NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Guideline

Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System

September 2023

RELIABILITY | RESILIENCE | SECURITY




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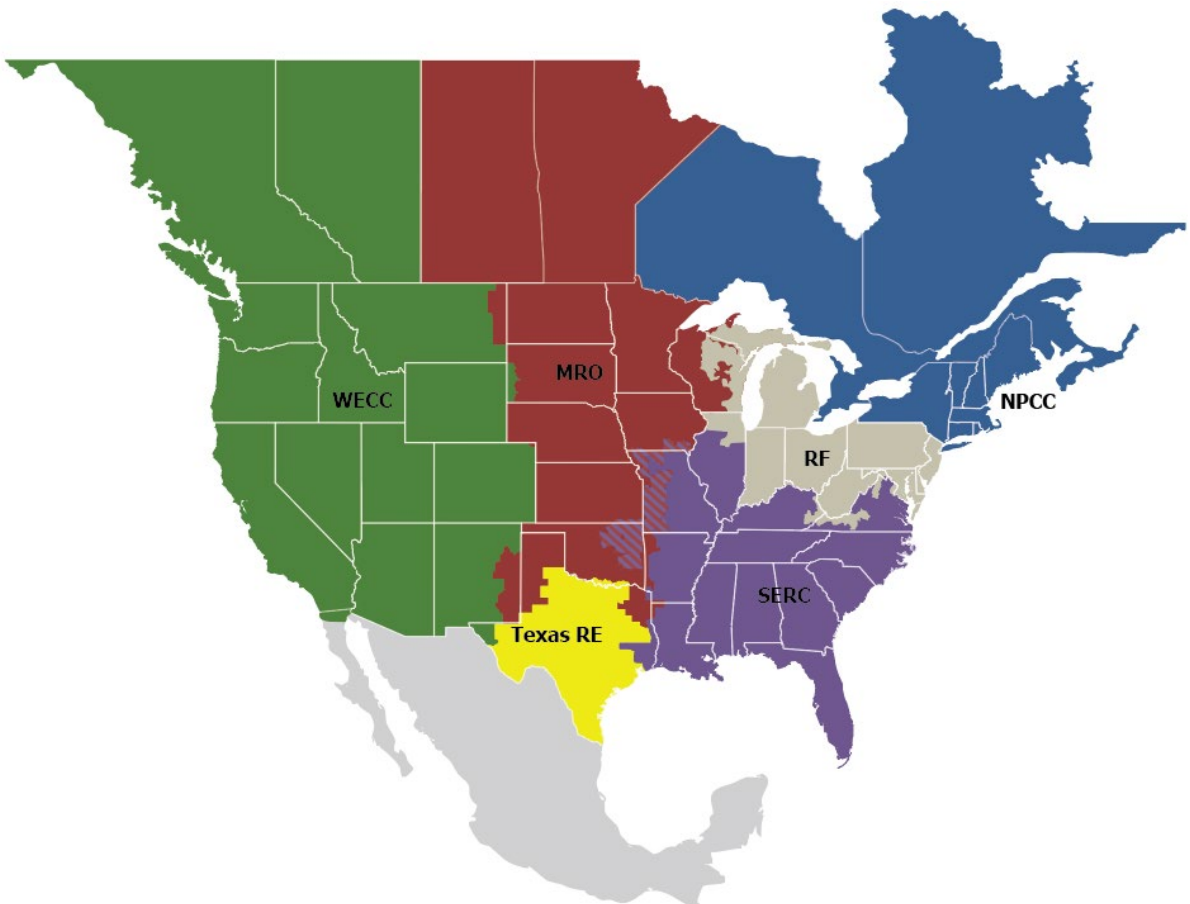
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of NERC and the six Regional Entities, is a highly reliable, resilient, and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

Preamble

The NERC Reliability and Security Technical Committee (RSTC), through its subcommittees and working groups, develops and triennially reviews reliability guidelines in accordance with the procedures set forth in the RSTC Charter. Reliability guidelines include the collective experience, expertise, and judgment of the industry on matters that impact BPS operations, planning, and security. Reliability guidelines provide key practices, guidance, and information on specific issues critical to promote and maintain a highly reliable and secure BPS.

Each entity registered in the NERC compliance registry is responsible and accountable for maintaining reliability and compliance with applicable mandatory Reliability Standards. Reliability guidelines are not binding norms or parameters nor are they Reliability Standards; however, NERC encourages entities to review, validate, adjust, and/or develop a program with the practices set forth in this guideline. Entities should review this guideline in detail and in conjunction with evaluations of their internal processes and procedures; these reviews could highlight that appropriate changes are needed, and these changes should be done with consideration of system design, configuration, and business practices.

Executive Summary

NERC, as the Federal Energy Regulatory Commission (FERC) certified ERO,[2] is responsible for the reliability of the BES and has a suite of tools to accomplish this responsibility, including but not limited to the following:

- Lessons Learned
- Reliability and security guidelines
- Assessments and reports
- The Event Analysis Program
- The Compliance Monitoring and Enforcement program
- Mandatory Reliability Standards

It is in the public interest for NERC to develop reliability guidelines that are useful for maintaining and enhancing the reliability of the Bulk Electric System (BES). Reliability guidelines establish a voluntary code of practice on a particular topic for consideration and use by BES users, owners, and operators. The NERC Reliability and Security Technical Committee (RSTC), through its subcommittees and working groups, develops and triennially reviews and, as necessary, updates reliability guidelines in accordance with the procedures set forth in the RSTC Charter.[1]

Each entity registered in the NERC compliance registry is responsible and accountable for maintaining reliability and compliance with applicable mandatory Reliability Standards. Reliability guidelines include the collective experience, expertise, and judgment of the industry on matters that impact BPS operations, planning, and security. Reliability guidelines provide key practices, guidance, and information on specific issues critical to promote and maintain a highly reliable and secure BES. Reliability guidelines are not to be used to provide binding norms or create parameters by which compliance to NERC Reliability Standards are monitored or enforced. Entities are encouraged to review these guidelines in detail and in conjunction with evaluations of their internal processes and procedures. While the incorporation of guideline practices is strictly voluntary, reviewing, revising, or developing a program using these practices is highly encouraged to promote and maintain BES reliability.

[1] https://www.nerc.com/comm/RSTC/RelatedFiles/RSTC_Charter_Board_Approved_Nov_4_2021.pdf

Introduction

Purpose

The purpose of this reliability guideline is to ensure registered entities have relevant information to (i) plan for the procurement of sufficient fuel to serve load and have modeled contingencies for both short-term operational horizons to long-term planning timeframes, (ii) fully understand fuel supply chain risks, and (iii) offer additional conditions and constraints, especially during extreme events, to consider when performing studies. This reliability guideline may offer potential scenarios to analyze - e.g., loss of fuel, compressor outages, etc., but it is not intended to provide the environmental conditions contemplated under those studies.

Background

The rapid advancement of renewable generation, retirement of coal- and oil-fired generation, and increased use of natural gas have necessitated the need to re-evaluate the methods that the industry has historically utilized to analyze and maintain BPS reliability. Specifically, the increased reliance on just-in-time dispatchable generation, in particular, natural gas, to back up variable generation. This reliance requires an examination of the potential for compounded fuel/energy supply challenges and exemplifies the increased importance of thoroughly characterizing cross-sector interdependencies.

In November 2017, NERC published the Special Reliability Assessment: Potential Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System (2017 NERC Special Assessment).[5] In that report, NERC made numerous recommendations for assessing disruptions to natural gas infrastructure and related impacts to the reliable operation of the BPS in planning studies, several of which were assigned to the NERC Planning Committee (PC), a predecessor to the Reliability and Security Technical Committee (RSTC). In July 2018, the PC convened a workshop to highlight ongoing "fuel assurance" discussions and studies and to convene experts from across industries to develop a plan for action. In November 2018, the NERC Board approved a set of recommendations developed by the PC to address issues raised as a result of concerns from the 2017 NERC Special Assessment. One such recommendation was the development of this reliability guideline, which was assigned by the PC to the newly formed Electric Gas Working Group. The initial guideline was approved by the RSTC in March 2020. This document is the first revision to the March 2020 guideline and will provide entities guidance on how to evaluate such risk factors, ascertain potential impacts on the BPS, and potentially mitigate the risks.

This guideline offers a definition of "fuel assurance" in **Chapter 1** and takes a cursory look at all major fuel sources used to supply electric generation in **Chapter 2**. As each fuel type possesses a variety of physical and commercial characteristics that affect its delivery through its entire supply chain, **Chapter 3** describes specifically what those characteristics may be and provides guidance to assist planners and system operators in the development of fuel security analyses. Appendix A includes a design basis that was approved by the RSTC in October 2022 for a potential future electric-gas study.

here have been a number of relevant studies performed—especially by regional transmission organizations, independent system operators (RTO/ISO), and other organizations[2] to analyze and assess generator fuel-related considerations. This guideline combines the experience gained from these studies and post-event analyses to outlines a framework in **Chapter 4** that may be applied across all NERC Regions for effectively evaluating potential reliability risks to the BPS through the lens of fuel assurance. Applying this framework for a given area will provide indications of where credible risks to reliability exist and will highlight areas for further analysis and consideration.

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[2] E.g., *The Eastern Interconnection Planning Collaborative Gas-Electric Interface Study* performed under the DOE grant and completed in June 2015

While this guideline discusses planning, commonalities in the assessment techniques, processes, and procedures that are applicable to all time frames; the insights should be useful and worthwhile for adoption by more than just Transmission Planners and Planning Coordinators. Terms like "planner," "generator owner/operator," and "fuel supplier" are not capitalized intentionally so that the concepts presented may be considered and applied in the broadest sense as they pertain to the BES.

In accordance with Section 8 of the RSTC charter, approved Reliability Guidelines or Technical Reference Document shall be reviewed for continued applicability by the RSTC at a minimum of every third year since the last revision. The contents of this guideline encompass updates developed by the Electric Gas Working Group during its 2023 triennial review[3] that include insights and recommendations taken from the *FERC-NERC-Regional Entity Staff Report: The February 2021 Cold Weather Outages in Texas and the South Central United States*.[4] The EGWG will continue to work with NERC to gauge the effectiveness of this reliability guideline and support efforts for continued improvement and opportunities for education and information sharing.

[3] September 2023
[4] https://www.nerc.com/pa/rrm/ea/Documents/February_2021_Cold_Weather_Report.pdf

Chapter 1: Fuel Assurance

For the purposes of this guideline, "fuel assurance" will be defined as follows:

- **Fuel Assurance:** Proactively taking steps to identify fuel arrangements or other alternatives that would provide confidence such that fuel interruptions are minimized to maintain reliable BPS performance during both normal operations and credible disruptive events.

Fuel Assurance is critical across all planning time horizons and continuing on to real-time operations.[5] The criteria to establish the level of confidence referenced in the definition is unique to respective planning areas and is established by planners, system operators, and/or generator owners/operators based on internal assessments, situational awareness, contractual supply arrangements, and understanding of asset characteristics. The regional planner's focus is to assess the vulnerabilities of the entire region to withstand fuel disruptions that could impact multiple generators and impact reliable BPS performance. The role of the system operator demands significant situational awareness and system operators would benefit from utilizing all relevant public and verified non-public information available in order to facilitate reliable delivery of fuel in the operational horizon. Generator Owners/Operators should communicate in a timely manner to the system operators how the terms of their fuel and transportation contracts may impact their unit specific performance parameters and operations and whether they reasonably foresee fuel availability issues. As the fuel mix of generation and wholesale electricity market structures can vary greatly across reliability areas, this guideline does not and cannot prescribe a single approach to the process.

NERC encourages planners to proactively model, evaluate and consider specific BPS impacts based on credible events that could compromise the provision of reliable service to all or part of the region within the regional planner's area of responsibility and to develop strategies to mitigate credible risks. Regional planners may consider modeling foreseeable fuel disruptions to better understand the impact of catastrophic events so that they may prepare for such emergencies. Recognizing that there is no way to anticipate or measure all potential threats and catastrophic scenarios, stakeholders and system operators should focus on effective measures that will maintain reliable and fuel-secure BPS operations during credible events. While the individual unit owners are ultimately responsible for effectively managing the fuel needs of particular units, the system operators, in advance of an actual contingency, should understand the risk and consequences of losing critical generators. They should consider the steps necessary to limit the reliability impact of such losses, such as maintaining adequate reserves and potentially select other sources of supply in advance if the risk is unacceptable.

