primary driver of demand for regulation services. Storage technologies specialized to provide power

[23] NREL. The Role of Energy Storage with Renewable Electricity Generation. January, 2010.

quality services include flywheels, ultracapacitors, and Superconducting Magnetic Energy Storage (SMES) energy storage systems.[24]

POWER QUALITY TECHNOLOGIES

Flywheels

Flywheels store kinetic energy in a rotating cylinder in a near frictionless/vacuum environment.

Exhibit A2-3-4: Flywheel Technology Advantages and Disadvantages

Advantages	Disadvantages
• High charge/discharge efficiency (up to 90 percent) • Flexible ambient temperature needs • Longevity (up to 20 years) and low maintenance (lower lifetime costs than battery storage systems)	• High initial costs • Limited discharge time (not an issue for some designs)[25]

While there are only a few small flywheel installations in the U.S., government grants and loan guarantees are enabling the development of new projects. Beacon power, the leading developer of commercial flywheels, has been running a successful 1 MW pilot project in ISO-NE since 2008 and recently received a $43 million DOE loan guarantee for a 20 MW New York facility and a $24 million stimulus grant for a second 20 MW facility. Though still in the early stages of commercial deployment, the technology exhibits much potential. With continued government support and robust prices for regulation service, utility-scale flywheels could be widely deployed to meet renewable intermittency concerns this decade.

Ultracapacitors

Ultracapacitors, also known as supercapacitors or electric double layer capacitors, store energy in an electric charge on the surface of two electrodes (plates) of opposite polarities separated by an electrolyte.

[24] Please note, other storage technologies, such as pumped hydro storage, are technically capable of providing this class of reliability service.

[25] Pembina Institute. *Storing Renewable Power.* June, 2008.

Exhibit A2-3-5: Ultracapacitor Technology Advantages and Disadvantages

Advantages	Disadvantages
• High charge/discharge efficiency (up to 95 percent) • Longevity (up to 20 years) and low maintenance(lower lifetime costs than battery storage systems)	• Low energy density (1/5 to 1/10 of battery technologies) • Voltage balancing requirements to support multiple units • High temperature requirements and associated self-discharge increase and lifetime reduction • Rapid discharge (seconds) and associated flexibility limits [26]

Currently there are only a few ultracapacitor demonstration projects, though federal grants and subsidies will help stimulate project development. In its most recent round of funding, the DOE provided a grant of over $5 million to one ultracapacitor developer. At this time it appears that, while promising, ultracapacitor technology is still several years away from being deployed commercially and more than a decade away from substantial utility-scale development.

Superconducting Magnetic Energy Storage (SMES)

SMES systems store energy within the magnetic field of a large coil of material that is super-cooled to become superconducting.

Exhibit A2-3-6: SMES Technology Advantages and Disadvantages

Advantages	Disadvantages
• Fast dispatch • Fast recharge • High efficiency • Lack of moving parts	• Low energy density • Significant cooling needs and associated high energy and maintenance costs[27]

The first SMES demonstration project was a 10 MW device that commenced operation in 1979 and was used by the Bonneville Power Administration. While there are currently a handful of commercial facilities and several demonstration projects, the upfront cost of a SMES facility is still too high for many additional projects to be developed. As technological advances continue and costs decline, SMES technology will likely be a frontrunner in the energy storage space, though substantial utility-scale development is more than a decade away.

[26] Pembina Institute. *Storing Renewable Power.* June, 2008.

[27] EPRI. Energy Storage Technologies for Distributed Energy Resources and Other Electric Power Systems Part I-Energy Storage Technology Overview. August, 2003.

Bridging Power Overview

Bridging power services, including contingency reserves (spinning) and ramping, requires very fast response times, longer-term dispatch, and intermittent cycling. Contingency reserves provide extra energy when needed due to unforeseen changes in system energy supply or demand. Ramping service provides a system operator with greater flexibility when dealing with significant and/or unforeseen changes in ramp up or ramp down rates required to follow load. Battery storage systems are generally the best type of storage system to provide bridging power services and are one of several technologies suitable to support energy management. While capable of doing so, battery storage systems typically are not used to provide power quality services as continuous cycling considerably reduces a battery system's operating life.[28]

BRIDGING POWER TECHNOLOGIES

Liquid Electrolyte "Flow" Batteries

Flow batteries store and release energy through an electrochemical reaction made possible by the flow of an electrolyte over a membrane/cell stack. The liquid electrolyte is stored in external reservoirs, the volume of which determines the system's electric storage capacity. Several flow technologies are in development, the most promising of which are polysulfide bromide (PSB), zinc bromine (ZnBr), hydrogen bromine (H-Br) and vanadium redox battery (VRB).

Exhibit A2-3-7: Flow Battery Technology Advantages and Disadvantages

Advantages	Disadvantages
• High capacity potential • Long, flexible discharge times • Fast response time • Modular construction • High charge/discharge efficiency (up to 96 percent) • Low incremental upgrade costs • Longevity and low maintenance costs (lower lifetime costs)	• High upfront costs • Large space requirements (multiple story building for some applications) • Toxicity of some electrolyte fluids[29]

Even though small-scale flow battery storage systems have been installed at more than a dozen commercial sites worldwide, flow technologies are still in the demonstration phase and must realize significant cost reductions before they will be widely developed. The DOE recently issued over $30 million in grant money to five developers of flow storage facilities ranging from

[28] NREL. The Role of Energy Storage with Renewable Electricity Generation. January, 2010.

[29] Pembina Institute. *Storing Renewable Power.* June, 2008.

500 kW to over 1 MW. Large-scale flow storage systems will likely not be commercially viable for at least several more years.

Advanced Batteries

There are a variety of advanced battery technologies in development such as sodium-sulfur (NaS), sodium-nickel chloride (ZEBRA), lithium polymer, and lithium ion (Li-ion) battery technologies. Mature technologies include lead-acid and nickel-cadmium batteries which are being phased out gradually due to their toxicity and the advantages of newer technologies.

Exhibit A2-3-8: Advanced Battery Technology Advantages and Disadvantages

Advantages	Disadvantages
• High energy density • Fast response time • Modular construction • Small space requirements • High charge/discharge efficiency (NaS – up to 90 percent; Li-ion > 95 percent)	• High temperature requirement (NaS - ~300°C; not applicable to all advanced batteries) • High upfront costs • Limited cycle lifetime (high lifetime costs)[30]

While advanced batteries are still in the demonstration phase, over 270 MW of demonstration sodium sulfur storage systems were in development globally as of 2009.[31] Lithium ion systems, while less mature, are attracting private investment and federal support. The DOE recently issued more than $45 million in grants to six developers of advanced battery storage facilities, three of which will be lithium ion-based manufacturing facilities. Advanced battery technologies will likely be among the first storage technologies widely deployed on a utility-scale to firm renewable generation.

Vehicle-to-Grid (V2G)

The vehicle-to-grid storage concept refers to the use of a large population of plug-in electric vehicle (PEV) and plug-in hybrid electric vehicle (PHEV) batteries to store and later dispatch power to provide reliability services. The battery technologies relied upon would be similar or identical to one or more or the advanced battery technologies described above. While the implementation of V2G technology could provide significant flexibility to grid operators as more electric vehicles are sold and programs become available, a variety of barriers could prove prohibitive to the large-scale implementation of V2G systems in the near to mid-term.

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[30] Pembina Institute. *Storing Renewable Power.* June, 2008.

[31] NREL. The Role of Energy Storage with Renewable Electricity Generation. January, 2010.

A number of technical issues associated with V2G technology, such as potential backflow, power spikes, and frequency instability could necessitate very expensive control systems and require complicated operational procedures that could also limit V2G program popularity. An overarching issue facing the V2G concept is customer participation, which will not only be limited by electric vehicle market penetration but also by the consumer acceptance of V2G programs. Providing regulation service is not expected to reduce PEV battery life or prevent PEV charging,[32] though it is unclear whether PEVs providing other reliability services could avoid these issues. Establishing industry standards for V2G systems is a key first step needed facilitate the deployment of V2G systems but standards are just beginning to be developed.[33]

While a well designed V2G program with appropriate control systems and the widespread use of better battery technology could likely overcome these and many other potential barriers, there is little evidence that the conditions necessary to implement a sizable V2G program will materialize this decade.

Energy Management Overview

Energy management benefits associated with energy storage systems include load leveling, capacity firming, and transmission and distribution (T&D) deferral. This class of benefits makes it possible to shift the dispatch of power over longer timeframes, thereby reducing the extent to which additional power quality and bridging power services are needed to integrate intermittent renewable resources. Load leveling makes it possible to take low-cost energy generated in off-peak hours and sell it during on-peak hours. Capacity firming refers to the use of stored energy to replace or function as peaking generators, and T&D Deferral refers to the ability of a system operator to defer investment in transmission and distribution lines and substations by mitigating T&D loading during peak hours.[34]

ENERGY MANAGEMENT TECHNOLOGIES

Pumped Hydro Storage (PHS)

PHS systems use power produced during off-peak hours to pump water from a reservoir at a lower elevation to a reservoir at a higher elevation. The PHS facility releases water from the higher reservoir during peak hours to provide electricity and reliability services. There are over 22 GW of operational pumped storage hydro in the U.S., much of which provides reliability services associated with all three energy storage classes.[35] Existing pumped storage facilities will likely provide additional reliability services in the future.

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[32] KEMA, ISO/RTO Council (IRC). Assessment of Plug-in electric Vehicle Integration with ISO/RTO Systems. March 2010.

[33] National Institute of Standards and Technology (NIST). NIST Framework and Roadmap for Smart Grid Interoperability Standards - Release 1.0. January, 2010.

[34] NREL. The Role of Energy Storage with Renewable Electricity Generation. January, 2010.

[35] Ventyx

Exhibit A2-3-9: Pumped Hydro Storage Technology Advantages and Disadvantages

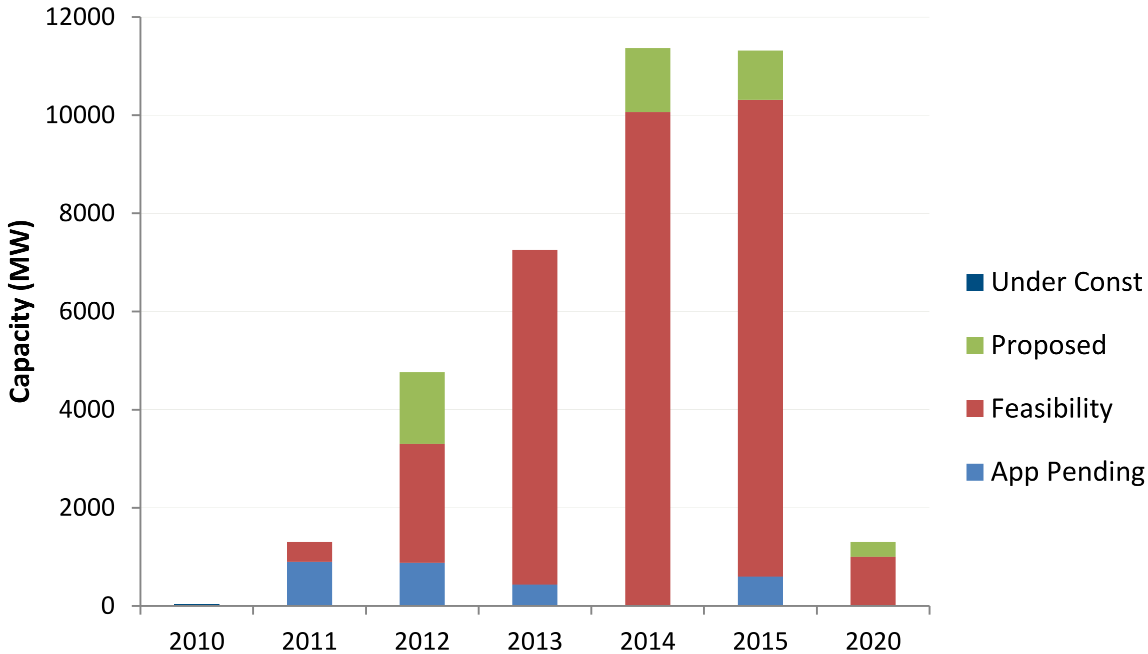
Advantages	Disadvantages
• Mature technology • Fast response time (with spinning turbines) • High round-trip efficiency (up to 85 percent) • Significant discharge capacity (up to 22 hours) • Longevity (50+years) and associated low lifetime costs	• Long lead times • High upfront costs • Geographical constraints • Significant land and water requirements[36]

Little additional pumped storage hydro capacity has come online over the past two decades due to local opposition, lack of policy support, and a collapse in natural gas prices. In the last decade, ten pumped storage projects representing more than 7 GW of capacity have been cancelled. More than eight of those projects, collectively amounting to over 5 GW, were canceled in 2009 as the recession drove down natural gas prices and energy demand. Nevertheless, approximately 30 GW of new pumped hydro capacity was proposed between 2006 and 2009, indicating a continued interest in development.[37] The exhibit below provides an overview of the pumped storage project pipeline in the U.S.

[36] Pembina Institute. *Storing Renewable Power.* June, 2008.

[37] NREL. The Role of Energy Storage with Renewable Electricity Generation. January, 2010.

Exhibit A2-3-10: Proposed Pumped Hydro Storage Projects by Status and Proposed Online Date



Source: Ventyx
Note: Pumped hydro projects in the feasibility stage typically have obtained a preliminary permit from FERC.[38] Projects in the application pending stage have submitted applications for one or more permits and/or licenses on the county, state, or federal level.

Currently the 40 MW Olivenhain Hodges Pumped Storage project in California is the only facility under construction in the U.S. Over 60 percent of proposed pumped storage projects are located in the Western Electricity Coordinating Council (WECC) NERC region and another 15 percent are located in the Northeast Power Coordinating Council (NPCC) region.

Challenges facing planned large hydro project are very site specific, thus making it very difficult to determine how many projects will ultimately succeed. However, we can determine that only two of the proposed projects in the pipeline can successfully developed this decade as they are the only two to have initiated the FERC licensing process which typically takes five years to

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[38] While FERC has issued preliminary permits to 32 pumped storage projects with an aggregate capacity of more than 25.6 GW, the fact that these permits have been issued does not indicate that a large tranche of new capacity will soon be developed. Preliminary permits merely reserve a site for a particular developer for three years, a period during which FERC expects developers to work towards initiating the licensing process (the permit essentially gives developers three years to conduct a feasibility study). Permits for 13 of the projects expire by the end of 2011 and permits for the remaining 19 expire by the end of 2012.

complete.[39] Developers must procure a license from FERC as well as other permits (the number of which is site specific) before they may begin construction. Historically, not all FERC licensed projects have been constructed. The construction of new pumped storage project generally takes about five years. Assuming that there are no major delays in the licensing process, the procurement of other necessary permits, financing or construction, it will take about 10 years to successfully develop a project starting from the date it begins the FERC licensing process. Considering these constraints, we believe that no more than a few proposed pumped storage projects could be successfully developed before the mid 2020s.

Compressed Air Energy Storage (CAES)

CAES technology stores off-peak energy by using it to compress air in an underground cavern (ex. salt cavern, mine). The energy is extracted by releasing the compressed air, mixing it with natural gas, and powering a turbine by burning the mixture.

Exhibit A2-3-11: CAES Technology Advantages and Disadvantages

Advantages	Disadvantages
• Significant capacity (largest existing facility:290 MW; largest proposed: 2700 MW+)[40] • Improved gas turbine heat rate efficiency • Accelerated gas turbine ramp rates • Lower gas turbine emissions • Cost-effectiveness relative to other storage options	• Reduced performance in cooler climates • Natural gas requirement (124 PSI or higher)[41] • Geographic constraints (due to large storage reservoir requirement)[42]

CAES technology has been commercially deployed at a 110 MW facility in Alabama since 1991 and a 290 MW unit in Hundorf, Germany since 1978. Several other projects are under development including the 200 MW Iowa Stored Energy Park, a 300 MW, $366 million PG&E facility in California, and a 150 MW, $125 million Iberdrola facility in New York. Both the PG&E project and the Iberdrola project recently received DOE grants amounting to roughly $25 million and $30 million respectively. To provide some context to the number of projects that

[39] Source: FERC eLibrary. These two projects include Eagle Mountain Pumped Storage (1.3 GW) and Elsinore Valley Municipal Water District (.5 GW) both of which are in California. This is the typical time frame for a project applying through the new Integrated Licensing Process (ILP) which involves a three year pre-filing process (which involves two years of studies) and a two year application approval process. While the Eagle Mountain project is applying through the ILP, the Elsinore project is applying using the traditional application process (which takes longer than the ILP process but has less strict deadlines and little public utility commission involvement).

[40] Duke University CCPP. *Energy Storage for Low-Carbon Electricity-Policy Brief*. January, 2009.

[41] NYSERDA. *Compressed Air Energy Storage Engineering and Economic Study*. December, 2009. A new CAES design, known as Adiabatic CAES, requires electricity but not fuel. This technology is still in its infancy.

[42] Pembina Institute. *Storing Renewable Power.* June, 2008.

could be developed in a given state, a recent New York State Energy Research and Development Authority (NYSERDA) study found that New York had 10 or more suitable and cost effective sites for 100MW+ CAES facilities.[43] CAES technology is one of the most promising utility-scale energy storage systems and numerous CAES projects could be developed in select regions of the country within the coming decade.

Thermal Energy Storage

Thermal energy storage involves the use of a medium such as heated water, ice, or heat transfer fluid. The use of solar water heaters and ice cooling systems, which create ice in off-peak hours to cool air during on-peak hours, are both widely used to reduce or offset home and facility energy demand for heating and cooling. Thermal storage for heating and cooling purposes can reduce system load during peak hours and providing load shifting and a form of demand response. However, the small-scale and geographic dispersion of such installations renders them unable to directly minimize the impact of intermittent renewables.

Concentrating solar power (CSP) storage technology uses heat collected by the troughs or power towers of a CSP to warm a heat transfer fluid (HTF) such synthetic oil, molten salt, or water. The HTF is stored in an insulated container and later released to produce superheated steam that then drives a turbine. The energy can be stored for days and provide hours of power. CSP storage is highly efficient but its contribution to providing system reliability services will be limited given the high cost, permitting challenges, transmission needs, and geographic constraints (limited to southwestern U.S.). Additionally, most proposed CSP facilities do not include storage systems given that the addition of a 6-hour storage option can raise upfront capital costs by up to 50%.[44] For these reasons, the ability of molten thermal storage technology to address renewable intermittency this decade will be limited.

Hydrogen Fuel Cells

Hydrogen energy storage systems store energy by using energy to split hydrogen from water (water electrolysis), storing the hydrogen and later using it to produce power through a fuel cell stack (typically a proton exchange membrane, or PEM). Despite the high energy density of hydrogen, absence of harmful emissions, and the reliability of fuel cells, hydrogen storage systems have several disadvantages that may limit the potential success of the technology in the near to mid-term. These shortcomings include the large space requirements, short lifespan of fuel cells, high cost, and very low efficiency (30-50 percent) relative to other storage technologies.[45] The National Renewable Energy Laboratory (NREL) and Xcel Energy recently initiated a $2 million joint demonstration project to further explore the technology. Given that

[43] NYSERDA. Compressed Air Energy Storage Engineering and Economic Study. December, 2009.

[44] World Resource Institute & Goldman Sachs. Juice from Concentrate-Reducing Emissions with Concentrating Solar Power. May, 2009.

[45] Pembina Institute. *Storing Renewable Power.* June 2008.

utility-scale hydrogen storage technology is still in its infancy, it is unlikely that cost-effective commercial installations could be deployed in this decade.

The exhibit below provides an overview of the development stage of storage technologies by capacity and dispatch capabilities.

Exhibit A2-3-12: Overview of Technologies

	Concept Stage		Demonstration Stage		Commercial Stage	
Energy Storage Dispatch Requirement						
Capacity	**Seconds**	**Hours**	**Seconds**	**Hours**	**Seconds**	**Hours**
Several kW			• Ultracapacitor	• Flywheel • Lithium/Metal Air Battery		• Thermal Storage (heating and cooling)
100s of kW - few MW		• Flywheel • Advanced Batteries	• Ultracapacitor	• Flow Batteries • Hydrogen fuel cell	• Flywheel • SMES	
10s of MW	• Flywheel • Ultracapacitor			• Advanced Batteries • Thermal Energy Storage • CAES • Hydrogen fuel cell	• SMES	
100s of MW			• SMES	• Thermal Storage		• CAES • Pumped hydro

Source: EPRI[46], ICF Analysis

Capital Costs

Capital cost estimates for power-sector energy storage technologies vary greatly depending on the services provided, maturity, and installation size. Note that the illustrative capital costs provided below represent only one component of the total cost of these systems.

[46] EPRI. Energy Storage Technologies for Distributed Energy Resources and Other Electric Power Systems Part I-Energy Storage Technology Overview. August, 2003.

Exhibit A2-3-13: Illustrative Capital Cost Estimates by Energy Storage Type

Energy Storage Type	Illustrative Capital Cost per Unit Power ($/kW)
Long Duration Ultracapacitor	$250 to $700
CAES	$980 to $1,100
Pumped Hydro	$700 to $2000
Flow Batteries	$800 to $2700
Advanced Batteries	$400 to $4,000
Long Duration Flywheel	$3,000 to $10,000
High Power Flywheel	$250 to $500
High Power Ultracapacitor	$100 to $500
Hydrogen Fuel Cell	$4000-$5500
CSP with 6 hours Storage	$6000+

Source: Electricity Storage Association, World Resource Institute, Connecticut Center for Advanced Technology, NYSERDA, ICF Analysis
*Note: CAES cost range includes the cost of a GE 7FA gas turbine and assumes an online year of 2014

The exhibit below provides illustrative costs for combined cycle and combustion turbine units. CCGTs and CTs, in addition to large-scale energy storage facilities (ex. pumped storage, CAES, CSP) may require significant transmission upgrades. While estimates for transmission costs vary by location, capacity, and type of transmission, we estimate that a typical new 500kV line costs $2 million per mile (nominal $).

Exhibit A2-3-14: Illustrative Capital Costs of Conventional Generation Technologies

Conventional Technology	Illustrative Capital Cost (2009$/kW)
Combined Cycle	$1054
Combustion Turbine	$782

Source: ICF International
Note: These illustrative costs assume the use of GE 7FA technology and an online year of 2014

Given the high cost and limited deployment of many of these energy storage systems, we expect that energy storage will largely remain at the upper end of the reliability service supply curve in the near- to medium-term. Among the storage technologies evaluated, the flywheel, CAES, advanced battery, and CSP systems are best poised for development this decade. The primary drivers behind the deployment of these and other storage systems will be high intermittent renewable integration costs and legislation that subsidizes and/or requires energy storage systems.

California is a forerunner in assessing how to best promote energy storage system development through legislation. California Governor Arnold Schwarzenegger recently signed into law AB

2514, a bill that requires the California Public Utility Commission (CPUC) to open proceedings to define procurement targets for "viable and cost-effective" energy storage systems. In early July, CPUC staff issued a white paper, *Electric Energy Storage: An Assessment of Potential Barriers and Opportunities*, which recommended rulemaking priorities and included a consideration of several potential incentives:

- Energy storage system procurement standards
- Feed-in tariff(s)
- Higher rates of return for utility investments in storage systems
- Incentive rate of return on power purchase agreements (PPA) with storage developers
- Funding for expanded storage system research and development efforts and pilot programs

The CPUC also introduced ideas such as placing storage technologies in the state's energy resource loading order; requiring utilities to include storage technologies in their integrated resource plans (IRP); modifying reliability service market rules to better accommodate storage system bids into the regulation market; and integrating storage systems in transmission planning.[47]

Demand response resources and reliability services provided by some types of storage systems will likely play key roles in efforts to firm or stabilize intermittent renewable generation in select regions this decade. However, the extent to which they will offset the need for reliability services provided by gas-fired generation will largely depend upon the reliability of DR resources, the rate of storage technology advancement, and the extent to which state and federal policies foster their development.

[47] California Public Utilities Commission. Electric Energy Storage: An Assessment of Potential Barriers and Opportunities – Policy and Planning Division Staff White Paper. July, 2010.

Chapter 4: Literature Survey on the Impact of Renewable Generation on Conventional Generation

Incorporating increasing amounts of intermittent renewable resources into the power system has multiple impacts. Under constant load conditions, as generation from wind-based power plants increases, generation supplied from conventional power plants must decrease. The magnitude of changes that occur in dispatch of conventional units differs based on time of day and season. In many regions in the U.S., the power output from wind turbines is negatively correlated with load. This implies that the generation from wind based power plants is low during on-peak hours and high during off-peak hours; thus, more power from conventional units is needed during on-peak than is needed during off-peak periods as wind penetration increases. Solar power plants, on the other hand, have generation profiles that largely match load profiles. As a result, as solar generation increases, the peaking requirements for other conventional fuels based electricity generation could diminish.

