ELECTRIC POWER RESEARCH INSTITUTE

Exploring the Impacts of Extreme Events, Natural Gas Fuel and Other Contingencies on Resource Adequacy

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Technical Update, January 2021

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ABSTRACT

The electric power industry is shifting its generating portfolio towards variable energy resources and natural gas. As these changes are occurring, the industry needs to plan for resource adequacy that will make electric service more resilient to significant disruptions of supply whether they are the result of weather, cyber / physically attacks, fuel constraints or multi-factor events. Across each of these topics the power industry today employs planning methods that tend to understate the probability of supply disruptions affecting multiple units and their impact on consumers and the system itself.

This white paper focuses on planning for resource adequacy given a world in which supply disruptions are correlated and no longer limited to the outage of independent units and may be due to widespread or long-duration events with significant economic impacts on consumers. The paper highlights the following attributes of planning for resource adequacy in an environment of increasing numbers of extreme events:

- Supply disruptions that are common mode events caused by weather, cyber / physical attacks, natural gas constraints or combinations of factors.
- The occurrence of an event (zero/one), consideration of its physical impacts (the amount of unserved energy, breadth of customer base impacted, and duration) and its economic costs to consumers.
- The need for the definition of probabilistic metrics and methodologies that over time can be used to incorporate consideration of common mode and high impact supply disruptions.

The paper concludes with an identification of strategies that an individual utility and/or an ISO/RTO could follow based on its unique situation.

Keywords
Resource Adequacy, Extreme Events, Common Mode Events, Planning, Effective Load Carrying Capability (ELCC), Cyber Security, Fuel Security, Probabilistic Analysis, Natural Gas, Intermittent Supply, Stochastic Mathematical Programming, Unserved Energy, Value of Lost Load, Disruptive Weather.

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SECONDARY AUDIENCE: Utility operational planners, state regulators including staff of state energy offices and public utility commissions

KEY RESEARCH QUESTION

Extreme weather events and limitations on natural gas availability are occurring more frequently, while the metrics and methodologies for addressing these events have not kept pace. For example, weather is causing significant changes in the correlated output of variable energy resources. In addition, the increased threat of cyber-attacks must be addressed in power system planning and preparedness. Therefore, there is a need to understand events that can simultaneously impact multiple generating units and to develop metrics and methodologies with which to measure and plan for their impacts on resource adequacy.

RESEARCH OVERVIEW

This document provides an analysis of current reporting, resource adequacy metrics, and supply planning related to events that can disrupt supply on a system-wide basis, and offers opportunities for improvement. The paper categorizes and reviews the sources of supply disruption, including extreme weather events, cyber / physical risks, and fuel supply constraints. It addresses a critical gap in current metrics and approaches that do not focus on the correlated impact on multiple resources of common mode events, often weather-related, that can cause significant disruptions in supply. It highlights the fact that the metrics used to measure resource adequacy are themselves inadequate in that Loss of Load Expectation (LOLE) and Effective Load Carrying Capability ELCC are measures of system capacity that often do not account for common mode events, and do not measure the depth, breadth or duration of outages or their economic impact. In a world evolving toward renewable resources with increased variability, the role of technologies that can respond to this variability, i.e., natural gas, storage, and flexible demand, are critical enablers. The availability of consistently collected and reported data on extreme events handicaps both analysis of the probability and severity of service disruptions and the development of effective responses. The impact of long-term trends in weather is non-linear in that the severity of events is increasing more than the frequency. For the power industry, weather data needs to be collected and analyzed at the regional and national level for the duration of system-wide storms rather than just on a local, station-by-station basis as is currently the case.

KEY FINDINGS

1. The electric industry systematically understates the probability and depth of many high impact common mode events:
    - Extreme weather events are rising in frequency, intensity, geographic scope, and duration; the impact of weather is non-linear and rising much faster than frequency; a ten-year historical calculation of extreme event probability understates the likelihood of an extreme event in a changing climate (4-1).

- ELCC calculations generally do not consider weather correlated deviations from standard profiles for variable energy resource (VER) output that might result in large fleet-wide variations in the output of both existing resources and incremental units (3-7).
- The availability and output of renewable sources being correlated with weather requires other resources and/or demand to rapidly respond to significant changes in renewable energy production (4-5).
- It is acknowledged that natural gas-based generation is a critical supply technology needed to maintain reliable service to consumers; it is generally assumed to be an "available resource" even though both operational and regulatory issues can and do lead to that capacity being unavailable (4-8).
- The industry's methodologies for calculating resource adequacy assume that outages and reductions in output are independent and uncorrelated. Increased dependence on renewable technologies combined with a recognition of common mode events that affect multiple generators makes it clear that the assumption of independence may no longer be valid (3-7).

2. Due to the rising trend in disruptive events and common mode outages, the traditional approaches to ensure resource adequacy need to evolve:
    - To project disruptive event probabilities moving forward, the historical probabilities for the frequency, intensity, geographic scope, and duration of weather events need to be adjusted upwards to take recent climate trends into account. Probabilistic weather forecasts are another tool that can help deal with rising frequency, intensity, and duration of extreme weather events (4-5).
    - The resource adequacy framework needs to be modified to reflect the depth, duration, and economic costs of unserved energy, and supplemented to account for common mode events. Scenario planning for high impact common mode outages should be included in resource planning. Such planning should include scenarios that are relevant to the specific region, and consider both investments and potential operational responses (3-1).
    - The interaction between the natural gas and electric power markets needs to be restructured to remove the operational inefficiency that exists today due to the nonalignment of the daily and longer market cycles of the two industries (5-8).
    - Planning in the power industry needs to evolve to acknowledge the stochastic realities brought about by variable resources, increased variability in weather, and changing consumer behavior. These changes can be addressed by the development of probabilistic metrics and analytic / modeling systems that can measure, probabilistically, the economic impacts of these changes beginning with the development of scenario planning methods of extreme events (3-11).

The authors' key recommendations are to:

- Develop scenarios by region of high impact, common mode events, and estimate the probability distributions of the scenario's physical impacts and associated economic costs (6-1).
- Develop regional Value of Loss Load (VOLL) studies that update and extend the available estimates of customer outage costs (6-1).
- Develop a modeling framework to combine an operational model of the natural gas pipeline network with a production costing power system model (6-1).

- Develop a disruptive weather classification system including intensity, geographic coverage, and duration directly targeted for use by the US Electricity Market (6-2).
- Develop Value of Load at Risk as a conceptual framework to address the shortcomings of the current resource adequacy metrics (6-2).
- Develop a stochastic mathematical programming model for resource planning and pricing resource scarcity (6-3).

WHY THIS MATTERS

The electric industry and its customers need to anticipate and better prepare for high impact events resulting from simultaneous outages and significant correlated changes in output. A recognition of the rising frequency of common mode failures provides the opportunity to better understand when a combination of low output from variable renewable sources, uncertainty in output from gas generation, and disruptive weather can lead to widespread outages.

HOW TO APPLY RESULTS

The study concluded with six interconnected recommendations that focused on better collection and classification of data on high impact extreme events, and on the development of metrics and probabilistic models for supply planning.

LEARNING AND ENGAGEMENT OPPORTUNITIES

The data and model development recommendations provided will be of direct interest to and supported by the North American Electric Reliability Corporation (NERC) and the Department of Energy, including the Energy Information Administration (EIA).

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1 INTRODUCTION

It is human nature to under-estimate the likelihood of extreme events. Across topics varying from weather to fuel supply and cyber security, today's power industry employs planning methods that tend to understate the probability of supply disruptions affecting multiple units and their impact on consumers and the system itself. The electric power industry is moving inexorably into a new era in which generation portfolios are changing, a larger proportion of generating assets are variable renewable resources, generation occurs behind as well as in front of the meter, the economy has become increasingly dependent on a reliable supply of electricity, and consumer preferences for reliability and the carbon content of their energy supplies are rapidly evolving. As these changes are occurring, the industry needs to be planning for resource adequacy in a manner that will make electric service more resilient to significant disruptions of supply whether they are the result of weather, cyber / physically attacks, or multi-factor events.

The objective of this white paper is to focus on supply disruptions that are not limited to the outage of individual units but may be widespread or long-duration events, their impacts, and the metrics to measure and enhance resource adequacy with attention to the following attributes:

- The underlying structure of the causality of events and our ability to forecast their probability of occurrence and severity.
- Any natural interdependence between causes (anticipated perfect storms).
- In addition to the occurrence of an event (zero/one), consideration of its physical impacts (including extent and duration) and its economic costs to consumers.
- Definition of metrics (generally probabilistic) for which occurrence, extent, duration and impact can be extracted today or developed over time.
- Identification of strategies that an individual utility and/or an ISO/RTO could follow based on its unique situation.

Significant supply disruptions are often common mode events[1] and can be caused by natural disasters, pipeline failures, cyberattacks, or extreme weather.[2] Such common mode events are

[1] The term "common mode events" is used throughout the paper to describe circumstances when two or more resources simultaneously or in overlapping time periods become unavailable or experience a constraint on or reduction in output for the same reason. This includes both cases caused by a single external event, such as the failure of a gas pipeline, and cases in which a combination of factors affect the ability of the system to serve load, as could occur when constraints prevent available resources from offsetting a decline in the output of wind and / or solar generation.

[2] Although it is outside the scope of this white paper, we note that the increase of distributed intelligent devices and control systems in customer homes and businesses creates the possibility of correlated demand events that could impact system reliability. For example, simple time-of-use rates could create discrete and nearly instantaneous changes in demand from electric vehicles and other smart devices and control systems that is timed to take advantage of a significant change from peak to off-peak rates.

inconsistent with the traditionally applied resource adequacy assumption that individual generator outages are independent and not correlated with one another.

Given common mode events, an assumption of independent outages understates the probability of multiple units being simultaneously unavailable.[3] As a result, existing approaches for evaluating resource adequacy may not adequately reflect the risks related to such events. However, by characterizing different common mode events, the industry can develop risk metrics and plan for and become increasingly resilient in its response to these events.