Fuel Assurance Principles

While each reliability area is unique, there are common principles for fuel assurance that may be applied more broadly to assist planners and system operators in their assessments of fuel supply reliability. Below are some examples of actions that various entities may perform to advance fuel assurance initiatives.

Transmission Planners/Planning Coordinators

Planners should consider using steps outlined in **Chapter 4** of this guideline to develop credible fuel-related contingencies that may be used in planning studies. Any identified fuel-related contingencies should be evaluated for reliability risks, and planners should determine what (if any) mitigation should be put in place. Planners might consider conducting generator fuel-related surveys to determine potential risks to the fuel supply of the generators. Using the survey data, planners may perform fuel-related reliability risk analyses as described in **Chapter 4** Planners should also seek and use experts familiar with regional markets and practices to help interpret and analyze the survey data.

[5] Time_Horizons.pdf (nerc.com)

System Operators

System gas requirements and availability are influenced by locational electrical demands and constraints and when unit commitment are made. This suggests the need for a centrally situated party to maintain a high-level of situational awareness. System operators should consider how to work voluntarily with as many stakeholders as possible through non-disclosure agreements or other mechanisms to receive non-public information that would assist their detailed understanding of grid demands and challenges and to maintain this utmost situational awareness. FERC Order 787, for example, allows interstate gas pipelines and electric transmission operators to share, on a voluntary basis, non-public operational information with each other to promote grid reliability and operational planning. System operators should consider how they can maximize the use of public and non-public information, how to best coordinate with all parties while preserving the confidentiality of the non-public information and make decisions that facilitate the proper utilization of gas infrastructure, leverage the value of precedent transportation arrangements, and respect the pipeline operational constraints.

Generator Owners/Operators[6]

Generator owners/operators should seek reliable delivery solutions from a transportation, commodity, and commodity procurement perspective. BES reliability risks associated with emissions limits, fuel availability, transportation or delivery options should be monitored and evaluated. For example, with regard to use of natural gas, consider the “firmness” of the transportation agreement to include policies, processes or tariff provisions which could restrict gas flow (e.g., NAESB pipeline scheduling timeline), flow rule and constraint realities, and the commodity availability at the relevant trading hub.

Generator owners/operators should consider credible fuel-related contingencies that may impact their facilities and provide fuel-related facility outage concerns as necessary to the relevant reliability authority. Planning for credible fuel-related contingencies strengthens a generator’s ability to ensure it can run when called upon during critical events. Lastly, where fuel delivery constraints are routinely evident, generator owners/operators should consider whether new options for fuel deliveries to a specific facility or their fleet are available.

[6] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf (Page 14)

Chapter 2: Electric Generation Fuel Supply Primer

This section describes the supply chain of each major generator fuel supply type at a high level. It describes illustrative challenges that may be encountered between production and consumption as well as other viable considerations specific to each fuel type. These considerations will assist planners in forming realistic assumptions when developing their own fuel assurance and reliability risk analysis.

Natural Gas

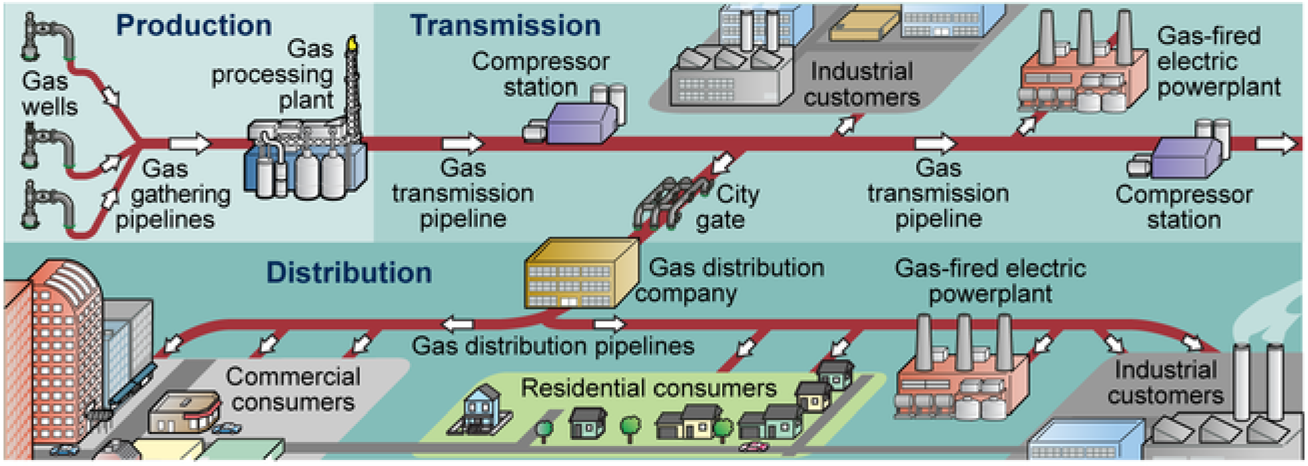
Over the last 18 years domestic production of natural gas has doubled[7], mostly due to new well development techniques that have lowered production costs and allowed extraction in previously uneconomic or technologically inaccessible fields. The relative economics of natural gas, coupled with tightening environmental regulations on other fuel types, led to the increased development of new gas-fired generation in some regions. Additionally, gas-fired combustion turbines and reciprocating engines have relatively fast-start times and ramping capabilities that complement the variable nature of wind and solar resources that are being developed in many parts of the United States at accelerating rates. Consequently, the bulk electric system increasingly relies on the gas industry to deliver more natural gas with greater flexibility.

These increased new demands on the natural gas industry are highlighting issues that planners and system operators may not have had to grapple with previously, but which are becoming more important to ensuring electric reliability. The physical differences between systems that convey compressed pipeline quality gas and electricity drive operational and administrative differences, which manifest through fundamental differences in scheduling and operational flexibility. Clearly, the throughput capacity of the natural gas system is of paramount importance; however, the timing that shippers nominate fuel and how that fuel must be taken is of equal importance and might, in many circumstances, impact their ability to run when called upon. Pipeline operators' nomination and scheduling systems, and ultimately flow, are timed to ensure gas system reliability. Unlike the electric grid, pipeline operators require time to configure their systems in advance, and constrained conditions may limit system operators' ability to call on gas-fired generators if fuel has not been nominated in accordance with pipeline tariff nomination deadlines and flow rules. Additionally, when pipelines are flowing at near or maximum capacity, pipeline operational flexibility that is typically provided on a best efforts basis and supports non-spinning Operating Reserves may not be available. Both conditions require planners and system operators to examine the scheduling constraint timelines and the physical realities of the gas systems when performing studies and constructing day ahead operating plans, especially during stressed conditions. However, the limitations and constrained conditions may not exist universally and require a careful, regional analysis of the natural gas supply chain. This section breaks the natural gas supply chain into segments, describes their function at a high level, and identifies areas of potential risk.

The natural gas supply and delivery chain includes three major segments, listed below:

- Production and Processing
- Transmission and Storage
- Distribution

[7] https://www.eia.gov/dnav/ng/hist/n9070us2A.htm



Source: GAO analysis of Energy Information Administration and Natural Gas Council documents. | GAO-20-658

Figure 2.1: Natural Gas Supply Chain

The rest of the section describes the characteristics of each segment and considerations relevant to the electric industry.

Production and Processing

Natural gas is primarily found in reservoir pools and shale rock formations in the earth and brought to the surface through production wells. Unprocessed natural gas withdrawn from natural gas or crude oil wells is usually "wet" natural gas because, along with methane, it contains natural gas liquids (NGL)—ethane, propane, butane, and pentane—and water vapor. Since methane, the primary constituent of pipeline-quality gas, remains in its gas phase down to -260 deg F, wellheads are more susceptible to "freeze-offs" when the wells have relatively high fractions of water vapor, which freezes in the wellhead or gathering system blocking the flow of gas. While the most effective method of preventing wellheads from freezing is to remove the water, this is not always cost-effective or possible. Another common method is to inject methanol into the gas stream for later removal. Producers may also be able to increase production in other areas or rely on using supplies they have natural gas in storage.[8] Some wellhead natural gas is sufficiently dry, and less prone to "freeze-offs." Additionally, electrically driven equipment, including compressors and processing facilities, used in the natural gas supply chain should be reviewed to ensure that it is on a critical circuit and would not be cut during manual load shedding, or that coordination occurs with operators of these facilities with sufficient time to facilitate switching to co-located non-electrically driven equipment or on-site backup power generation. It is imperative that both planners and system operators understand the diversity of production sources, what risks fuel producers face, and how those producers may mitigate those risks.

From the wellhead, natural gas is sent to processing plants where water vapor and nonhydrocarbon compounds are removed and NGLs are separated from the wet gas and sold separately. Like any other type of operations in the gas and power sector, processing plant operations can be impacted during critical events, and natural gas must be processed in order to meet interstate gas pipeline quality specifications. The processed natural gas is called dry, consumer-grade, or pipeline-quality natural gas. If the natural gas is not processed, and a pipeline cannot blend the gas, in most instances it will not be accepted into the interstate gas pipeline system. The processed natural gas is then transported via gathering systems into either intra- or interstate gas pipelines.

Transmission and Storage

Large-diameter interstate and intrastate pipeline transmission systems transport processed natural gas to large-volume customers (e.g., local distribution companies (LDCs), natural gas-fired power generation, industrial users, gas

[8] *Id*.

marketers). Processed natural gas is also transported to various storage facilities for future consumption. Compressor stations are located along the pipelines and storage network to maintain pressure at serviceable levels. In most cases, compressor units are powered by the natural gas in the pipelines. However, some compressor stations may have both natural gas and electric or even diesel-driven compressor units, and; others may rely solely on electric power. As mentioned above, it's important that pipeline operators identify their electric compressors and communicate those sites to the applicable Distribution Providers and Transmission Operators so that, should an event warrant load shedding, those units are prioritized and curtailed last and restored first.

While the natural gas transmission system may continue to operate even with the failure of as many as half of the compressors, the pressure may not remain high enough to meet the specific pressure requirements of each power generator interconnected to the pipeline, which can range from around 100 psi up to more than 1,000 psi for some turbine models.[9] To add redundancy, many gas-fired generators have on-site boost compression that increases the pressure of the pipeline-delivered natural gas to the combustion inlet pressure required by the unit. Generation facilities that do not have boost compression may be more susceptible to outage under certain pipeline operating conditions.

Typically, limited supply and transportation disruptions can be managed through substitution, transportation rerouting, on site peaking supply, third-party delivered supply contracts, and storage services (though such infrastructure redundancy is much more limited in certain portions of North America, such as the Northeast). However, unlike electricity through a transmission line, gas flows much more slowly through a pipeline, which also necessitates more advanced planning by shippers and end users. Pipeline operators carefully manage the flows into and out of their pipelines, especially when demand on the pipeline is expected to be high, through scheduling procedures, alerts, notices, operational flow orders (OFOs)[10], and ultimately imposing over-run penalties restricting withdrawals if the shipper disregards the OFO A fundamental understanding of pipeline operations and market constructs is necessary to understand how gas scheduling may impact electric reliability.

Distribution

Intrastate transportation, balancing, storage, and distribution of natural gas by LDCs is subject to provincial regulation. LDCs are regulated by most states as local natural gas utilities that have an obligation to serve the customers for which the system is built to serve reliably (e.g., residential, and commercial heating customers). State statutes and public utility regulations may allow intrastate pipelines and LDCs to curtail services to some industrial or non-core customers, possibly including power generators, during emergencies to maintain the operational integrity of the system and/or maintain natural gas service to designated high-priority customers. Historically, these state regulatory requirements give the highest priority to residential (essential human need) and small commercial customers without short-term alternatives.