Conventional power plants generally cannot rapidly increase or decrease output due to mechanical and thermal limitations of the power equipment. System operators face unique challenges in ensuring that a sufficient number of conventional power plants can supply power during the peak hours and curtail output during off-peak hours to accommodate wind generation. Energy storage can provide flexibility in the aligning of electricity supply and demand. To "firm up" wind or other renewable generation, a system operator may propose changes to ancillary service requirements such as the amount of regulation, load following and/or spinning reserves procured. These changes could also result in increased operation of peaking units—generally combustion turbines—since they have desirable operating characteristics such as quick start and fast ramp rates.

Various entities such as California ISO, NYISO, and ERCOT have conducted studies to assess the impact of increasing renewable generation, especially wind, on the power system. Virtually all of these studies assess the impact of increasing wind penetration on the dispatch of conventional units. These studies also recommend increased utilization of units with fast ramp and/or quick start capability. The California ISO study recommends adding more capacity with faster and more durable ramping capabilities to accommodate forecast errors and intra-hour wind variations. The New York study found that 65 percent of the energy displaced by wind generation would come from natural gas, 15 percent from coal, 10 percent from oil, and 10 percent from imports. The ERCOT study showed that for every 1,000 MWh of wind generation, combined-cycle plant energy output drops approximately 800 MWh. Study findings such as these have significant implications on conventional generation performance and corresponding fuel usage, as a greater reliance on quick start units such as gas turbines could imply more volatile demand for natural gas.

A brief survey of renewable integration studies is included below. Since we reviewed only a limited number of wind integration studies, the survey is not intended to be comprehensive.

The intent of this survey was to obtain a view of the "state-of-the-art" in the analysis of wind integration. Further, while the wind integration studies reviewed in this report address various facets of renewable integration such as transmission planning, production cost impacts, and stability considerations, we focus our attention on only two key considerations:

1. Impact of the intermittency of renewable generation on natural gas-based generation including peaking plants, and
2. Impact of intermittent renewable generation on energy storage options

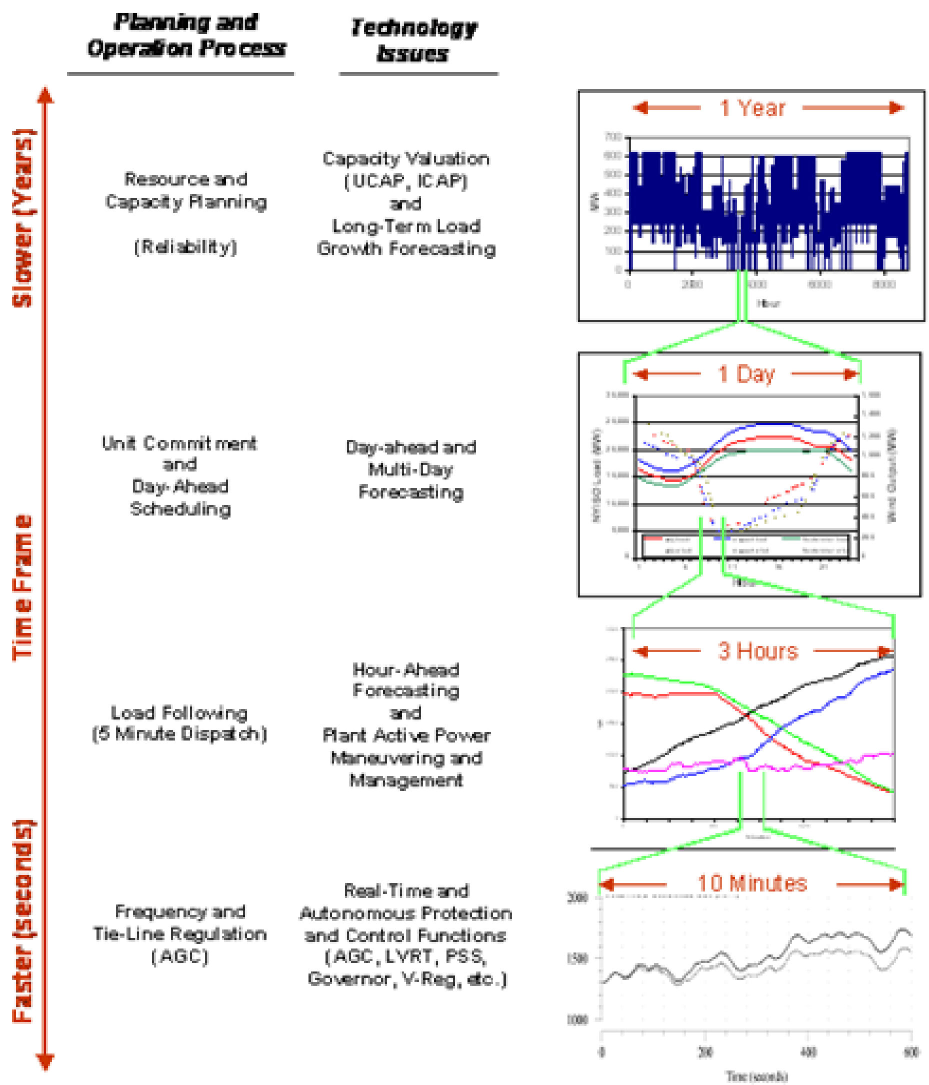
Note that this chapter focuses only on qualitative discussions of the above two factors. We address these issues quantitatively in Chapter 5.

Two overarching attributes of variable generation that affect the reliability of the bulk power system include:

- **Variability**: The output of variable generation changes according to the availability of the primary fuel (wind, sunlight and water flow) resulting in increased fluctuations in plant output on all time scales.
- **Uncertainty**: The ability to forecast the magnitude and phase (i.e. timing) of variable generation output is less predictable than for conventional generation.

Exhibit A2-4-1 below depicts the timescales relevant in planning and operational decisions. In this study, we focused on load-following capability at three hour intervals.

Exhibit A2-4-1: Planning and Operational Process Timescale



Source: NERC. Accommodating High levels of Variable Generation. April, 2009

Almost all of the wind integration studies reviewed address the impact of intermittency of renewable generation on natural gas-fired generation. This impact consists of changes in output from base load or mid-merit, and peaking natural gas-fired units and additional requirements for fast ramp generation due to the variability of wind output. Energy storage is also mentioned prominently as an alternative to capture some of the off-peak wind generation and to supply peak load; however, the disadvantages of energy storage technologies such as high capital costs and technological limitations are also noted.

Below we list key observations from specific wind integration studies. The summary at the end of this chapter provides a concise overview of key observations from these studies and identifies the need for further analysis.

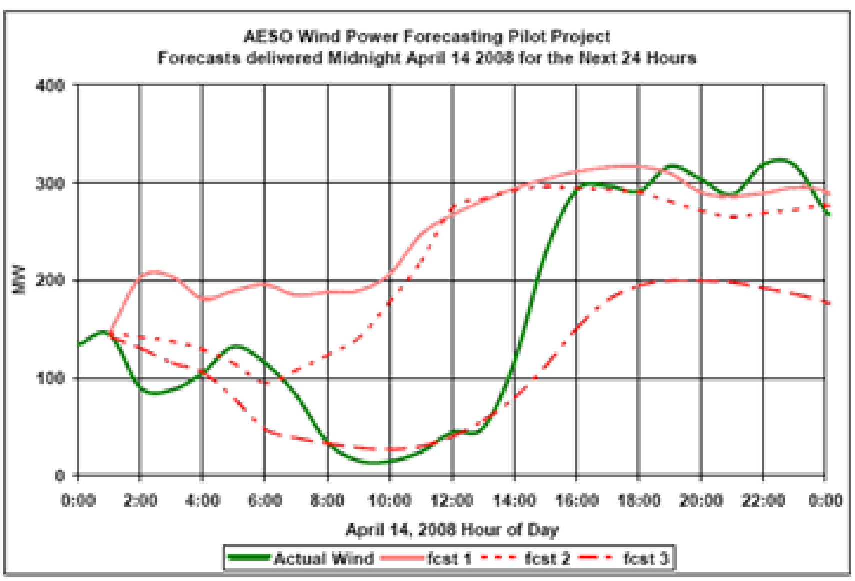
NERC Study Summary – Accommodating High Levels of Variable Generation[48]

Anticipating the growth of variable generation, in December 2007, the North American Electric Reliability Corporation's (NERC) Planning and Operating Committees created the Integration of Variable generation Task Force, charging it with preparing a report to identify 1) technical considerations for integrating variable resources into the bulk power system and 2) specific actions for practices and requirements, including reliability standards. The report, *Accommodating High levels of Variable Generation*, describes the characteristics of variable generation and identifies changes to planning and operations practices and tools required to reliably integrate large amounts of variable generation into the bulk power system.

Several key points can be derived from this study:

- Integrating large amounts of plug-in hybrid electric vehicles, storage, and demand response programs may provide additional resource flexibility and can improve bulk power system reliability.
- Forecasting techniques should be incorporated into day-to-day operating routines/practices and unit commitment, dispatch, and operations planning policies. Exhibit A2-4-2 from the report shows the differences between actual wind generation and various forecasts for a day in the Alberta power system. Forecasts can diverge considerably from actual wind generation, which will affect unit commitment, dispatch, and ramp rate requirements.

Exhibit A2-4-2: Sample Wind Power Forecast



Source: NERC. Accommodating High Levels of Variable Generation. April, 2009

[48] NERC. Accommodating High levels of Variable Generation. April, 2009.

- To the extent possible, practices, minimum requirements, and/or market mechanisms (i.e. price signals) should be developed to ensure that conventional generation has the desired characteristics (e.g., ramping requirements, minimum generation levels, shorter scheduling intervals, etc.) and also to foster the development of an appropriate resource mix that will support reliability.
- Large photovoltaic (PV) plants, which have been widely proposed in the Southwestern U.S. and southern California, have the potential to place extremely fast ramping resources on the power system. Under certain weather conditions, PV installations can change output by +/- 70 percent in a timeframe of 2 to 10 minutes, many times per day. Therefore, these plants should consider developing the ability to manage ramp rates and/or curtail power output.
- New variable generation technologies can readily contribute to the ancillary services and ramping needs of the power system. Upward ramping and regulation needs, beyond the maximum generation afforded by availability of the primary fuel (wind or sun), are important planning considerations.
- Additional sources of system flexibility include the operation of structured markets, shorter scheduling intervals, demand-side management, reservoir hydro systems, gas storage and energy storage. System planners must ensure that suitable system flexibility is included in future bulk power system designs, as this system flexibility is needed to deal with, among many conditions, the additional variability and uncertainty introduced into power system operations by large-scale integration of variable generation.
- Energy storage technologies also have the potential to assist the large-scale integration of variable generation; however, the cost of storage devices compared to other methods of flexibility currently has limited their applicability.
- Plug-in electric vehicles (PEVs), including Plug-in Hybrid Electric Vehicles (PHEVs), may prove to be a source of flexibility for the electric power system sometime in the future. The key technology which limits market penetration of electric vehicles is battery requirements (i.e. cost and length of charge). As electric vehicles become available, they could also provide energy storage services that can benefit a bulk power system experiencing increasing levels of variability.
- The expected increase in variable generation on the bulk power system will increase the amount of operational uncertainty that the system operator must factor into operating decisions. The system operator may decide to dispatch additional capacity for ramping capability and ancillary services, use demand response, and use wind power management capability (i.e. ramp rate or power limiting functions) to position the bulk power system to withstand credible contingencies.

DOE Study Summary – 20% Wind Energy by 2030[49]

This report was prepared by DOE in a joint effort with industry, government, and the nation's national laboratories (primarily the National Renewable Energy Laboratory and Lawrence Berkeley National Laboratory). The report considers associated challenges, estimates the impacts, and discusses specific needs and outcomes in the areas of technology, manufacturing and employment, transmission and grid integration, markets, siting strategies, and potential environmental effects associated with a 20 percent wind scenario.

The report offers several key findings:

- The 20 percent wind scenario would require delivery of nearly 1.16 billion MWh of wind energy in 2030. In this scenario, wind would supply enough energy to displace about 50 percent of electric utility natural gas consumption and 18 percent of coal consumption by 2030.
- The increased wind development in this scenario could reduce the need for new coal and combined cycle natural gas capacity but would increase the need for additional combustion turbine natural gas capacity to maintain electric system reliability.
- A system with wind generation needs more active load-following generation capability than one without wind, or more load-management capability to offset the combined variability of load net of wind.
- The benefits of broader regional energy markets include reduction in variability by forming large operational structures, the availability of more load-following resources, and more useful financial mechanisms for managing the costs of wind integration. Handling large output variations and steep ramps over short time periods (e.g., within the hour), though, can be challenging for smaller balancing areas.
- Studies and actual operating experience indicate that power systems in which other generators are available to provide balancing energy and precise load-following capabilities are better able to facilitate wind integration.
- The greater the number of wind turbines operating in a given area, the less their aggregate production variability. System operators in the United States have found that as more wind generating capacity is installed, the combined output becomes less variable. Geographic dispersion and large balancing areas also reduce the impacts of variability and ease wind integration.
- To achieve balance in a power system using wind energy, the 20 percent wind scenario would require the use of the existing fleet of flexible, dispatchable, mainly gas-fired generators designed for frequent and rapid ramping. Further, the 20 percent wind scenario requires additional gas combustion turbine capacity (Gas-CT) to maintain grid reliability when wind resources vary.

[49] DOE. 20% Wind Energy by 2030 - Increasing Wind Energy's Contribution to U.S. Electricity Supply. July, 2008.

EWITS Study Summary[50]

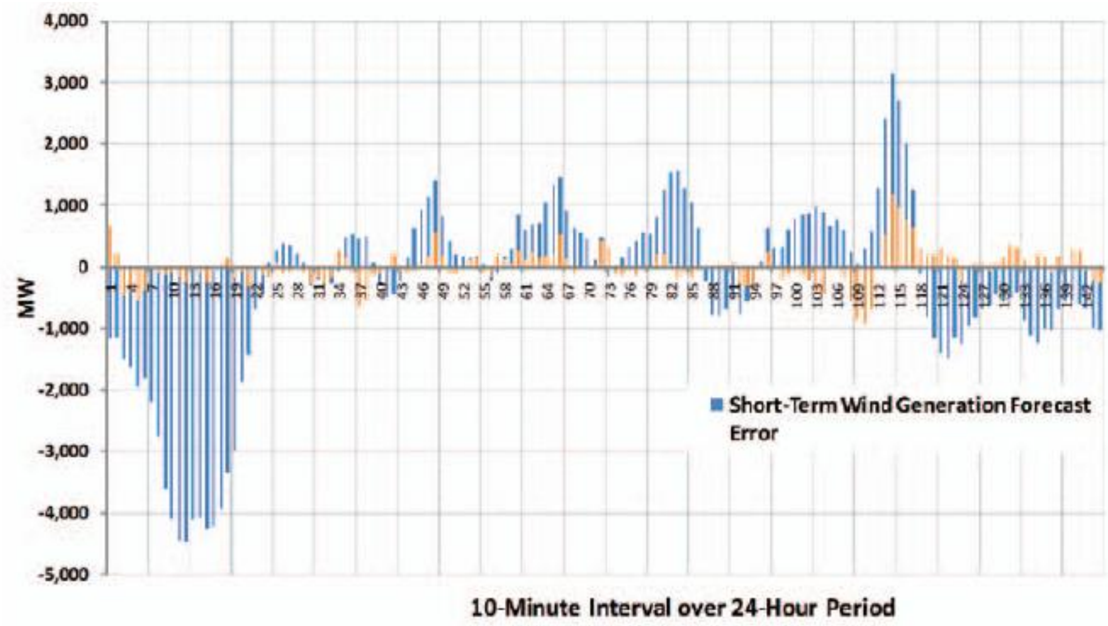
DOE commissioned the *Eastern Wind Integration and Transmission Study* (EWITS) through its National Renewable Energy Laboratory (NREL). The investigation, which began in 2007, was the first of its kind in terms of scope, scale, and process. The study was designed to answer questions posed by a variety of stakeholders about a range of important and contemporary technical issues related to a 20 percent wind scenario for the large portion of the electric load (demand for energy) that resides in the Eastern Interconnection.

Several key points can be derived from this study:

- Geographical diversity helps substantially in reducing system variability and uncertainty. Large operating areas—in terms of load, generating units, and geography—combined with adequate transmission, are the most effective measures for managing wind generation.
- Smaller, but more frequent, changes in wind generation over one to four hours are operationally important. On these time scales, uncertainty regarding how much wind generation will be available is more important than variability. A centralized wind production forecast will assist balancing authorities in mitigating the impact of changes in wind generation; however, a level of operating reserves may still be required to mitigate the remaining errors.
- Errors in the short-term forecast of wind generation will therefore increase the requirement for regulation. Exhibit A2-4-3 shows the possible magnitudes of errors in short-term wind generation forecast over a 24-hour period.

[50] NREL. Eastern Wind Integration and Transmission Study. January, 2010.

Exhibit A2-4-3: Short-Term Wind Forecast Error



Source: NREL. Eastern Wind Integration and Transmission Study. January, 2010

- High penetration of wind generation and the increased requirements for regulation and flexibility will boost the value of these services and increase cost. In addition, questions arise about the depth of the resource "stack" for flexibility, which could potentially be another limitation.
- The Western Interconnection, with the exception of California, comprises smaller, less tightly interconnected balancing areas. Even modest penetrations of wind generation, much smaller than those considered here, can have very significant operational and cost impacts because of the additional requirements they bring for regulation and balancing.
- Carrying additional reserves to accommodate wind variability and uncertainty would displace coal units in favor of more flexible gas-fired combined cycle (CCGT) and combustion turbine (CT) units.

WWSIS Study Summary[51]

NREL's *Western Wind and Solar Integration Study* (WWSIS) is one of the largest regional wind and solar integration studies to date. It was initiated in 2007 to examine the operational impact of up to 35 percent energy penetration of wind, photovoltaics (PV), and concentrating solar power (CSP) on the power system operated by the WestConnect group of utilities in Arizona, Colorado, Nevada, New Mexico and Wyoming.

[51] NREL. How do Wind and Solar Power Affect Grid Operations: The Western Wind and Solar Integration Study. September, 2009.

The report offers several key findings:

- Balancing area coordination is imperative to integrate 35 percent renewables in the study footprint (the WestConnect region).
- The aggregation of wind and solar sites mitigates the relative impacts of the large ramps.
- The operational impacts of renewable generation do not differ markedly between using local resources versus remote, higher quality resources. The overall cost savings, displaced generation, and spot prices are very similar.
- What happens in the study footprint depends very much on what is happening in the rest of WECC. The study footprint typically exports power to the rest of WECC, but this decreases significantly when the renewables penetration in the rest of WECC increases from 11% to 23%.
- Pumped hydro storage usage increases but no need for increased pumped hydro storage was identified.
- There is significant year-to-year and month-to-month variation in wind and solar resources.
- The size of the area (in terms of MW load) matters. For small areas, such as Wyoming, wind can easily provide over 100% of the load needs. This study finds that high penetrations of wind and solar cannot be met without increased cooperation between balancing areas.
- Geographic diversity helps mitigate variability. The relative variability in any particular state is much higher than the relative variability of the aggregated study footprint.
- Drops in wind and solar generation combined with the rise in evening load drive extreme net load up-ramps in late afternoons during the late fall and winter. The drop in load during the evening in summer and early fall drives extreme down-ramps.
- No significant operational issues were identified with wind and solar penetrations of up to 23 percent in the study footprint and 11 percent outside the study footprint. The impact is more severe at 35 percent inside the study footprint and 23 percent in the rest of WECC.
- Combined cycle and gas turbine units account for most of the displaced load. At 35 percent penetration of renewables, coal units are also displaced.
- At higher penetrations, load must become an active participant in managing wind output variability through interruptible load arrangements or demand response programs.

NYISO Wind Integration Study Summary[52]

In response to emerging market conditions, and in recognition of the unique operating characteristics of wind generation, the New York Independent System Operator (NYISO) and New York State Energy Research and Development Authority (NYSERDA) commissioned a joint study to produce empirical information to assist NYISO in evaluating the reliability implications of increased wind generation.

The report offers several key observations:

- Uncertainties introduced by errors in day-ahead forecasts for wind add slightly to load forecasting errors, which are presently accommodated by system operations. The worst under prediction of load, 2.4 percent of load energy served, occurs without wind generation. The worst over prediction of load without wind generation is 2.8 percent, and 3.7 percent with wind generation.
- Hour-ahead wind forecasts significantly reduce the uncertainties associated with the day-ahead forecasts. On a system-wide basis, the wind forecast error is reduced by 50 percent to 60 percent. Existing NYISO operating practices account for uncertainties in load forecast. The incremental uncertainties due to imperfect wind forecasts are not expected to affect the reliability of the NY State Bulk Power System.
- More load following may be needed during times when system load has historically been nearly constant.

ISO-NE Wind Integration Study Summary[53]

This report documents the status of wind generation technology and forecasting, providing information on topics related to the interconnection of wind generation facilities to the bulk power system, the operation of the bulk power system with significant amounts of wind generation, and the technology underlying wind generation forecasting and its application to power system operation. In addition, the project team (GE, EnerNex Corporation, and AWS Truewind) provides specific recommendations based on their work in the electric power and wind generation industries.

Several key points can be derived from this study:

- Fluctuations in wind generation over intervals of 5 to 10 minutes or longer appear not to be so well behaved or predictable. Errors in short-term wind forecasts will increase the

[52] NYISO, NYSERDA. The Effects of Integrating Wind Power on Transmission System Planning, Reliability, and Operations. March, 2005.

[53] ISO-NE. Technical Requirements for Wind Generation Interconnection and Integration. November, 2009.

regulation burden as units following the load via frequent economic dispatch are effectively controlled by the forecast rather than by actual wind speeds.

- Large changes in balancing area demand over one or more hours are operationally significant. Adequate flexibility in the committed generation must be available to avoid significant violations of control performance or shedding of load.
- Wind generation can enhance these periods of stress on the system by moving in an undesirable direction (i.e. down in the morning or up in the evening).

CAISO Wind Integration Study Summary[54]

The California ISO (CAISO) initiated this wind integration study to help policy makers understand the unique challenges to ensuring that the operation and design of the transmission grid fully supports the state's aggressive renewable standard. This study was performed by a working group consisting of CAISO, GE Energy Consulting, Pacific Northwest National Laboratory, and AWS Truewind. The focus of this report is on the transmission and operating issues associated with the addition of more than 4,000 MW of new wind generation in the CAISO grid.

The report offers several key observations:

- The California ISO regulation ramping requirements for the 20 percent RPS is expected to increase by about ±15 to ±25 MW/min. The California ISO maximum load following ramping requirements for the 20% RPS is expected to increase by about ±30 to ±40 MW/min.
- The California ISO current generating resources seem adequate to meet the anticipated ramping requirements for load following and regulation; however, during drought conditions or low hydro years, regulating response could be slow due to the reliance of thermal units with slower ramp rates. Depending on system load, additional units may have to be committed to meet regulation needs
- Approximately 800 MW/hr of generating capacity and ramping capability will be required to meet multi-hour ramps during the morning load increase coupled with declining wind generation. System operators will need to quickly ramp down dispatchable resources during the evening load drop-off and accommodate increases in wind generation. Quick start units must be available to accommodate hour-ahead forecast errors and intra-hour wind variations.
- System operators should encourage the development of new energy storage technology; however, a number of problems with new storage technology must be overcome in order for the technology to be competitive. These problems include high

[54] California ISO. *Integration of Renewable Resources*. November, 2007.

capital costs, low efficiency, net negative system characteristics, and limited storage capability.

CEC Intermittency Analysis Project Study Summary[55]

The Intermittency Analysis Project (IAP) presents a state-wide perspective of the transmission infrastructure and services needed to accommodate the renewable penetration levels in California as defined in that state's renewable energy policy. The IAP is technical in nature and intended to provide a year-2020 perspective on potential operational needs to meet future growth and demand. The IAP considered four types of renewable generation to meet California's renewable energy goals: wind, solar, geothermal, and biomass. The objectives of this study were to evaluate California grid operation with increasing levels of intermittent generation and evaluate possible mitigation methods.