This paper will examine how consideration of common mode events that can have a high impact on the ability supply energy may change resource planning and the definition and determination of resource adequacy. For example, given different drivers and mitigation options for relevant common mode events, a straight-forward translation of loss of load probability into a reserve margin requirement may be insufficient for ensuring reliability without additional analyses. Planners may need to characterize the multiple events that could affect their system, develop risk metrics and consider different responses for each type of common mode event. This white paper will describe methods for analyzing the probability and impact of disruptive common mode events and considering those events in planning to achieve resource adequacy and resilience, focusing on experiences in the U.S. While this paper does not explore future climate scenarios, uncertainty and variance of long run climatological models is a subject of ongoing research which will have consequences for adequacy studies.

The white paper that follows is organized around five topics that together present a view of the primary issues facing the industry in dealing, from a long and short-term planning perspective, with high impact events and their relationship to the assurance of resource adequacy / resilience of the electric power sector as a whole.

Section 2 focuses on the background of resilience and its relationship to resource adequacy.

Section 3 provides an overview and an evaluation of the metrics currently used to evaluate resource adequacy.

Section 4 provides the background on the evolution of supply disruptions required to place the analysis of these events into the context of planning for resource adequacy and system resilience. The discussion of disruptive events is broken into its broad categories related to weather, cyber / physical security, and failures that reflect a combination of factors, potentially including human error, illustrated by a discussion of inadequate natural gas supply.

Section 5 builds upon the background of Section 3 and 4 to provide an analysis of needed methodological enhancements (including improved forecasting) that need to be developed and or adopted to improve planning capability; to forecast the occurrence; measure the impact and better prepare for the occurrence of those events. It discusses the development of resilience metrics and addresses the value to consumers of unserved energy, including the limitations of

[3] For example, in a portfolio of resources, each with a 5% outage rate, the assumption of independent outages results in the probability of two units being simultaneously out of service equal to .05 times .05 or 0.25%, and of three units being out being .05 cubed, or 0.0125%. In reality, on a common pipeline, the probability of the two units both being out with an insufficiency in fuel is 100%.

and potential improvements in valuation methodologies that could be used to better place resource adequacy metrics in an economic context.

Section 6 provides a number of recommendations for future work to improve both planning and implementation for resource adequacy.

2

DEFINITION OF POWER SUPPLY RESILIENCE AND CURRENT STATE OF THE ART

EPRI has defined three forms of resilience

- Power supply,
- Transmission, substation, and distribution infrastructure (wires), and
- Communications.[4]

The three forms of resilience are interrelated and cannot be neatly separated. For example, the transmission system is an important factor in supply-side resource adequacy. It is reflected in the overall level of capacity needed and the necessary distribution of that capacity. The post-disruption condition of transmission and connected systems also affects resilience through impacts on the ability to supply power during an event, supply restoration and system recovery. In this White Paper, we will examine methodologies for evaluating supply resilience given functioning wires and communications systems, note the relationship between the three forms of resilience, and include a qualitative discussion of resilience planning for events in which other systems are not fully operational. While the focus of this white paper is supply resilience, we will also consider and discuss the larger issue of overall resilience.

The white paper will consider NERC's recent recommendation that the industry, "develop comparative measurements and metrics to understand the different dimensions of resilience (e.g., withstanding the direct impact, managing through the event, recovering from the events, preparing for the next event) during the most extreme event and how system performance varies with changing conditions," as well as those of the National Infrastructure Advisory Council (NIAC).[5] We will begin to examine how planning for supply resilience can adapt to these frameworks.

Resource adequacy is about relatively common, known and anticipated types of events. Resilience is about dealing with events that are harder to predict, often have a common cause affecting multiple resources, and are often widespread and of long duration.

According to FERC/NIAC resilience is "The ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event." [6] In a recent white paper, EPRI defined the new term supply resilience as "the ability to harden supply resources, including associated fuel and all supply components against—and quickly recover from—externally driven high-impact, low

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[4] *Power System Supply Resilience: The Need for Definitions and Metrics in Decision-Making*. EPRI, Palo Alto, CA: 2020. 3002014963.

[5] NERC. *2020 State of Reliability: An Assessment of 2019 Bulk Power System Performance.* Atlanta, GA: NERC (July 2020); NIAC. *Critical Infrastructure Resilience Final Report and Recommendations.* (October 19, 2010).

[6] Federal Energy Regulatory Commission. *Grid Reliability and Resilience Pricing and Grid Resilience in Regional Transmission Organizations and Independent System Operators*, 162 FERC ¶ 61,012, at P 23 (2018).

frequency (HILF) events."[7] While resource adequacy is about reducing the frequency of any shortage of energy to an extremely low level (usually expressed as one day in 10 years), resilience is about the entire system and its ability to avoid, function during, recover from a major event that is often beyond the generation portion of the system, and restore service and incorporate lessons learned so as to minimize societal impact. Historically, the resource adequacy construct has been very successful. While the August 14 and 15, 2020 west-wide heatwave with temperatures 10-20 degrees above normal resulted in rolling blackouts in California, very few of the customer outages that have occurred in the last few years have been the result of a lack of generation.[8] Distribution outages are much more frequently a problem causing customer outages. When generation outages are involved, it is often part of a larger problem such as a major weather event.

We have reviewed what utilities and ISOs/RTOs currently do in their supply planning processes to include consideration of disruptive common mode events to the extent that they are considered. In our review of utility IRPs, we have found very little consideration of these common mode events beyond concerns about fuel supply. ISOs/RTOs that have capacity markets have made adjustments in recent years to require gas-fired plants with a capacity responsibility also have firm gas or a short-term alternative fuel supply. Also, in the three northeastern ISOs, capacity delivery requirements have been extended to the winter. We have not found utilities that explicitly include disruptive common mode events in their IRP analyses. Resilience is occasionally mentioned and included as a qualitative metric, such as reliance on markets for energy and capacity,[9] or fuel diversity.

ISOs/RTOs reported their resilience concerns in the grid reliability and resilience pricing docket (AD18-7). The concerns reported largely reflected geographic differences. Four RTO's reported gas related concerns; SPP reported concerns about coordinating large amounts of renewable resources; and California ISO reported concerns related to fire, earthquakes, drought, and changing weather conditions.[10]

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[7] EPRI, 2020.

[8] CAISO, "Preliminary Root Cause Analysis: Mid-August 2020 Heat Storm," October 2020, http://www.caiso.com/Documents/Preliminary-Root-Cause-Analysis-Rotating-Outages-August-2020.pdf

[9] Indianapolis Power and Light 2016 IRP.

[10] *Power System Supply Resilience: Incorporating Supply Resilience into Resource Planning*. Hytowitz R., Ela E, Entriken B, Singhvi V. EPRI Seminar on Fuels, Power Markets, and Resource Planning, November 13, 2019.

3
OVERVIEW OF THE METRICS USED TO EVALUATE RESOURCE ADEQUACY

3.1 History of Reserve Margin

A probabilistic reliability metric for delivery of electricity to consumers was first proposed in 1947. A one-day-in ten years ("one–in–ten") Loss of Load Expectation (LOLE) was selected for generation capacity sufficiency. It was an engineering-based rule of thumb with little if any economic underpinning that became the accepted level of reliability in terms of system capacity. The US power pools (e.g., NEPOOL, NY Power Pool, and Pennsylvania Jersey Maryland Interconnection) were determining reserve margins based on one-in-ten for many years prior to the establishment of formal RTO markets. For decades, NERC standards specified a one -in-ten standard as a metric for the NERC regions to use in reliability planning.

Until 2000, almost all generation resources were fossil fueled, nuclear and hydro. An active demand side response did not exist. Generation units had known capacities in all hours that they were available and were controllable within operating limits. The first commercial wind plant went online in New Hampshire 1980. By 2002 there were 10 GW of wind in the US. Solar PV capacity started to come online in the early 1990s and did not reach 1 GW until 2008.

The concept and calculation of capacity reserve margin addresses the question: will there be sufficient generation capacity at the time of system peak demand to meet that demand? It never addressed the size of the possible shortfall in capacity. Peak demand was assumed to be exogenously determined and not responsive to short-run prices or system conditions. In addition, limited consideration was given to events that could lead to resource shortages in periods of lower demand. Fortunately, in the systems of the past, if a system was in compliance with a one-in-ten standard, any shortfall was likely to be small. Thus, the relatively rare loss of load events resulted in minimal actual load shedding.

Typical Loss of Load Expectation (LOLE) calculations do not take account of events such as correlated outages of a large number of generating units due to a common cause. The assumptions that are usually made are: 1) independent outages; and 2) units not on forced outage can provide their full output as needed. The capacity of a unit at the time of system peak was deemed to be a unit's capacity value in terms of the reserve margin calculation. In fact, many of the situations that now make it very important to expand the notion of reliability and include resilience were not even on the horizon. Outages of more than a few units were unlikely. A common mode failure such as a lack of natural gas was never considered. Wind and solar penetration were minimal, and a highly interconnected system that depends upon complex, vulnerable infrastructure did not exist.

3.2 Effective Load Carrying Capability (ELCC)

The notion of Effective Load Carrying Capability (ELCC) had been developed a few years before a paper by Len Garver's that described an efficient algorithm for estimating capacity value.[11] The basic idea is to estimate the MW contribution of a technology toward meeting a Loss of Load Expectation (LOLE) standard, and hence a corresponding reserve margin standard. Originally, ELCC was applied to thermal units to calculate the difference in contribution to LOLE-measured reliability between units that had different sizes and forced outage rates[12]. Only much later was it applied to wind, solar and storage.