Pipeline Tariffs and Contracting Arrangements

The interstate pipeline industry is contract-based, and understanding the supply and transportation fuel arrangements requires having a basic knowledge of these contract terms and conditions. Shippers that are interconnected directly to interstate facilities contract with the pipeline and storage operators in accordance with the terms of FERC-approved agreements and tariffs. Gas-fired generators purchase bundled commodity supply and transportation services from a third-party marketer or an exchange or enter into commodity and transportation contracts separately. Marketers either hold the transportation service outright or offer capacity released by other shippers with firm entitlement rights under an asset management agreement. The entitlement holder may not need all of its capacity at all times and allow marketers to re-sell released capacity to offset the entitlement holder's fixed reservation cost. However, it is important to note that the volume and liquidity of this secondary market moves

[9] https://gasturbineworld.com/shop/performance-specs/2022-performance-specs-38th-edition/

[10] An Operational Flow Order is a mechanism to protect the operational integrity of the pipeline. It requires shippers to balance their gas supply with their usage on an hourly and/or daily basis, within a specified balance, per the tariff's requirements. It is not a curtailment.

inversely to the demands of firm shippers. That is, when gas demand is highest, shippers that have not made prior arrangements may not be able to obtain the bundled fuel and transportation in the secondary market. Shippers that are interconnected to intrastate pipelines or to LDCs will have contracting arrangements unique to the jurisdiction and the contracting parties; users are advised to consult the facility-specific contracts for additional details.
Interstate shippers may select transportation and storage services based on the level of certainty and reliability desired. Some gas-fired generators contract for firm transportation ("FT"), which is a reservation of capacity on the pipeline from the origin ("receipt point specified") to the designated delivery point. The delivery point is usually a city gate (if the generator is connected to the LDC), an interconnecting pipeline, or the gas meter at the generator's facility. The receipt points may vary, and a few examples include generators holding FT:

1. only on a short lateral that interconnects to an interstate pipeline;
2. on segments of an interstate pipeline that are known to be constrained; or
3. to a liquid trading hub or a dedicated storage facility;

Other generators that are interconnected to a main pipeline within a liquid trading hub may not enter into a transportation contracts. On the other hand, some generators may contract for FT and storage, which may be classified as "enhanced" transportation services. This contracted service allows shippers to call on gas "non-ratably" and generally shortens the flow lag from normal FT or IT service. Enhanced service should not be mistaken for "no-notice" or on-demand service, which is a premium service in which the pipeline commits to serve the shipper when called upon, yet typically is ratable service. Consequently, current FT recourse pipeline services may not be well-suited to serve non-spinning Operating Reserves, which require electricity to be generated with little or no advance notice and gas at large rates to be delivered non-uniformly. The intent is not to enumerate every possible contracting combination but to illustrate that the contracting arrangements are extremely varied and may not be the primary determinant of gas availability.

Contracting firm transportation capacity alone does not guarantee delivery of natural gas supplies at a specific location and time. Firm delivery must also consider the purchase of fuel (sufficiently in advance of when needed), pipeline nomination cycles, flow rules, and then-effective pipeline constraints. The North American Energy Standards Board ("NAESB") has developed uniform nomination windows for shippers to "nominate" gas prior to and during the gas day, which currently runs from 9:00am – 9:00am Central Clock Time ("CCT"). While shippers may nominate during any nomination cycle, during high demand periods most gas deliveries are nominated and scheduled at the Timely Nomination Cycle. Therefore, it is important for a shipper to nominate at the earliest cycle to ensure that it has secured its delivery point. There typically is less capacity available later in the nomination cycles. This is especially true if the receipt point is relatively illiquid, or the transportation path follows segments that are known to often be constrained. Moreover, firm shippers may "bump" scheduled interruptible shippers up to the Intraday 3 cycle (7:00pm CCT intraday) per FERC policy.

Another important consideration is that pipeline operators are not obligated to flow the gas until the flow time specified in the NAESB nomination timeline approved by FERC. In some cases, this delay from the end of the nomination cycle until gas is allowed to flow to the shipper is up to 4 hours. However, many pipelines have tariff authority and often use best efforts to allow a generator gas to flow sooner than the flow time specified in the NAESB timeline. It is important to note that when gas demand is high, this operational flexibility should not be assumed. In fact, planners should make allowances for these constraints in their modelling efforts and system operators and generators should communicate frequently with the pipeline operators, and review pipeline critical notices, to understand how much flexibility, if any, may be afforded under stressed conditions.

An additional complexity is that pipeline operators may also issue OFOs which to require shippers to stay within certain daily and/or hourly tolerance bands per the pipeline tariff. These OFOs may be necessary to maintain the pipeline's, and their shippers', operational reliability, and integrity, particularly during extremely (high or low) demand periods. For example, during a ratable OFO, this means that shippers must flow their daily scheduled quantity of gas in 1/24th hourly increments, with some small percentage of a hourly tolerance band, but returning back within balance by the end of the gas day. Should a shipper disregard the OFO, significant penalties may accrue for non-compliance. If an OFO is issued, affected generators may need to modify their minimum or maximum run times; and reduce their ability to follow load. Synchronized generators, operating under a ratable OFO, may need to reduce their regulation ranges and operating reserve capabilities. Pipeline operators are required to post all critical and non-critical notices on their respective Electronic Bulletin Boards ("EBB"), including the specifics, duration, and geographic location of any OFO. Finally, it is important to know whether shippers have contractual entitlement to have gas delivered to a "primary delivery point." If a pipeline calls a primary delivery point restriction it is important to understand whether the generator has delivery at that primary delivery point. under constrained conditions, when firm transportation shippers are using their full contractual entitlements and there is not excess capacity, a pipeline operator may the pipeline operators restrict delivery to "primary delivery points." U", unless the shipper's location is a "primary delivery point" it would not be able to schedule gas to the facility and thus be unavailable.

While we cannot overstate the complexity of how a large number of shippers and pipeline operators may interact under certain scenarios, most of the information necessary to develop reasonable judgments is publicly available. FERC requires pipeline and storage operators to post a significant amount of data on their EBBs, including information about pipeline design, operating and operationally available capacity by receipt and delivery point, critical and non-critical notices, identification of firm pipeline shippers, and capacity release information. Additionally, interstate pipelines and storage operators may communicate non-public information, on a voluntary basis, to grid operators and vice versa to facilitate the reliable operation of their respective grids, per FERC Order 787. Intrastate pipelines are typically under the jurisdiction of state regulatory authorities, and the amount of publicly available information varies widely from state-to-state. While FERC Order 787 only covers pipeline and storage operators and grid operators, it does not prevent grid operators from requesting and receiving non-public data from intrastate pipeline operators and LDCs under non-disclosure agreements.

In addition to transportation services, customers may also purchase the physical commodity bundled with transportation directly from a gas producer or from a gas marketer to receive natural gas at a contracted delivery point. Larger volume customers (e.g., LDCs and electric generation facilities) may also purchase natural gas upstream at or near the point of production and contract for pipeline service to transport the commodity to the point of delivery. In addition, based on market conditions, these entities and other market participants may purchase natural gas at a market center and contract for transportation from that point to a delivery point(s). While commodity arrangements may be as varied as transportation arrangements, the generators that are typically used for grid balancing – i.e., gas peakers, typically do not have enough operational certainty to enter into forward contracts for the commodity. If these particular generators do not receive unit commitments with sufficient advanced notice, they may not be able to source the commodity during the operating day under constrained conditions, and especially at more thinly traded hubs. A reasonable proxy for liquidity may be the volume of transaction for a particular point on Intercontinental Exchange, Inc. ("ICE").

In summary, gas-fired generators' contractual arrangements offer insight into how gas may be transported to facilities; however, other factors influence generator's ability to effectuate gas deliveries. These conditions may be crudely grouped as "transportation constraints." Another important consideration, especially for gas peakers, is the relative natural gas supply liquidity during periods of high demand of the shipper's trading hub. If the supply/trading hub is relatively illiquid and the generator does not usually receive unit commitments day ahead, the risk that these generators may not be able to source the commodity during peak demand days increases. Obviously, both transportation and commodity are required to ensure fuel can be delivered. Some generators may be uniquely positioned or have sufficiently mitigated performance risk through transportation and commodity contracts to be at low risk if of non-performance. Conversely, other generators may be poorly positioned and have high transportation and commodity risk. While still others may have either heightened transportation or commodity risk, but not both. It may be necessary planners examine historical pipeline critical notices and trading hub history in addition to historical generator performance to determine fuel availability risk.

Oil

Fuel oil is obtained from the petroleum distillation process as either a distillate or a residual and is then distributed to regional bulk terminals for distribution to end users. Transportation to generation sites is typically by pipeline, barge, truck, or a combination of the three methods where it is off-loaded into on-site fuel tanks. Each power plant with storage tanks will have unloading facilities that frequently limit the ability to replenish the on-site storage tanks. Each generator with oil as either the primary or back-up fuel must decide the amount of fuel oil that will be kept in inventory or reserved for other uses such as maintenance or black start service obligations. Aside from any emissions limitations, facilities typically do not have sufficient replenishment capability to run continuously at maximum output for long durations. Replenishment rates are dependent on availability of transport tankers (maritime or over-the-road) and pipelines, and expected transportation constraints - e.g., competition with resupply of home heating oil, dearth of licensed drivers, roads impassable due to weather conditions, rivers impassable due to ice conditions, etc. There are multiple types of fuel oil and generators are typically designed to operate on or switch to a specific type. A majority of oil combustion capable units in the NERC footprint fire distillate ultra-low-sulfur fuel oil #1 – e.g., ultra-low-sulfur diesel, jet fuel, kerosene, etc. or #2, also known as home heating oil. Others primarily combust distillate fuel oil one of the three residual “bunker” fuels #4, #5, and #6.

Coal

Four major types of coal are used to produce electric power, each of which varies in heat content and chemical composition:

- **Bituminous:** Bituminous coal is a middle rank coal between subbituminous and anthracite containing 45%–86% carbon. Bituminous usually has a high heating (Btu) value (11,000 – 15,000 Btu/lb). and is the most common type of coal used in electricity generation in the United States. In 2021, bituminous accounted for about 45% of coal mined in the U.S., with a majority originating from mines in five states. Since 2020, all coal produced in Canada was sourced from bituminous seams.
- **Subbituminous:** Subbituminous coal is black and dull (not shiny) containing 35%–45% carbon and has a higher heating value (8,500 – 13,000 Btu/lb) than lignite. In 2021, subbituminous accounted for about 46% of coal mined in the U.S. with more than 85% coming from the Powder River Basin in Wyoming.
- **Lignite:** Lignite coal, aka brown coal, is the lowest grade coal with the least concentration of carbon (25%–35%) and the lowest heat content (4,000 – 8,000 Btu/lb). In 2021, lignite accounted for about 8% of coal mined in the U.S. with most going to electricity generators a short distance from the mine. Most lignite is produced and consumed in North Dakota and Texas.
- **Waste coal:** Usable material that is a byproduct of previous coal processing operations. Waste coal is usually composed of mixed coal, soil, and rock (mine waste), often called gob or culm. Most waste coal is burned as-is in unconventional fluidized-bed combustors with the fuel source co-located with or near to the generator. The heat and carbon content of waste coal is highly variable and is often blended with higher grade coals to ensure a minimum combustor heat input. Most waste coal combusting facilities are located near former mine sites and were purpose built for reclamation.

Coal is extracted from surface and underground mines in various regions around the United States. The United States has over 250 years of remaining coal reserves. It is then crushed and washed in preparation for transport to power plants. Transportation is typically by rail, barge, truck, or conveyor belts; the latter used at what are called mine-mouth power plants. Coal may be delivered directly to a power plant or to a nearby unloading terminal from which it proceeds to the power plant by truck or a conveyance system. At the plant, coal is stored on-site in piles to be used as needed for generation, typically in an amount sufficient for several weeks to several months of operation. Long-term supply contracts are used to ensure high levels of reliable coal deliveries. Equally as important, coal plants require certain reagents to scrub the flue gas – e.g., any of a number of forms of lime, aqueous or anhydrous ammonia, activated carbon, etc. and chemicals to support ongoing operations – e.g., water treatment chemicals.

These reagents and chemicals are typically transported via truck and most facilities have storage sufficient for a few weeks operations.

Nuclear

Nuclear plants are refueled every 18–24 months. Required outages cannot normally be delayed due to costs and scheduling of specially trained labor. Nuclear plants need to maintain certain reactivity levels in nuclear fuel. At times, this reactivity requirement has led to units derating in shoulder months in order to conserve fuel and be available to operate 100% during peak months.