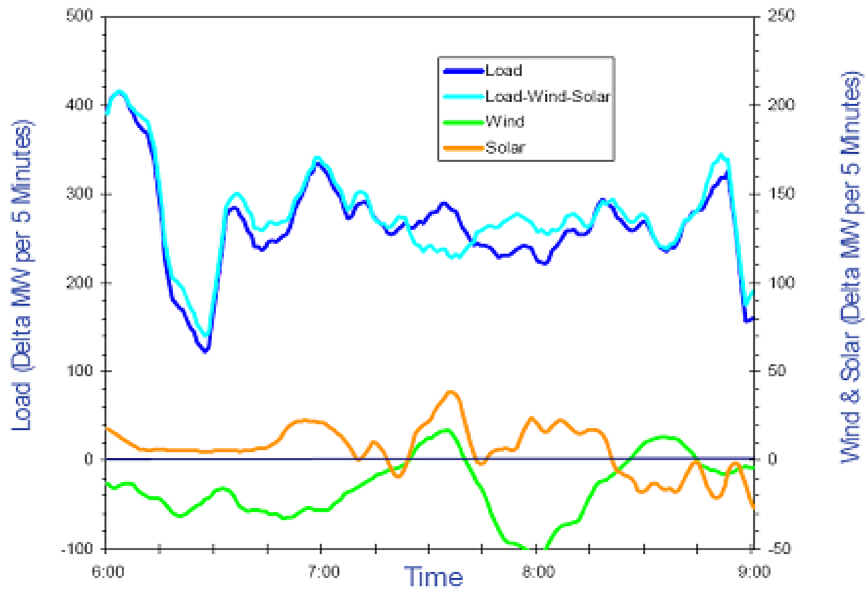
Several key points can be derived from this study:

- Generating resources with lower minimum power output levels provide greater flexibility and allow successful operation at minimum load. New generating resources should be encouraged and/or required to have this capability; existing generation should be encouraged and/or required to upgrade their capability.
- Active participation by large loads is another way to assure adequate flexibility.
- The additional variability and uncertainty associated with intermittent renewables will increase the amplitude of sustained load ramps (both up and down) and the frequency of generation starts and stops. The overall hourly flexibility requirement is expected to be about 130 to 400 MW/hr greater than that required for load alone for various renewable penetration scenarios.
- During light load conditions, total requirements for flexibility needs are smaller, but the relative impact of intermittent renewables is larger. The impact of renewables is expected to increase the hourly light load flexibility requirement by about 1,000 MW/hr than that required for load alone.
- Uncertainties in forecasts create a somewhat different flexibility requirement. The California grid should target sufficient in-state generating resource capability to meet day-ahead forecast errors in the range of ±5,000 MW of generation capacity and hour-ahead forecast errors in the range of ±2,000 MW of generation capacity. The forecast statistics show that intermittent renewables increase the hour-ahead uncertainty about 20 percent over the load alone uncertainty.
- The California grid should target a combination of in-state generating resources that provide a minimum level of generation ramping capability, both up and down. On

[55] California Energy Commission. Intermittency Analysis Project: Appendix B - Impact of Intermittent Generation on Operation of California Power Grid. July, 2007.

average, the system should maintain about +/-130 MW/minute for a minimum of five minutes (roughly a 10 MW/minute increase over the requirement due to load alone). During light load conditions, approximately 70 MW/minute of down load-following capability are required. Exhibit A2-4-4 from the report shows an example of changes in load-following requirements due to renewable resources.

Exhibit A2-4-4: Changes in Load-Following Requirements Due to the Introduction of Wind



Load–Following Requirement for July 2003 Example 3-Hour Period.

Source: California Energy Commission. Intermittency Analysis Project: Appendix B - Impact of Intermittent Generation on Operation of California Power Grid. July, 2007

Overall, the day-ahead forecast including wind and solar introduces about twice the uncertainty as the load forecast alone. Still, significant errors in wind forecast at low load periods have a larger impact relative to the balance of generation available. The uncertainty due to intermittent renewables can be three times greater than the uncertainty due to load alone at moderate to light load levels.

ERCOT Wind Integration Study Summary[56]

ERCOT commissioned GE Energy to perform an intensive study of ancillary services requirements of accommodating large-scale expansion of wind generation capacity. The specific objectives of this study were to quantify the impact of various wind development scenarios on the levels of ancillary services required; evaluate the methodology used by ERCOT to determine the amount of ancillary services required and recommend methodology improvements where appropriate; estimate the impact of wind generation on the costs to

[56] ERCOT. Analysis of Wind Generation Impact on ERCOT Ancillary Services Requirements. March, 2008.

procure ancillary services; and identify changes to current procedures or propose new procedures required for operations with impending severe weather conditions.

The report offers several key observations:

- Regulation deployment changes due to wind vary greatly for different times of day and for different seasons. The impact of wind generation on up-regulation procurement is greatest in the evenings throughout the year and summer mornings.
- Extreme changes in wind occur as rapid ramps, not as abrupt changes that occur for a conventional power plant trip. Extreme wind generation output changes are usually due to predictable weather phenomena and are more likely to occur in the morning and in the evening during winter.
- The frequency and severity of extreme short-term (15 minute to one hour) wind generation output changes increase at a faster than linear rate with increasing wind generation capacity.
- At 15,000 MW of wind generation capacity, the operational issues posed by wind generation will become a significant focus in ERCOT system operations.
- Although wind forecast errors are greater than load forecast errors, on a percentage basis, uncertainty in the wind forecast is more appropriately addressed by procuring ancillary services than by distorting unit commitment.
- ERCOT should consider introducing a new non-spinning reserve service with a startup time of 10 to 15 minutes. This can significantly reduce the amount of responsive reserves needed for identified periods of wind generation drop risk.
- Spinning reserve requirements with high wind penetration should be temporally variable on an hourly and seasonal basis to minimize system operating cost while maintaining reliable operation. In addition to standing patterns, the response reserve service (RRS) procurement should be adjusted for periods of specific risk.

Literature Survey Summary

The wind integration studies reviewed agree on several key points:

1. Variations in wind and load are uncorrelated with each other.
2. Wind output usually varies inversely with load.
3. Significant ramp events can occur with wind generation due to both predictable and unforeseen variability in wind speeds. These ramp events require corresponding fast ramp/quick start generation to compensate for wind variability.
4. It is important to consider net load (load + wind) when determining ancillary service requirements.

5. The magnitude of chronological (time-series) variations increase with higher wind penetration.
6. Both statistical and chronological variations can be reduced by geographical diversity and mitigated by larger balancing area operations.
7. Energy storage is a promising technology to compensate for variations in wind; however, storage technologies are limited due to high capital costs, low energy storage capability, and low efficiency.
8. Aggregation of wind and solar sites could mitigate the relative impacts of the large ramps caused by wind speed variations; however, large photovoltaic (PV) plants can serve as extremely fast ramping resources by altering output by +/- 70% in a timeframe of two to ten minutes, several times per day.

The wind integration studies reviewed in this study have not explicitly addressed the most cost-effective mechanism of meeting the need for fast response generation. While multiple options for meeting the need for fast-response exist, using natural gas-fired combustion turbines for this purpose could require additional natural gas supply. The changes in requirements of natural gas, for example, the transient "spiky" needs to compensate for fast ramp up/down of wind generators, could result in changes to gas supply, storage and transportation. Therefore, an additional dimension to wind integration cost is the cost of additional gas transportation and storage infrastructure and the cost of physical and financial contracts that could be needed for providing firming up power to compensate for the intermittency of renewables. The reports discussed are mixed on this subject. In fact, most seem to imply that large area balancing and other options/actions such as demand response would make infrastructure additions less likely.

The next chapter in this study performs sample illustrative modeling to understand the impact of the need for fast response generation, on gas-fired generation. Further analysis will evaluate the corresponding impact on natural gas transportation and storage. The model also estimates the need for energy storage for the illustrative examples considered, as an alternative to combustion turbines for responding to the fast ramps caused by changes in wind generation.

Chapter 5: Analysis, Modeling, and Illustration of the Impact of Intermittency on the Need for Fast Ramp Generation

In this chapter we describe the analysis of the impact of intermittent renewable power on the need for fast ramp generation and provide an estimate of any related system costs. This analysis is not intended to be exhaustive; instead, the goal is to identify relationships between changes in load and changes in output from intermittent renewable resources (primarily wind) and to suggest possible mitigation measures for any additional burdens on the electric power system.

Previous wind integration studies identify fast ramp generation as a critical component of any integration strategy. Hydro and combustion turbines are two key sources of fast ramp capacity but hydro is limited by water availability and environmental constraints; thus, combustion turbines such as the GE class 7E or 7F machines or aeroderivatives such as GE's LM-class machines or their equivalent serve as default fast ramp generation providers.

Impact of Load and Wind Shapes on Ramp Rate Requirements

During periods of decreasing wind speed and increasing load, ramping requirements will be higher than during periods when wind speed is constant or increasing. Additional generation will be required to meet not only the increase in load but to also compensate from the loss of wind output since a decrease in wind generation needs to be replaced by generation from other sources to meet load. Conversely, when wind speed and load rise in tandem, ramping requirements will be lower than when wind output is decreasing or constant.

Exhibit A2-5-1: Contribution of Wind to Ramp Rate Requirements

Time (minutes)	Load (MW)	Ramp Rate for Load (MW/min)	Wind (MW)	Load-Wind (MW)	Ramp Rate for Load-Wind (MW/min)	Impact of Wind on Ramp Rates
0	500	-	10	490	-	-
10	600	10	15	585	9.5	Decrement
20	700	10	20	680	9.8	Decrement
30	800	10	25	775	9.2	Decrement
40	900	10	30	870	9.7	Decrement
50	850	-5	35	815	-5.7	Increment
60	800	-5	32	768	-4.7	Decrement
70	750	-5	27	723	-4.5	Decrement
80	820	7	22	798	7.5	Increment
90	850	3	16	834	3.6	Increment
100	950	10	11	939	10.5	Increment
110	1000	5	20	980	4.1	Decrement

In the table above, the column “Ramp Rate for Load” and the column “Ramp Rate for Load-Wind” list the ramp rates required to meet load (without wind) and the net load (with wind), respectively. The “Impact of Wind on Ramp Rates” provides a comparison of the two ramp rate columns to illustrate whether the addition of wind results in an increment or decrement to ramping requirements.

A point to note in the above table is that both positive and negative ramp rates increase in magnitude when wind varies inversely with load. An increment in positive ramp rates implies increased ramping requirements due to wind and an increment in negative ramp rates result in increased negative ramp requirements due to wind. This increase in negative ramp implies that the conventional units must decrease output by a larger magnitude with wind than without wind.

In circumstances when natural-gas fired generation is used to meet ramping requirements, an increment in ramp rates will result in a more “spiky” natural gas demand since the ramp requirements increase more (or decrease more in the case of negative ramp requirements) with wind, thus increasing the magnitude of transient operation of the combustion turbines. A decrement in required ramp rates due to wind will smooth out the fluctuations in load plus wind shapes, thus requiring less peaking/fast ramp units operation. Also, one could postulate that an energy storage device would see more “charges” and “discharges” during periods of increment and less operation during periods of decrement.

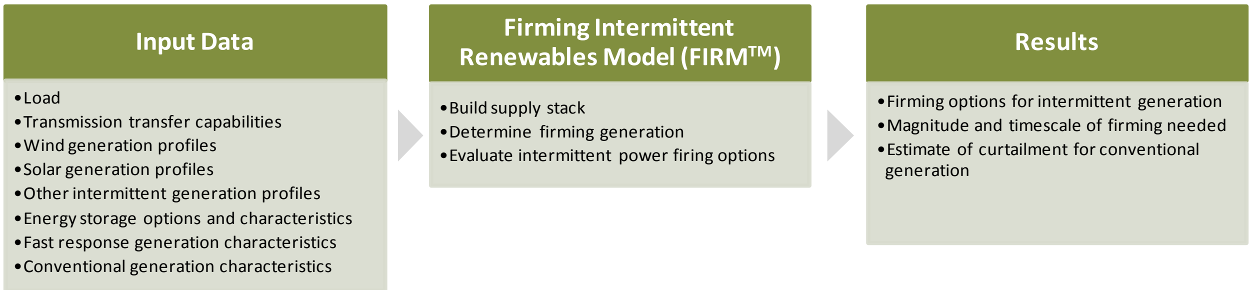
To model the impact of wind and load shapes on an intra-hour scale, a model more detailed than a standard production simulation program is required. Such a model and results from simulations in the model are described below.

ICF utilized its in-house developed model, Firming Intermittent Renewables Model (FIRM™), to run several sample cases in various regions of the U.S. for several representative simulation years in order to estimate the impact of additional renewables on fast ramp generation and energy storage requirements.

Brief Model Description

FIRM™ is a spreadsheet dispatch model that is used to study intra-hour and intra-day variations in generation and load. The inputs and outputs for this model are given in Exhibit A2-5-2 below.

Exhibit A2-5-2: Inputs and Outputs for FIRMTM



FIRM™ can be used to study various impacts of intermittent generation and load variations. The model uses representative single-day renewables (wind, solar) and load shapes along with conventional generation data including ramping characteristics in a region to determine the impact of renewables on the ramp rate requirements of the system. Ten-minute data are used for the load and renewable generation shapes in order to capture the need for fast ramp generation in the system. Using the generation and load input data such as full-load variable cost, FIRM™ creates a merit-order dispatch stack for economic dispatch. The model takes into account operating reserves needed and will observe regulation requirements in assessing the need for fast ramp generation. Further, the type and amount of curtailment of conventional generation during off-peak periods due to increases in wind generation will also be determined. The model will "dispatch" energy storage as an alternative to fast ramp generation to determine the amount of energy storage that will be needed.

FIRM™ is fully customizable with the unique characteristics for each type of generation and region, and provides a snapshot of the system requirements in the load following timeframe (10 minutes) with and without various types of intermittent generation.

Model Assumptions & Data Sources

The following key assumptions are made in the operation of FIRM™.

a) Pumped storage is dispatched only to compensate load ramps and not for renewable generation ramps.

b) Transmission constraints within a region are ignored for this analysis.

c) Where appropriate, inter-regional transmission capacity is assumed sufficient for transfer of wind generation without curtailment due to congestion.

d) Exports and Imports into/from a region are held constant during the simulation period (24 hours).

e) While demonstrating the effect of wind on curtailment of conventional generation, Reliability Must-Run units are not considered.

f) Wind speed measurements at multiple points in a study region are considered for developing the wind shapes, to account for the impact of geographical diversity in wind speeds.

g) Load shapes data are obtained from ISO websites.

h) Wind shape data are obtained from the NREL database used for its EWITS study.[57] Actual historical wind shapes are considered for determining ramp rate requirements.

i) Generation capacity by type and peak load and energy for the regions under consideration for each model year are obtained from ICF's Integrated Planning Model (IPM®) data and other databases. IPM is an energy and environmental market simulation model that builds capacity economically as needed to satisfy a variety of constraints including regional reserve margin requirements, RPS mandates and transmission limits.

j) Changes to market structure and tariffs are not considered.

k) Balancing area coordination is limited in this study to considering geographically diverse wind generation since the concept of coordination over large operating areas is still evolving.

Model Application

Analysis of additional fast ramp requirements and energy storage due to renewable penetration was performed using FIRM™ for four analysis years: 2010, 2015, 2020 and 2025. For each of these years, three representative days were analyzed: summer peak, winter peak, and shoulder, resulting in 12 cases for each simulation. The summer and winter representative days contained the summer and winter peak load hours, respectively. These simulations were performed for three regions: New England (ISO-NE), Wyoming-California (WY-CA), and Oklahoma-Kansas (OK-KS) to estimate the expected variations and the corresponding impact on requirements for fast ramp/quick-start generation. We focus on these regions in particular due to their high natural gas consumption and high penetration of intermittent renewable generation.

Using FIRM™, the amount of fast ramp generation needed was determined based on the magnitude of variations in wind, solar, load and net load-wind-solar single-day representative profile and extrapolated as needed to obtain annual estimates. The input data were based on ICF's Expected Case projections of generation expansion and load growth, and system operator guidelines for operating reserves, spinning reserves, and other ancillary services for each region. Also estimated from this model (extrapolated as necessary) is the amount of conventional generation (type and illustrative magnitude) that may need to diminish output to incorporate intermittent renewable generation. The model also analyzed the need for and market attractiveness of energy storage applications by identifying intra-day periods when it

[57] The NREL mesoscale model data sets were produced by AWS Truewind (for the eastern U.S.) and 3Tier (for the western U.S.). ICF relied on data at the 100 meter hub height level. Models used by AWS Truewind and 3Tier were calibrated using actual wind measurements.

makes sense for energy storage-based technologies to operate and provide "balancing power" to compensate for the intermittency of renewable generation.

Variation in Actual Wind Speeds

The model is run using actual wind shapes from years 2004, 2005 and 2006. Results from applying wind shapes from three years are shown to illustrate the magnitude and the extent of variations that could be possible in ramp rate requirements and curtailment of conventional generation. The exhibits below compare the actual wind shapes between the years 2004, 2005 and 2006 for the three regions analyzed in this study for a representative summer day.

Exhibit A2-5-3: Representative Daily Summer Wind Shapes in ISO-NE

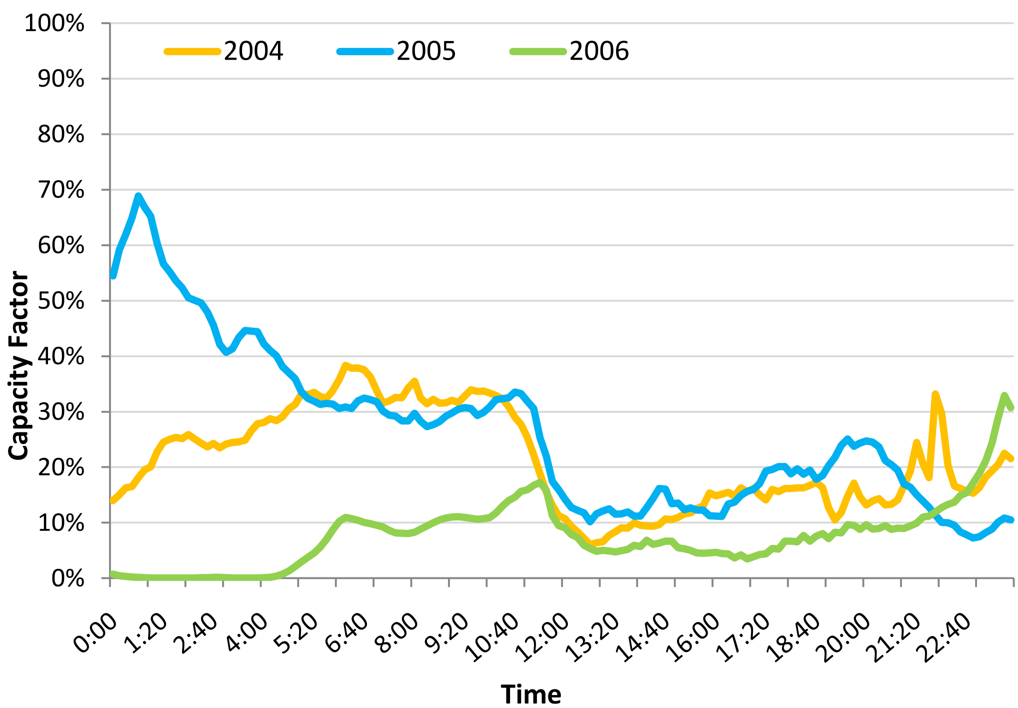


Exhibit A2-5-4: Representative Daily Summer Wind Shapes in OK-KS

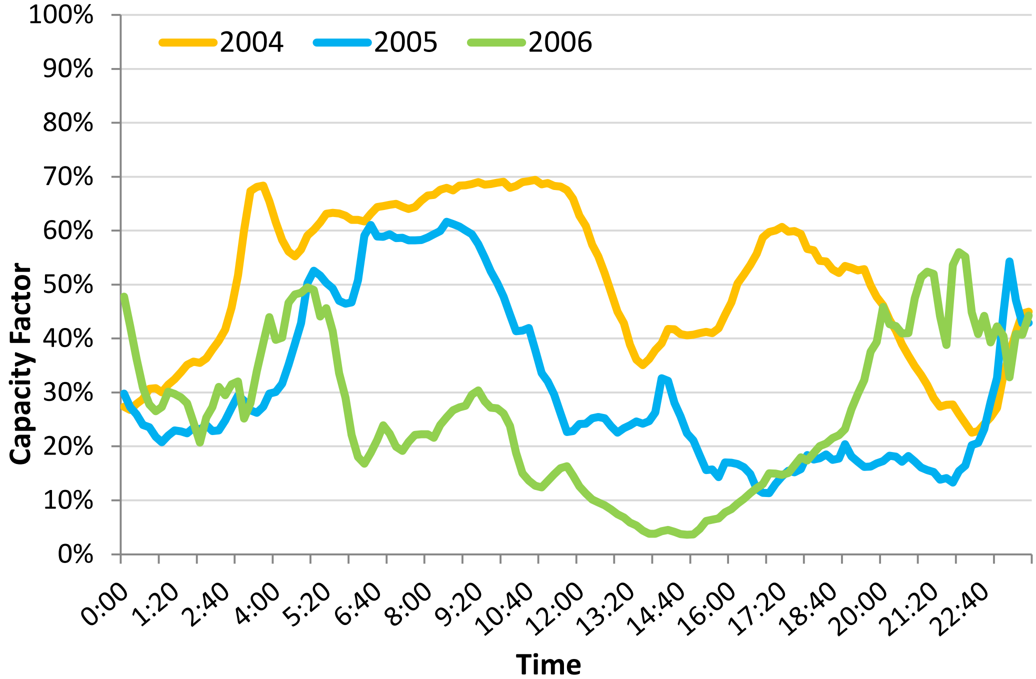
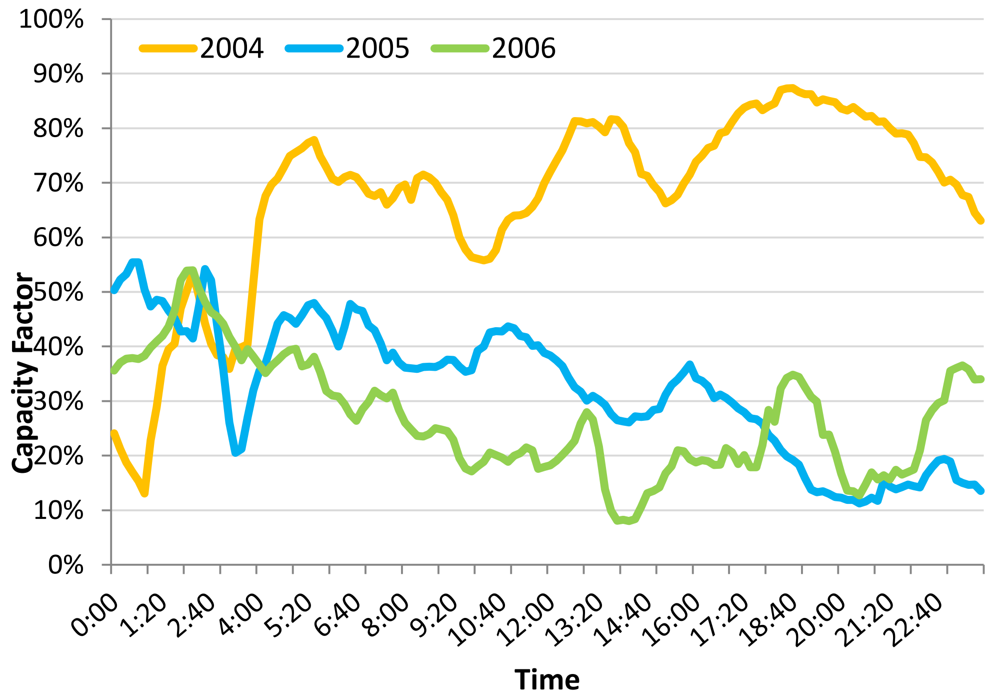


Exhibit A2-5-5: Representative Daily Summer Wind Shapes in WY



It can be seen from the figures above that the wind shapes for the same summer day vary considerably between study years 2004, 2005 and 2006. Therefore, it is essential to consider a multiple number of actual wind shapes to understand the impact on gas-fired generation.

Seasonal Variation in Wind Speeds

As mentioned earlier, this study is performed for one representative day for each of the three seasons: summer, winter and shoulder. The shoulder wind shape is assumed in this study to reflect spring and fall seasons. The reason for simulating representative days for three different seasons is to understand the changes in gas-fired generation due to seasonal variations in wind speeds. The exhibits below show the seasonal variations in wind speeds for 2005 (an example year).