The calculations of ELCC begins with a system that is at the desired LOLE and adds the target generator (which lowers the LOLE) and then adds load to return the system to the original LOLE. That additional load is the ELCC of the target generator. It also can be expressed as a percent (100*Y/X%). Figure 3-1 illustrates this methodology.[13]

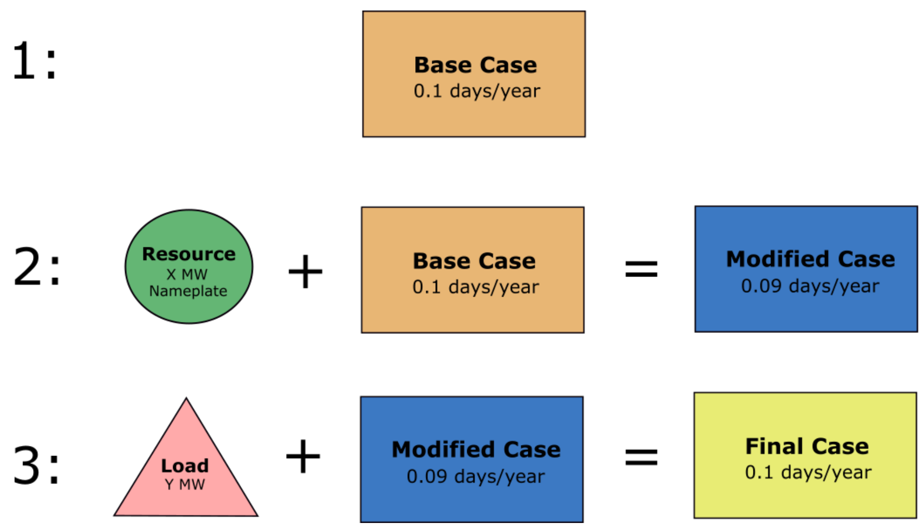

Figure 3-1
Load approach ELCC calculation
(Source: PJM[14])

A variant on the load approach instead adds a generator with a zero forced outage rate instead of load (see Figure 3-2). The resulting ELCC is 100*Z/X%. The important difference is that the generator approach included the resource's forced outage rate in the ELCC, so the generator approach has an ELCC that is (1 minus the equivalent forced outage rate at time of demand) times the load approach ELCC.

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[11] L.L. Garver, "Effective Load Carrying Capability of Generating Units." *IEEE Trans. on PAS* (PAS-85), August 1966; pp. 910–919.

[12] Most organizations no longer calculate specific ELCC values for dispatchable resources. Portland General Electric (PGE) does, and the range of ELCC values reflects differences in unit size, forced outage rates, and ambient temperature effects on output. https://portlandgeneral.com/about/integrated-resource-planning

[13] Patricio Rocha Garrido, "Effective Load Carrying Capability (ELCC)" Presented to *Market Implementation Committee: Special Session on Capacity Market Capability of Energy Storage Resources* on Feb. 24, 2020, https://www.pjm.com/-/media/committees-groups/committees/mic/2020/20200224-capacity-market/20200224-item-02-effective-load-carrying-capability-elcc.ashx

[14] Ibid.

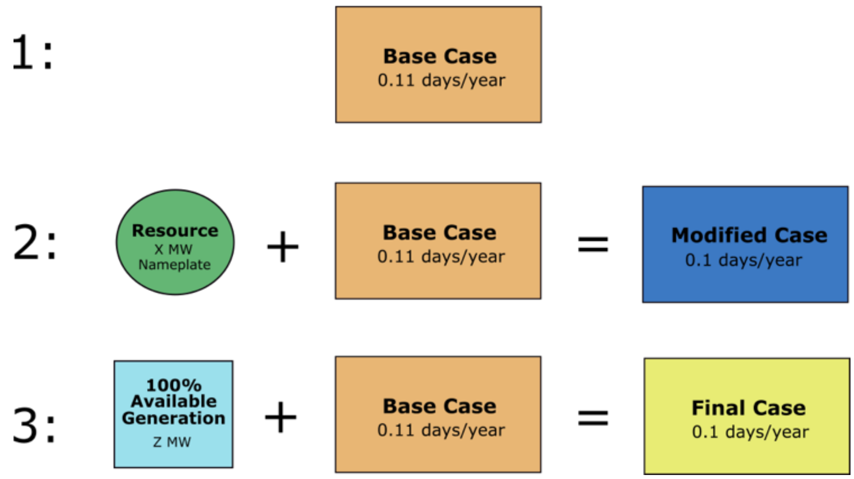

Figure 3-2
Generator approach ELCC calculation
(Source: PJM[15])

Today, ELCC is widely used by utilities and RTOs for resource planning and in capacity markets. ELCC is calculated by PJM for wind, solar and storage[16] and by MISO for wind[17] for their capacity market calculations. As we shall see, there are many challenges with using ELCC for resource planning and in capacity markets. While ELCC can likely be improved and is an important metric for thinking about resources over the short term, as more variable energy resources (VERs) and storage become part of the mix, conventional ELCC calculations become increasingly problematic.

ELCC works reasonably well when the number of VERs and storage is small compared to the overall size of the system. For conventional dispatchable resources, ELCC is well defined given system demand and target LOLE. That is, the ELCC of a conventional dispatchable generation unit has a unique value that is independent of the other resources.

ELCC is usually calculated for incremental additions, taking the rest of the system as fixed. Sometimes the average ELCC for a set of resources is calculated.[18] However, ELCC calculations do not consider common mode events such as unexpected changes in wind or solar output across a large a set of resources.

For VERs and storage, ELCC is not unique. As more VER units are added, the ELCC of each incremental unit added tends to decline. It is easy to see why this is so for solar: as more and more units are added, the net peak load (system peak load less output of variable resources) moves later in the day to when there is less sun light. The net effect is a declining ELCC for each incremental unit as more solar plants are added. The same effect is observed for wind and

[15] Ibid.

[16] A. Levitt, "PJM Initial Package for ELCC Solution," Presentation to *Capacity Capability Senior Task Force*, June 2020, https://www.pjm.com/-/media/committees-groups/task-forces/ccstf/2020/20200622/20200622-item-07a-pjm-initial-proposal-package.ashx

[17] MISO, "Planning Year 2020-2021 Wind & Solar Capacity Credit," December 2019, https://cdn.misoenergy.org/2020%20Wind%20&%20Solar%20Capacity%20Credit%20Report408144.pdf

[18] PJM, 2020.

storage. Figures 3-3, 3-4 and 3-5 from Portland Gas and Electric's (PGE) 2019 Integrated Resource Plan (IRP)[19] illustrate these factors.

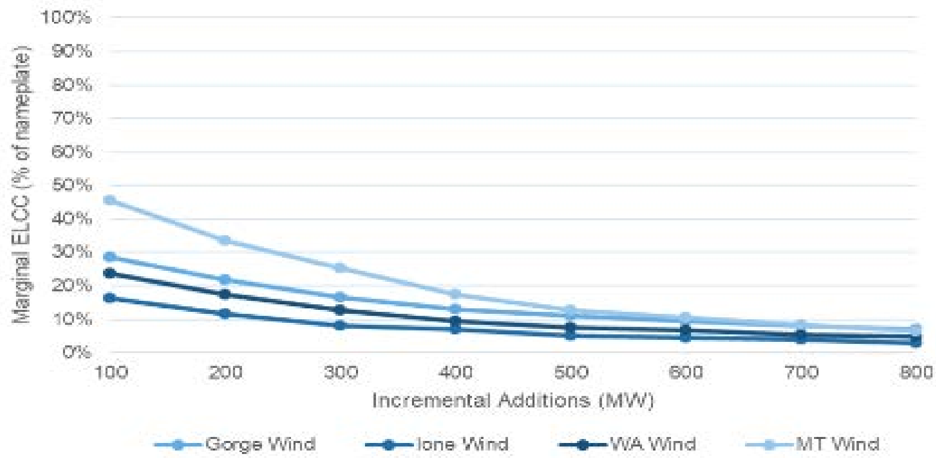

Figure 3-3
Marginal ELCC for wind resources
Source: PGE 2019 Integrated Resource Plan[20]

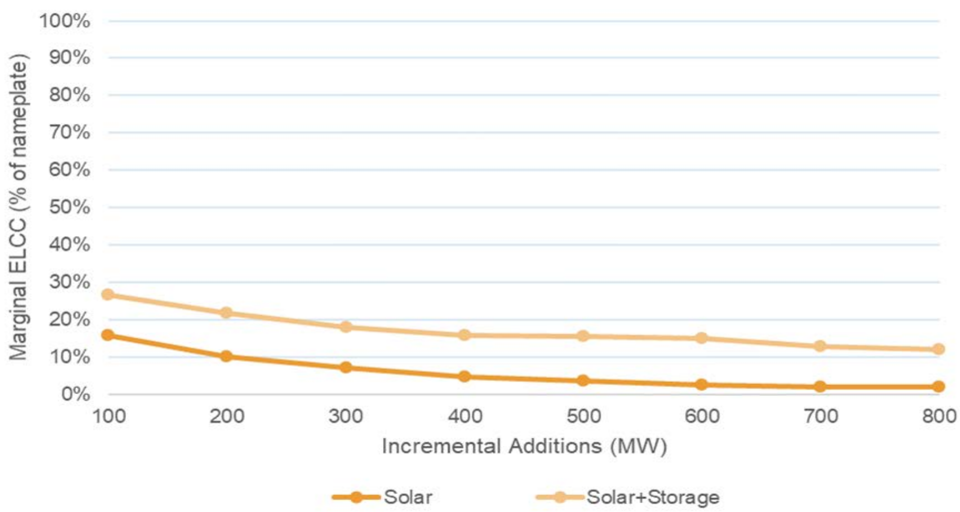

Figure 3-4
Marginal ELCC for solar resources
Source: PGE 2019 Integrated Resource Plan[21]

[19] Portland General Electric, "2019 Integrated Resource Plan," 2019, https://portlandgeneral.com/about/integrated-resource-planning

[20] Ibid.

[21] Ibid.

Figure 3-5 below shows PGE's calculations for storage technologies. Again, the ELCC declines with penetration.