Four major processing steps must occur to make usable nuclear fuel: mining and milling, conversion, enrichment, and fuel fabrication. The uranium used in power plants comes from Kazakhstan, Canada, Australia, and several western states in the United States. Major commercial fuel enrichment facilities are in the United States, France, Germany, the Netherlands, the United Kingdom, and Russia.[11]

Both fresh and spent fuel are typically stored on site at nuclear plants in specialized facilities, when not in the reactor, that are built to withstand significant physical events, including weather, seismic, and other types of natural disaster. Licensees must abide by robust security measures (e.g., armed security officers), physical barriers, and intrusion detection and surveillance systems.[12]

The Nuclear Regulatory Commission regulates nuclear facilities in the United States and the Nuclear Safety Commission regulates facilities in Canada. Nuclear power plants must show that they can defend against a set of adversary characteristics called the Design Basis Threat (DBT). DBT imposes security requirements on nuclear power plants based on analyses of various factors, such as the potential for a terrorist threat. The Nuclear Regulatory Commission regularly evaluates the DBT for updates and alignment with the threat environment.

Nuclear facilities use digital and analog systems to monitor, operate, control, and protect their plants. Digital assets critical to plant systems for performing safety and security functions are isolated from the external networks, including the internet. This separation provides protection from many cyber threats.

Hydro

An integrated hydro-electric system, like those found in the Pacific Northwest, is more frequently energy limited than capacity limited from its mix of storage and run-of-river projects. The storage projects fill and draft annually and tend to have a steady discharge. Fluctuations in discharge (generation) are usually driven by snow melt water content, flood control, maintenance of navigation channels, seasonal icing, and downstream water temperature objectives. The run-of-river projects more closely follow demand as the projects fill and draft daily. However, run of river projects have limited storage to meet demand because the water needs to be in the right place(s) at the right time(s). Hydro-electric generation also has many non-power objectives that can limit hydro- electric power production (e.g., lake/river level management, recreational use, stream flow speeds, etc.) Information sharing, communication, and coordination is critical across different hydro projects, utilities, states, and countries.

Variable Energy Resources, Energy Storage, and Developing Technologies

Technologies like weather dependent BPS-connected solar photovoltaic and wind generation are being integrated at an accelerating pace, and the "fuel" for wind and solar generation are effectively limitless but are only available as weather conditions permits. For storage devices, including batteries and pumped storage hydro, the energy they provide is dependent on some other electric energy producing resource. Therefore, storage devices are not electric

[11] https://www.nei.org/fundamentals/nuclear-fuel

[12] https://www.nrc.gov/reading-rm/doc-collections/fact-sheets/security-enhancements.html and https://www.nrc.gov/reading-rm/doc-collections/fact-sheets/cyber-security-bg.html

generators, but rather may time shift the consumption of electricity generated in a less constrained period to a more constrained period.

Operators and planners should ensure sufficient energy is available given the non-dispatch-limited controllable nature of solar and wind resources and the regulatory imposition of “must-take” requirements in many areas. In particular, peak demand hours will present new challenges for planning and procuring fuels for flexible, swing generation, such as natural gas generation, as the penetration of nature-controlled resources increases. Two primary concerns are emerging as penetrations increase. Many regions are using probabilistic analysis and capacity-based metrics, such as Effective Load Carrying Capability, to model the resource adequacy contribution of variable generation during extreme conditions, yet the actual generation during these conditions could vary widely in either direction across a planning footprint. Therefore, it is important to examine the distribution of possible variable generation outputs from the modelling efforts and select appropriately low tail probability generation scenarios to ensure there are sufficient back-up resources in the event these low probability generation conditions occur. The second concern is to ensure that back-up resources may be both deliverable and able to respond in the operational horizon to changes in variable generation. There exists an inherent error between the forecasted variable generation and what is actually produced in the operating day. While the error may be small, there may be unique conditions that make this error much larger – e.g., icing of wind turbine blades, fog, smoke, temperature extremes, etc., and it is imperative to ensure there are sufficient back-up resources that are capable of responding during these outlier events. Moreover, these issues may be compounded by the inherent increase of forecast risk across weekend and holiday periods when gas typically trades for multiple days ahead of the Day Ahead electric market. These conditions highlight the importance of modelling low probability, or extreme scenarios, with respect to resource adequacy contribution and potential for generation forecast error, quantifying the potential need, and confirming that there is sufficient dispatchable generation is available and any temporal constraints that dispatchable generation may have due to fuel arrangements.

Other technologies (e.g., energy storage) are still in the early stages of development, and deployment of these technologies will require further evaluation and consideration as they mature. For instance, system operators and planners need to understand how co-located facilities with variable energy production and storage systems charge and discharge onto the grid. The charging and discharging behavior of energy storage devices may be responsive to regulatory demands and incentives, or ancillary service market price signals, and are not always conducive to assisting operators manage real time energy demand. For storage devices, including batteries, the energy they provide is dependent on some other electric energy producing resource. Therefore, storage devices are not electric generators but rather a mechanism for time shifting the production of electricity for later deployment and offer fuel assurance only to the extent that they can shift energy generation from a less constrained period to a more constrained period. Additionally, many of today's energy storage technologies are subject to operational temperature limitations that may limit their ability to charge and discharge[13].

Hydrogen and ammonia are other emergent technologies developing technology that will require close attention and coordination as they potentially grow as fuels for power generation. If hydrogen utilizes the same transportation infrastructure as natural gas, it has 1/3rd the heating value on a volumetric basis, which will require significant build out to deliver the same energy. Today, most hydrogen is produced using natural gas reforming technologies and is primarily used in petroleum refining and chemical production. As hydrogen technologies advance and hydrogen use as a power generation fuel expands, it will be necessary for planners to consider many of the same concerns that exist today with the supply and procurement of natural gas in addition to coordinating with hydrogen producers relying on electrically intensive processes such as electrolyzers and hydrogen fueled generators to ensure that sufficient stocks and production are maintained to ensure the availability of generation during extreme conditions.

[13] https://batteryuniversity.com/article/bu-410-charging-at-high-and-low-temperatures

Chapter 3: Fuel Supply Risk Analysis Consideration

As described in **Chapter 1**, fuel assurance is critical across all planning time horizons and continuing on to real-time operations. Some fuel assurance risks may not be completely mitigated and must be accepted, and some risks may increase the fuel assurance risk of other resource types in the same time horizon. Fuel assurance risk is not static over time, and there may be interdependencies between different resource types, especially in the real time. Therefore, it is imperative that a thorough risk analysis investigate how fuel may be limited over various time horizons, how risks between fuel type may be interrelated, and if the generator's parameters allow timely conversion of fuel into electricity to match system demands. This chapter describes the supply chain considerations of each generator fuel supply type that will help planners and system operators form realistic assumptions when developing their own fuel-related reliability risk analyses.

Natural Gas

Chapter 2 touched on the myriad ways transportation and commodity procurement are combined to deliver gas to generators. There are four main considerations when qualifying fuel risk for gas-fired generators, but no one factor may be able to adequately capture fuel risk or be dispositive of risk. Moreover, some risks may not be additive, and it may be difficult, if not impossible, to quantify these risks. However, a structured framework may allow planners and operators to assign generators to risk categories or rank generators by their relative risk. Planners and operators may then use these results to influence decisions regarding the quantity and type of Planning and Operating Reserves required.

The four factors are:

- The timing of when the generator typically receives a unit commitment relative to the NAESB gas pipeline nomination cycles;
- The gas fired generator's contractual arrangements—i.e., the "firmness" of the transportation path from the customer's receipt point to the generation facility's meter (delivery point);
- The "firmness" of the generator's supply arrangements as well as the accessibility of readily available supply alternatives in the spot market to supplement or backup day-ahead purchases (such as having trading hubs, pools or pipeline interconnects in close proximity);
- Historic constraint points along the generator's transportation path.

While a generator's contractual arrangements are not the only determinant of fuel assurance risk, planners and operators may easily ascertain whether a generator has purchased firm transportation or storage from a pipeline, which pipeline rate schedule establishes the terms of the generator's service, and the generator's receipt and delivery points. Each pipeline posts an Index of Customers—a list of their firm transportation and storage shippers—on their public websites and updates the Index quarterly. The Index is not dispositive of a generator's contractual arrangements; a generator may contract with an asset manager rather than with the pipeline for its natural gas transportation and supply needs. Nor is the possession of rights to firm transportation dispositive of fuel assurance risk. In some circumstances, such as when the pipeline is fully subscribed, the generator may be unable to purchase firm transportation absent an expansion of pipeline capacity.

After identifying the generator's contractual arrangements, planners and operators should inquire further into the generator's circumstances:

- **Is the primary delivery point coincident with the generator's gas meter?** If it is not, this might indicate a pipeline capacity constraint at the generator's location. In this circumstance, planners and operators should consider how often and under what conditions the pipeline restricted deliveries to primary delivery points or to primary point shippers. When such restrictions occur, a generator on a secondary delivery point would be unable to transport gas to its facility. There are sufficient occurrences where deliveries to secondary firm locations can occur and may otherwise lessen some of this type of fuel delivery risk.

- **If the generator obtains pipeline capacity through capacity release or through a marketer/asset manager, under what conditions can the releasing shipper or manager "recall" the capacity?** Capacity release and market/asset manager arrangements might permit the release shipper or manager to recall (i.e., take back) pipeline capacity obtained by a generator. Planners and operators should identify the circumstances under which recall might occur and consider the pipeline capacity unavailable under those conditions.
- **How frequently is the natural gas commodity traded at points accessible to the capacity path? What volume of natural gas commodity trades at those points?** Pipeline transportation contracts specify the receipt point where the shipper will deliver natural gas commodity into the pipeline system. While not dispositive, pipeline paths that include "liquid" points—points that have high volumes of trades throughout a given gas day or interconnect with other interstate pipelines with liquid trading points—tend to provide more certainty that the natural gas commodity will be available to the generator. If the generator's transportation path does not include liquid points, then planners and operators should further investigate the "firmness" of supply.
- **How does the minimum pressure the pipeline must provide at the generator's delivery point compare to the minimum required pressure to operate the generator's facility?** If the contractual delivery pressure is less than the generator's minimum operating pressure, how often has the facility been de-rated or unavailable due to pressure limitations? How often has the pipeline restricted the shipper to its tariff pressure limitations? If no minimum pressure is specified in the generator shipper's pipeline transportation contract, has the generator been derated or unavailable due to low supply pressure?

As the section above indicates there are many factors that impact the real time delivery of natural gas supply to a power generator. No single factor should be deemed dispositive as to whether a natural gas fuel arrangement is reliable or unreliable, as pipelines and pipeline conditions vary across the United States. Notwithstanding, **Appendix A** outlines some factors Planners may consider when determining the reliability of supply arrangements (specifically, fuel supply delivery).

The timing of the generator's unit commitment might affect its ability to obtain fuel. As a general rule, natural gas fuel procurement and associated scheduled pipeline deliveries are best ensured with a timely dispatch signal/unit commitment. Regardless of how "firm" a generator's pipeline capacity contract may be, if committed after the day ahead Timely Cycle, natural gas supply availability, in the commodity market, should also be considered.

Furthermore, fuel delivery flexibility and constraints can vary by pipeline, season, planned or unplanned maintenance events, delivery location and peak demand events. The points listed below provide some guidance when considering the importance of the timing for a generator unit commitment, as it relates to scheduling deliveries on the pipeline. Except for a force majeure situation or previously notified maintenance event, once scheduled by the pipeline, a generator using a firm primary path (primary receipt and delivery points) should not be subject to interruption throughout the five pipeline nomination cycles. Consequently, the following points apply to generators using secondary firm, non-traditional or interruptible transportation rights:

- If a generator, without primary firm rights through or to a constrained delivery point is dispatched too late in the gas day and scheduled volumes are at or near capacity (at the constrained point), the pipeline may not have sufficient excess capacity to meet all or part of the generator's nominated volumes.
- A generator, using firm transportation rights, may "bump" any interruptible shipper's scheduled volumes, until the intra-day 3 ("ID3") nomination cycle.
- If a generator's interruptible scheduled volume survives through the ID3 nomination cycle, it cannot be interrupted or otherwise lessened by a firm shipper's ID3 nomination.