Exhibit A2-5-6: Seasonal Variations in Wind Output in ISO-NE - 2005 Representative Daily

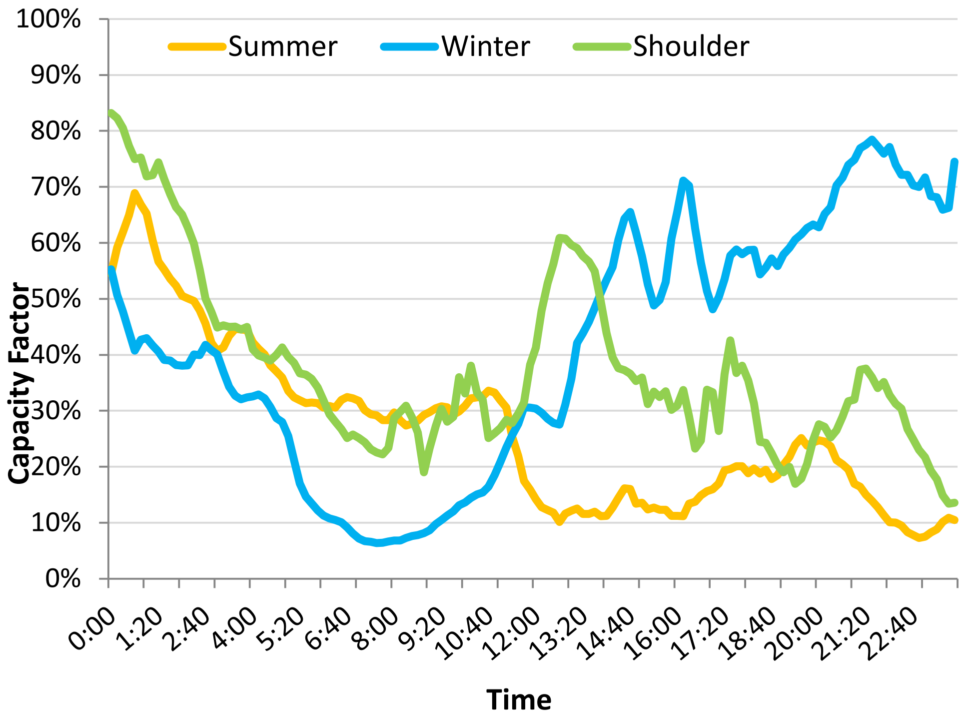


Exhibit A2-5-7: Seasonal Variations in Wind Output in OK-KS - 2005 Representative Daily

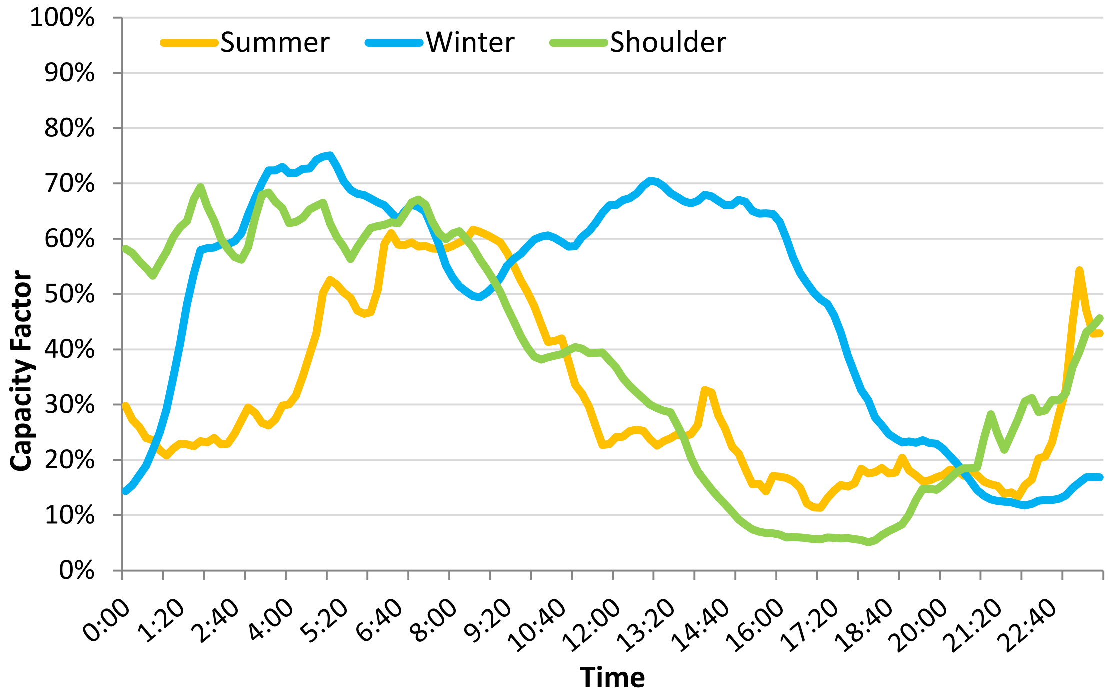
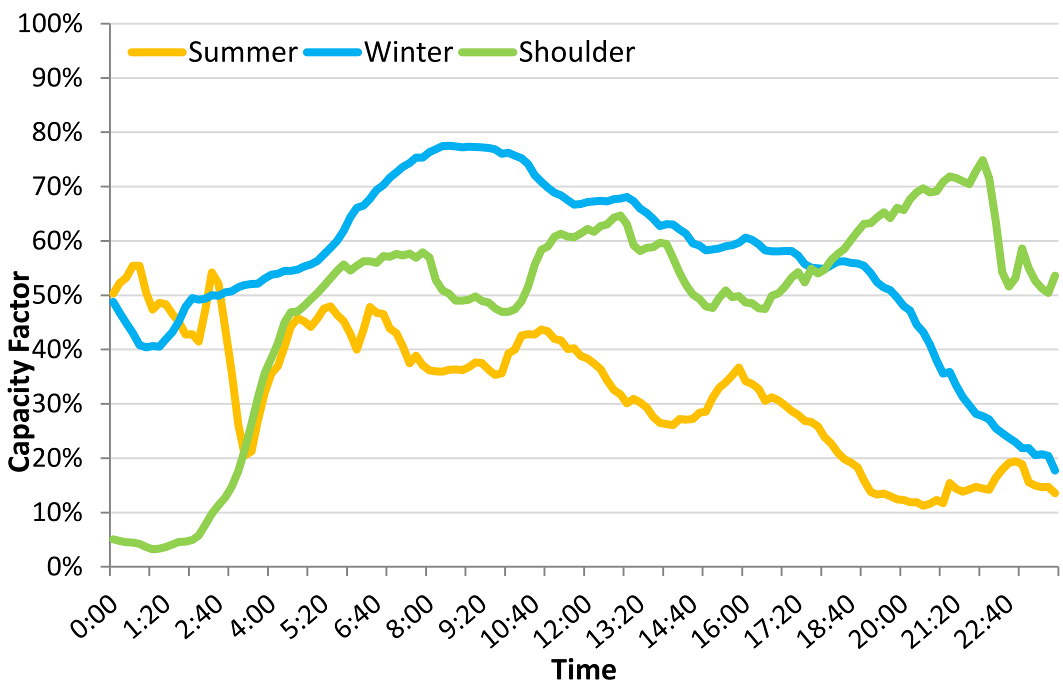


Exhibit A2-5-8: Seasonal Variations in Wind Output in WY – 2005 Representative Daily



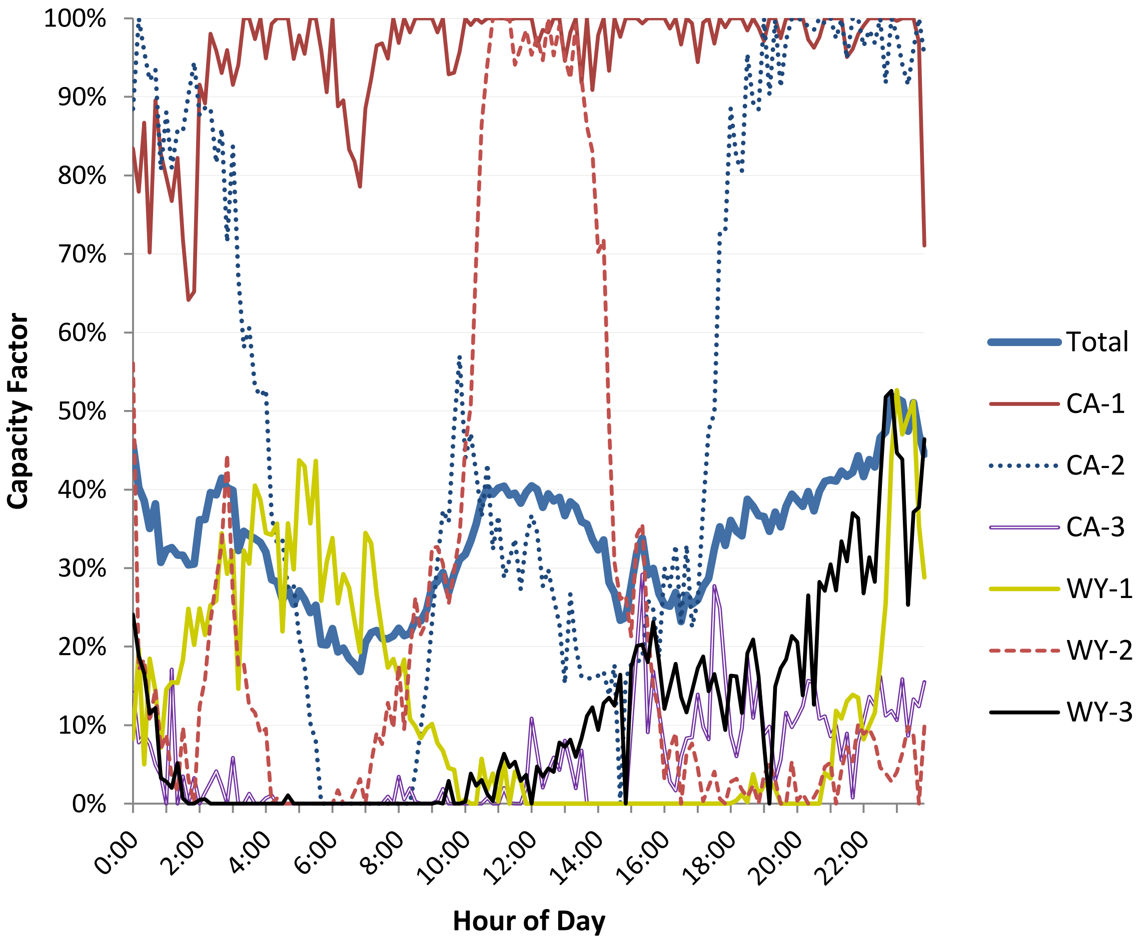
The three figures above show the seasonal variations in wind speeds for year 2005 actual wind shapes for the three study regions. It can be seen that there are considerable variations between the summer, winter and shoulder seasons. This implies that there will be significant variation in the amount of required ramp rates and curtailment of conventional generation between the three seasons.

In this study, representative days for each season were chosen to illustrate the effect of intra-hour variations on ramp rates.

Geographical Variations in Actual Wind Speeds

There is significant variation in wind speeds from a single wind site to another, and from a one region to another. Considering wind generation over a larger area, reduces some of these variations from specific locations, thus providing a relatively smoother wind generation profile. This characteristic is shown in the figure below.

Exhibit A2-5-9: Benefits of Geographical Diversity

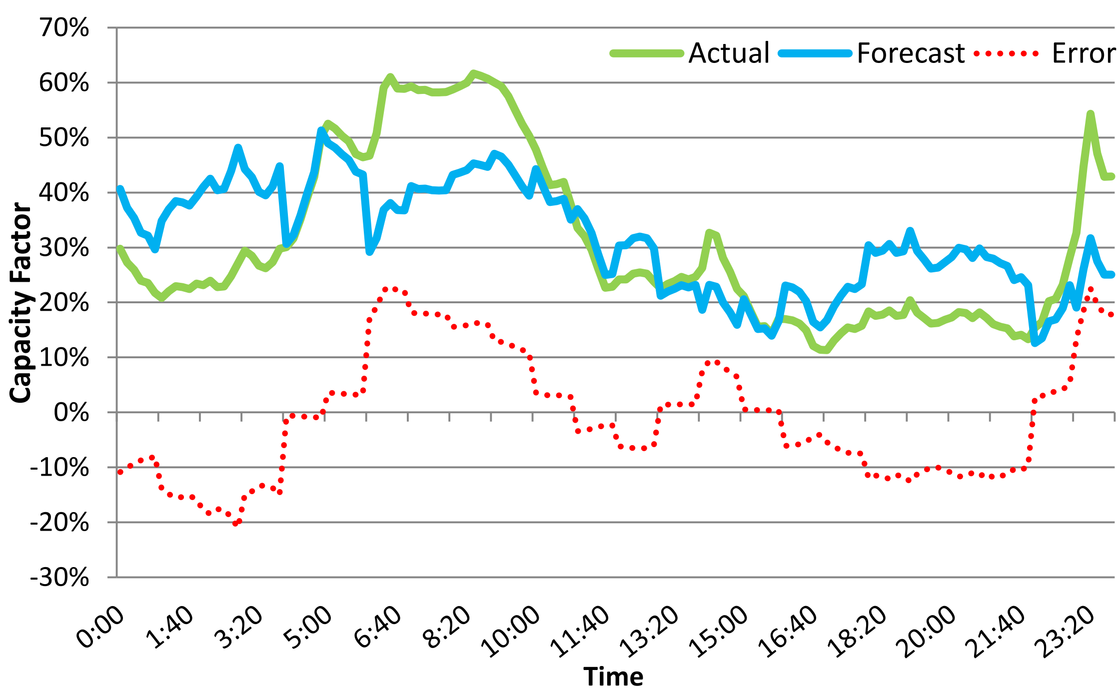


In this study we consider a combine wind shape that is a sum of a diverse set of individual wind shapes. This reduces the extent of variations in wind generation and considers the benefits of considering geographically diverse wind generation in a single coordinated manner. For the same amount of wind capacity, using wind shapes from geographically diverse regions would reduce variations in ramp rates required when compared to using wind shapes from a single region.

Comparing 4-hour Forecast vs. Actual Wind Speeds

As mentioned in the previous chapter, most wind integration studies conclude that the forecast accuracy is significantly improved as one gets closer to the actual time of dispatch. The wind forecast data available for this study was a 4-hour forecast of 10-minute wind speeds. The difference between a 4-hour forecast and actual wind speeds is shown below for a single representative day.

Exhibit A2-5-10: Illustrative Difference between Forecast and Actual Wind Output for OK-KS – 2005 Summer



In the figure above, the difference between 4-hour forecast for 10-minute wind speeds and the actual wind speeds can be clearly seen. There is significant forecast error in the 4-hour forecast data available for this study. Therefore, the actual wind shapes are used in the model to illustrate the impact of wind generation on ramp rates and conventional generation curtailment. However, it is noted that forecasting methods such as persistence forecast (the wind speed in the next interval is a function of the wind speeds of the previous intervals) will yield better results for predicting the wind speeds in the next 10-minute period. But when the time interval between forecast and the actual wind speeds is shorter, the options for compensating the variations in wind generation are reduced with peaking generation being the preferred method in the current power system.

Model Results

The model results are described in this section for each region. Results are presented for years 2010 and 2025 for each region for three representative days are described earlier. The results for years 2015 and 2020 are given in the attachment "2015-2020 Regional Net Load.xlsx".

For each of the three regions, the following results are provided along with pertinent observations.

1) Maximum fast ramp capacity needed due to wind and its pattern of variation
2) Amount of conventional generation curtailed
3) Approximate magnitude of energy storage that could be utilized to compensate for wind speed variations

Impact of Renewables on required Ramp Rates

<u>ISO-NE Region Results</u>

The exhibit below gives the total assumed wind capacity for each simulation year in the New England (ISO-NE) region (assuming no transmission limitations within the region). The numbers in the table below were derived from ICF's multi-client analysis performed using the IPM® energy market simulation software. This analysis simulated the entire U.S. power market to determine the most economically attractive generation (type and amount) subject to various environmental, fuel, and transmission policies and constraints.

Exhibit A2-5-11: Projected Cumulative Wind Capacity in ISO-NE

Year	ISO-NE Wind Capacity (MW)
2010	477
2015	3,211
2020	3,211
2025	3,852

The following two exhibits provide results for the increment and decrement maximum ramp rates (in MW/min), respectively, required to compensate for the variations in wind for each simulation year for each season, using year 2004, 2005 and 2006 actual wind shapes.

Exhibit A2-5-12: Maximum Increment in Ramp Rates due to Intermittent Renewables in ISO-NE (MW/min)

Maximum Increment Ramp Rate due to Wind									
Simulation Year	2004 Actual Wind shapes			2005 Actual Wind shapes			2006 Actual Wind shapes		
	Summer	Winter	Shoulder	Summer	Winter	Shoulder	Summer	Winter	Shoulder
2010	4	3	7	2	4	3	2	3	2
2015	30	17	44	17	24	23	15	21	12
2020	30	17	44	17	24	23	15	21	12
2025	36	20	53	20	29	27	18	26	14

Exhibit A2-5-13: Maximum Decrement in Ramp Rates due to Intermittent Renewables in ISO-NE (MW/min)

Maximum Decrement Ramp Rate due to Wind									
Simulation Year	2004 Actual Wind shapes			2005 Actual Wind shapes			2006 Actual Wind shapes		
	Summer	Winter	Shoulder	Summer	Winter	Shoulder	Summer	Winter	Shoulder
2010	-7	-2	-1	-2	-4	-5	-2	-2	-4
2015	-49	-13	-9	-15	-27	-33	-14	-14	-28
2020	-49	-13	-9	-15	-27	-33	-14	-14	-28
2025	-58	-15	-11	-18	-32	-39	-17	-16	-34

The above exhibits show the impact of additional wind in each year. For example, in Exhibit A2-5-14, based on year 2004 wind shapes, the impact of wind in year 2015 in a typical summer day on max increment ramp rates is 30 MW/min during a 10-minute period. The impact of using different year windshapes on the increment ramp rates is evident as well. Note that these wind shapes are actual and not forecasted data. From this, one can clearly see the considerable swings on required ramp rates due to varying wind speeds in the region. The incremental and decremental ramp rates in above two tables for years 2015 and 2020 are the same since there is no additional wind generation being installed in year 2020.

Exhibit A2-5-15 and Exhibit A2-5-16 below show the largest positive and negative net total ramp rates (in MW/min) needed in the region with the additional wind. The two tables above show the additional ramp rates required due to wind whereas Exhibit A2-5-17 and Exhibit A2-5-18 below show the net ramp rates (considering both load and wind variations). Increment and Decrement in ramp rates are useful to estimate the impact of wind on the system whereas the largest net total ramp rates required are useful to estimate the maximum amount of generation needed over a 10 minute time period to compensate for both wind and load variations in the region.

Exhibit A2-5-14: Largest Positive Net Ramp Rates in ISO-NE (MW/minute)

Largest Positive Net Ramp Rate									
Simulation Year	2004 Actual Wind shapes			2005 Actual Wind shapes			2006 Actual Wind shapes		
	Summer	Winter	Shoulder	Summer	Winter	Shoulder	Summer	Winter	Shoulder
2010	27	38	27	27	38	27	26	38	27
2015	37	45	50	34	54	40	30	41	30
2020	40	49	51	37	58	42	33	46	33
2025	44	55	61	41	65	48	36	50	36

Exhibit A2-5-15: Largest Negative Net Ramp Rates in ISO-NE (MW/minute)

Largest Negative Net Ramp Rate									
Simulation Year	2004 Actual Wind shapes			2005 Actual Wind shapes			2006 Actual Wind shapes		
	Summer	Winter	Shoulder	Summer	Winter	Shoulder	Summer	Winter	Shoulder
2010	-39	-29	-24	-34	-30	-24	-35	-31	-26
2015	-84	-30	-30	-38	-38	-36	-40	-45	-37
2020	-87	-34	-33	-41	-41	-37	-43	-49	-40
2025	-101	-37	-37	-46	-46	-43	-48	-55	-45

The exhibits below show the pattern of ramp rate variations for the simulation years 2010 and 2025 for the representative days in summer, winter, and shoulder seasons. These results are shown for the ramp rates developed using year 2005 actual wind shapes. In each figure for ISO-NE and for other regions, the load pattern without wind and load with wind (Net Load = Load – Wind) is shown for comparison purposes. The figures also contain two patterns of required ramp rates – the yellow line represents the required ramp rate to meet only load variations if wind generators are not present, while the green line represents the required ramp rate to meet the Net Load (Load-Wind) variations.

Exhibit A2-5-16: Load and Ramp Rate Patterns for Representative 2010 Summer Day in ISO-NE

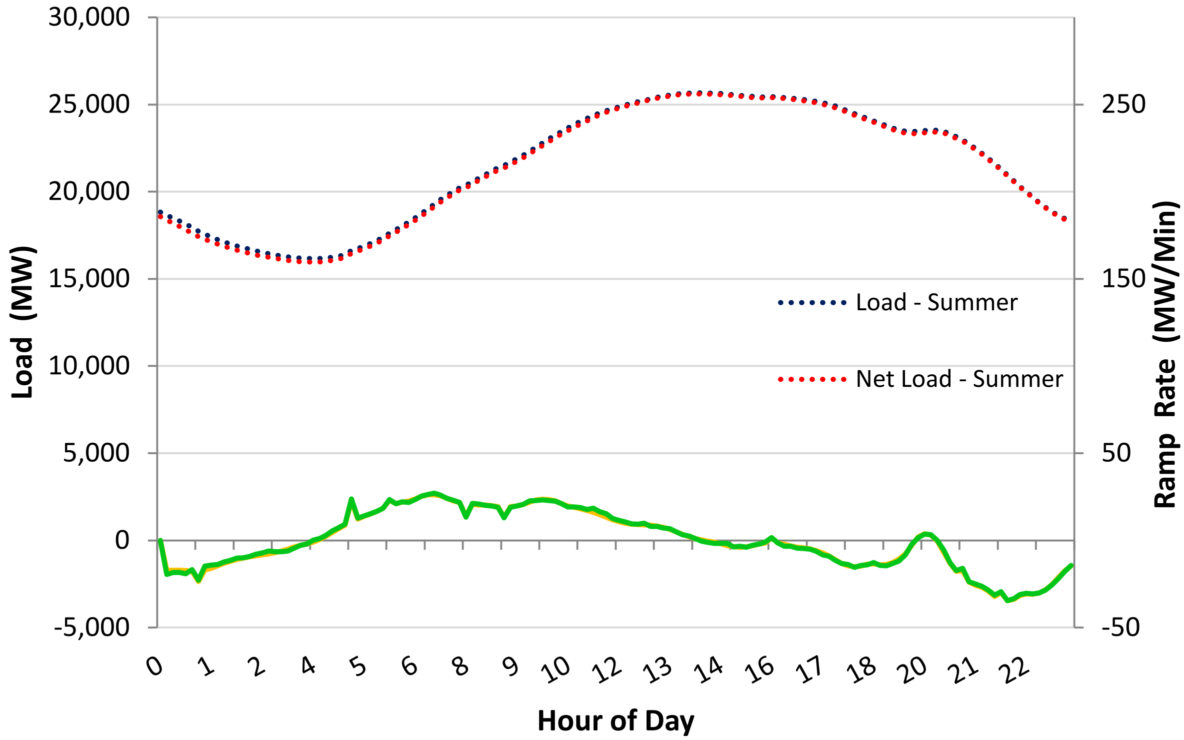


Exhibit A2-5-17: Load and Ramp Rate Patterns for Representative 2010 Winter Day in ISO-NE

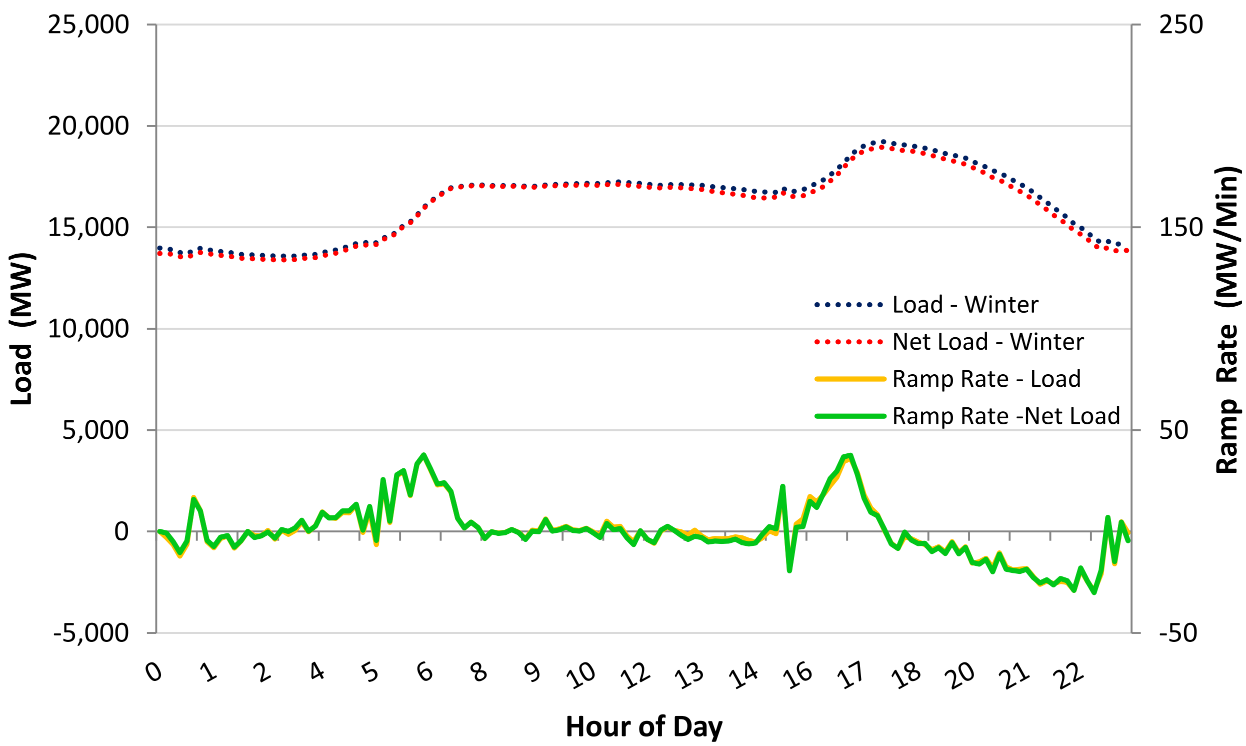


Exhibit A2-5-18: Load and Ramp Rate Patterns for Representative 2010 Shoulder Day in ISO-NE