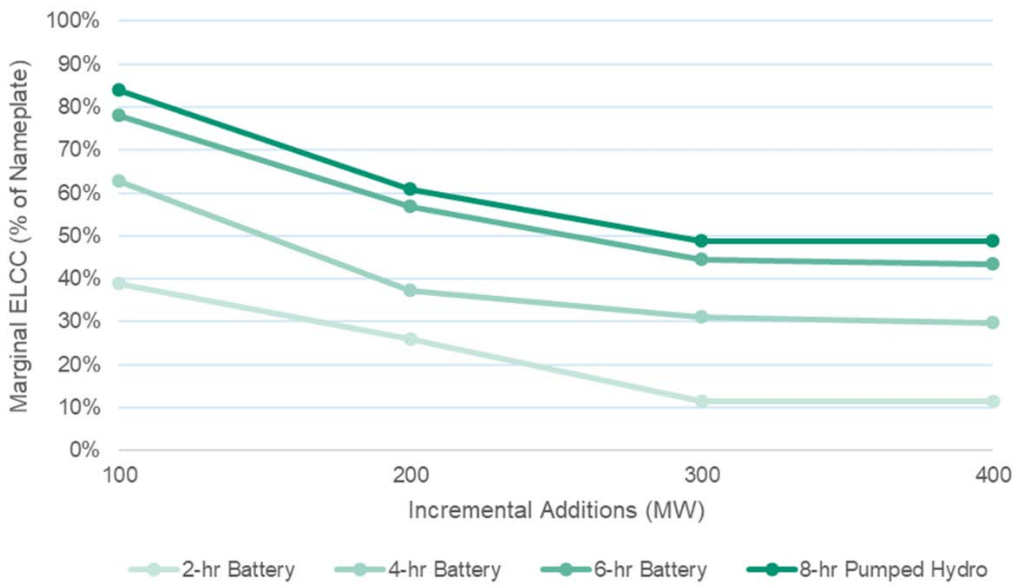

Figure 3-5
Marginal ELCC for storage resources
Source: PGE 2019 Integrated Resource Plan[22]

VER and storage resources have a cumulative impact that reduces the ELCC of incremental units as more are added.

The way in which VER and storage resources interact with the rest of the system also can affect their capacity contributions. The Pacific Northwest Power and Conservation Council has developed a new metric that is similar to ELCC. They call it Associated System Capacity Contribution (ASCC).[23] It is a stochastic measure of the capacity value of an incremental resource addition given the composition of the rest of the system. The Council's calculations show that, like ELCC, ASCC declines with the addition of more VERs. The Council provides an example of a seven resource ASCC table that includes: two wind locations, solar, batteries, energy efficiency, demand respond and gas combustion turbine.[24] The Council developed the figure below (Figure 3-6) to illustrate how incremental additions of wind and solar produce different ASCCs depending on how much solar and wind have already been added. Starting with low levels of wind and solar (500 MW each), the ASCC for an incremental addition is 55%. If wind additions are 1000 MW and solar additions are 2000 MW, incremental ASCC is 28%.

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[22] Portland General Electric, 2019.

[23] J. Fazio, "Adequacy Reserve Margins and Associated System Capacity Contributions," Presentation to SAAC Meeting, August 2020, https://nwcouncil.app.box.com/s/3zs5v9jr6k8wb1jnvsvrjlc2t6tqgdmx

[24] Associated System Capacity Contribution (ASCC) Results, Excel Spreadsheet, https://nwcouncil.app.box.com/s/zq11rh4ogjpvslbcbhva975j3ovs3kyz

Wind Capacity (MW)	Solar Capacity (MW)	Composite ASCC
500	500	55
1000	1000	42
1500	1500	30
2000	2000	22
2500	2500	20
500	1000	47
1000	500	45
1000	2000	28

Figure 3-6
Example of Associated System Capacity Contribution (ASCC)
Source: Pacific Northwest Power and Conservation Council[25]

The Council makes an additional important observation about ASCC. Even for a single resource, ASCC is a function of how it is utilized in the system. The Pacific Northwest has a great deal of hydro. The Council's calculations show that solar output, for example, when operated as part of the overall system, can be time shifted to hours of need from hours of production using the Pacific Northwest hydro system, thereby providing more ASCC value than it would on a standalone static basis.

Analysis by the Council demonstrates this effect. In Figure 3-7 below, the Council analyzes an incremental addition of 930 MW of energy efficiency (EE) and 3000 MW of solar in the context of the Pacific Northwest system. The effect of considering the integrated system is very striking. Considered as a standalone resource, EE would have capacity value of 713 MW, but 1184 MW as part of the integrated Pacific Northwest system. As a standalone resource the solar would have a capacity value of 109 MW, but as part of the integrated system it has a capacity value of 1157 MW. Note that the large differences like this would not likely occur in a system without a great deal of storage.

[25] Associated System Capacity Contribution (ASCC) Results, Excel Spreadsheet, https://nwcouncil.app.box.com/s/zq11rh4ogjpvslbcbhva975j3ovs3kyz

Standalone EE Capacity Contribution	Reduction in MW need =	713 MW
	Added EE =	930 MW
	Standalone Capacity Value	77%
Integrated EE Capacity Contribution	Reduction in MW need =	1184 MW
	Added EE =	930 MW
	Integrated Capacity Value	127%
Difference between integrated and standalone		50%
Standalone Solar Capacity Contribution	Reduction in MW need =	109 MW
	Added Solar =	3000 MW
	Standalone Capacity Value	3.6%
Integrated Solar Capacity Contribution	Reduction in MW need =	1157 MW
	Added Solar =	3000 MW
	Integrated Capacity Value	38.6%
Difference between integrated and standalone		35%

Figure 3-7
Calculation of Associated System Capacity Contribution ASCC
Source: Pacific Northwest Power and Conservation Council[26]

3.3 Correlation of Output and ELCC

ELCC calculations generally do not consider weather correlated deviations from standard profiles for VER output that might result in large fleet wide variations in the output of both existing resources and incremental units. An example of this is the wide, unanticipated swings in wind output in ERCOT on February 10, 2014 as shown in Figure 3-8.[27] The red line shows day ahead expected wind output, and the green line shows the hour by hour estimates of wind for the next hour. The blue line is the actual wind output. Day-ahead expected wind was 4,250 MW for hour ending 22. It turned out to be only 1,250 MW, a shortfall of 3,000 MW. (In hour eight, the difference between day-ahead forecast and actual was also almost 3000 MW.) ERCOT has a large number of wind plants, but wind velocities are correlated and, hence, the MW output of the wind fleet is correlated as well.

[26] J. Fazio, "Implementing the PNW Adequacy Standard into the Council's Seventh Power Plan," presented at RAAC/SAAC Joint Meeting, December 4, 2018 https://nwcouncil.app.box.com/s/q1v56p6ijrl9hqd6k3fecozo1cu3mmvn

[27] ERCOT, "Cold Weather and Wind Forecasting," ERCOT and Texas RE Generator Weatherization Workshop, September 2015, http://www.ercot.com/content/wcm/key_documents_lists/68798/Operations_Analysis_Impact_of_Cold_Weather_on_Wind_Forecast.pdf

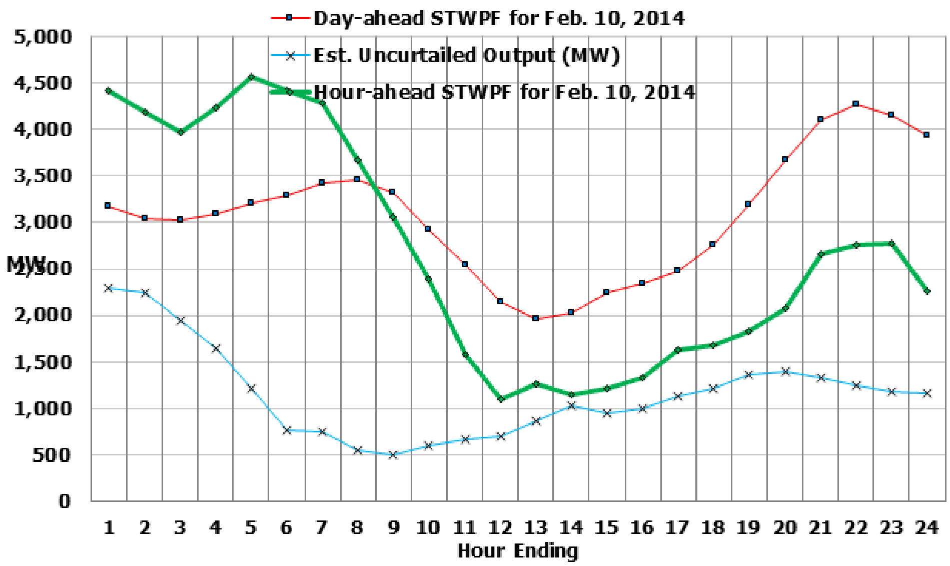

Figure 3-8
Day ahead Wind forecast availability in ERCOT February 10, 2014
Source: ERCOT[28]

ELCC calculations do not consider common mode events. For example, each gas unit has an ELCC close to its capacity at time of peak adjusted for forced outages. The ELCCs of gas units would be lower if, rather than considering all gas units on a system as independent with uncorrelated outages, common mode failures of natural gas supply that could affect all, or a subset, of units were considered. Under these circumstances, the incremental ELCC of each gas unit would reflect the risk of reliance on the set of gas units that have a common gas supply.

3.4 ELCC and Outage Duration and Depth

LOLE does not take into account the depth of an outage or its duration. If there are insufficient resources to meet load in an hour, then LOLE=1.0 in that hour, but it does not tell us if the system is one megawatt hour short or one gigawatt hour short. Obviously those two types of events are totally different from a customer perspective. ELCC, which is calculated based on LOLE, is therefore insensitive to outage depth.

In the past when units were considered independent, unless there were major catastrophes (1965 and 2003 Northeast Blackouts), the amount of load shed was typically not very great. Today, with much more correlation of generation unit fuel supply (gas, wind, solar) and other emerging threats, the amount of load shed has the potential to be quite large. The implication of this is that ELCC provides an incomplete representation of the reliability of supply from a customer perspective. It is thus important to think about how to supplement ELCC and / or develop alternative metrics that better measure duration and depth of outage for system resource planning.

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[28] ERCOT, 2015.