The natural gas industry does not have a history of susceptibility to failure or to wide-spread failure from a single point of disruption due to multiple factors including (i) the dispersion of production and storage, (ii) access to multiple pipeline paths for most pipeline customers, and. That said, a temporary outage of (i) a single facility, single pipeline, or a delivery point, (ii) loss of a percentage of gas supply due external factors – e.g., wellhead freeze offs, hurricanes, cyber security risk, etc. and (iii) loss of a large gas processing facility are credible scenarios to examine. When considering such a natural gas supply disruption within a given area, the examination would not just be limited to the loss of the natural gas supply but also the associated loss of electric generation and any ancillary needs, such as the loss of electric natural gas compression.

Planners should fully examine the credible reliability risks associated with the natural gas supplied to generators within the reliability footprint of the planner. Further, planners should view the system through an "all-hazards" lens and evaluate additional considerations, including weather, regional policies, and cyber-related risks. The following paragraphs outline the information that planners should seek to understand as a precursor to a more rigorous fuel assurance and reliability risk analysis.

To begin, planners should seek to understand the strategies employed regarding natural gas supply to each generator within their reliability footprint and any applicable regulatory requirements. This could include regular and emergency transportation/service agreements, call options, or other marketing arrangements being employed by the generator owners/operators to meet its resources capacity obligations. This examination could also include reviewing access to on-site fuel storage (e.g., fuel oil, propane, LNG, compressed natural gas), access to off-site storage, access and availability of an alternate pipeline connection, and the availability of non-firm natural gas services and supply. Planners may also consider the alternative fuel capability of the generator, how any such alternatives are contracted and managed, and any environmental and regulatory requirements that may limit the use of the alternative fuel.

The PJM study "Fuel Security Analysis:[14] A PJM Resilience Initiative" investigated the two following natural gas "disruption" scenarios with different recovery expectations:	
"Line Hit," such as an excavating crew accident This type of disruption is easily identified, isolated to a smaller area requiring repairs, and would only cause about a five-day disruption.	**"Other," such as corrosion** This could take longer as investigations are needed over a larger area and will likely be a more "sustained" type of outage.

Figure 3.1: Fuel Security Analysis

Planners should examine each generator and its potential physical access to supply (including access to pipeline, distribution, and storage facilities), the amount of capacity subscribed and available at each supply facility, and the ability of the facility to meet daily and seasonal demand swings. In addition, planners should review potential curtailments to key supply points on their respective transportation agreements (e.g., LDCs needing to redirect supply to "essential human needs" if a severe supply disruption occurs). These details are important in order to formulate supply alternatives to consider when examining a possible supply shortage or failure. While physically severing an interstate pipeline is very uncommon, it can occur in situations like third-party damage. Furthermore, a facility may need to be taken out of service for maintenance. Other considerations include specific pipeline resilience, geography, and potential state or federal restrictions on pipeline expansion, competition for supply with heating and industrial demands, and upstream demand that may impact the region. Environmental permits, such as those that allow streambed alteration, may be required, and will vary by repair required and specific location. Quick agreement on

[14] https://www.pjm.com/-/media/library/reports-notices/fuel-security/2018-fuel-security-analysis.ashx?la=en

any environmental mitigation measures will speed up obtaining those permits. As noted previously, the planner's role is to have specific knowledge of the fuel assurance of individual generators in order to be able to assess, over the planning area, whether any fuel assurance problems at a particular unit can impact the maintenance of reliability to the area as opposed to just impacting the deliverability of that particular unit. Planners need to recognize this distinction so as to avoid taking on management responsibilities that more appropriately lie with the individual unit owner.

In order to assess the forgoing, data can be obtained from certain public sources. FERC regulations and the business practice standards of the Wholesale Gas Quadrant of the North American Energy Standards Board applicable to natural gas pipelines, which are incorporated by reference into FERC regulations, include various posting requirements for regulated pipelines. These standards require the posting of information related to pipeline capacity, natural gas quality, operational notices, customer indices, tariff provisions, and other items. The U.S. Energy Information Administration also publishes detailed information on U.S. natural gas pipelines and underground storage. FERC also requires that interstate pipelines and certain intrastate and Hinshaw facilities file various forms and operational reports. In addition to the forgoing, the various states also require LDCs to file certain information with the state commissions and/or publicly post certain information. The aforementioned information and data from the applicable generators should also be used to evaluate fuel risk.

Furthermore, as increasing penetration of wind and solar resources and battery energy storage occurs to meet state objectives and policies for emissions reductions, natural gas will become the swing fuel. Natural gas will be in high demand, not only during periods of extreme cold and hot weather, but also during periods of low solar and wind output or even when needed for battery energy storage when solar and wind energy is depressed. At other times, when solar and wind energy is in excess and battery energy storage is insufficient to absorb this excess, natural gas generators and thus natural gas usage will significantly decline to accommodate the solar and wind energy and avoid curtailments of clean energy.

Oil

The main risks associated with fuel oil are:

- Severe cold weather events of unusually long duration;
- Multiple, severe cold weather events that occur before sufficient replenishment has occurred; and
- Deeper and more-protracted reliance on oil due to the failure of other resource types.
- Air permitting for hours of utilization of fuel oil can be restrictive
- Some combustion turbines require demineralized water injection for NOx emissions control and replenishment rates for demineralized water can create a restriction on generator availability

These risks may be quantified through modelling of the following variables, initial conditions, and constraints:

- Initial inventories may be quantified through fuel surveys, historical tankage levels, and adjustments due to commodity prices, especially relative to the predominant marginal fuel;
- Burn rates may be determined from equipment technical specifications, field unit parameters, and survey responses from the generators;
- Emissions limitations may be determined from a review of each facility's Title V Operating Permit and recent operating profile;
- Replenishment rates may be more difficult to model; however, the maximum replenishment rate is limited by the offload capability at the facility. However, if severe weather persists, trucks and barges may not be able to replenish on-site inventories at these maximal rates and may need to be adjusted downward. These

limitations could be due to physical transportation conditions or could be due to competition with heating oil deliveries.

Regardless, the main risks are needs outpacing replenishment plus on site storage over varying time horizons, and facilities reaching emissions limitations for the remainder of the heating season.

Coal

Coal supply risks are associated with supply limitations and the transportation of coal from the mine to the power plant. Future coal generation and, therefore, coal supply risks will be influenced by environmental rules, market rules, NERC guidelines, and the deployment of carbon capture technology. With respect to coal transportation, approximately 70% of coal to US power plants is delivered by rail, and the rail network is comprised of an extensive grid of intersecting and interconnected tracks that offer multiple pathways for rerouting deliveries in the event of a physical disruption, but temporary slow-downs or disruptions to supply can occur in the rail system due to weather (e.g., floods or snow), derailments, or track repairs. Similar to other fuel types, longer-term disruptions can occur during unanticipated long-term events such as the pandemic, that cause labor shortages resulting in limited rail and trucking capacity. Barge transport can be temporarily impaired by icy, low-level, or flooded conditions on river systems. Generators rely on their on-site coal supply for operation until deliveries can be restored. However, conditions like frozen or wet coal could impact on-site coal supply. Coal commodity and rail transportation contracts may contain ratability language that states shipments must be taken consistently. This ratability causes a natural rise and fall of the on-site stockpile based on periods of high and low demand. Any supply disruptions during the periods of high demand may exacerbate low inventories. Additionally, coal plants are typically optimized to run using only one of the four types of coal, potentially limiting generation capability if that coal becomes unavailable due to long-term supply or transportation disruptions.

Nuclear

As described in **Chapter 2** nuclear facilities store fuel on-site in a highly controlled and secure environment. There are many layers of safety at nuclear sites to protect from physical and cyber risks.

Hydro

All hydroelectric projects are dependent on upstream sources for fuel supply water. Those sources can be snowpack, other hydro projects, free flowing rivers, lakes, streams, or a combination. Ultimately, the source is a function of precipitation. History has shown quite a diversity in the volume of water available for hydropower generation. The total volume can run between 50–150% of the expected average. In some areas, much of the precipitation falls in the form of snow and becomes useable water during the spring thaw. The rate of the melt or "run-off" is almost as important as the volume. Slow melts are best as fast melts can lead to spilling water past fully loaded turbines or loss of water as a fuel due to lack of storage. Deeply cold winters can also result in frozen rivers and streams, cutting off fuel to downstream projects during times of elevated power demand. Temperature and precipitation are critical factors in the availability of water for hydropower production.

Variable Energy Resources, Energy Storage, and Developing Technologies

Where many of the risks associated with fuels described in the prior sections can be empirically measured in definite terms, the risks associated with wind and solar are probabilistic and subject to environmental variation. The primary risk is uncertainty in meteorological conditions, such as wind speed and cloud cover, and can vary widely by region and locality within a planning footprint. These risks also vary through time. For instance, a wind farm may be able to sustain operations through a cold weather event of short duration during which blade icing occurs but does not reach a threshold which requires turbine shutdown, while the same farm may reach the shutdown threshold during a longer duration event. Awareness of turbine limitations for wind speed should also be included. Output is decreased not only for low wind conditions, but turbines have cut-out protection that immediately cease output during high wind, and low and/or high temperature conditions to protect the turbines from damage. The same occurs for solar generation at high temperatures where output decreases as a function of ambient temperature and enclosed panels are subject to the same radiative heating effects as an automobile which raises the temperature seen by the panel. Since sunlight irradiance can be limited by conditions other than natural weather, the operator should also be aware of other airborne events such as fire, smoke, dust, and atmospheric conditions limiting solar radiation. Another aspect to consider for solar resources is the effect of cosmic events such as solar eclipse. Solar panels are also designed with specific solar emissivity settings set in the PV module. Although these settings are technology related and have little variance, planners and operators should be aware of how sunlight irradiance may have different effects on different solar resources as well as how solar panel cleaning intervals may impact output. Weather related uncertainty risks may be quantified through probabilistic modelling using historical weather data to determine a distribution of production levels. Since most distributed energy and behind the meter resources are wind or solar driven, planners should attempt to collect a reasonable amount of information on the location and type of these resources and include them in the probabilistic modelling. In order to bound the potential risk outcomes from the uncertainties impacting wind and solar resources, studies should examine scenarios that include a range of geographical and production variabilities, i.e., different weather scenarios overlaid on the region. There are software and services that provide wind and sunlight irradiance forecasts that can aid planners in assessing risk. It is also worth mentioning that probabilistic planning outcomes can be improved with greater amounts of actual performance data. As more performance data is collected over time for wind and solar resources, models should be updated to improve the accuracy of studies.

Chapter 4: Fuel-Related Reliability Risk Analysis Framework

The BES, for the most part, is similar enough from area to area that a specified baseline set of criteria can be defined and followed, resulting in similar and comparable results from transmission planning studies. TPL-001 defines and prescribes these planning studies very well; criteria have been developed over many years, resulting in multiple revisions to the standard. Even though TPL-001 references a fuel contingency analysis in Table 1 Steady State & Stability Performance Extreme Events as a possible study contingency, the (default) contingency results in the loss of only two generating stations and may not represent a significant pipeline segment, compressor station, storage facility, barge transport, or other fuel supply disruption for many systems. This chapter provides details regarding the scope of fuel-related generator outages beyond the minimum requirements for TPL-001 transmission system planning assessments.

The framework presented below does not identify a single methodology but rather outlines an approach to assist planners in determining what factors may be considered to conduct a meaningful fuel-related reliability risk analysis for the BPS. The actions described are intended to be flexible enough to account for all fuel types, broad enough to support the unique circumstances in each region, and executable out of order (or in some cases not at all). This framework does not provide specific solutions or next steps that could be taken after assessing the results of any particular study.