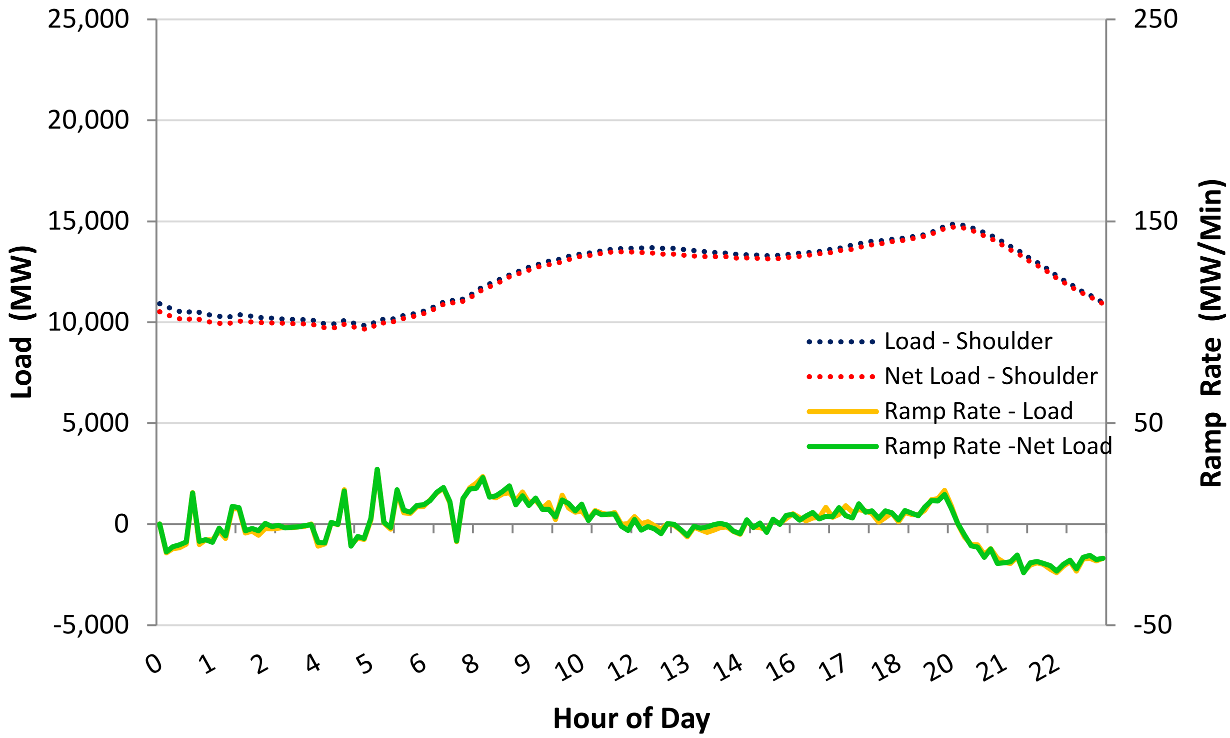


Exhibit A2-5-19: Load and Ramp Rate Patterns for Representative 2025 Summer Day in ISO-NE

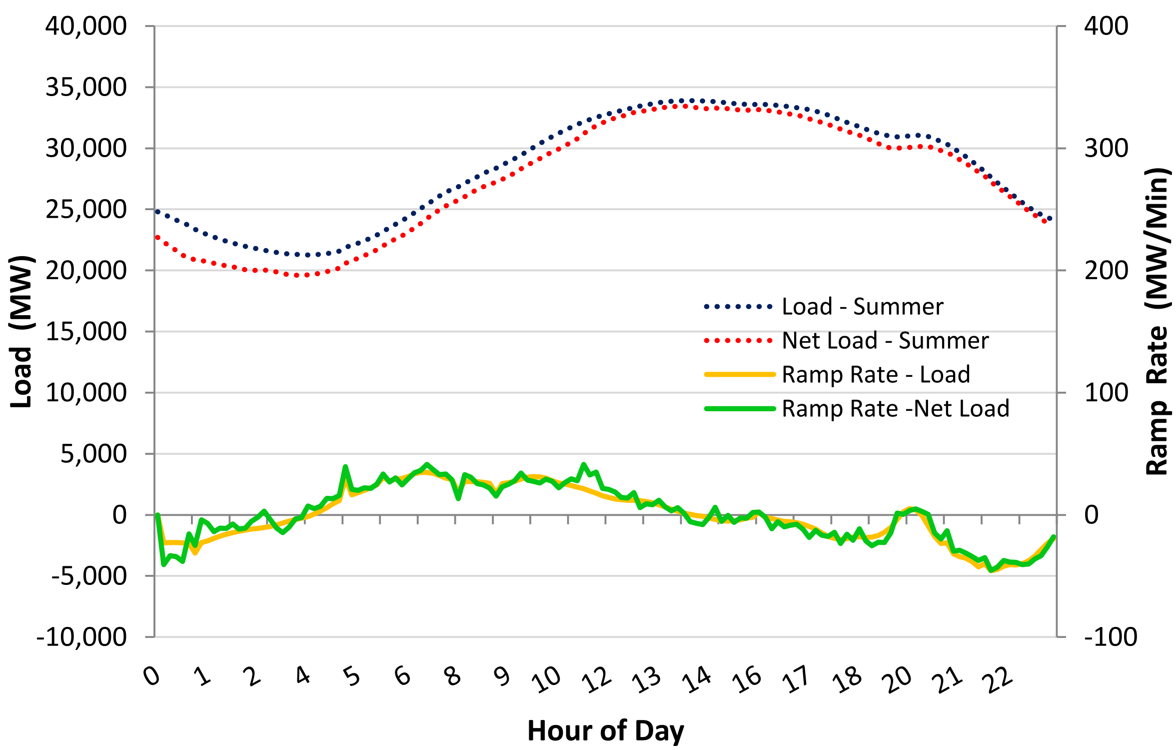


Exhibit A2-5-20: Load and Ramp Rate Patterns for Representative 2025 Winter Day in ISO-NE

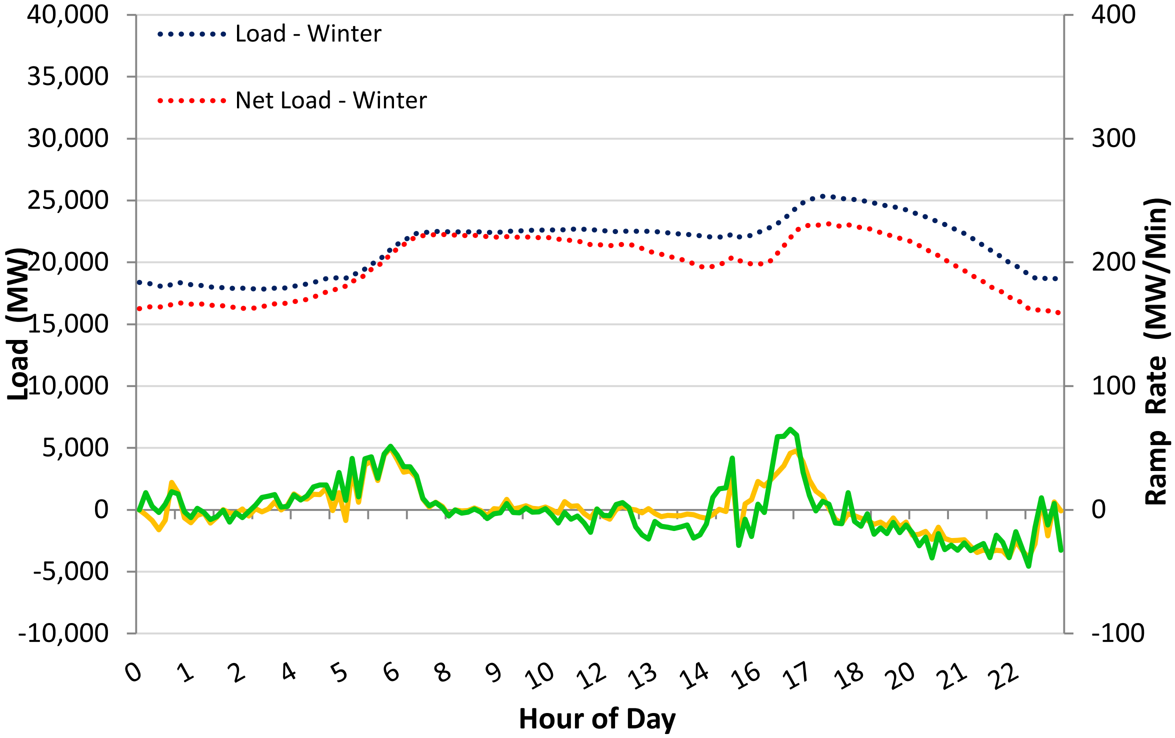
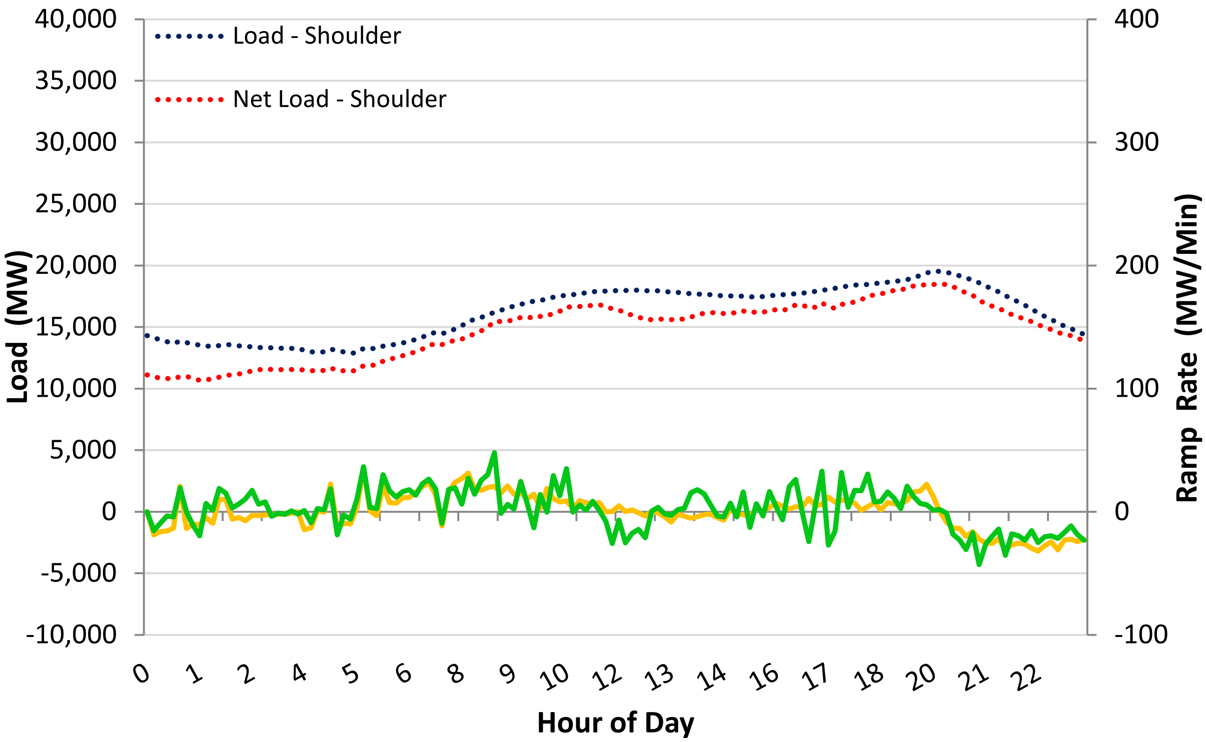


Exhibit A2-5-21: Load and Ramp Rate Patterns for Representative 2025 Shoulder Day in ISO-NE



All of the above exhibits illustrate the impact of wind on ramp rates by showing the required ramp rates for each 10-minute period within a representative day for load-only variations and for net load (load-wind) variations. Comparing the variations in required ramp rates without wind (Ramp Rate–Load; Yellow line) and with wind (Ramp Rate-Net Load; Green line), it can be noted in all of the above figures that the required ramp rates vary significantly and are much more "spiky" when wind is added into the region (the green line is much more varying than the yellow line). Since most of intermediate and peaking generators in ISO-NE are natural gas-based, the changes in required ramp rates could translate into significant changes in the timing, duration and magnitude of the required gas supply.

<u>OK-KS Region Results</u>

Exhibit A2-5-22 below gives the total assumed wind capacity for each simulation year in the Oklahoma-Kansas (OK-KS) region (assuming no transmission limitations in the two regions).

Exhibit A2-5-22: Projected Cumulative Wind Capacity in OK-KS

Year	OK-KS Wind Capacity (MW)
2010	2,194
2015	6,651
2020	12,052
2025	13,481

The two exhibits below provide results for the increment and decrement maximum ramp rates (in MW/min) required to compensate for the variations in wind for each simulation year for each season using year 2004, 2005, and 2006 wind shapes.

Exhibit A2-5-23: Maximum Increment in Ramp Rate due to Intermittent Renewables in OK-KS

Maximum Increment Ramp Rate due to Wind									
Simulation Year	2004 Actual Wind shapes			2005 Actual Wind shapes			2006 Actual Wind shapes		
	Summer	Winter	Shoulder	Summer	Winter	Shoulder	Summer	Winter	Shoulder
2010	9	5	17	16	9	8	23	11	8
2015	26	16	50	48	28	25	69	33	23
2020	48	28	91	87	51	45	125	61	42
2025	53	32	102	97	57	51	139	68	47

Exhibit A2-5-24: Maximum Decrement in Ramp Rate due to Renewables in OK-KS (MW/min)

Maximum Decrement Ramp Rate due to Wind									
Simulation Year	2004 Actual Wind shapes			2005 Actual Wind shapes			2006 Actual Wind shapes		
	Summer	Winter	Shoulder	Summer	Winter	Shoulder	Summer	Winter	Shoulder
2010	-18	-5	-17	-26	-16	-12	-32	-10	-10
2015	-56	-16	-53	-80	-48	-36	-99	-30	-30
2020	-101	-29	-96	-144	-88	-65	-179	-55	-54
2025	-112	-33	-107	-161	-98	-72	-200	-61	-60

The above exhibits show the impact of additional wind in each year. For example, in Exhibit A2-5-25, based on year 2004 wind shapes, the impact of wind in year 2015 in a typical summer day on max increment ramp rates is 26 MW/min in a 10-minute period. In the same example as above, the max increment ramp rate almost doubles to 48 MW/min if year 2005 wind shapes are used and increases to 69 MW/min if 2006 wind shapes are used. From this, one can clearly see the considerable swings on required ramp rates due to varying wind speeds in the region.

Exhibit A2-5-26 and Exhibit A2-5-27 show the largest positive and negative net total ramp rates (in MW/min) needed respectively, in the region with the additional wind. Exhibit A2-5-23 and Exhibit A2-5-24above show the additional ramp rates required due to wind whereas Exhibit A2-5-26 and Exhibit A2-5-27 below show the net ramp rates (considering both load and wind variations).

Exhibit A2-5-25: Largest Positive Net Ramp Rate in the OK-KS region (MW/min)

Largest Positive Net Ramp Rate									
Simulation Year	2004 Actual Wind shapes			2005 Actual Wind shapes			2006 Actual Wind shapes		
	Summer	Winter	Shoulder	Summer	Winter	Shoulder	Summer	Winter	Shoulder
2010	29	25	15	33	28	13	36	28	14
2015	47	29	41	54	43	29	69	38	29
2020	68	37	81	80	64	50	112	53	49
2025	76	41	91	89	71	56	125	59	54

Exhibit A2-5-26: Largest Negative Net Ramp Rate in the OK-KS region

Largest Negative Ramp Rate									
Simulation Year	2004 Actual Wind shapes			2005 Actual Wind shapes			2006 Actual Wind shapes		
	Summer	Winter	Shoulder	Summer	Winter	Shoulder	Summer	Winter	Shoulder
2010	-18	-5	-17	-26	-16	-12	-32	-10	-10
2015	-56	-16	-53	-80	-48	-36	-99	-30	-30
2020	-101	-29	-96	-144	-88	-65	-179	-55	-54
2025	-112	-33	-107	-161	-98	-72	-200	-61	-60

The exhibits below show the pattern of ramp rate variations for the simulation years 2010 and 2025 for the representative days in summer, winter, and shoulder seasons. These results are shown for the ramp rates developed using year 2005 actual wind shapes.

Exhibit A2-5-27: Load and Ramp Rate Patterns for Representative 2010 Summer Day in OK-KS

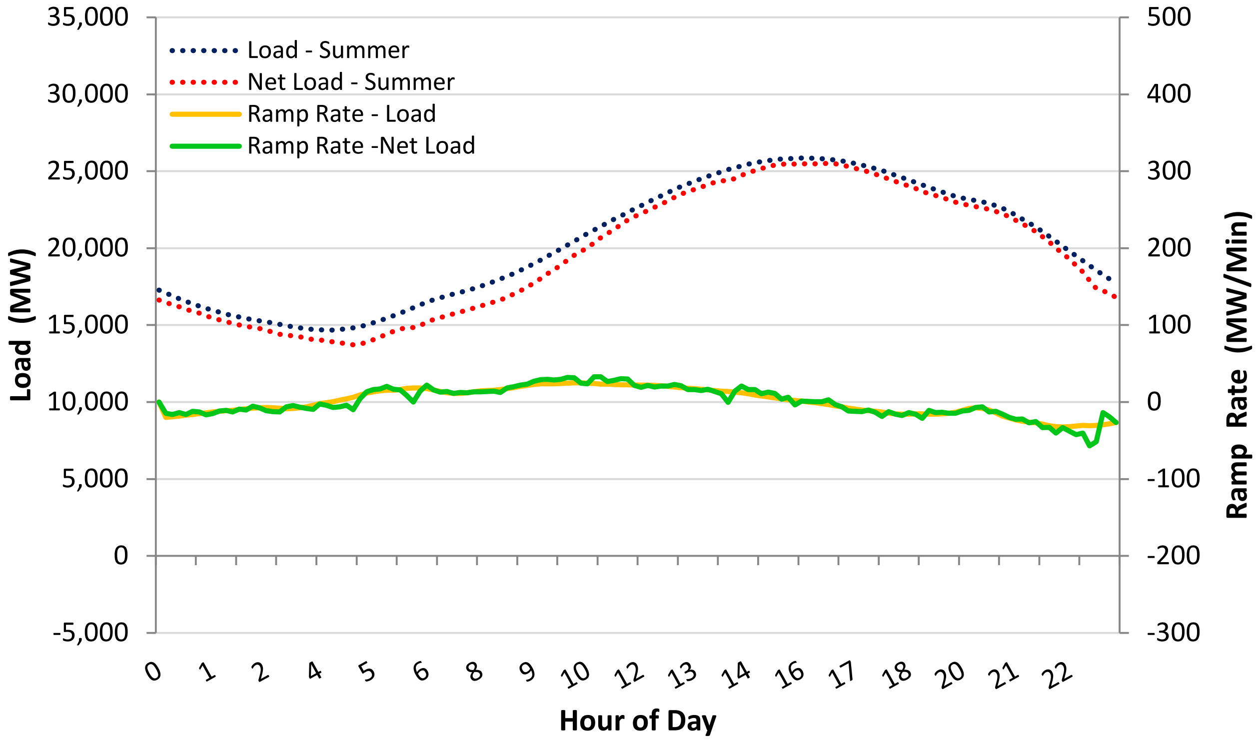


Exhibit A2-5-28: Load and Ramp Rate Patterns for Representative 2010 Winter Day in OK-KS

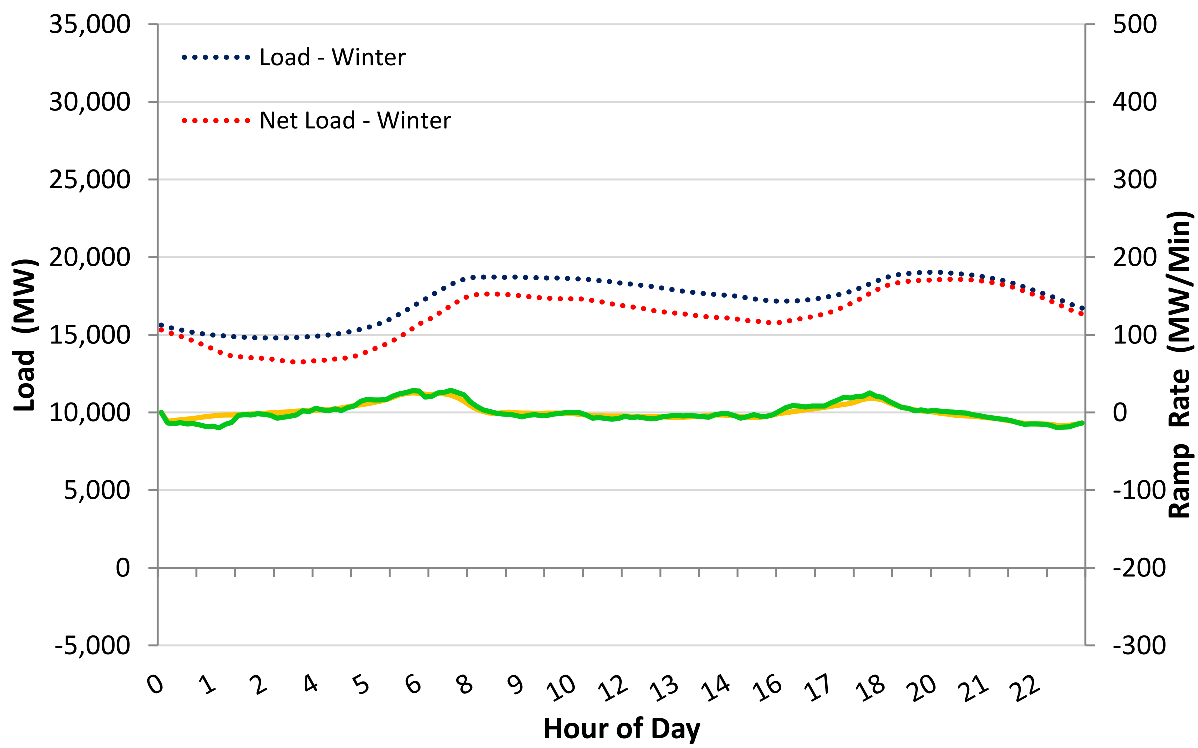


Exhibit A2-5-29: Load and Ramp Rate Patterns for Representative 2010 Shoulder Day in OK-KS

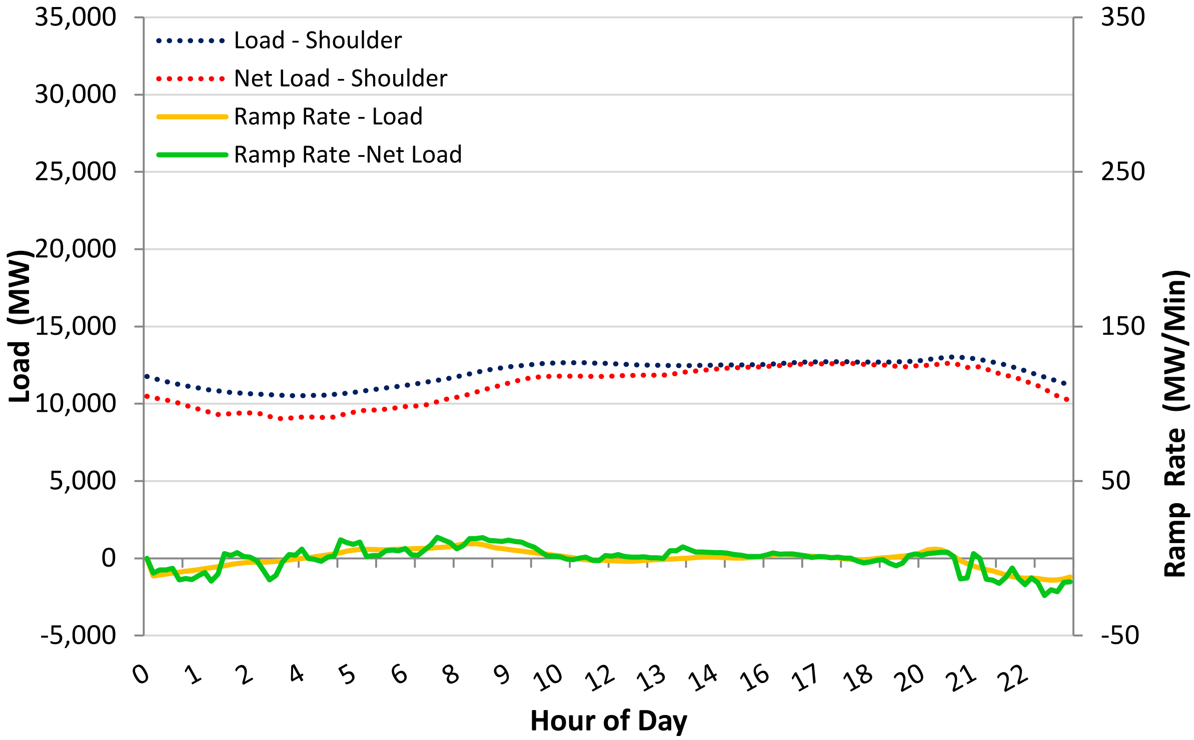


Exhibit A2-5-30: Load and Ramp Rate Patterns for Representative 2025 Summer Day in OK-KS