3.5 The Value of Energy Loss

It is useful to characterize generation shortage events by:

1. Frequency of occurrence.
2. Depth – the amount and nature of customer load not served including whether outages impact critical facilities.
3. Duration - how long it lasts.
4. Location - the shortage may be localized because of the pattern of supply loss and how it interacts with the transmission and distribution system.
5. Time of occurrence – outages may have greater impacts or costs when they occur during a heat wave or cold snap and during weekday hours than on weekends.
6. Opportunity to prepare – Notice and the opportunity to prepare for an interruption of service may mitigate impacts on consumers.

Figure 3-9 shows the six characteristics above for supply disruptions resulting from different events.

Event	Frequency	Duration	Depth	Locational	Time	Notice
Wildfires	High	Moderate	High	Yes	Variable	Limited
Extreme heat	Moderate	Moderate	Moderate	Yes	High	Moderate
Extreme cold	Moderate	Moderate	Moderate	Somewhat	High	Moderate
Earthquakes & Tsunamis	Rare	Short to Moderate	High	Yes	Variable	No to Limited
Hurricanes	Moderate to High	Moderate to Long	High	Yes	Moderate	Moderate
Cyber attacks	Rare	Moderate to Long	Moderate to High	??	Variable	No
Physical attacks	Rare	Short to Moderate	Moderate to High	Yes	Variable	No
Geomagnetic Disturbance / EMP Attack	Rare	Short to Moderate	Moderate to High	Regional to Uncertain	Variable	Moderate to None
High winds	Moderate	Short	Shallow	Yes	Variable	Limited
Gas infrastructure	Moderate	Moderate	Moderate to High	Somewhat	High	No

Figure 3-9
Characterization of events

Wildfires are frequent in the west and have resulted in prophylactic customer outages in locations where utilities turned customers off to deenergize transmission lines that were feared might trigger fires. PG&E calls this Public Safety Power Shutoffs (PSPSs).[29] These localized events were frequent in the last few years, resulting in blackouts in affected areas. These events also coincided with high temperatures, which makes the value of energy for air conditioning very high. PG&E is planning to add reciprocating engine units and microgrids to mitigate PSPS events. In addition, wildfires tend to reduce solar output. In California, there were significant declines in solar output this summer due to wildfires[30].

The 2014 polar vortex event affected a large part of the eastern US and Midwest. A regular polar vortex has a strong, stable jet stream that typically "keeps" the cold air in Canada. In 2014, however, the jet stream was weak and wavy. This weak jet stream, combined with a detached low-pressure system over the U.S., lead to cold temps dipping as far south as Florida. That winter saw many locations in the East and Midwest with record cold temps and higher snowfall levels, as the anomalous polar vortex lasted many months throughout most of the winter. It resulted in extremely high demand (electric heating), natural gas shortages and some coal supply limitations.

The examples of wildfires and the Polar Vortex highlight the need for the development of a metric that can be used to reflect the depth and duration of high impact events. Expected Unserved Energy (EUE) should be considered in this regard. It could be calculated for each outage event, since EUE accounts not only for instances of shortfall, but also for the level of customer loss in terms of MW hours.

NERC's 2018 Assessment of Probabilistic Adequacy and Measures[31] drew the conclusion that EUE should be reported since only this metric considers the magnitude of a loss of load event. They conclude that it is particularly important for weather-related events and common mode failure events.

As part of evaluating system resilience and reliability, it is very important to measure the depth and frequency of outages. These are the factors that have significant customer impacts. The notion of value of loss load (VOLL) translates unserved energy into the estimated dollar cost to customers of an outage. Many studies have been done to ascertain VOLL, which varies by customer class, individual customers preference, time of the year, and other factors. Unfortunately, very few studies have been done that look at outages that extend for more than a day.

The cost of an outage to the customer increases as its duration extends. For most consumers, the initial cost for kWh of unserved energy in an hour long or momentary interruption is higher than

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[29] PG&E, "Learn about Public Safety Power Shutoff (PSPS) events," 2021, https://www.pge.com/en_US/residential/outages/public-safety-power-shuttoff/learn-about-psps.page

[30] E.F. Merchant, "California's Wildfires Hampered Solar Energy Production in September," *Green Tech Media*, October 2020, https://www.greentechmedia.com/articles/read/wildfires-in-california-undercut-solar-production-in-september

[31] NERC, "Probabilistic Adequacy and Measures Technical Reference Report," July 2018, https://www.nerc.com/comm/PC/Probabilistic%20Assessment%20Working%20Group%20PAWG%20%20Relat/Probabilistic%20Adequacy%20and%20Measures%20Report.pdf

the average cost per kWh of unserved energy over a four - sixteen hours loss of service. Limited data are available on the costs to customers of longer duration outages. In longer outages, different customers will realize differing opportunities to adapt to the loss of power. A given manufacturing facility might be able to tolerate being out for a few hours and then catch up on its production over the next few days. However, if the outage goes on for days or weeks, the economic losses likely will mount.

Such estimates of outage costs, when adapted for the circumstances of specific utilities or markets, make it possible to explicitly include estimated dollar costs to customers' EUE in system planning. Regulatory agencies have used such estimates in market design as in the case of ERCOT's Operational Reserve Demand Curve. It is also possible to envision designs that would enable customers to bid their values of unserved energy into power markets.

In the future, customers may be able to place a value on electric service and participate in an active demand side of power markets by responding to prices. These developments could allow for a more efficient electric system in which customers pay for the level of service that they need and reduce reliance on planning-based estimates of the value of uninterrupted services to different customers.

3.6 Modeling the Impacts of Common Mode Events in Resource Planning

It is important to develop new system planning techniques that account for EUE and associated customer costs related to extreme common mode events. Even if these events do not occur on a regular basis in a given system, the cost is very high when they do occur. A more resilient system will be impacted by fewer of these events, and when they affect the system, the events will be of shorter duration and/or less deep.

For example, fuel diversity, fuel source diversity (e.g., multiple pipelines or multiple rail links), geographic diversity, storage, microgrids, and demand response contribute to resilience but potentially at a cost. Common mode events are not included in standard system expansion models, but it is important to plan for them.

Multiple studies have developed estimates of the value of unserved energy to customers, which makes it possible to assign a reasonable economic value to at least shorter duration customer outages. Figure 3-10 presents total outage costs and customer interruption costs per kW and per kWh from a 2015 meta-analysis.

Interruption Cost	Interruption Duration					
	Momentary	30 Minutes	1 Hour	4 Hours	8 Hours	16 Hours
Medium and Large C&I (Over 50,000 Annual kWh)						
Cost per Event	$12,952	$15,241	$17,804	$39,458	$84,083	$165,482
Cost per Average kW	$15.9	$18.7	$21.8	$48.4	$103.2	$203.0
Cost per Unserved kWh	$190.7	$37.4	$21.8	$12.1	$12.9	$12.7
Small C&I (Under 50,000 Annual kWh)						
Cost per Event	$412	$520	$647	$1,880	$4,690	$9,055
Cost per Average kW	$187.9	$237.0	$295.0	$857.1	$2,138.1	$4,128.3
Cost per Unserved kWh	$2,254.6	$474.1	$295.0	$214.3	$267.3	$258.0
Residential						
Cost per Event	$3.9	$4.5	$5.1	$9.5	$17.2	$32.4
Cost per Average kW	$2.6	$2.9	$3.3	$6.2	$11.3	$21.2
Cost per Unserved kWh	$30.9	$5.9	$3.3	$1.6	$1.4	$1.3

Figure 3-10
Estimated interruption cost per event, Average kW and Unserved kWh (U.S. 2013$) by duration and Customer Class

Resource planning is typically done using scenario analysis. A better approach is to include high impact common mode events directly in the optimization of the resource plan using stochastic mathematical programming techniques. The model would have a large number of "states of the world" that capture conventional uncertainties (load, outages, natural gas prices, solar insolation, wind speed) as well as common-mode events and extreme events. A state of the world is an outcome for each of the uncertain factors. Each state of the world would have an associated probability.

The problem can be formulated as a stochastic mathematical program. The objective function would be the minimization of the expected value of the sum across states of the world of 1) capital cost, 2) operating and maintenance cost, 3) fuel cost, and 4) unserved energy cost.

Mathematical decomposition can be used to solve a stochastic mathematical problem.[32] A decomposed stochastic mathematical program with many thousands of states of the world can be solved efficiently using parallel cloud computing. When the problem is decomposed, each state of the world and year (and maybe season and location) is a small subproblem. Decomposition is a mathematical algorithm that divides the problem into states of the world subproblems that communicate with the master resource decision problem.

[32] A. Sanghvi and I. Shavel, "Investment Planning for Hydro-Thermal Power System Expansion: Stochastic Programming Employing the Dantzig-Wolfe Decomposition Principle," IEEE Transactions on Power Systems, PER-6(2):115 – 121. May 1986. DOI: 10.1109/TPWRS.1986.4334916

The stochastic problem’s solution would provide insight into the performance of the model-selected optimal set of resources. The model’s reporting function should record detailed results for all states of the world in a database. It would then be possible to investigate how the optimal solution performed in each state of the world. The reporting function should also summarize (and produce distributions for) high-level results such as production cost, unserved energy, unserved energy cost, carbon and other emissions across state of the world. This will facilitate further analysis of states of the world that had a high impact on the optimal resource plan.

The model and its reporting function could also be utilized to perform scenario analysis. If a resource plan was provided as an input (rather than determined by the model), the model’s state-of-the-world subproblems would calculate key parameters for the input system for future years.

4
INCORPORATING HIGH IMPACT COMMON MODE EVENTS INTO RESOURCE ADEQUACY AND SUPPLY RESILIENCE

There have been a breadth of prior papers, studies and policy documents that have characterized the issues associated with high impact low frequency events. The majority of these have focused on high level discussion interspersed with case studies. Few have focused on development of metrics with which to measure the impact and all have effectively dodged any statistical or probabilistic classification of either extreme or low frequency. None of the papers identified have focused on the critical issue of the correlation of events, and on the heightened impact of correlated events on consumers.