The methodology described in this section may be applied narrowly or across a broad range of credible assumptions as determined by the planner performing the study. The selected assumptions should ensure that the study is both relevant and meaningful. It may be prudent to subject the BPS system under study to a range of high-probability, low-impact (HPLI) contingencies as well as some high-impact, low-probability (HILP) contingencies. Studying HPLI contingencies may shed light on operational needs during such instances and inform changes to processes and procedures to preserve reliability (e.g., improvements in the ability of generators to schedule or contract for natural gas). Even if they are not the primary motivation for the analysis, studying HILP contingencies that stress test the system will bookend the study set and may inform regulators or other interested parties of the reliability impact of such extreme conditions and may inform emergency preparedness efforts. Examples of HILP scenarios include severe reduction of non-firm natural gas supply, prolonged pipeline repair, extreme prolonged weather events that affect both supply of and demand for natural gas, or unanticipated low production from variable energy resources (VERs) such as solar and wind.

Based on the unique risks in different regions, the fuel-related reliability risk analysis outlined in this chapter (although not required) is recommended as a best-practice approach for supporting existing studies (e.g., TPL-001 extreme events analysis) or for conducting a stand-alone analysis. In either case, documentation of each step of the process is critical. Documenting the rationale behind the methodology and assumptions will better inform those reviewing the study both presently and in the future and may also inform subsequent studies.

Step 1: Problem Statement and Study Prerequisites

To perform a valid fuel-related reliability risk analysis, there are numerous considerations that should be taken into account that will help shape the direction and results of the analysis. Prior to beginning any analysis, the planner must determine the purpose or goal of the study and, just as importantly, what the study will not do. It is at this point that the criteria, concerns, scenarios and required data will become more evident. Determining which elements of fuel supply risk are to be examined in a single study can be challenging as different combinations of risks can lead to an unmanageable number of model runs.

Consider the following to help define the study:

- Have a clearly defined goal for the study. Set the criteria of the study and define the criteria for system performance. A study that crosses the threshold of meeting certain criteria will do so when fuel is in short supply, generators are no longer able to run, or there is a supply/demand imbalance. The imbalance can be system-wide or equally as important, a local area imbalance that results in the potential exceedance of a NERC Reliability Standard defined System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) of the BPS. This philosophy can help determine contingencies that may not be obviously catastrophic, but still highlight issues that may need mitigation.

- Communicate the goals of the study with stakeholders and gain agreement on principal concepts.
- Decide the analysis timeline prior to commencing work. If the problem definition and the solution are going to be two separate phases of a study, set that expectation early in the process. Often, the deriving solution means following the directives of governing entities (NERC, FERC, governmental agencies, state public utility commissions, etc.). If this is the case, that is the goal of the study.
- Clearly state the boundaries of the study. If there are certain aspects that will not be addressed by the study, make that distinction clear as early in the process as possible.

Step 2: Data Gathering

Data is essential for a valid fuel-related reliability risk analysis. While the planners performing the study are very familiar with the transmission system and the inputs needed to perform traditional studies, there are many considerations outside the normal inputs that are needed for this analysis. Much of the data needed is likely not directly accessible to the planner and will therefore require the assistance of others in their company (e.g., operations personnel) or even fuel suppliers themselves. FERC has through its Order 787 authorized the sharing of confidential information between jurisdictional pipelines and system operators in order to ensure reliability. Planners should consider using that authority to obtain needed information from the pipelines on a cooperative basis. The following is a list of data sources and methods for acquiring data that can be used by planners to collect the information that they need to perform the study outlined in **Step 1**:

- Coordinate fuel assurance assumptions with generator owners/operators:
  - This may be achieved with surveys that may include, but are not limited to, primary fuel availability, details of fuel supply and transport agreements, usable on-site storage capability, historic inventory levels, resupply and back- up fuel availability and strategy, resource limitations on alternate fuels (MW output, switching time and process details, changes in heat rate), emissions concerns, and staffing concerns.
    - It may be helpful to discuss the formation of such a survey with generator owners/operators and other stakeholders to seek their guidance and expertise on the level of data they may be able and willing to provide.
  - Validate/benchmark that the data received is consistent with the recent operational experiences when possible

Table 4.1: Suggestions to Establish and Maintain a Suitable Fuel Survey
Consider managing a survey of this type through an established stakeholder forum
• This will ensure that any changes to the survey are subject to stakeholder discussion and therefore more thoroughly vetted • Ensure that the information is reaching the target audience as there can be a disconnect between generator owners/operators and the stakeholder representatives
Consider hosting additional engagements like a winter generator readiness seminar
• This offers the opportunity to discuss with a more targeted audience of generator owners/operators and not just their representatives
Consider conducting fuel-constrained scenarios as part of your regular training cycle
• This offers an opportunity to solicit concerns and gather potential impacts of limited fuel supply on system operations across a wide spectrum of electric and cross-sector stakeholders • This exercise also has the potential to identify fuel disruption impacts that can be further addressed directly with fuel suppliers to seek actions to mitigate these impacts

- Gather appropriate fuel supply contingencies (to be further analyzed and filtered in Step 4):
  - Coordinate with fuel suppliers or fuel specialists within your company, member companies, and/or collaborate with the experts who own and operate the fuel supply chains, including (but not limited to) natural gas and fuel oil pipelines, fuel producers, fuel oil refineries, storage and trucking companies, rail carriers, and ocean or river bound tanker ships/barges. Their input will aid in the assessment of the potential for disruption or failure. It will also lend credence to the assumptions.
  - Take steps to fully understand what information is already posted on a gas pipeline's EBB and how that information can readily be used for greater situational awareness. Ask for educational sessions when necessary to understand how to interpret posted information in a way that provides the most value.
  - Discuss the fuel supplier's response plans if fuel supply disruptions were to happen. Rather than rely solely on a hands-off type of study (which still has value), consider the possible mitigating actions of the fuel supplier after the disruptions occur in order to incorporate the impact to the BPS into your analysis. Also consider the time considerations between the disruption and when it will impact the power system. Not all failures have an immediate impact.
    - Outreach may include a review of disruption scenarios with each of the fuel suppliers operating within the studied region to assess the viability of both the assumed disruption scenarios as well as the potential downstream impacts.[15]

Step 3: Formulate Study Input Assumptions and Initial System Conditions

Assumptions and system conditions may be developed by using information obtained from data gathering efforts outlined in Step 2 as well as regional historical experience to establish relevant scenarios for incorporation into the analysis. These assumptions may be specific (e.g., specific generator outage rates determined from regional historical averages) or expressed in terms of a range (e.g., low, medium, and high ranges of projected generator retirements

[15] As an example, ask the pipeline companies what remaining capacity would be available if they lost a particular pipeline segment. Depending on the pipeline configuration, the capacity serving the area's generators may be reduced by 10%, 50%, or not impacted at all. Each case would produce different input assumptions for the study.
Consider review of internal operational policies and procedures with the pipelines to better understand the impact of those procedures during a fuel supply disruption scenario.

affecting future fuel mix). Steps to develop these assumptions and conditions for the analysis include (but are not limited to) the following:

- Determine which fuel(s) to study. When doing so, consider the interdependence of various fuel types and how a large disruption to one fuel source may impact another fuel source.
- Develop fuel assumptions using the best available information:
  - Document fuel supply assumptions for plants where data is not available or up to date to maintain visibility of areas where the study may have weaknesses.
  - Consider fuel supply alternatives, such as dual fuel use and service from alternate pipelines.
- Determine weather and load assumptions:
  - Weather input to the study can be historical normal and extreme weather applied to future scenarios or some version of a weather or climate forecast that describes the study time frame.
  - For a fuel risk analysis, the system under study is more than just the BPS. There are going to be shared resources between different sub-systems that are interdependent; for example, natural gas is used for both heating and power generation. Understanding the relationship between those two classes of natural gas demand is paramount when performing this study. Knowing what will happen when the natural gas system is full due to colder temperatures will define what direction the study goes and, in large part, the results of the study. Fuel oil works in a similar fashion but with a different mode of transportation. Although pipelines can carry fuel oil, it is typically via truck or barge. But the fundamental concept is the same—when it gets cold and the demand for fuel is up, supply chains become full and resulting supply options and priorities may be unexpected.
- Determine interchange assumptions and interface capability:
  - This should include coordination with neighboring entities to ensure accuracy and agreement of their interchange contribution. Consider whether the conditions selected for the study will also impact an adjacent area's interchange contribution.
  - A study may assume interchange transaction quantities that reflect the economic interaction between the studied systems and neighboring systems consistent with real-time operations. Alternatively, a historical analysis may be performed to determine an upper and lower bound for capacity and energy imports and exports.
  - Coordination with neighboring systems should also include potential impacts of a natural gas disruption in one area on gas-fired generation in adjacent areas—affecting the amount of electric interchange support available.
- Determine generator outage rates and reductions assumptions:
  - Generator outage rates may be defined by using standard methods (e.g., EFORd) or using a simple analysis of historical performance. Depending on the approach or assumptions, this may deviate from the normally accepted methods.
- Take care not to double count outages. Understand that if a generator is out of service due to normal outages, it cannot also be counted as a generator that is out of service due to fuel and vice-versa.[16]
- Determine assumptions related to VERs:
  - These considerations will be critical in areas with high penetration of VERs where the output range can vary significantly.[17]

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[16] During 2022, wind generation output ranged from 0.55 GW to 24.3 GW in MISO

[17] *During 2022, wind generation output ranged from 0.55 GW to 24.3 GW in MISO*

- Consider the evolution of generation technology, changes in fuel mix, and the interdependency of future resource installation:
  - The current interconnection queue and integrated resource plans/resource adequacy plans may inform planners of resources to be selected in longer-term analyses.
  - Resource planning forecasts are performed on a regular basis. These studies evaluate the future needs and technologies to meet those needs:
    - These studies may reveal, for example, the likelihood of renewable energy variable energy resource additions and battery energy storage that result in early retirement of coal or fuel oil resources.
    - State emissions reduction objectives and policies could result in significant changes to the resource mix over a short period of time placing additional and changing demands on certain fuels such as natural gas for additional dual-fuel resources, as another example, would likely introduce more gas/fuel oil generators into the interconnection queue.
  - It may be difficult to predict how the future resource mix will vary based on factors like governmental policy initiatives. Include a range of assumptions for items that have uncertainty.[18]

ISO-NE OPERATIONAL FUEL SECURITY ANALYSIS[19]

ISO New England's Operational Fuel Security Analysis modeled a wide range of resource combinations that might be possible several years into the future. The study examined varying resource retirements, LNG availability, oil inventory, interchange, and renewable resources. In addition to a reference case which incorporated the likely levels of each variable, these input assumptions were varied individually to characterize the sensitivity between unfavorable to favorable boundary cases. Several combination scenarios, examining how multiple related changes would affect the outcome, were also examined which adjusted more than one of the key variables to represent future resource portfolios that could develop and their effects on fuel security.

Figure 4.1: ISO-NE Operational Fuel Security Analysis

- Determine performance criteria. for example:
  - If the study being performed contemplates a HILP contingency, perhaps the performance criteria would be that 90% of firm load is maintained for a short period of time. However, when HILP is studied, it should be done for emergency preparedness and not for measuring the reliability of specific system resources. Another consideration in this scenario would be acceptable system ratings and limits. If the study being performed contemplates a HPLI contingency, perhaps the performance criteria would be set to a base case, or up to unavailability of interruptible load.
- Determine the study frequency, outlook, and duration according to the risks identified through data gathering. Depending on the assumptions, electric system, or fuel supply chains that may have changed, the planner should use engineering judgement and historical information. See the three-column graphic on the next page for additional information.
- Determine performance criteria. For example:
  - If the study being performed contemplates a HILP contingency, perhaps the performance criteria would be that 90% of firm load is maintained for a short period of time. However, when HILP is studied, it should be done for emergency preparedness and not for measuring the reliability of specific system resources. Another consideration in this scenario would be acceptable system ratings and limits. If the study being performed contemplates a HPLI contingency, perhaps the performance criteria would be set to a base case, or up to unavailability of interruptible load.

[18] https://www.iso-ne.com/static-assets/documents/2018/01/20180117_operational_fuel-security_analysis.pdf
[19] Id.

- Determine the study frequency, outlook, and duration according to the risks identified through data gathering. Depending on the assumptions, electric system, or fuel supply chains that may have changed, the planner should use engineering judgement and historical information. See the three-column graphic on the next page for additional information.