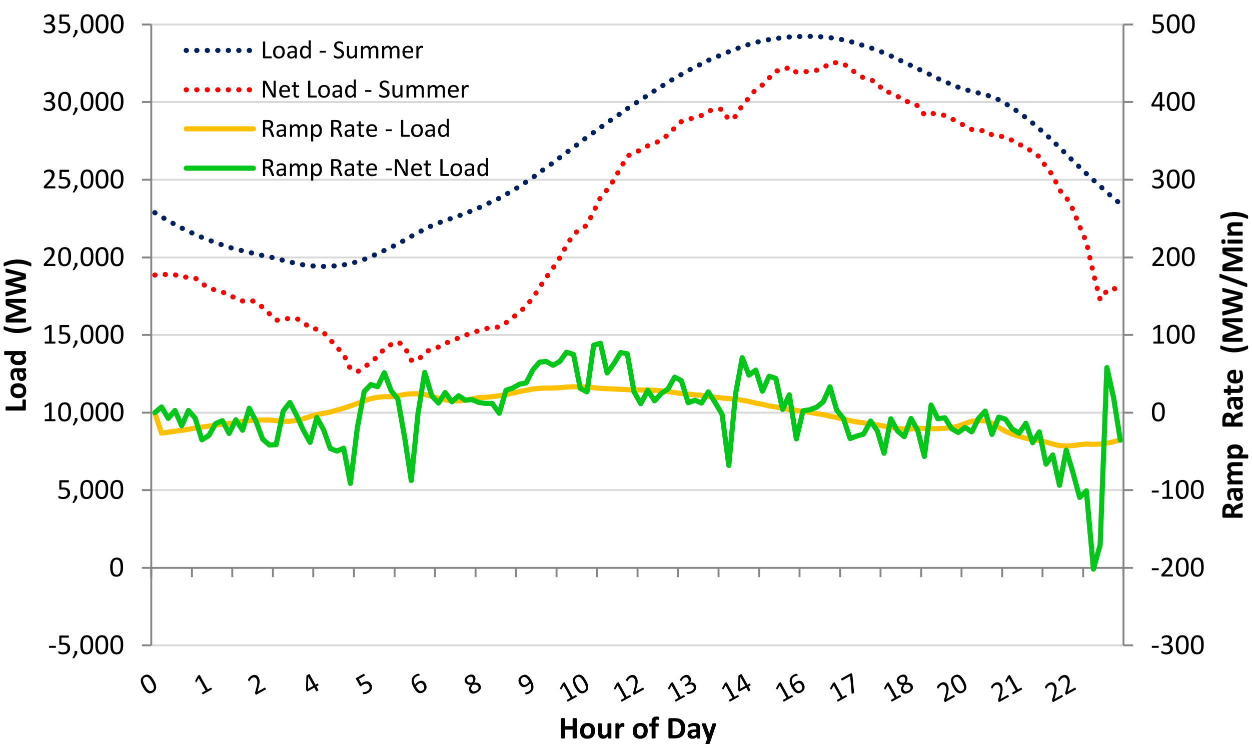


Exhibit A2-5-31: Load and Ramp Rate Patterns for Representative 2025 Winter Day in OK-KS

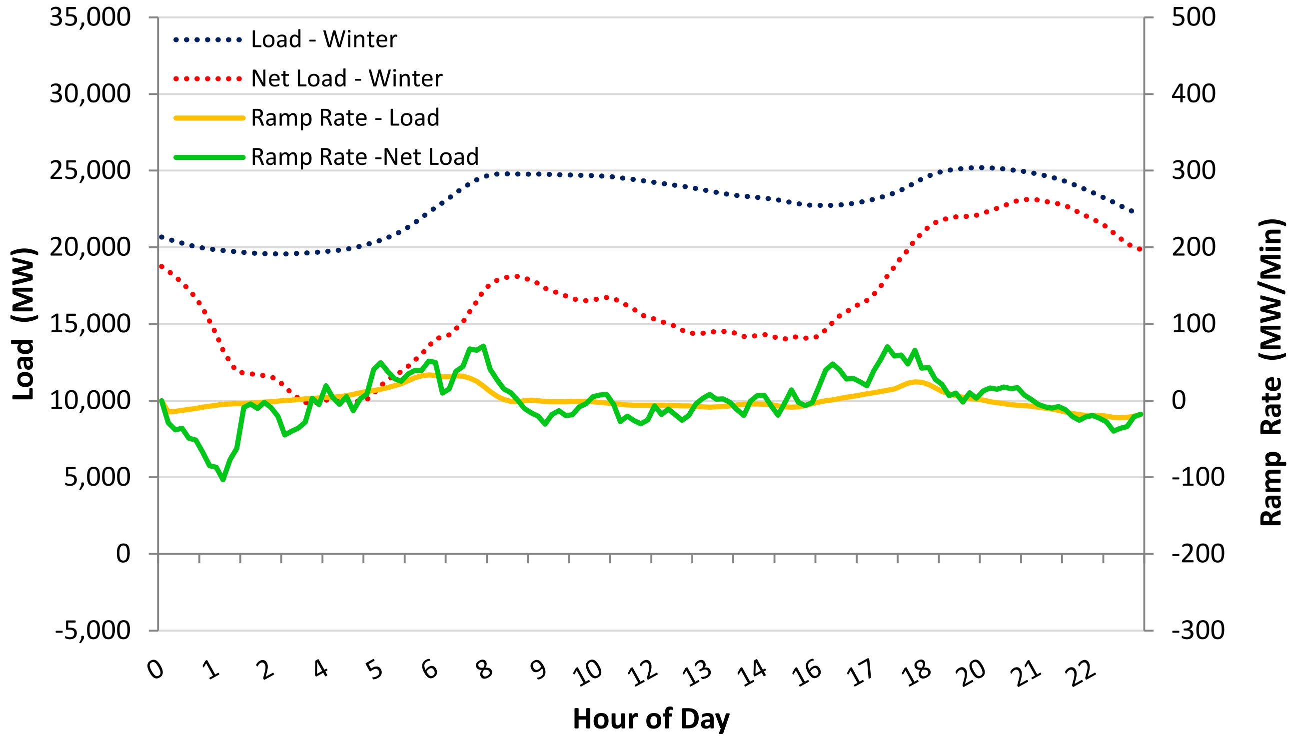
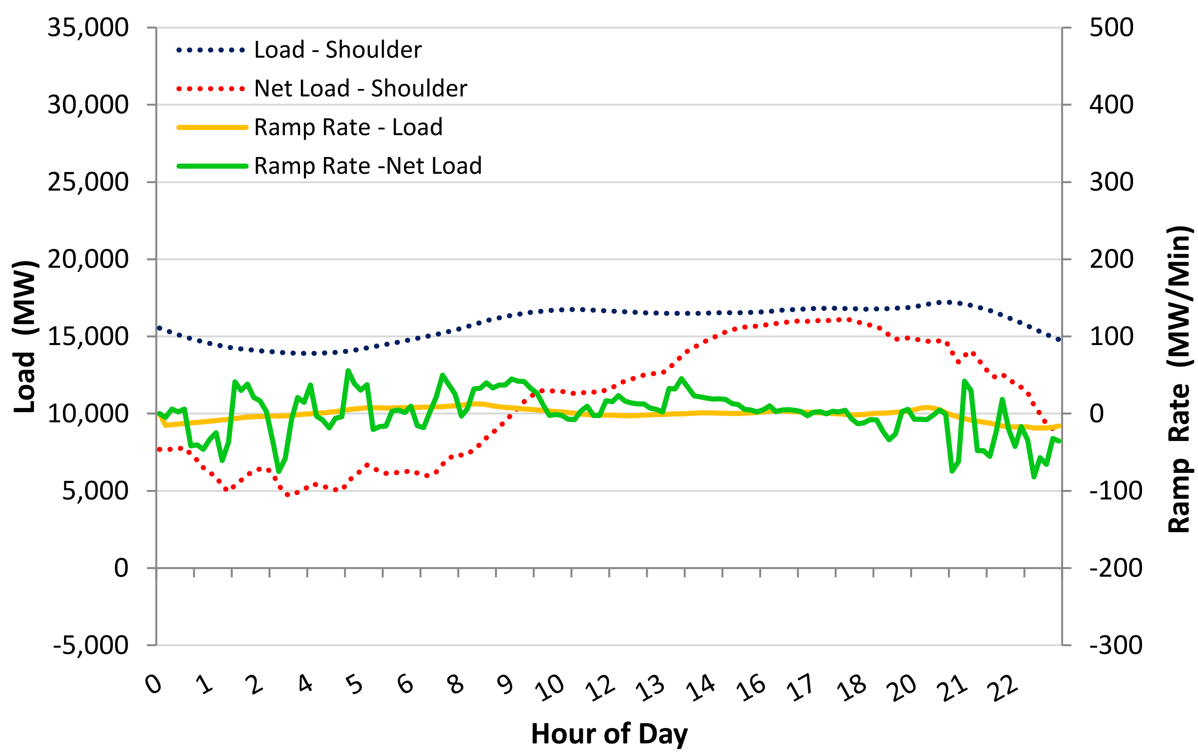


Exhibit A2-5-32: Load and Ramp Rate Patterns for Representative 2025 Shoulder Day in OK-KS



All of the above exhibits illustrate the impact of wind on ramp rates by showing the required ramp rates for each 10-minute period within a representative day for load-only and net load (load-wind) variations. Similar to the results for ISO-NE region, it can be noted in all of the above exhibits that the required ramp rates vary significantly and are much more “spiky” when wind is added into the region.

There are various ways of meeting the ramp rate requirements shown above. Some of these options include demand response, energy storage, and hydro generation. However, these options are region-specific, unproven to some extent, and expensive (such as energy storage). Therefore, for this study we assume that a significant portion of the ramp rate requirements are met by gas based generation, and hence changes in required ramp rates translate into changes in required gas supply.

Wyoming-California Results

Exhibit A2-5-33 below gives the total assumed wind capacity for each simulation year in Wyoming and California (assuming no transmission limitations between the two regions).

Exhibit A2-5-33: Projected Cumulative Wind Capacity in WY-CA

Year	WY-CA Wind Capacity (MW)
2010	5,463
2015	12,706
2020	13,018
2025	14,330

For this region, it is assumed that all the wind generation developed in the state of Wyoming can be transported to California. This is a reasonable assumption considering the fact that six major transmission lines with a total transfer capacity exceeding 12 GW are proposed with the intent of transferring power from Wyoming to California. All balancing requirements for this and for in-state wind generation are met using conventional generation within California.

Exhibit A2-5-34 and Exhibit A2-5-35 give results for the increment and decrement maximum ramp rates (in MW/min), respectively, required to compensate for the variations in wind for each simulation year for each season, using year 2004, 2005 and 2006 actual wind shapes.

Exhibit A2-5-34: Maximum Increment in Ramp Rates due to Intermittent Renewables in CA-WY (MW/minute)

Maximum Increment Ramp Rate due to Wind									
Simulation Year	2004 Actual Wind shapes			2005 Actual Wind shapes			2006 Actual Wind shapes		
	Summer	Winter	Shoulder	Summer	Winter	Shoulder	Summer	Winter	Shoulder
2010	27	9	26	53	16	51	43	17	12
2015	63	20	60	124	38	118	99	39	28
2020	64	21	62	127	38	121	101	40	28
2025	71	23	68	140	42	133	112	44	31

Exhibit A2-5-35: Maximum Decrement in Ramp Rates due to Intermittent Renewables in WY (MW/minute)

Maximum Increment Ramp Rate due to Wind									
Simulation Year	2004 Actual Wind shapes			2005 Actual Wind shapes			2006 Actual Wind shapes		
	Summer	Winter	Shoulder	Summer	Winter	Shoulder	Summer	Winter	Shoulder
2010	-64	-13	-32	-37	-15	-30	-35	-17	-11
2015	-149	-30	-74	-86	-35	-70	-82	-39	-25
2020	-152	-30	-76	-88	-36	-72	-84	-40	-26
2025	-167	-33	-83	-97	-39	-79	-93	-44	-29

The above exhibit shows the impact of additional wind in each year. For example, in Exhibit A2-5-36, based on year 2004 wind shapes, the impact of wind in year 2015 in a typical summer day on max increment ramp rates is 63 MW/min in a 10-minute period. The impact of using different year wind shapes on the increment ramp rates can also be clearly seen in the two exhibits below. In the same example as above, the max increment ramp rate of 63 MW/min for summer 2015 almost doubles to 124 MW/min if year 2005 wind shapes are used and increases to 99 MW/min if 2006 wind shapes are used. From this, one can clearly see the considerable swings on required ramp rates due to varying wind speeds in the region.

Exhibit A2-5-37 and Exhibit A2-5-38 show the largest positive and negative net total ramp rates (in MW/min) needed, respectively, in the region with the additional wind. Exhibit A2-5-35 and Exhibit A2-5-36 show the additional ramp rates required due to wind whereas tables Exhibit A2-5-37 and Exhibit A2-5-38 below show the net ramp rates (considering both load and wind variations).

Exhibit A2-5-36: Largest Positive Net Ramp Rates in WY-CA (MW/minute)

Largest Positive Net Ramp Rate									
Simulation Year	2004 Actual Wind shapes			2005 Actual Wind shapes			2006 Actual Wind shapes		
	Summer	Winter	Shoulder	Summer	Winter	Shoulder	Summer	Winter	Shoulder
2010	69	80	47	67	87	46	89	88	45
2015	103	84	57	117	100	78	150	102	50
2020	109	93	60	119	110	82	158	112	55
2025	120	102	66	131	121	90	173	123	60

Exhibit A2-5-37: Largest Negative Net Ramp Rates in WY-CA (MW/minute)

Largest Negative Net Ramp Rate									
Simulation Year	2004 Actual Wind shapes			2005 Actual Wind shapes			2006 Actual Wind shapes		
	Summer	Winter	Shoulder	Summer	Winter	Shoulder	Summer	Winter	Shoulder
2010	-102	-68	-62	-112	-66	-70	-96	-72	-46
2015	-183	-76	-97	-148	-71	-114	-136	-86	-50
2020	-192	-83	-103	-159	-78	-120	-145	-93	-55
2025	-210	-92	-113	-175	-86	-132	-159	-103	-61

The exhibits below show the pattern of ramp rate variations for the simulation years 2010 and 2025 for the representative days in summer, winter, and shoulder seasons. These results are shown for the ramp rates developed using year 2005 actual wind shapes.

Exhibit A2-5-38: Load and Ramp Rate Patterns for Representative 2010 Summer Day in WY-CA

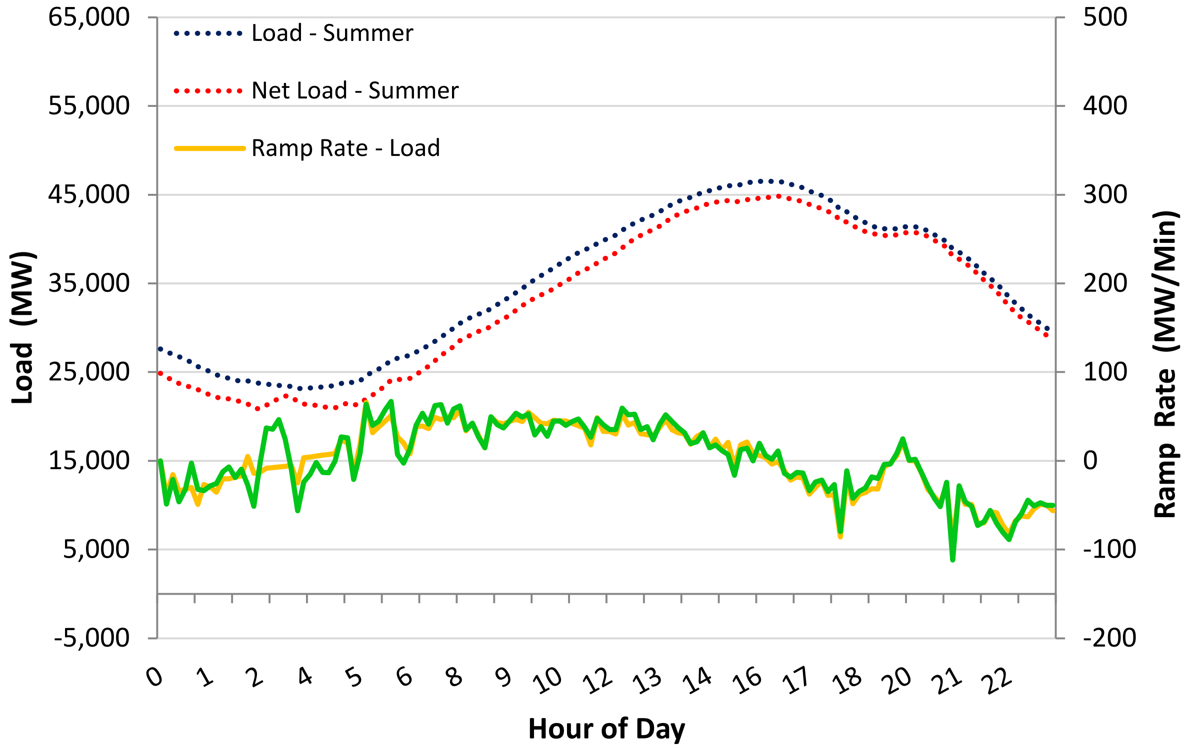


Exhibit A2-5-39: Load and Ramp Rate Patterns for Representative 2010 Winter Day in WY-CA

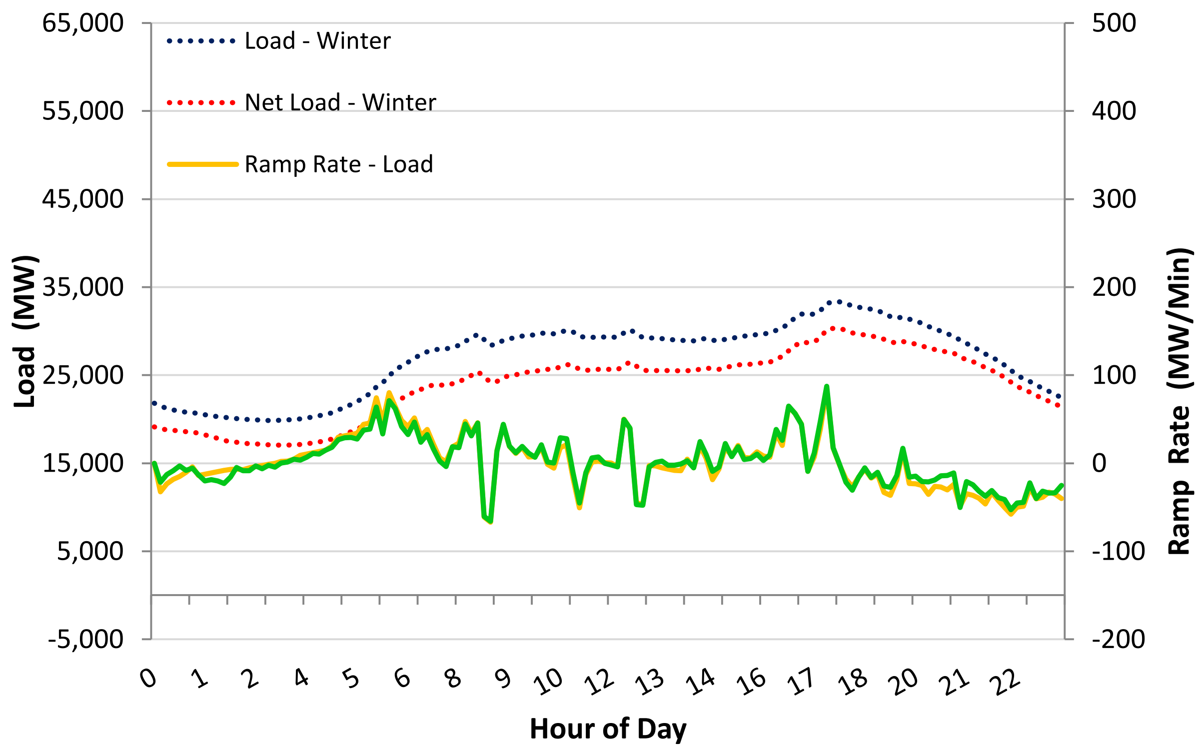


Exhibit A2-5-40: Load and Ramp Rate Patterns for Representative 2010 Shoulder Day in WY-CA

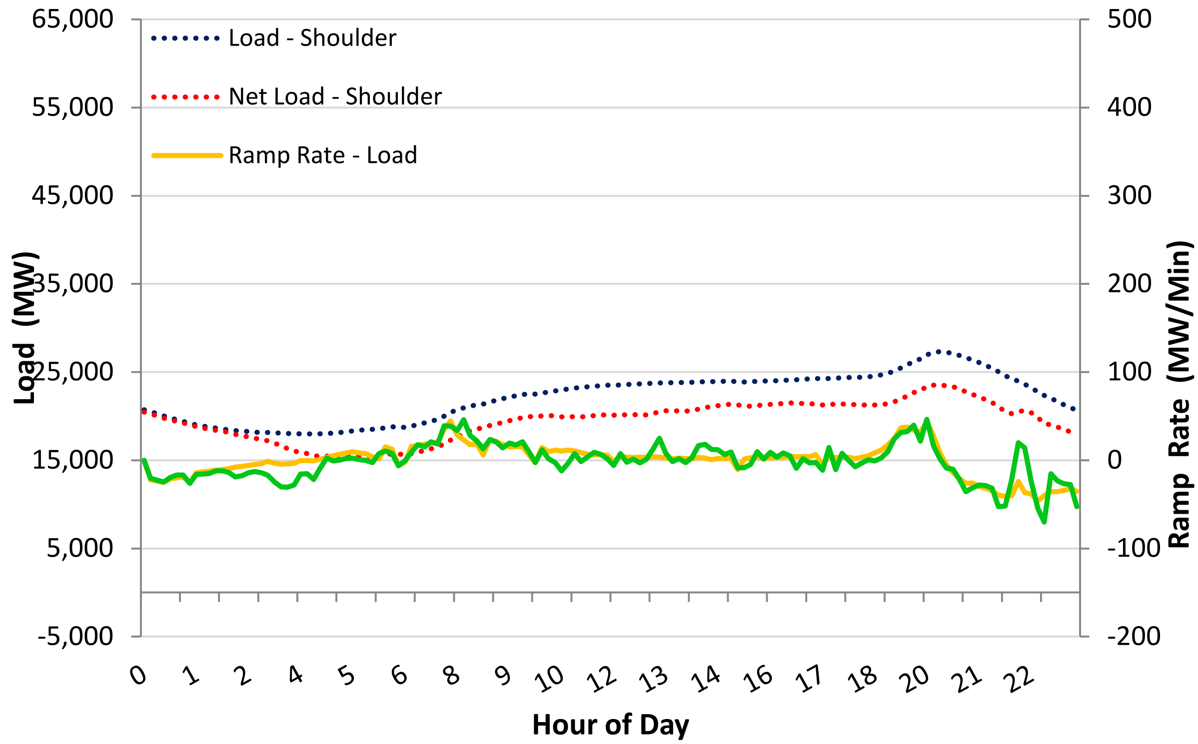


Exhibit A2-5-41: Load and Ramp Rate Patterns for Representative 2025 Summer Day in WY-CA