Reliability and resilience are about serving customers' energy (MWh) needs and the value of the services that electricity provides. Metrics such as reserve margin and ELCC measure capacity (MW) are imperfect proxies for reliable energy. A fundamental physical measure for reliability is *unserved energy*. Customers also care about *how often outages occur (frequency) and how long outages last (duration)*, and these factors affect customers' outage costs and willingness to pay for more reliable service. The value of uninterrupted service is significantly different for different types of customers and varies with the circumstances of the interruption. Financial metrics that reflect the *value of lost load* to affected customers as well as the indirect regional economic impacts of longer duration outages will be needed to evaluate investments in improving supply resilience.

For purposes of supply planning and resource adequacy, key questions are whether the impact and probability of different potentially disruptive events have been adequately considered. While some relevant events may be categorized in the literature on HILF, the resource planner should be addressing two concerns: a) the rising frequency and intensity of events that have a high impact on the power system, and b) the correlation of events, which has led to the probability of high impact events being often understated. Most operational plans rely upon an assumption of independent variability of multiple resources which is not correct. And the anticipated frequency and intensity of extreme weather events and cybersecurity attacks on the power system in the future are understated if one simply relies upon historical frequency data.

4.1 Disruptive Weather Events

Extreme weather is generally defined as natural disasters and other weather events that are unusual compared to the climatological averages, with some using a 10% threshold. These events include:

- Landfall Hurricanes/ Tropical Storms
- Heavy Precipitation/ Flooding
- Drought
- Extreme Heat Events

- Wildfires (related to Drought and Heat Events)
- High Winds
- Severe Weather (Tornados, Thunderstorms)
- Snow/ Ice Storms
- Cold Events

According to a study by Mukherjee *et al.*,[33] weather caused 52.9% of all outages from 2000 to 2016. Obviously, most weather events are local or regional in nature, so each region of the country is experiencing different combinations of these weather event types (drought in one region at the same time there are heavy precipitation events in another region). These weather events have different impacts to the various components of the power system, including generation, transmission, distribution, and end-use customers. For example, the widespread derecho (wind) event in the Midwest in summer, 2020 wrecked more havoc on transmission, distribution, and end customers and less on generation per se.

As a result of climate change, many types of extreme weather events are occurring more frequently. Often, these events are associated with increased intensity, geographic coverage, and duration as well. Many of these extreme events in the U.S. (e.g., heavy precipitation/ flooding; extreme heat, cold) are the result of a weaker jet stream caused by the arctic warming at twice the rate of the equator which causes storm systems (e.g., inland tropical storms) to move more slowly, thereby extending the duration of such events.

What we know today is that:

- Hurricanes are increasing in intensity (wind speed), geographic coverage, and duration. Recent studies have shown that hurricanes are now moving more slowly over land, and their intensity is decaying more slowly, thus increasing flooding.[34,35]
- Extreme heat events are increasing in frequency, intensity, and geographic coverage. 16% more land area in the Northern Hemisphere is annually being exposed to heat waves.[36]
- Cold events are less cold on average but are increasing in frequency. The pace of record low temps is less than half of record high temps in the U.S. in the most recent two decades; this demonstrates "less cold on average". Yet in the most recent decades, we are seeing a weaker winter jet stream that "allows" cold air from polar Canada to dip down into the northern half

[33] S. Mukherjee, R. Nateghi, and M. Hastak, "A multi-hazard approach to assess severe-weather-induced major power outage risks in the U.S.," *Reliability Engineering and System Safety*, 175 (2018) 283-305.

[34] "5 Things We Know About Climate Change and Hurricanes," *New York Times*, November 10, 2020. https://www.nytimes.com/2020/11/11/climate/hurricanes-climate-change-patterns

[35] "Warming May Make Hurricanes Weaken More Slowly After Landfall," *New York Times*, November 11, 2020.

[36] Vose, R.S., D.R. Easterling, K.E. Kunkel, A.N. LeGrande, and M.F. Wehner, 2017: Temperature changes in the United States. In: Climate Science Special Report: Fourth National Climate Assessment, Volume I [Wuebbles, D.J., D.W. Fahey, K.A. Hibbard, D.J. Dokken, B.C. Stewart, and T.K. Maycock (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, pp. 185-206, doi: 10.7930/J0N29V45.

of the U.S. with greater frequency (e.g., creating cut–off lows, sometimes referred to as the Polar Vortex).[37,38]

- Heavy snow events are increasing in frequency, even while total snowfall amounts are declining. Snow events in the west are declining, while events in the north are increasing.[39]
- Extreme precipitation events and flooding are increasing in frequency and intensity.[40]
- Sea level rise is increasing the number of coastal flood days in the U.S.[41]
- Droughts are increasing in frequency, intensity and duration. This is seen in snow cover decline, greater evaporation, and higher average temperatures.[42]
- Wildfires are increasing in frequency, intensity, geographic coverage, and duration. Five of the top six largest fires in California since 1932 have occurred this past year. This is linked to upward trends in extreme heat events, earlier snowmelt, increased evaporation, and drought. The duration of the U.S. wildfire season is two months longer than prior decades.[43,44,45]
- For severe weather events (e.g., hail, tornados, strong thunderstorms), the trends with respect to frequency and intensity are uncertain.[46]

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[37] Ibid

[38] Gibbens, Sarah, "The polar vortex is coming-and raising the odds for intense winter weather" in *National Geographic*, January 11, 2021.

[39] Easterling, D.R., K.E. Kunkel, J.R. Arnold, T. Knutson, A.N. LeGrande, L.R. Leung, R.S. Vose, D.E. Waliser, and M.F. Wehner, 2017: Precipitation change in the United States. In: Climate Science Special Report: Fourth National Climate Assessment, Volume I [Wuebbles, D.J., D.W. Fahey, K.A. Hibbard, D.J. Dokken, B.C. Stewart, and T.K. Maycock (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, pp. 207-230, doi: 10.7930/J0H993CC.

[40] Ibid.

[41] Sweet, W.V., R. Horton, R.E. Kopp, A.N. LeGrande, and A. Romanou, 2017: Sea level rise. In: Climate Science Special Report: Fourth National Climate Assessment, Volume I [Wuebbles, D.J., D.W. Fahey, K.A. Hibbard, D.J. Dokken, B.C. Stewart, and T.K. Maycock (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, pp. 333-363, doi: 10.7930/J0VM49F2.

[42] Wehner, M.F., J.R. Arnold, T. Knutson, K.E. Kunkel, and A.N. LeGrande, 2017: Droughts, floods, and wildfires. In: Climate Science Special Report: Fourth National Climate Assessment, Volume I [Wuebbles, D.J., D.W. Fahey, K.A. Hibbard, D.J. Dokken, B.C. Stewart, and T.K. Maycock (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, pp. 231-256 doi: 10.7930/J0CJ8BNN.

[43] Ibid.

[44] K. Patel, "Six trends to know about fire season in the western U.S.," NASA Global Climate Change blog, December 2018, https://climate.nasa.gov/blog/2830/six-trends-to-know-about-fire-season-in-the-western-us/

[45] Union of Concerned Scientists, "Infographic: Wildfires and Climate Change, Visualizing the Connection in Five Sets of Photos and Charts," September 2020, https://www.ucsusa.org/resources/infographic-wildfires-and-climate-changeopen

[46] Kossin, J.P., T. Hall, T. Knutson, K.E. Kunkel, R.J. Trapp, D.E. Waliser, and M.F. Wehner, 2017: Extreme storms. In: Climate Science Special Report: Fourth National Climate Assessment, Volume I [Wuebbles, D.J., D.W. Fahey, K.A. Hibbard, D.J. Dokken, B.C. Stewart, and T.K. Maycock (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, pp. 257-276, doi: 10.7930/J07S7KXX.

As Figure 4-1 summarizes, we are seeing greater frequency and intensity in almost all cases.

Type of Extreme Weather	Frequency	Intensity	Geographic Extent
Extreme Heat Events[47]	↑	↑	↑
Drought[48]	↑	↑	↑
Wildfires[49]	↑	↑	↑
Extreme Precipitation/ Flooding[50]	↑	↑	↑
Hurricanes/ Tropical Storms[51]	↔	↑	↑
Cold Events[52]	↑	↓	
Heavy Snow Events[53]	↔	↔	
Severe Weather (e.g., tornados, hail)[54]	↔	↔	

Figure 4-1
Direction of change of impact by extreme weather event

Measured in dollar terms, the frequency and impact of extreme billion-dollar weather events are rising even more quickly (as shown in Figure 4-2).

Time Frame	# of $1B+events/ year	$B Impact/ year
1980's	2.9	17.8
1990's	5.3	27.4
2000's	6.2	51.8
2010 – 2014	11.9	81.0
2015 – 2019	13.8	107.0
2017 – 2019	14.6	153.0
2020	22.0	95.0

Figure 4-2
Billion U.S. Dollar events /year and $ Impact /year[55]

47 Vose, 2017.

48 Wehner, 2017.

49 Ibid.

50 Easterling, 2017.

51 "5 Things We Know About Climate Change and Hurricanes," *New York Times*, November 10, 2020. https://www.nytimes.com/2020/11/11/climate/hurricanes-climate-change-patterns.

52 Vose, 2017.

53 Easterling, 2017.

54 Kossin, 2017.

55 NOAA National Centers for Environmental Information (NCEI), "U.S. Billion-Dollar Weather and Climate Disasters," 2021, https://www.ncdc.noaa.gov/billions/. A.B. Smith, "2010-2019: A landmark decade of U.S. billion-dollar weather and climate disasters," January 2020, https://www.climate.gov/news-features/blogs/beyond-data/2010-2019-landmark-decade-us-billion-dollar-weather-and-climate

As can be seen in Figure 4-2 above, the average annual number of $1B+ events in the U.S. has increased from 2.9 per year in the 1980's to 15 events per year over the last four years (2017 - 2020 year to date), **a five-fold jump.**[56] The average annual dollar impact of $1B+ events has increased from $17.8B in the 1980's to $153B in 2017 – 2019 (2020 data is not yet available). This is an **8.6 times** increase relative to the 1980's (the figures are inflation adjusted).