Table 4.2:Choosing a Study

Frequency	Outlook	Duration
For choosing a study frequency (i.e., how often the study is performed), consider the following: • Operational time frame studies could be performed on a weekly, or monthly basis, or other near- term periodicity. For example, one existing analysis involves a winter weekly or non-winter biweekly energy study that is used on an ongoing basis for operations planning. • Seasonal studies could be performed periodically in the prewinter or pre-summer time frames in anticipation of the peak load seasons. • Longer-term studies could be performed annually, every few years, or on a longer-term periodicity as necessary. • Ad-hoc (one-time) studies could also be performed to assess a unique set of conditions and to achieve specific objectives and may be more limited in scope.	For choosing a study outlook (i.e., when does the studied time horizon begin) consider the following: • Short-term operations planning study outlooks (e.g., one-week out, one-month out, six-months out, other-less than a year out) could be used. • Alternatively, near-term (1–5 years), long-term (6–10 years) transmission planning time horizons, or even greater study outlooks could be used if appropriate for the objectives of the study. For example, one existing analysis was based on a five-year look-ahead study to assess system resilience under future resource portfolios.	For choosing a study duration (i.e., what is length of the study window), consider the following: • The duration could be anywhere from a snapshot of the current system to a few days out or even to multiple years, depending on what is appropriate for the assumptions or objectives of the study. For example, one existing analysis involves a 14-day study window to model a plausible 14-day extreme cold weather scenario based on historical weather analysis. • Consider varying durations of fuel disruptions to determine how reliability conditions may change over time given a particular fuel disruption.[20]

Step 4: Contingency Selection

The data gathered at this point will help to form the basis for contingencies to the fuel supply of the studied system. Some aspects will be known, and some will be assumed. It is possible that not all contingencies will be included in the final study once the probability and credibility of the various scenarios are better established. It may be prudent to establish a priority level for different contingencies based on the planner's experiences. There are many factors to

[20] ISO-NE performs a 21-day look ahead energy assessment based on the lead time it takes to schedule an LNG and fuel oil truck delivery within the associated region.

consider in filtering and selecting the appropriate contingencies to study; this may include, but is not limited to, the following:

- The cause of the fuel disruption (which helps with developing proper mitigation)[21]
- The frequency with which the disruption has occurred in the past in this or other locations
- The probability or likelihood that the disruption will occur in the future
- The expected duration of the disruption based on historical data or reasonable assumptions that acknowledge system improvements over historical data:
  - Fuel disruption duration can be seasonally dependent. For example, a failed fuel delivery system during the high-demand winter months will likely be shorter in duration than a disruption during low-demand periods.
- The amount of fuel supply interrupted (This is a line to be drawn based on relevance to the scenario being studied.)[22]
- The amount of fuel supply interrupted (This is a line to be drawn based on relevance to the scenario being studied.)[23]
- The location of the disruption, even outside of your footprint as fuel delivery is a worldwide operation
  - Interdependence of global markets on local systems should not be overlooked (e.g., LNG imports to Europe surged following the Russian invasion of Ukraine in 2022.)
- The generating units that may be affected by the disruption (Be sure to account for remaining generating capability if any.)
  - Consider alternatives available to impacted generating units, such as dual fuel use and service from alternate pipelines[24]
- The extent or scope of the interruption as to whether it impacts other companies, industries, or other subsystems, such as the following:
  - If flooding has washed out the railways in a particular area, rerouting coal delivery around that area will likely be more difficult due to all rail traffic trying to reroute to meet guaranteed delivery dates.
  - Consider the likelihood of mutual assistance between suppliers. It is within the realm of possibility that a pipeline or fuel oil transporter could suffer a loss of capability and receive assistance from an interconnected pipeline or associated supplier.
  - Consider whether electric load shedding to resolve BPS problems will impact fuel availability or subsequent plant operations.
  - Consider the impact of electric contingencies on the natural gas system or recovery from a natural gas disruption (e.g., loss of power to electric driven natural gas compressor stations or transmission contingencies that may restrict the redispatch of non-natural-gas-fired generators).
- The influence of governmental agencies may also factor into the studied response to contingencies:

[21] NERC Generator Availability Data System data collection was updated for 2020 reporting and going forward cause coding for “lack of fuel” reporting will be much improved.
[22] The loss of a single natural gas compressor engine at a station is more likely than the loss of an entire compressor station. Many fuel supply systems contain redundancies and safeguards, making a full outage of service less likely than a partial outage.
[23] The loss of a single natural gas compressor engine at a station is more likely than the loss of an entire compressor station. Many fuel supply systems contain redundancies and safeguards, making a full outage of service less likely than a partial outage.
[24] Eastern Interconnection Planning Collaborative (EIPC), 2015 Gas-Electric System Interface Study, Section 10 on Natural Gas and Electric System Contingency Analysis, https://eipconline.com/phase-ii-documents.

- Consider historical reactions by governing agencies.
- Consider guidance from governmental agencies, such as the potential for cyber and/or man-made threats to fuel delivery systems.

PJM FUEL SECURITY ANALYSIS

- Consider working with relevant governmental agencies to share the analysis, develop and gain any needed approval for mitigation measures.
  - Nontraditional solutions may be available when directed by emergency management or similar agencies. Conversely, fuel supply could be made unavailable due to decisions made at the governmental level. For example, a port necessary for the delivery of LNG or fuel oil may be shut down following worldwide events that result in a state of heightened security. Another example may be the limited usage of fuel oil unless a special (environmental) waiver is granted by state or federal officials.[25]
- Document the rationale for each contingency selected.

Step 5: Selection of Tool(s) for Analysis

Because of individual system conditions and goals, no single type of transmission system analysis will meet the need of every planner. Therefore, each planner should consider the information gathered in the steps above and choose analysis tools that can provide information that will allow for a thorough assessment of their supply and transmission systems. This analysis may be power flow, stability or dynamic simulation, production cost modeling, market simulation, fuel oil and natural gas pipeline hydraulic flow modeling, deterministic versus probabilistic modeling, in-house tools, or any combination of these tools and others.

Regardless of the tool(s) chosen, the rationale for the selection should be documented and reviewed periodically to ensure that the appropriate tools continue to be utilized and provide continuity from the end of the analysis to what was defined in the goals.

Step 6: Perform Analysis and Assess Results

Based on the information from Steps 1–5, system analysis will be performed and assessed. The assessment will evaluate system performance based on the criteria defined in Step 3 to determine if system deficiencies exist and, if so, what actions might be considered to improve the observed deficiencies. Every step of the process was defined, including the criteria for system performance. At this point of the analysis, the state of the system is known. If the assessment determines that the system does not meet the prescribed criteria for reliable operation of the power system, and corrective actions are needed, this step is where that would happen.

When delivering the results of the study, consider the audience. Consider their level of knowledge of the system being studied and speak to the audience at a level they will understand. Use commonly understood terminology, processes, and procedures so that the audience will more likely comprehend the results as intended.

Step 7: Develop Solution Framework

As noted in Step 3, fuel assurance studies should be completed on an ongoing basis. Regular analysis will help planners and other stakeholders better understand emerging risks as the power grid undergoes rapid transformation. Planners are encouraged to develop a solution framework to ensure fuel assurance in advance of any potential credible

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[25] Following a pipeline disruption event impacting one of the looped lines in a pipeline segment, PHMSA has historically required a mandatory capacity reduction (typically about 20% firm capacity reduction) in the adjacent non-impacted lines within the same pipeline right-of-way until initial investigation of the incident is complete. PHMSA has also historically restricted access to an affected pipeline segment following an event for safety reasons, delaying immediate restoration efforts by pipeline operators. Both the capacity reduction and delayed restoration due to PHMSA's response should be considered when studying the natural gas pipeline contingency impact and duration.

reliability issues. It is at this point that the planner should consider engaging governmental agencies that may be able to assist with developing a framework of potential solutions. One example might be contacting state environmental departments to discuss power plant air and water permits should a HILP contingency occur. At a larger regional level, planners are encouraged to consider developing a response and mitigation plan for grid, generator, and natural gas operators to guide their response to fuel assurance contingencies as identified in Step 4. Further, the development of a communications protocol for grid, generator, and natural gas operators could benefit the regional response to and mitigation of contingencies as identified in the risk analysis framework. These proactive actions will ensure preparedness and improved situational awareness to handle these potential risks in the future.

Appendix A: Factors to Consider

Does the transportation contract provide firm no notice service supported by natural gas storage, which mitigates nomination and scheduling concerns as well as commodity supply risk due to storage-based supply. With no notice service, the pipeline commits it will have capacity to serve the no notice shipper throughout the Gas Day. An arrangement including these attributes generally would be more reliable than one without these capabilities, particularly during peak demand periods and/or when the generator is dispatched intra-day.

Does the delivery of the natural gas supply include some form of firm park-and-loan service allowing the generator to have an imbalance between the amount of gas received into its transportation contract and the amount of natural gas consumed at the generator without risk of service interruption or severe imbalance or overrun penalties. Such service could mitigate the gas supply risk by allowing the generator to take firm delivery of a volume of gas not solely tied to the amount of natural gas scheduled during the normal pipeline nomination cycles.

Does the pipeline transportation agreement include the firm right to take delivery of the natural gas supply on an hourly basis consistent with the expected burn profile of the generator? In some cases, pipeline delivery contracts and/or tariffs limit hourly deliveries to 1/24th, 1/20th, or 1/16th of the daily delivery volume. Generally, firm hourly delivery entitlement that meet the generator's needed hourly burn profile will be more reliable than those which need to operate at hourly take levels beyond the firm hourly entitlement.

Does the pipeline offer additional nomination cycles beyond those established by the NAESB standardized timeline, and if so, have those nomination cycles been effective resolving or limiting imbalance positions on the pipeline?
Does the generator have transportation rights to support its full generation output? If the generator has firm entitlement rights only for a portion of its output [either hourly or daily], this may indicate that incremental capacity is unavailable and gas deliveries may be limited under certain conditions.

Appendix B: Design Basis for a Natural Gas Study Whitepaper

Introduction

The purpose of this document is to guide the performance studies of the interface between the electric and natural gas systems. The recommendations below are not intended to require any analyses to be performed, nor are they intended to provide market solutions, but rather to improve upon the methods and approach in performing that analysis. A realistic set or range of initial conditions should be reviewed/considered when performing this reliability analysis.

What is a Design-Basis Gas Event?

A design-basis gas event is an event used to establish acceptable performance requirements of the reliable operation of the Bulk Power System (BPS) processes, structures, systems, and components, following a disruption of the natural gas fuel delivery system (i.e. pipeline or distribution network).

Examining an Event

When considering such a natural gas disruption within a given area, the examination is not just limited to the loss of the natural gas transportation. Rather, it includes any loss of electric generation with associated energy and essential reliability services, and any ancillary natural gas delivery system needs, such as the loss of electric compression on the natural gas system, the loss of processing plants, and the unavailability of production. The examination should also take into account the level of flexibility available on natural gas pipelines, according to the individual pipeline tariffs, and the impact that wholesale electric markets may have on the procurement of sufficient natural gas supply.

Assessment

Evaluation[26] should include the credible reliability risks (including durations) associated with the natural gas supplied to generators within the reliability footprint of the Registered Entity (RE) performing the evaluation, and its neighbors, which could have an impact on the reliable operation of the BPS of the RE. Further, the system should be viewed through an “all-hazards” lens, to include additional considerations, such as weather impacts, supply chain logistics, regional policies, wholesale electric market design, and security risks (cyber and physical). Evaluation should also include examination of each generator/plant as well as groups of generators/plants that are on the same gas transportation system. Assessments should include dependence on electric supply, potential physical access to natural gas supply (including access to pipeline, distribution, and storage facilities), the amount of capacity subscribed and available at each natural gas supply[27] facility, the amount of flexibility from daily nominations allowed, impacts of extreme weather events, and the ability of the natural gas facilities to meet daily and seasonal demand swings. As part of this assessment, considerations should be made for potential service restrictions and curtailments to key supply points based on the applicable transportation agreements and regulations (e.g., what level of service priority does a generation facility have pursuant to its transportation agreements, scheduling protocols, federal and state tariffs, and applicable regulations, particularly when severe weather or supply disruptions occur). The evaluation of the impact of curtailments of fuel supply should include the ability of dual fuel generators/plants to continue operation, and the associated limitations (e.g. switching time and limited maximum output), on alternate fuel from stored fuel or from multiple natural gas pipeline connections.