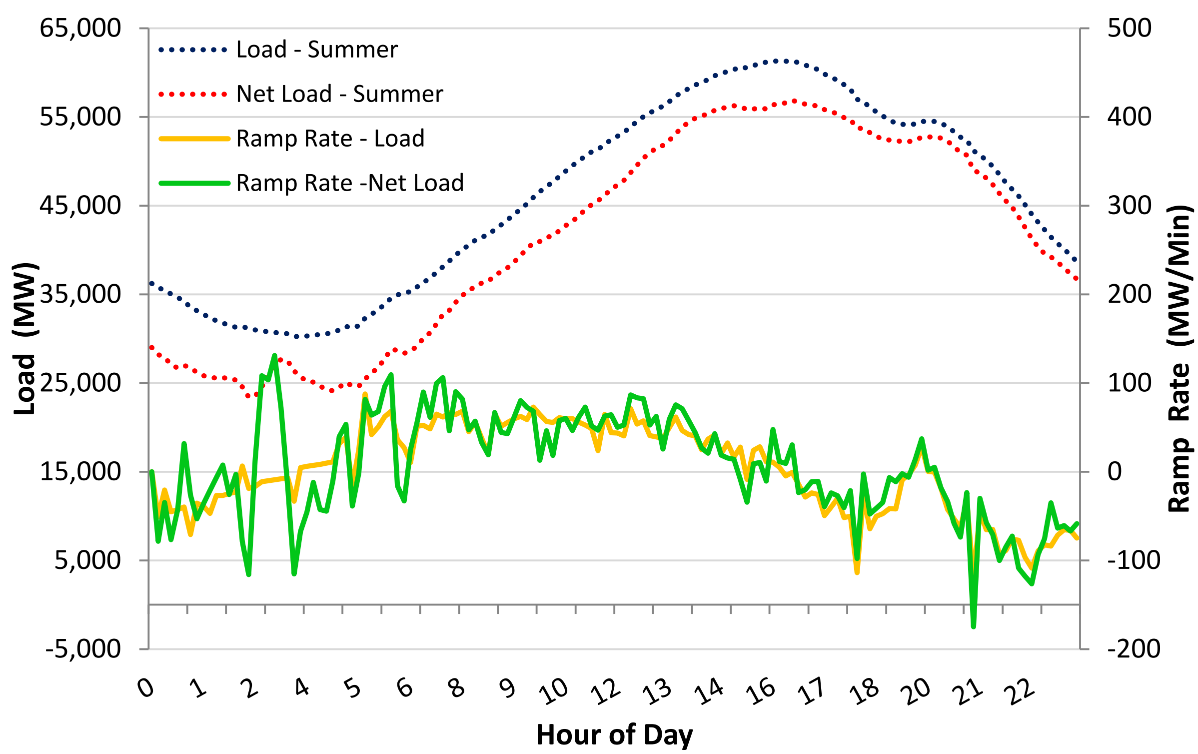


Exhibit A2-5-42: Load and Ramp Rate Patterns for Representative 2025 Winter Day in WY-CA

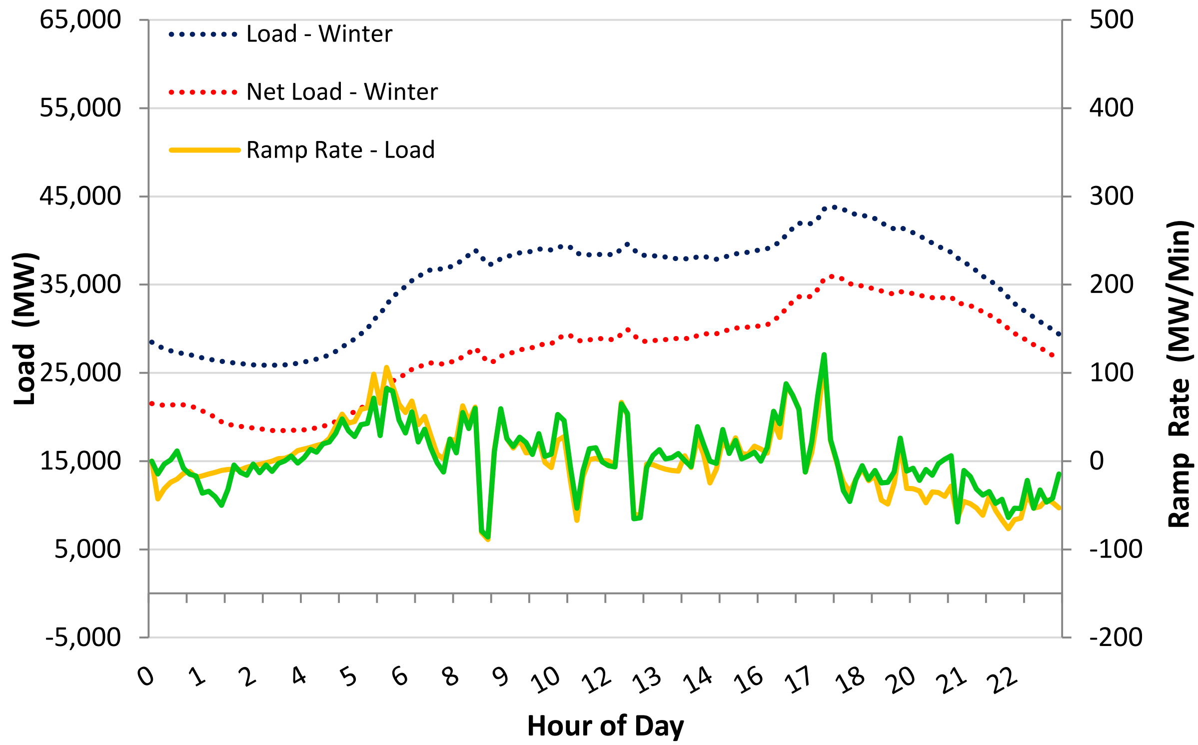
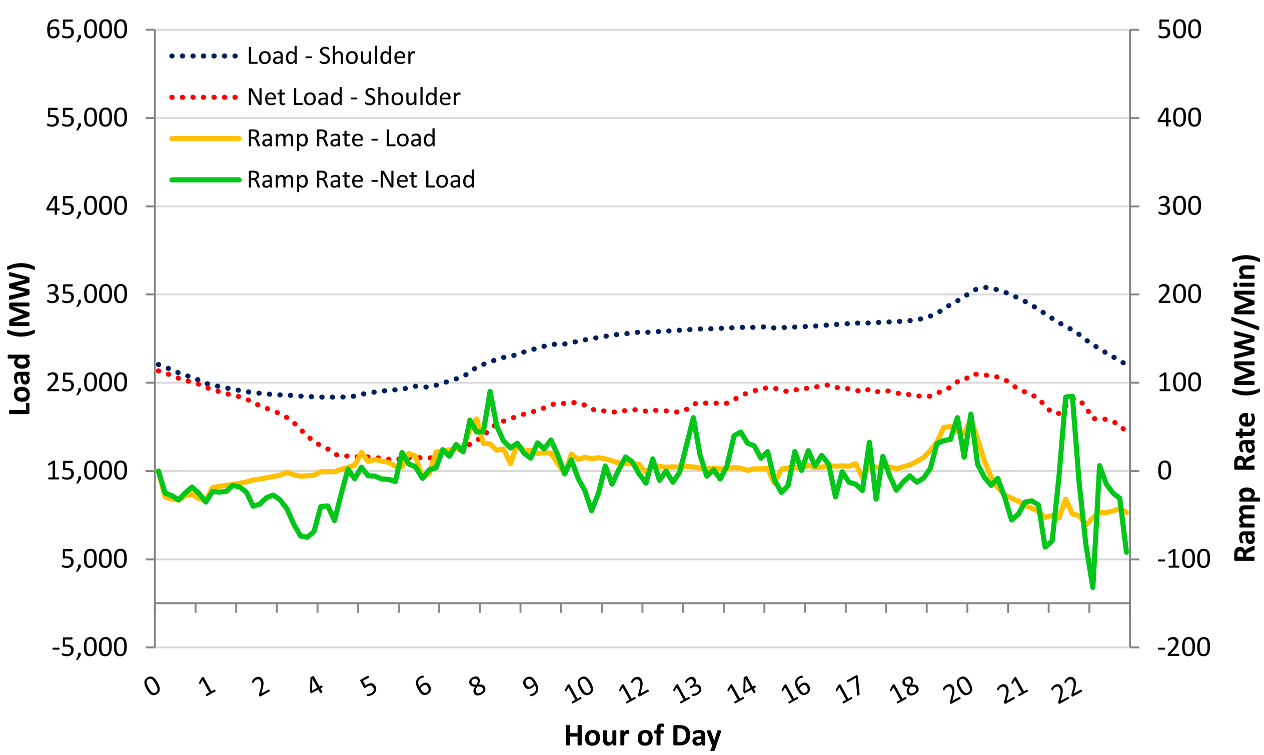


Exhibit A2-5-43: Load and Ramp Rate Patterns for Representative 2025 Shoulder Day in WY-CA



All of the above exhibits illustrate the impact of wind on ramp rates by showing the required ramp rates for each 10-minute period within a representative day for load-only variations and for net load (load-wind) variations. Similar to the results for ISO-NE and OK-KS regions, it can be noted in all of the above exhibits that the required ramp rates vary significantly and are much more "spiky" when wind is added into the region. Assuming that the majority of the ramp rate requirements are met by gas-based generation (which is true especially in California), the changes in required ramp rates translate into changes in required gas supply. There are various ways of meeting the ramp rate requirements shown above. Some of these options include demand response, energy storage, hydro generation etc. However, these options are region-specific, unproved to some extent, and expensive (e.g. energy storage). Therefore, for this study we assume that a significant portion of the ramp rate requirements are met by gas-based generation, and hence changes in required ramp rates translate into changes in required gas supply.

Impact of Renewables on Curtailment of Conventional Generation

This section gives an illustrative sample of the amount of conventional generation such as coal and combined cycle units that could be curtailed in off-peak hours due to the increase in renewable generation during those hours. The results are given for the analysis performed using year 2004, 2005 and 2006 actual wind shapes.

Exhibit A2-5-44 below gives the amount of generation from combined cycle plants that could be curtailed during a sample representative day in summer, winter and shoulder. This curtailment amount is derived assuming that all of the available wind generation at any time during the day will be utilized without requiring the wind generators to back down due to excess supply.

Exhibit A2-5-44: Illustrative Sample Combined Cycle Generation Curtailment

Region	Simulation Year	Combined Cycle Generation Curtailment (MWh) for a representative seasonal day								
		Year 2004 Actual Wind Shapes			Year 2005 Actual Wind Shapes			Year 2006 Actual Wind Shapes		
		Summer	Winter	Shoulder	Summer	Winter	Shoulder	Summer	Winter	Shoulder
ISO-NE	2010	(1,251)	(9,269)	(4,073)	(1,742)	(4,699)	(4,012)	(300)	(3,705)	(4,121)
	2015	(8,816)	(61,261)	(28,886)	(11,905)	(31,649)	(27,924)	(2,059)	(25,655)	(27,216)
	2020	(8,290)	(61,261)	(28,754)	(11,542)	(32,114)	(28,589)	(1,872)	(25,887)	(27,466)
	2025	(11,217)	(73,583)	(34,721)	(14,771)	(38,035)	(33,677)	(2,711)	(30,724)	(32,483)
OK-KS	2010	(10,466)	(6,169)	0	(7,966)	(16,899)	0	(6,453)	(14,024)	0
	2015	(34,957)	(29,004)	0	(29,145)	(65,104)	0	(22,058)	(55,801)	0
	2020	(57,018)	(51,856)	(1,839)	(45,242)	(87,966)	(1,839)	(39,491)	(91,970)	(1,839)
	2025	(77,323)	(56,029)	(23,742)	(61,197)	(132,703)	(26,339)	(47,979)	(116,067)	(30,462)
WY-CA	2010	(61,394)	(21,087)	(53,293)	(28,664)	(74,702)	(63,084)	(24,453)	(23,521)	(19,320)
	2015	(168,346)	(49,568)	(117,763)	(70,844)	(170,140)	(142,871)	(58,854)	(56,519)	(49,173)
	2020	(134,508)	(50,778)	(121,292)	(65,070)	(174,314)	(153,741)	(54,697)	(57,826)	(50,453)
	2025	(157,257)	(55,864)	(133,678)	(73,952)	(191,866)	(169,248)	(61,673)	(63,322)	(55,838)

The results in Exhibit A2-5-44 can be used to derive the corresponding amount of natural gas that may not be required for base-load and intermediate generation if all of the available wind is fully utilized. However, the pattern of demand for natural gas will vary due to ramp rate requirements for integrating the full amount of wind generation, as shown in various charts in the previous section.

It can be observed from the above table that the amount curtailment varies widely depending on how much wind is available. For example, for the year 2015, on a representative summer day, the generation from combined cycles could be curtailed by as much as 168,346 MWh in the California region if the wind patterns were similar to those in year 2004. However, wind patterns similar to years 2005 or 2006 could result in generation curtailment amounts of 70,844 MWh or 58,854 MWh, respectively, less than half of the values when year 2004 wind shapes are used. This example illustrates the uncertain nature of wind and the challenge in forecasting changes in natural gas consumption due to integration of wind generation and the corresponding changes in the utilization of the natural gas transportation infrastructure.

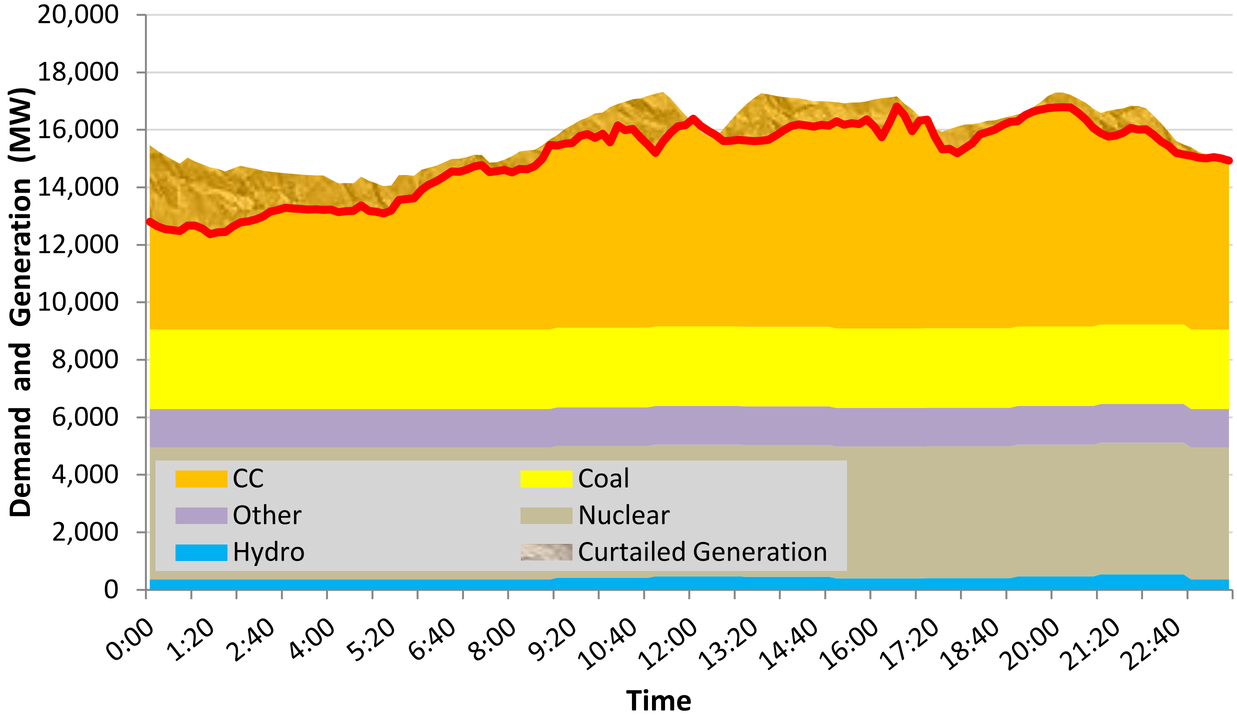
Exhibit A2-5-45 below gives the amount of generation from coal plants that could be curtailed during a sample representative day in summer, winter and shoulder. Curtailments of coal generation due to wind depend on the "depth" of generation with a variable cost of supply greater than coal in the supply stack, since the generation with the highest variable cost would be the ones curtailed first to accommodate the cheaper wind generation (subject to operational requirement constraints such as ramp rates). As shown in the exhibit below, no curtailment in coal generation is needed in either ISO-NE or California since these regions have zero or very little coal generation.

Exhibit A2-5-45: Illustrative Sample Coal Generation Curtailment

Region	Simulation Year	Coal Generation Curtailment (MWh) for a representative seasonal day								
		Year 2004 Actual Wind Shapes			Year 2005 Actual Wind Shapes			Year 2006 Actual Wind Shapes		
		Summer	Winter	Shoulder	Summer	Winter	Shoulder	Summer	Winter	Shoulder
ISO-NE	2010	0	0	0	0	0	0	0	0	0
	2015	0	0	0	0	0	0	0	0	0
	2020	0	0	0	0	0	0	0	0	0
	2025	0	0	0	0	0	0	0	0	0
OK-KS	2010	(6,842)	(3,240)	(7,121)	(4,456)	(8,346)	(19,852)	(3,867)	(6,338)	(37,220)
	2015	(8,280)	0	(22,049)	(2,719)	(12,192)	(60,046)	(2,603)	(6,170)	(112,817)
	2020	(27,961)	0	(39,045)	(14,266)	(46,013)	(106,588)	(4,790)	(14,309)	(202,227)
	2025	(11,236)	0	(21,928)	(2,087)	(18,753)	(94,860)	(1,700)	(4,403)	(197,892)
WY-CA	2010	0	0	0	0	0	0	0	0	0
	2015	0	0	0	0	0	0	0	0	0
	2020	0	0	0	0	0	0	0	0	0
	2025	0	0	0	0	0	0	0	0	0

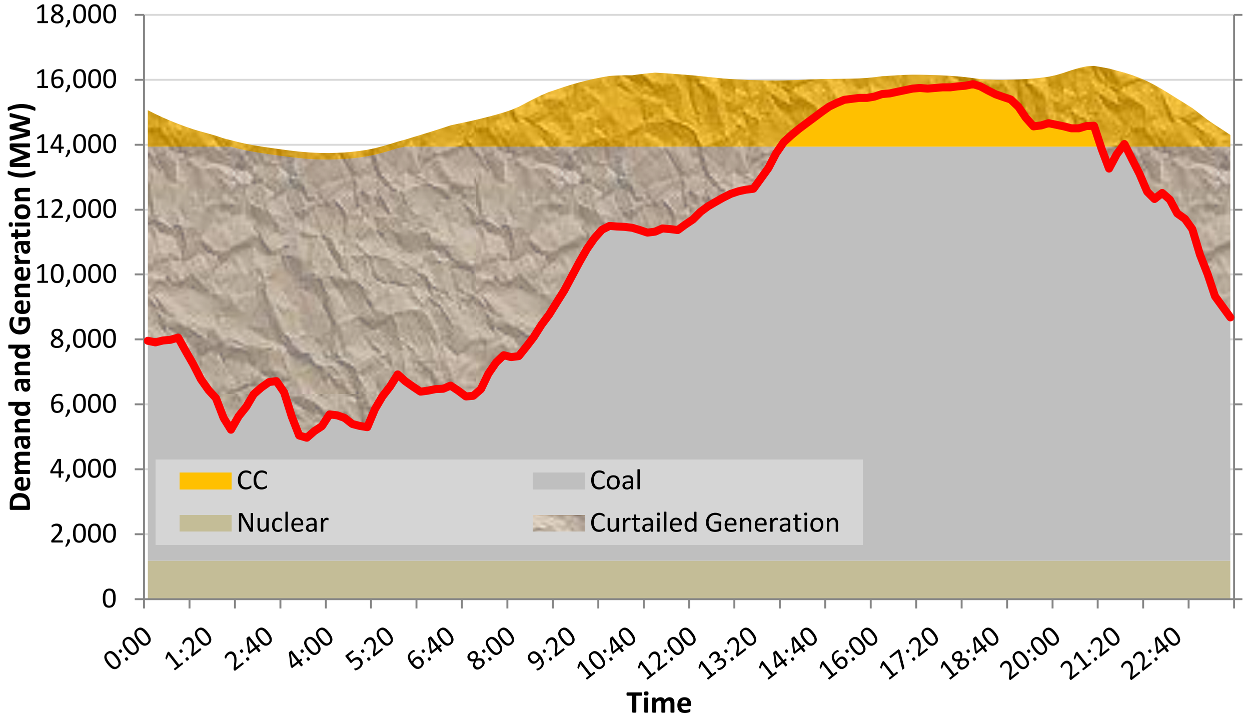
The exhibits below show the impact of wind on conventional generation in each of the three regions for year 2025 – representative shoulder day.

Exhibit A2-5-46: Impact of Wind on Conventional Generation Curtailment in ISO-NE – 2025 Shoulder Period



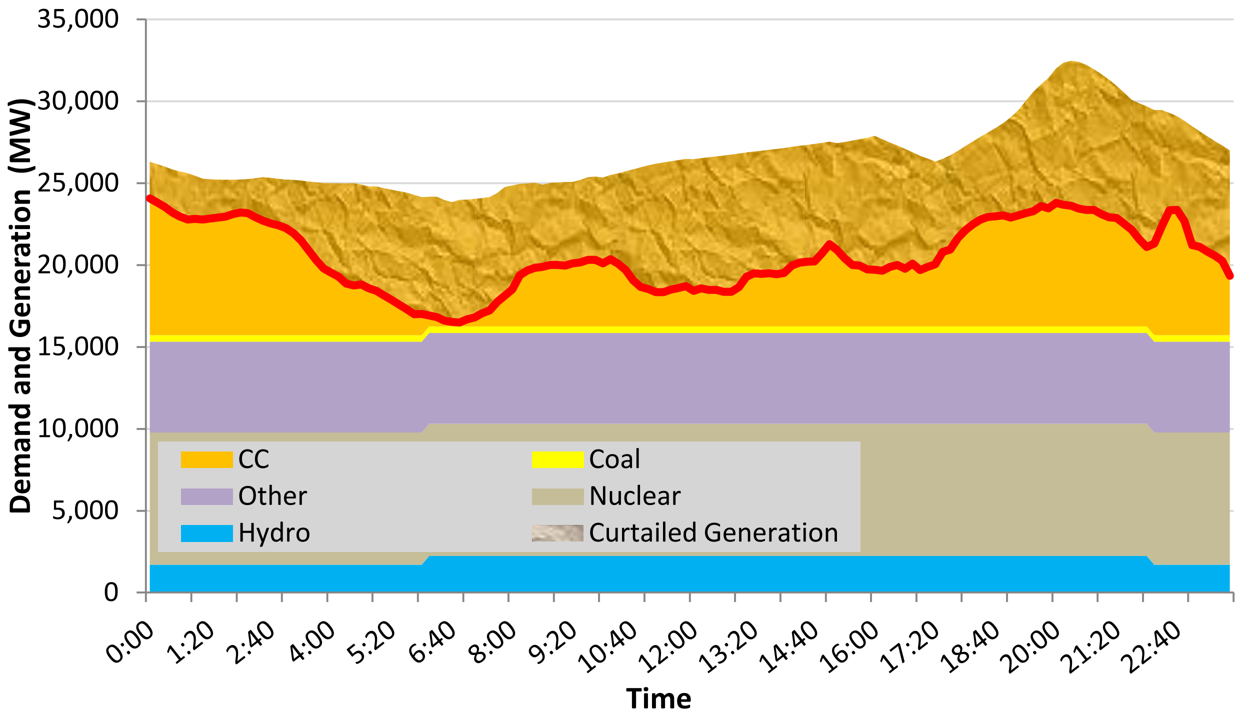
Note: Unit types generating <300MW have not been shown

Exhibit A2-5-47: Impact of Wind on Conventional Generation Curtailment in OK-KS – 2025 Shoulder Period



Note: Unit types generating <400MW have not been shown

Exhibit A2-5-48: Impact of Wind on Conventional Generation Curtailment in California – 2025 Shoulder Period



Note: Unit types generating <300MW have not been shown

The analysis above presents illustrative curtailment amounts that could result due to penetration of renewable generation. However, it is important to note that these amounts could be higher than what could be curtailed in reality, for two reasons.

a) This study does not consider variation in transmission exports or imports when wind generation changes.

b) As mentioned in renewable integration studies such as the WWSIS, the variation in wind can also be handled with coordination between neighboring balancing areas.

It is expected that more coordination among balancing areas will reduce the amount of conventional generation needed to compensate for variations in wind generation. This is due to the geographical diversity of wind and load plus the fact that generation over a wider region is available for commitment and dispatch to meet intermittent variations in wind. While this study considers the geographical diversity of wind in its analysis, the kind of real-time coordination needed to fully realize all the advantages of balancing area coordination is still evolving and challenging due to various operational and scheduling reasons. WECC has established a "Dynamic Scheduling Taskforce" to study the possibility of balancing area coordination for better utilization of distant wind generation.

As sources of fuel used for generating electricity become more diverse and geographically dispersed, it becomes necessary to develop transmission infrastructure to transport the electricity generated using those fuel sources to load centers. This is especially true for non-transportable fuel sources such as wind or solar as opposed to coal or natural gas. The development of additional renewables-based generation and full utilization of existing renewable generation will be constrained without the addition of sufficient transmission capacity. Transmission expansion will also play a key role in mitigating the impact of the variability of wind by providing access to a wider variety of loads and increasing the options for dispatching conventional generation in response to varying wind generation. Another method of increasing renewable penetration and utilization is to interlink power grids with transmission links. This will then enable (with the development and implementation of appropriate coordination mechanisms) advanced power grid operations such as dynamic scheduling to take place over a wider region, thus enhancing the ability of the power system to absorb the variations in renewable generation output without any detriment to its reliability. This concept of an “expanded, interlinked transmission grid” is a necessary step for long-term, sustainable development of renewables-based generation.