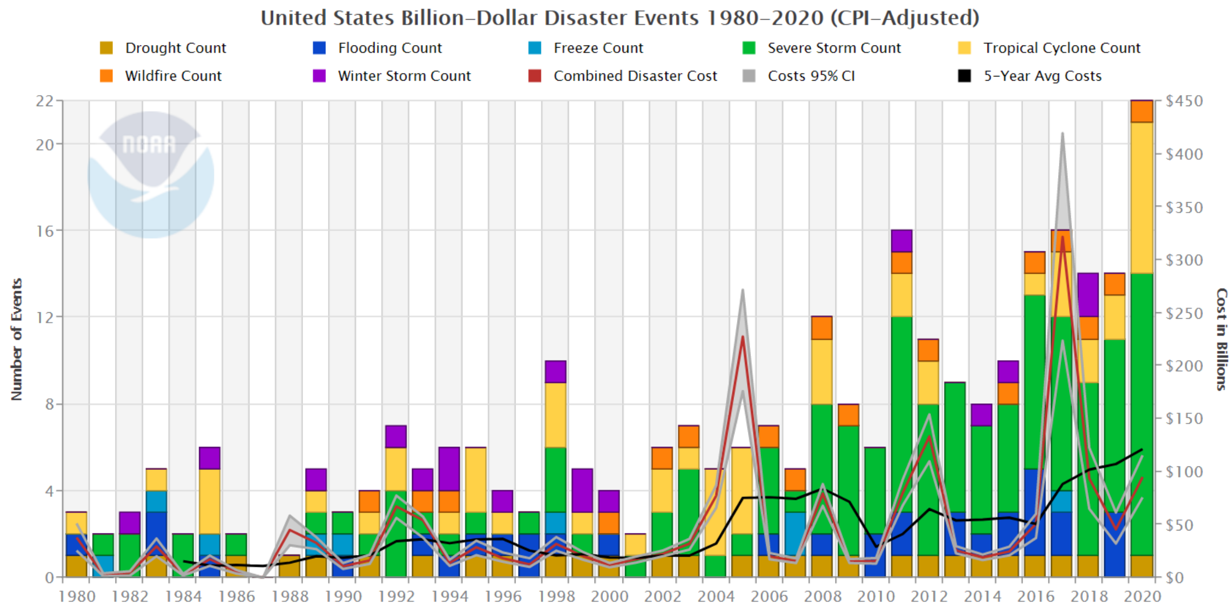

Figure 4-3
Billion-dollar event frequency by type
(Source: NOAA U.S. Billion-dollar Weather and Climate Disasters – 2020)

The dramatic rise in number and dollar impact of $1B+ events as shown in Figure 4-3 is driven partly by an increase in wealth (e.g., value of homes), population, and people moving into geographic areas more prone to impact from extreme weather events. It is difficult to cleanly separate the impact in terms of economic losses between demographic and wealth factors, and changes in extreme weather events. Nevertheless, **the combinatorial non-linear effect of increases in extreme event frequency by greater intensity by wider geographic coverage by duration** is a large contributor to **the fivefold increase in $1B+ events, and the 8.6 times increase in dollar impacts.** This non-linear impact has significant implications for the energy industry.

There are three conclusions to be derived from the discussion above.

1. Impactful weather events are increasing in frequency, and intensity, and geographic expanse, and duration. This combination of factors is dramatically influencing the number and severity of weather-induced events in the electric power industry, just as they are influencing the rapid rise in the number of $1B+ economic impacts for the U.S. economy overall.
2. In projecting disruptive weather event probabilities moving forward, systems planning for electric reliability requires incorporation of this rate of change in the planning process. The

[56] Calculated from Annual Electric Power Industry Report, Form EIA-861 detailed data files 2013 and 2019.

historical probabilities for the frequency, intensity, geographic scope, and duration of weather events need to be adjusted upwards to take recent climate trends into account. Probabilistic weather forecasts are another tool that can help deal with rising frequency, intensity, and duration of extreme weather events.

3. Extreme events and their impacts occur over a wide range of severities, and hence a probabilistic framework in assessing and forecasting these events and their trends may be called for. Extreme events can be both probabilistically assessed and, with current and evolving methodologies for weather forecasting, be probabilistically forecast. By this, we mean that for any given extreme weather system in the near-term forecast (within 7- 10 days), we can evaluate the probabilities of each level of potential intensity for a given location, and for the geographic coverage of the storm overall. Proposed approaches to the adoption or adaptation of advanced weather forecasting technologies and techniques are discussed in section 5 below.

4.2 Loss of Load due to Natural Gas Supply Interruption as an Extreme Common Mode Event

In the winter of 2014, the Midwest, South Central, and East Coast regions of North America experienced weather conditions known as a Polar Vortex in which extreme cold weather resulted in record high electrical demand in these areas. At the same time, the cold weather of the polar vortex increased the demand for natural gas which resulted in a significant amount of gas-fired generation being unavailable due to natural gas curtailments. This confluence of factors led to the exhaustion of all electric reserves, the calling for demand management tools, voltage reduction measures and in specific instances shedding of about 300 MW or 0.1% of total load in the Eastern Interconnection and in ERCOT[57]. Concurrently with loss of load events, record natural gas and electricity prices were reported during the first quarter of 2014.

This Polar Vortex event is an illustration of a common mode event: the system experienced a dramatic simultaneous loss of available generating capacity which would be poorly captured under the standard resource adequacy assessment methodology. Consider for example the loss of 16,000 MW of capacity in the ReliabilityFirst system on January 7, 2014 - 10,700 due to fuel supply interruptions with another 5,300 MW due to cold weather-related equipment failure.[58] The overall level of capacity outages at that time reached approximately 28,000 MW indicating that due to extreme weather conditions more than doubled from roughly 12,000 MW to 28,000 MW. Had all outages been independent events, such an increase in outage capacity for a system the size of ReliabilityFirst would be extremely improbable[59].

As witnessed by the polar vortex in 2014, the growing reliance of the bulk electric power system on gas-fired generation has increased the need to improve coordination between wholesale electricity and natural gas markets. The amount of natural gas used as fuel for power generation

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[57] NERC Polar Vortex Review, September 2014. https://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf

[58] Ibid, p. 9.

[59] Based on our estimate, this would represent 4.8 standard deviations above mean capacity on outage. The probability of such an event would be an order of magnitude of one chance in a million.

will significantly increase as coal fired and nuclear plants are replaced with gas-fired generating capacity . This is shown graphically in Figure 4-4, which presents US generation mix in 2009 and 2019. As shown in the figure, over the last decade, the natural gas use for electric generation in the US increased from 969 TWh (26%) to 1,461 TWh (41%).

In addition, the variability of electric generation from solar and wind increases the variability of pipeline deliveries to gas-fired generators used to balance the electric grid. The resulting intraday and sub-hourly swings in demand for natural gas as a fuel for electric generation pose reliability risks for both gas pipelines and electric systems and create new challenges for pipeline operators.

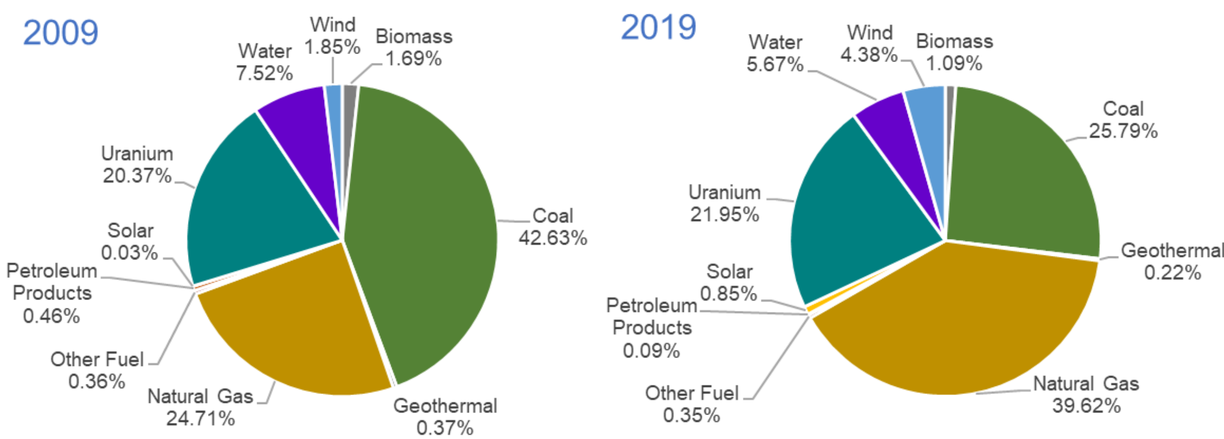

Figure 4-4
US Generation Mix in 2009 (left), natural gas: 969 TWh, CF 26% and in 2019 (right), natural gas: 1,461 TWh, CF 41%

(Source: S&P Global)

The electric power industry has recognized the importance of natural gas supply curtailment events. In 2011, NERC published a primer on gas-electric interdependency[60] addressing the issue. In 2012 ISO New England was taking steps to prepare for fuel shortages[61] as did other system operators and balancing authorities. However, as of today, fuel security assessment has not been integrated into the realm of resource adequacy evaluation, capacity markets design or integrated resource planning frameworks.

In a special report on the impact of the natural gas supply on power system reliability[62] published in 2017, NERC concluded that the impact of gas supply interruptions on electric system reliability depends on a variety of factors:

[60] NERC, "2011 Special Reliability Assessment: A Primer of the Natural Gas and Electric Power Interdependency in the United States," December 2011.

[61] ISO-NE, "Addressing Gas Dependence," July 2012. A White Paper by ISO New England and Strategic Planning Initiative.

[62] Special Reliability Assessment: Potential Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System. NERC. November 2017.

- Geographical location and overall infrastructure dynamic such as amount and distance from supply resources, the number and the size of generating facilities commonly served by the same pipeline system, and the resilience of the serving pipeline system itself.
- The interdependency of gas and electric networks: at the time of gas interruption due to delivery constraints, replacing supply of gas-dependent generators often becomes complicated due to electric transmission problems.
- Access to natural gas storage services, particularly to fast storage providing intra-day services.
- The type of transportation and dual fuel capability which provide the highest level of fuel supply reliability.
- The diversity of natural gas supplies (e.g., access to multiple pipelines) that improves power system reliability.