[26] Evaluation could be in any timeframe, Long Term Planning, Operations Planning, or Operations
[27] Supply facilities at any point in the natural gas supply chain

These key areas of evaluation would result in a confidence level of fuel assurance for all generators in a given planning area and would highlight any potential system reliability risks given a gas supply disruption that impacts a significant amount of critical generation resources.

Additional information is available in the NERC Reliability Guideline: Gas and Electrical Operational Coordination Considerations[28]

[28] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Gas_Electric_Guideline.pdf

Appendix C: Risk Analysis Framework Checklist

This checklist outlines the actions recommended in **Chapter 4** into a list that entities may use as a reference when performing their own analysis. As mentioned at the beginning of **Chapter 4**, the listed steps are intended to be flexible enough to account for all fuel types, broad enough to support the unique circumstances in each region, and may be performed out of order (or in some cases not at all).

Step 1: Problem Statement and Study Prerequisites

- Define the study goal (i.e., problem statement)
- Set the criteria for system performance
- Communicate the goals of the study with all stakeholders (electric and fuel suppliers)
- Gain agreement on principal concepts
- Determine the timeline prior to commencing work
- Set the boundaries of the study
- Document agreed upon goals, timeline, boundaries, etc.

Step 2: Data Gathering

- Coordinate fuel assurance assumptions with generator owners/operators
- Survey stakeholders (see **Appendix B**)
- Identify relevant fuel supply contingency events
- Maintain documentation for future use

Step 3: Formulate Study Input Assumptions and Initial System Conditions

- Determine fuel(s) to be studied
- Determine the interdependence of various fuel types
- Determine how a large disruption to one fuel source may impact another fuel
- If needed, develop fuel assumptions in the absence of actual information
- Determine weather and load assumptions
- Determine interchange and interface capability
- Determine generator outage and reductions rate assumptions (e.g., EFORd)
- Determine assumptions related to variable energy resources
- Determine expected changes in regulatory policy, generation technology, and fuel mix, including the interdependency of resource installation
- Determine performance criteria using stakeholder input (e.g., is load loss acceptable? If so, for how long?)
- Determine study frequency, outlook, and duration
- Include any special or additional assumptions or system conditions, the following are examples:
    - Heavy seasonal energy transfers

- Changes in generation mix
- Droughts
- Flooding
- System-wide blackout scenario

- Document rationale for assumptions and system conditions selected

Step 4: Contingency Selection

Filter down identified contingencies. Consider CEII ramifications. Consider factors like the following:

- Cause of the fuel disruption
- Frequency with which the disruption has occurred in the past in this or other locations
- Probability or likelihood that the disruption will occur in the future
- Expected duration of the disruption based on historical data or reasonable assumptions
- Amount of the fuel supply interrupted
- Location of the disruption
- Generating units affected by the disruption and remaining generating capability (if any)
- Extent or scope of the interruption (does it impact other companies, industries, etc.)
- Influence of governmental agencies on the response to contingencies
- Document rationale for contingency selection

Step 5: Selection of Tool(s) for Analysis

Select analysis tools appropriate for the study, such as follows:

- Power flow
- Stability simulation
- Production cost modeling
- Market simulation
- Pipeline hydraulic flow modeling
- Deterministic vs. Probabilistic modeling
- In-house tools
- Document rationale for selection

Step 6: Perform Analysis and Assess Results

- Perform analysis
- Document and assess results
- Consider CEII ramifications

Step 7: Develop Solution Framework

- Identify potential risks
- Develop solution framework as needed and in concert with stakeholders, regulators, etc.
- Update existing plans and procedures

Appendix D: Items to Include in a Fuel/Energy Survey

This list is indicative but not all encompassing of the questions that planners may ask of its generator owners/operators depending on the regional study goals and the possibility of regional fuel type generation considerations.

When drafting a survey, consider whether certain questions should be made mandatory. Also consider how to format answer selections; should some be limited to multiple choice, is free form text more appropriate, etc. It will also be important to seek consistency in units of measurement. Make an effort to clarify what units are desired (MW, MWh, MMBtu/day, etc.) so that compiling and analyzing responses is straightforward.

General Information

- Resource information
  - Name
  - Contact
  - Unit identifier
  - Type
- Square footage of fence footprint and what percentage of that space is empty
- Is there a “bump-up” compressor on-site? How often is it used?
- Net max and min sustainable rating
- Design and/or current operational max/min ambient temperature
- Unit maximum summer heat rate
- Unit maximum Winter heat rate
- Dual Fuel Unit heat rate on different fuels
- Primary fuel source
- Alternate fuel source
  - Fuel switching requirements, or other considerations
- Date of last MW disruption (or not received) on primary fuel (within the last 5 years)
- Amount of MWs disrupted (or not received)
  - Reason for disruption (or not received)
- Have any fuel supply procurement processes been compromised?
  - For example, limited trucking capability, navigation issues, lack of refinement capability from supplier
  - How often?
  - Any seasonal issues?
- Planned retirement date
- Is staffing required to start the unit?
- Is staffing required to switch fuels?

- Is unit black-start capable or on ISO/RTO system restoration Plan?
- Consumable item most limiting unit operations (e.g., limestone, chemicals, demineralized water trailers, air, or water emission credits)
- Does the unit/station have existing on-site natural gas compression
- Availability of on-site boost compression
- Is there backup power on-site?
- Are there state restrictions on future use of this unit?
- What is the impact and duration of maintenance shutdowns?
- What is the risk of third-party damage to plant, inventory, or transportation types to the plant?

Natural Gas Pipeline Information

- Companies providing physical natural gas pipeline connections
- Critical compressor facilities
  - Identify whether natural gas or electric compressors connected to or required by the unit (if known)
  - Identify if spare compression is available at each compressor site
- Required minimum pressure for full, half, and minimum output
- Required minimum pressure for unit operation (<full output)
- Peak burn rate
- Transportation contract
  - No-notice service, firm, enhanced Firm, secondary firm, interruptible, etc.
  - Transportation contract options available for natural-gas-fired generators
- Commodity
  - Type of service—firm or interruptible, Other?
    - Number of available suppliers
  - Number of pipelines
  - Storage access
  - Asset Management Arrangements (e.g., firm delivery expressed in MMBtu/day)
- Seasonal operations considerations
  - Identify any force majeure events called by the pipeline in the last 10 years
  - Identify any critical generators connected to the pipeline that could affect your deliveries
  - What is the nature of the balancing flexibility the pipeline offers you and provide a link to the tariff summary
- Seasonal maintenance considerations

Oil Information

- Limitations on oil burn, number of hours, emissions limitations, seasonality limits
- Number of hours of operation at max/min output on oil
- Maximum fuel storage capability
- Type(s) of oil (e.g., residual fuel oil, fuel oil #2, etc.)
  - Available usable fuel in storage (typical annual-average value)
- Plans to increase available usable fuel amount
- Assurance level for additional deliveries
- Can fuel be replenished faster than it is used?
- Alternate fuel contracts
- Number of alternate fuel suppliers
- Fuel primary and alternate transportation type (pipeline, barge, rail, truck, etc.)
- Fuel resupply limitations
  - Notice time and delivery time
  - Deliveries expected over given period of time (e.g., how many per day)
  - Proximity of supplier(s)
  - Available offloading facilities
- Does the unit need natural gas to start?
  - If so, is the fuel stored on site?
- Do other units share oil inventory?
  - If so, number of hours of operation at max output on shared oil

Coal Information

- Maximum storage capacity
  - Current inventory amount
- Inventory resupply plans
- Assurance level for additional deliveries
- Alternative suppliers
- Maximum output that can be sustained indefinitely
- Fuel primary transportation type (barge, rail, truck, etc.)
- Can fuel be replenished faster than it is used?
- Secondary transportation
- Fuel delivery time
- Is delivery on a schedule?

- Scheduled time between replenishments
- Maximum amount delivered in a single shipment
- Typical coal level for replenishment order
- Units that share coal inventory
- Max runtime for unit with shared fuel inventory
- Does the unit need oil or natural gas to start?
  - If so, what fuel(s) is stored on site?
- What is the unit's history of freezing coal inventory/piles and are any measures in place to mitigate freezing?

Alternate Fuel Information

- Alternate fuel source(s)
- Additional staffing requirements to start the unit on alternate fuel
- Number of hours of operation at max on alternate fuel
- Maximum fuel storage capability
- Available usable fuel in storage
- Plans to increase available usable alternate fuel amount
- Assurance level for additional deliveries
- Alternative suppliers
- Fuel primary transportation type (barge, rail, truck, etc.)
- Can fuel be replenished faster than it is used?
- Secondary transportation
- Alternate fuel resupply time
- Unit net MW max capability on alternate fuel
- Does the unit have to be taken off-line to switch to the alternate fuel?
  - If not, what is the MW output level needed to perform switching?
- Time to transition to alternate fuel
- Date alternate fuel capability was last tested
- Amount of net MW output achieved while on alternate fuel
- Does the unit need natural gas to start?
  - If so, is the fuel stored on site?
- Max number of starts per day on alternate fuel
- Number of starts per week on alternate fuel
- Can the generator operate on both fuels simultaneously?

Environmental/Emissions

- Unit environmental/emissions limitations
- Pollutant responsible for most limiting emissions limit
- Limit periodicity of pollutant responsible for most limiting emissions limit
- Pollutant responsible for most second most limiting emissions limit
- Limit periodicity of pollutant responsible for most second most limiting emissions limit
- Other environmental/emissions concerns

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Maggie O'Connell	Interstate Natural Gas Association of America
Levetra Pitts	North American Electric Reliability Corporation
Thomas Popik	Foundation for Resilient Societies
Elsa Prince	North American Electric Reliability Corporation
Joseph Ricasio	Independent Electricity System Operator
Sammy Roberts	Duke Energy
Scott Barfield	North American Electric Reliability Corporation
Phillip Shafeei	Colorado Springs Utilities
Tim Sherwood	Southern Company
Chris Smith	Interstate Natural Gas Association of America
Mark Spencer	LS Power Development
John Stevenson	New York Independent System Operator
Robert Tallman	North American Electric Reliability Corporation
Charles Yeung	Southwest Power Pool, Inc.

Guideline Information and Revision History

Guideline Information	
Category/Topic: Fuel Assurance	**Reliability Guideline/Security Guideline/Hybrid:** Reliability Guideline
Identification Number: RG-FAS-0923-2	**Subgroup:** EGWG

Revision History		
Version	**Comments**	**Approval Date**
1	Approved by the RSTC	March 2020
2	Approved by the RSTC	September 2023

Metrics

Pursuant to the Commission's Order on January 19, 2021, *North American Electric Reliability Corporation*, 174 FERC ¶ 61,030 (2021), reliability guidelines shall now include metrics to support evaluation during triennial review consistent with the RSTC Charter.

Baseline Metrics

All NERC reliability guidelines include the following baseline metrics:

- BPS performance prior to and after a reliability guideline as reflected in NERC's State of Reliability Report and Long Term Reliability Assessments (e.g., Long Term Reliability Assessment and seasonal assessments)
- Use and effectiveness of a reliability guideline as reported by industry via survey
- Industry assessment of the extent to which a reliability guideline is addressing risk as reported via survey

Specific Metrics

The RSTC or any of its subcommittees can modify and propose metrics specific to the guideline in order to measure and evaluate its effectiveness, listed as follows:

- RTOS will conduct periodic evaluations of the gas system supply constraints that have resulted in derates to generators. These will be categorized and tracked for trend analyses. This information is available to NERC in GADS7.

Effectiveness Survey

On January 19, 2021, FERC accepted the NERC proposed approach for evaluating Reliability Guidelines. This evaluation process takes place under the leadership of the RSTC and includes:

- industry survey on effectiveness of Reliability Guidelines;
- triennial review with a recommendation to NERC on the effectiveness of a Reliability Guideline and/or whether risks warrant additional measures; and
- NERC's determination whether additional action might be appropriate to address potential risks to reliability in light of the RSTC's recommendation and all other data within NERC's possession pertaining to the relevant issue.

NERC is asking entities who are users of Reliability and Security Guidelines to respond to the short survey provided in the link below.

[Guideline Effectiveness Survey]