Potential for Energy Storage to Firm Renewable Generation

An alternative method to compensate for the variations in renewable generation is by the use of energy storage devices such as batteries, flywheels, and compressed air energy storage (CAES). These energy storage devices typically have fast ramp rates, and therefore could possibly provide the increment or decrement ramp rates needed to match the variability in wind speeds. However, energy storage devices typically have a higher capital cost than more conventional fast ramp generation such as CTs, and the limitations on maximum storage could present a constraint on the amount of generation/load available from these devices.

In this study, the potential for energy storage to compensate for variations in wind speeds is investigated for the ISO-NE, OK-KS and WY-CA regions. The analysis is performed on an annual basis for the years 2010, 2015, 2020 and 2025 for three years of actual wind shapes – 2004, 2005 and 2006. This study assumes that the fast ramp characteristics of energy storage devices are sufficient to meet wind variations, and does not consider any specific technology in determining the need for energy storage devices.

Energy storage devices in general are characterized by two parameters: 1) the maximum charge or discharge capacity (Peak Capacity) in MW, and 2) the maximum energy storage capability of the device in MWh. For example, a 2 MW energy storage device with 20 MWh rating can supply power at the rate of 2 MW for 10 hours, when fully charged. In this study, the peak capacity of energy storage (in MW) is equal to the largest of the absolute value of the positive or negative ramps of the wind shapes.

The maximum energy storage capability is the maximum value of the cumulative ramps needed due to variations in wind shapes and is equal to the maximum dispatch of the wind generation.

Exhibit A2-5-49 gives the peak capacity and the maximum energy storage capability potential for energy storage for the three regions based on year 2004, 2005 & 2006 wind shapes, for the simulation years 2010, 2015, 2020 and 2025. These amounts in the table are based on the forecast installed wind capacities in ISO-NE, OK-KS and WY-CA.

Exhibit A2-5-49: Summary of Impact of Wind on Conventional Generation Curtailment

ISO-NE	2010		2015		2020		2025	
Windshape Year	Peak (MW)	Capacity (MWh)	Peak (MW)	Capacity (MWh)	Peak (MW)	Capacity (MWh)	Peak (MW)	Capacity (MWh)
2004	160	443	1,077	2,984	1,077	2,984	1,292	3,579
2005	153	442	1,027	2,976	1,027	2,976	1,232	3,570
2006	139	446	934	3,005	934	3,005	1,121	3,604
OK-KS	**2010**		**2015**		**2020**		**2025**	
Windshape Year	Peak (MW)	Capacity (MWh)	Peak (MW)	Capacity (MWh)	Peak (MW)	Capacity (MWh)	Peak (MW)	Capacity (MWh)
2004	537	2,057	1,628	6,237	2,950	11,301	3,300	12,641
2005	509	2,054	1,542	6,229	2,794	11,288	3,125	12,626
2006	377	2,062	1,142	6,251	2,069	11,327	2,314	12,669
California	**2010**		**2015**		**2020**		**2025**	
Windshape Year	Peak (MW)	Capacity (MWh)	Peak (MW)	Capacity (MWh)	Peak (MW)	Capacity (MWh)	Peak (MW)	Capacity (MWh)
2004	909	5,096	2,114	11,852	2,166	12,143	2,385	13,367
2005	925	5,161	2,151	12,005	2,204	12,299	2,426	13,539
2006	1,092	5,143	2,540	11,961	2,603	12,254	2,865	13,489

The methodology described above assumes that all of the variations in wind will be met by energy storage only. Therefore, the amount of energy storage as given in the table above can be considered much higher than what could be economically feasible. As shown earlier in the report, current capital costs of energy storage are much higher than comparable costs for conventional generation such as combined cycle or a combustion turbine. Therefore, energy storage devices can be considered at best to be a niche player for the role of compensating variations in wind generation. An alternative process that will result in a more conservative (lower) estimate would be to assume that other conventional generation such as coal and/or combined cycle units would provide sufficient power to compensate for a portion of the wind speed variations. This process will reduce the amount of energy storage required to meet fast ramp requirements.

It is important to note that the results shown in the exhibit above give only illustrative amounts of energy storage that could be used to compensate for wind variations. Note that the actual characteristics of energy storage devices needed (such as amount, technology, energy output etc.) will be determined based on more detailed regional analyses considering the region-specific generation mix and their ramping capabilities, economic characteristics such as variable cost, and by utilizing a more granular dispatch forecast based on production cost simulation tools. As discussed earlier, conventional generation providing fast ramp requirements, and utilizing a larger balancing area or increased coordination between multiple balancing areas, will reduce the need to compensate large wind variations and consequently, the amount of energy storage or other fast ramp generation needed.

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Chapter 3

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Appendix 3: Stakeholder Comments

ICF solicited the views of key stakeholders in various organizations on the topic of the roles of natural gas and energy storage in wind integration. We were able to obtain views on these topics from organizations including American Wind Energy Association (AWEA), Electric Power Supply Association (EPSA), and North American Energy Regulatory Council (NERC). A summary (sorted by topics and source) of the key points mentioned in the conversations are given below. Overall the interviews provide a variety of perspectives that that highlight the range of challenges facing the power sector as the market penetration of wind generation grows. They also highlight a number of solutions that could address some of those issues and lead to mutually beneficial results.

Firming Renewable Generation

- AWEA
  - There are no rules of thumb to describe the quantity of firming resources needed for every MW of wind developed.
  - Moving from hourly scheduling to 10 or 15 minute scheduling can better accommodate for wind forecast limitations.
  - Wind's reserve margin contribution may range from 15 to 30 percent.
  - Wind forecasts improve as you approach the hour for which wind is being forecasted.
  - Overall system operators must increase operating reserves with the addition of wind capacity.
- EPSA
  - Desire the same rules/penalties to apply to all generation including renewables. The same principles apply for renewables and demand response as does for conventional.
- NERC
  - Increased need for regulation resources due to renewables; however, some of the regulation could be obtained from wind plants themselves.
  - Create a 15 minute dispatch process for regulation instead of the current 1 hour.

Cost Allocation for Wind Integration

- AWEA
  - The cost of contingency reserves and other ancillary services associated with conventional generators and industrial customers are already spread among ratepayers. It would be unfair to make wind generators pay for these services.
- NERC

- Cost allocation for wind generation integration is a very complicated issue. Would prefer socialization however, messaging is critical in ensuring that the benefits due to wind are not misunderstood.

Role of Natural Gas

- AWEA
  - Natural gas is better at ramping. But natural gas will not be impacted significantly by wind.
  - Reform “must take” provisions in day-ahead natural gas purchase agreements. If these agreements were to move from day ahead to inter-day agreements, natural gas-fired generators could better accommodate short term changes in wind generation.
- EPSA
  - There are insufficient incentives for gas turbines and other units to compensate for renewables.
- NERC
  - There are reliability considerations and implications for the natural gas infrastructure due to increased renewable penetration.
  - Demand response and combustion turbines are two methods to compensate for unexpected up/down ramps caused by wind.
  - However, there may not be enough pipeline capacity to supply natural gas for combustion turbines. Therefore, cannot solely count on them for firming up wind
  - For gas storage unlike coal storage, it is much harder to know the quantity available and the location of availability.

Role of Energy Storage

- AWEA
  - Storage technologies are at the upper end of the “flexibility supply curve” in which the lowest cost firming solutions are natural gas, then demand response, then ancillary services, and finally storage.
  - There is no evidence that backup storage is needed for individual projects, rather, storage and other firming resources will be needed on a system wide level.
- EPSA
  - Energy storage does not have much potential since it has a long way to go on reducing cost. However energy storage applications will continue to increase.
  - Cannot plan a reliable system with only intermittent generation and energy storage.
- NERC

- Energy storage technologies such as flywheels and batteries can be used only for a short amount of time. The key parameter in evaluating energy storage is the amount of energy that could be supplied – not the capacity of the energy storage unit.

Role of Conventional Generation

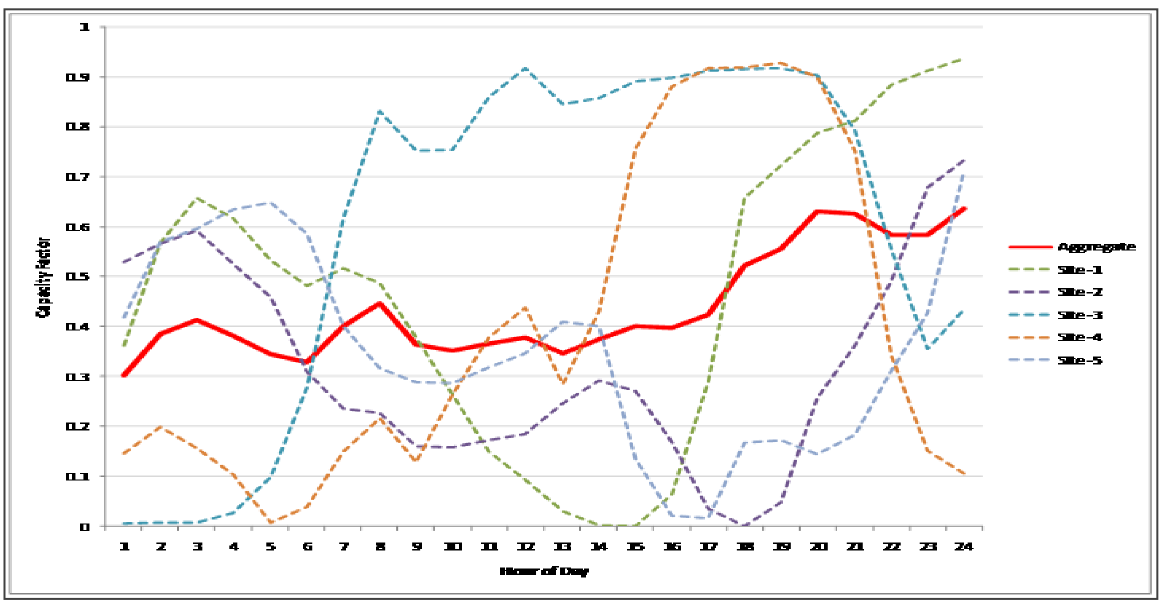
- EPSA
  - Wind will primarily offset coal which lacks flexible ramping capability.
  - Concerned about state RPS mandates. Would like to see rules on carbon.
  - Backbone of the electrical system is still coal and nuclear.
- NERC
  - It is possible for coal units to provide some of the ramp that is needed due to wind

Appendix 4: Determining the Required Level of Firming Service Capacity and Generation

For the Wyoming analysis, ICF relied on actual generation profiles from the Western Wind and Solar Integration Study (WWSIS). The forecast errors used in this study were developed from the EWITS[1] study for sites very similar in geography and wind characteristics to those in Wyoming, since forecast data was not available in the WWSIS study. Sixteen sites in Nebraska and South Dakota were chosen based on characteristics similar to wind resources in Wyoming – similar geography, power class ratings (power classes 4 to 7)[2] and their relatively high capacity factor.

Exhibit A4-1 illustrates how site-specific diversity in wind generation can be mitigated by aggregating wind generation from diverse locations. As shown in the figure, each site's capacity factor can vary between 0 and 100 percent throughout the day; these variations are reduced considerably, however, when site-specific generation is aggregated with other sites (as demonstrated by the relatively smaller variations of the solid red line in the figure). Therefore, for this analysis, multiple sites spread across a wide area have been chosen and their wind generation has been aggregated to reduce variations associated with a specific site.

Exhibit A4-1: Reducing Variations in Wind Generation by Aggregating Site-specific Values



One of the key steps in determining firming requirements is to decide on the forecast interval that is used to determine forecast errors. Once the magnitude of the errors are identified, then

[1] NREL, Eastern Wind Integration and Transmission Study, January 2010.

[2] Sites from the EWITS study have been chosen since forecast wind speed data for sites in Wyoming are not available for this study.

the amount of firming capacity needed, can be calculated based on statistical methods described below. ICF compared four-hour-ahead wind generation forecasts to actual wind generation data for the years 2004 through 2006 for 16 selected sites. [3] The aggregate capacity factor for the 16 chosen sites is about 40 percent. Four-hour ahead forecast information is the timeliest information that is publicly available for wind generation. Forecast errors between four-hour and actual data are relatively less than those between day-ahead values and actual data. With current market-based load following and rapid response generating services, power system operators have almost as many options to compensate for the variability of wind generation four hours ahead as they do for the day ahead, and therefore, assessing backup generation needed using four-hour ahead forecasts is both appropriate and prudent. Further, using four-hour-ahead forecasts instead of day-ahead forecasts is not unreasonable since it is probable that due to technological advances in forecasting technology, day-ahead forecasts in the future could be potentially at least as accurate as four-hour-ahead forecasts are at present.

Exhibit A4-2 shows that the distribution of the errors is somewhat normal, implying that the forecast errors are approximately symmetrical around the mean. The figure also shows that most of the forecast errors lie within three standard deviations (σ) of the mean[4]. Therefore, if the value of firming capacity is equal to the mean $\pm 3\sigma$ (referred to as the 3-sigma rule[5]), then, 98–99% of the forecast uncertainty errors may be compensated for by varying the firming capacity as needed based on variations in wind generation.

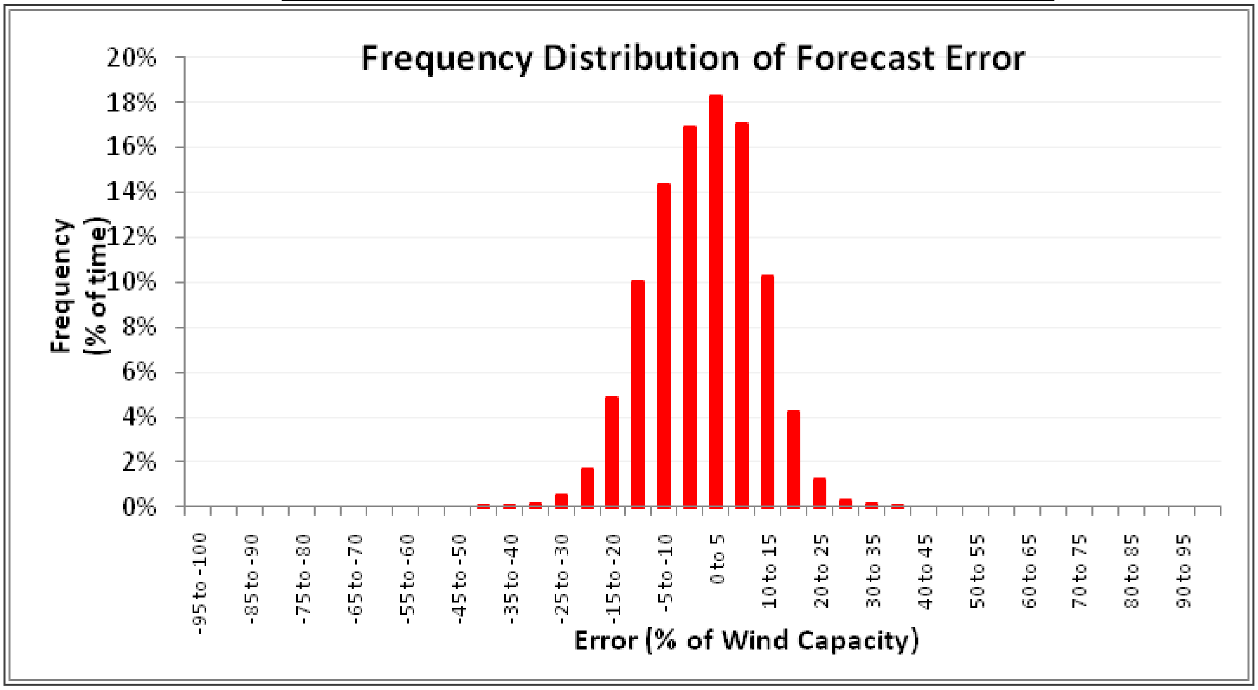
[3] Of the 16 sites, 10 are in Nebraska with 7 GW of nameplate capacity, and 6 sites in South Dakota with 5 GW of nameplate capacity. All but 3 of the sites are close to the Wyoming border.

[4] In this analysis, it is assumed that the forecasting behavior is not skewed by different penalties applicable for under forecasting and over forecasting. Thus, given that the forecasting technique is indifferent towards under vs. over forecasting, we assume a normal distribution of the forecast errors.

[5] In statistics, the 68-95-99.7 rule, referred to as the three-sigma or empirical rule, states that in a normal distribution, nearly all values lie within 3 standard deviations of the mean. Specifically, it states that in a normal distribution, about 68%, 95% and 99.7% of the values lie within 1, 2 and 3 standard deviations, respectively, from the mean.

Exhibit A4-2: Wind Generation Forecast Errors for Three Years (2004–2006)

MAE[6]	Standard Deviation (σ)	< 1 σ	< 2 σ	< 3 σ
8.2%	5.9%	67.65%	95.89%	99.12%



In this report, ±3 σ from the mean is used for the coverage level for calculating the level of backup power required. At this time, ICF is not aware of a single universal standard for calculating the level of backup power required, but both ±2σ and ±3σ have been used. A ±3σ metric provides a greater level of backup confidence compared to a ±2σ metric, and ICF used the ±3σ level in this report. A recent article in Wind Energy examined standard deviation methods for wind power[7]. In the Wind Energy article, the authors noted that recent studies (EnerNex Corporation, 2006[8]; EnerNex Corporation, 2007[9]; Idaho Power Corporation, 2007[10])

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[6] Mean Absolute Error (MAE) is the average of the absolute error values. The MAE figures in this study are normalized by the total amount of wind generation capacity.

[7] Using Standard Deviation as a Measure of Increased Operational Reserve Requirement for Wind Power, H. Holttinen et al., Wind Engineering, Volume 32, No. 4, pp. 355-378, 2008.

[8] EnerNex Corporation. 2006. Final Report – 2006 Minnesota Wind Integration Study. Minnesota Public Utilities Commission.

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have used ±2σ as the preferred metric to calculate load following requirements for wind. This level is based on the requirement (imposed by the North American Electricity Reliability Corporation [NERC]) that the minimum required score for control performance standard 2 (CPS2) is 90%, which approximately corresponds to the normal probability value for 2σ. The authors note that other studies have used ±3σ as the appropriate confidence interval (GE Energy, 2007[11]; Dragoon and Milligan, 2003[12]; Milligan, 2003[13]).

In planning for sufficient firming capacity to cover the times when actual generation falls short of the forecast, using three standard deviations from the mean provides a reasonable level of system reliability. Exhibit A4-3 shows the mean absolute error plus three standard deviations for three years, and the reserve requirement that would be needed for 1 GW of wind generation. The forecast error has similar characteristics for all three years and therefore, the (MAE+**3σ**) value for all years in the table is chosen as the percent of firming capacity that is needed. This percent value is the percentage of total wind capacity installed. Thus, for every 1 GW of wind generation, a reserve capacity of 259 MW, or 25.8 percent of the wind capacity is required for firming based on the statistical criteria explained earlier. Note that this firming value is less than that required to meet the maximum forecast uncertainty of 40 percent (or 400 MW) on the far right tail of the distribution, which is 40 percent or 400 MW of firming capacity.

Exhibit A4-3: Wind Generation Forecast Errors for Three Years (2004–2006)

	4-hour Forecast				
Shape Year	MAE	Standard Deviation (σ)	MAE + 3σ	Coverage	Reserve Requirements (GW)
2004	8.2%	5.9%	25.9%	99.2%	0.260
2005	8.0%	5.8%	25.5%	99.1%	0.255
2006	8.3%	5.9%	25.9%	99.0%	0.260
All Years	8.2%	5.9%	25.8%	99.1%	0.259

Deriving Estimated Utilization of Natural Gas Generating Capacity

To determine the sufficiency of existing natural gas supply infrastructure for handling the changes in gas demand that may be needed due to firming requirements for wind generation, it is necessary to estimate the utilization of gas-fired generation for compensating wind forecast

[11] GE Energy. 2007. Californian Intermittency Analysis.
[12] Dragoon, K. and Milligan, M. 2003. Assessing Wind Integration Costs with Dispatch Models: A Case Study of PacifiCorp. Windpower 2003 Conference Proceedings, May 18–21, 2003, Austin, Texas.
[13] Milligan, M. 2003. Wind Power Plants and System Operation in the Hourly Time Domain. Windpower 2003 Conference Proceedings, May 18–21, 2003, Austin, Texas.

uncertainties. This section describes a simple methodology for estimating the utilization of gas-fired generation.

Additional gas-fired generation is needed when "over forecast" errors occur. That is, when actual wind generation is less than that forecast, other generation needs to "fill the gap" between forecast and actual wind generation. Determining the amount of energy that is required to fill this gap (on an annual basis), can then provide an estimate of the utilization of additional generation needed for firming wind.

Exhibit A4-4 shows that for the actual wind shapes for all years (2004–2006), 83% of the over-forecast errors are contained within one standard deviation of the mean over-forecast error value. The table also shows that 420 MW of backup generation can cover 99% of the over-forecast errors.

Exhibit A4-4: Wind Generation Forecast Errors for Three Years (2004–2006)

Metric	Maximum Over-forecast (MW for 2GW Wind)	Coverage of Over-forecast Occurrences
Mean (μ)	81	–
Standard Deviation (σ)	113	–
$\mu + \sigma$	194	83%
$\mu + 2\sigma$	307	95%
$\mu + 3\sigma$	420	99%

The utilization of the backup generation at each incremental statistical interval can then be estimated by calculating the sum of all over forecast errors, over the analyses time period.

Consider:

CF – utilization of backup generation (expressed as a percentage)

$M_{3\sigma}$ – maximum forecast error for ($\mu + 3\sigma$) occurrences

W_{At} – Actual wind generation at time period t

W_{Ft} – Forecast wind generation for time period t

T – Total number of time periods

Then,

$$CF = \left\{ \left[(W_{Ft} - W_{At}) \Big|_{T = 1 \text{ to } t} \right] \Big/ \left(T \times M_{3\sigma} \right) \right\} \qquad \text{for all t when } W_{Ft} > W_{At}$$

Applying the above equation over the time period (2004–06) will give the estimated utilization for generation required for firming wind. Exhibit A4-5 below shows the amount of firming generation (energy in MWh) required to compensate for the wind over forecast errors at each of the incremental statistical intervals, and the utilization (otherwise known as capacity factor –

CF) of the backup generators. This table shows the amount of energy and utilization for different levels of compensating over forecast errors, assuming enough generation capacity is installed to cover **μ + 3σ** as shown in Exhibit A4-4 (420 MW). Thus, the amount energy supplied by 420 MW of generators installed, for between **μ** and **μ + 1σ,** between **μ + 1σ and μ + 2σ,** and between **μ + 2σ** and **μ + 3σ,** are given in Exhibit A4-5.

Exhibit A4-5: Wind Generation Forecast Errors for Three Years (2004–2006)

Between:	Incremental Dispatch (MWh)	Incremental Capacity (MW)	CF
μ and **μ + 1σ**	1,726,209	194	34%
μ + 1σ and **μ + 2σ**	305,666	113	10%
μ + 2σ and **μ + 3σ**	86,062	113	3%
TOTAL	2,117,937		

The reason for showing the amount of backup energy and the corresponding CF for backup generation at incremental levels of firming wind generation is to understand the degree of utilization and the nature of gas-fired generation that will be needed for firming. Usually, higher levels of CF imply that a more economical choice could be a combined cycle gas generator and lower levels of CF will imply a simple cycle gas turbine can be used.

The analysis implies that, as an example, for 2,000 MW of installed wind capacity, a gas-fired unit with a capacity of 194 MW could expect to have a capacity factor of about 34 percent if it generated only on hours where there is a wind generation shortfall (relative to forecast) to compensate for hours between **μ** and **μ + 1σ**, as shown in Exhibit A4-5 above. In some markets, this is a respectable capacity factor for a combined cycle unit. Since this is only for hours in which wind generation is over forecast, the combined cycle unit could provide energy from economic dispatch (depending on the current market price) during the remaining hours. For the hours in other levels (between **μ + 1σ** and **μ + 2σ ,** and between **μ + 2σ** and **μ + 3σ)**, the CFs are less than or equal to 10 percent which implies that either simple cycle gas turbines or energy storage units could be a more economical choice for firming wind when compared to a combined cycle unit.

This analysis concludes the average of 15.6 percent for the three capacity factors in Exhibit A4-5 applies to all units that will be used to backup wind generation. While perhaps on the high side, it is desirable to apply a higher-than-expected value to not understate the gas use for firming renewable generation in this analysis.

Applying this analysis to a regional or national level is not expected to change the capacity requirements significantly. As the footprint for developing wind generation is expanded to include larger blocks or areas, the multitude of forecast errors are expected to offset, rather than compound. So, a firming requirement of 25.8 percent of installed wind capacity is assumed in the subsequent analysis that follows throughout this report.