What has become increasingly acknowledged is that most natural gas supply interruptions are not caused by physical events (ruptures / leaks) but are operational. A recent analysis of natural gas fuel shortages in the US power sector, indicates that:[63]

- Natural gas pipeline failures account for a relatively minor fraction of fuel shortage power plant failures. Specifically, less than 9% of events and less than 5% of electric energy curtailed were due to pipeline failures.
- The majority of events of reduced or interrupted gas deliveries to power plants were due to operational or scheduling or market deficiency issues.
- Firm contracts are not a cure-all. Gas plants were affected by fuel shortages regardless of contract statuses.
- Fuel shortages affect peaking, shoulder and baseload units.
- At the time of fuel shortages experienced by power plants, relevant gas hubs were often under-utilized, and that gas could have been moved.

The need to better coordinate across electric and natural gas sectors to mitigate these risks is reflected in the FERC Orders 787 (2013) and 809 (2015).

In Order 787, FERC allowed for the voluntary sharing of non-public operating information between interstate pipelines, public utilities and electric transmission operators. For example, public utilities and system operators could ahead of time share planned fuel burn schedules of gas-fired generators with pipelines serving those generators.

In Order 809, the Commission adopted changes proposed by the North American Energy Safety Board (NAESB) that better align the timing of interstate pipeline nomination cycles with the timing of key decision cycles of electric system operation, introduce the new, third no-bump nomination cycle that give shipper another opportunity to adjust their nominations and to provide more certainty to interruptible transactions.

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[63] G.M. Freeman, J Apt, J. Moura, "What Causes Natural Gas Fuel Shortages at U.S. Power Plants?" *Energy Policy*, Vol. 147, December 2020.

While the industry recognizes the critical importance of gas-electric operational coordination issues for electric system reliability, conventional resource adequacy assessments fail to consider these issues. Prevailing analytic methods significantly understate the probability of simultaneous loss of multiple gas-fired generating units attributable to fuel supply interruptions.

Lack of attention to simultaneous events occurs for multiple reasons:

- To the best of our knowledge, statistical data reflecting correlated outages of gas-fired generators are not collected which significantly complicates modeling of such events.
- Known resource adequacy models have no logic for modeling correlated generator outages.
- Modeling / planning simulation studies of both the electric and gas sectors are conducted under the assumption that outages are independent events and, as a result, understate the probability of loss of load.

4.3 Cyber and Physical Security

A potential cyber-attack or combined cyber-physical attack on the power system represents a disruptive event with unique characteristics.

First, a cyber or cyber and physical attack on the power system could have large impacts. Robert Knake, former Director of Cybersecurity Policy for the National Security Council, has described a plausible scenario developed by Lloyd's of London that involves an attack on power generators in the Eastern Interconnection. Taking down only 10% of targeted generators, such an attack could, "cause a blackout covering fifteen states and the District of Columbia, leaving ninety-three million people without power… economic costs of $243 billion and a small rise in death rates as health and safety systems fail."[64] By contrast, the 2003 Northeast Blackout, which left 50 million people without power for four days, caused about $6 billion in losses.[65] Moreover, a successful cyber-physical attack on the power system could have significant geopolitical repercussions.

Second, cyber and physical attacks can occur with little or no warning. Some attackers may have an economic objective, as in the ransomware attack on a gas compression facility reported in February 2020.[66] Other attacks may coincide with external events and reflect motivations that utilities cannot readily observe. For example, the attack on PG&E's Metcalf substation occurred the night following the Boston Marathon bombing. State actors or sophisticated terrorist organizations could stage attacks to discredit the United States, distract attention from a diplomatic or military initiative that the U.S. would likely oppose, or retaliate for U.S. actions.

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[64] Knake, R. 2017. A Cyberattack on the U.S. Power Grid: Contingency Planning Memorandum, No. 31. Washington, D.C.: Council on Foreign Relations.

[65] The U.S. Department of Energy estimated costs of $6 billion, a figure that is near the $6.4 billion mid-range estimate prepared by Anderson Economic Group. For a summary of estimates of the blackout's costs, see: Electric Consumers Resource Council. 2004. The Economic Impacts of the August 2003 Blackout. Washington, D.C.: ELCON. (February 9, 2004).

[66] Cybersecurity & Infrastructure Security Agency. 2020. *Alert (AA20-049A) Ransomware Impacting Pipeline Operations.* Washington, D.C.: C&ISA (October 24, 2020).

The attacks on the Ukrainian power grid in 2015 and 2016, for example, appear designed to disrupt Ukrainian responses to Russian territorial intrusions.[67]

Third, the power system remains vulnerable to cyber and physical attack and has been a target of cyber-attacks by state sponsored operatives.[68] It is geographically dispersed, inherently open, interdependent with other systems, and its stability depends on maintaining balanced operations in real-time. As a result, there are additional attack vectors in electric power that are not found in IT systems and industrial control systems that lack comparable system stability requirements. A sophisticated attack could impact multiple systems, include cyber and physical elements, and be staged in waves with on-going impacts.

Fourth, oversight is divided among multiple federal, state, and local authorities. Assets that directly affect the bulk power system are subject to NERC Critical Infrastructure Protection (CIP) Reliability Standards approved by FERC. However, compliance with CIP standards does not ensure that the system is secure.[69] In a recent white paper, FERC Staff recognized the limitations of CIP standards:

> "While the CIP Reliability Standards form an effective technical baseline for cybersecurity practices, they have certain limitations. For instance, the Reliability Standards do not necessarily require entities to employ best practices. Moreover, the standards development process does not lend itself to addressing rapidly evolving cybersecurity threats. It can take many months for a new standard to be developed, and once approved, it may be several more months or years before fully implemented and enforceable. Since cybersecurity threats can adapt and spread quickly, attackers can use sophisticated methods to exploit the interdependency of connected networks and equipment and target facilities, some of which may not be covered under the standards."[70]

Some components of the power system remain subject to the regulatory oversight and operational authority of organizations with limited capabilities.[71] Smaller entities and individually less critical components may nonetheless open paths for adversaries to reach the critical systems.

While gaps remain, the power industry has made significant strides in improving cyber and physical security over the last fifteen years. These efforts have been reflected in and enhanced by

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[67] National Academies of Sciences, Engineering, and Medicine. 2017. Enhancing the Resilience of the Nation's Electricity System. Washington, DC: The National Academies Press.

[68] See, for example, reports of recent cyberattacks affecting U.S. power systems: https://www.nytimes.com/2020/10/23/us/politics/energetic-bear-russian-hackers.html.

[69] See: U.S. Government Accountability Office. 2019. Critical Infrastructure Protection: Actions Needed to Address Significant Cybersecurity Risks Facing the Electric Grid. Washington, D.C.: GAO. (August 2019); and Hayden, M., C. Hébert, and S. Tierney. 2014. Cybersecurity and the North American Electric Grid: New Policy Approaches to Address an Evolving Threat. Washington, D.C.: Bipartisan Policy Center.

[70] Federal Energy Regulatory Commission. 2020. *Cybersecurity Incentives Policy White Paper, A Staff Paper: Federal Energy Regulatory Commission Docket No. AD20-29-000.* Washington, D.C.: FERC. (June 2020). Hereafter: FERC Staff Cybersecurity Whitepaper 2020.

[71] Bailey, T., A. Maruyama, and D. Wallance. 2020. *The energy-sector threat: How to address cybersecurity vulnerabilities.* Washington, D.C.: McKinsey & Company.

the adoption of CIP standards for the bulk power system; formation of the Electricity Sector Coordinating Council (ESCC)[72] that provides executive level coordination on national level threats and incidents; development of the Electricity Information Sharing and Analysis Center (e-ISAC)[73] located at NERC that facilitates the sharing and analysis of threat information; application of the electricity Cybersecurity Capability Maturity Model (C2M2)[74]; evolution of the National Electric Sector Cybersecurity Organization Resource (NESCOR)[75] to become an organization within EPRI that supports development, specifies, and tests of security technologies, architectures, and applications; the National Institute of Standards and Technology's Guidelines for Smart Grid Cybersecurity,[76] Framework for Improving Critical Infrastructure Cybersecurity,[77] special publication on Cyber-Physical Systems and Internet of Things,[78] Cybersecurity Framework Smart Grid Profile;[79] and the Draft NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 4.0.[80]

The FERC proceeding to consider cybersecurity incentives may provide a further opportunity to encourage improvement and develop utility-specific metrics for evaluating progress. FERC Staff proposed two approaches for providing cybersecurity incentives. One would be based on a utility voluntarily applying certain CIP Reliability Standards to transmission facilities that are not subject to those requirements (e.g., applying all requirements applicable to medium or high impact systems to low impact systems). The second approach is based on a utility voluntarily implementing portions of the cybersecurity framework developed by the National Institute of Standards and Technology.[81] Comparing the two incentive approaches, the approach based on the NIST Framework may be more readily adaptable to changing circumstances and has advantages in that: 1) it is based on a detailed framework that can be tailored to specific utility circumstances; and 2) it can be extended beyond the bulk power system, as NIST has done in its

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[72] Electricity Subsector Coordinating Council, "ESCC Overview," 2021, https://www.electricitysubsector.org.

[73] "Electricity Information Sharing and Analysis Center" 2020, https://www.nerc.com/pa/CI/ESISAC/Pages/default.aspx.

[74] Department of Energy, "Cybersecurity Capability Maturity Model (C2M2)," February 2014, https://www.energy.gov/sites/prod/files/2014/03/f13/C2M2-v1-1_cor.pdf.

[75] EPRI Smart Grid Resource Center, "National Electric Sector Cybersecurity Organization Resource (NESCOR)," 2020, https://smartgrid.epri.com/NESCOR.aspx.

[76] National Institute of Standards and Technology. 2014. *Guidelines for Smart Grid Cybersecurity*, *NISTIR 7528.* Gaithersburg, MD: NIST.(September 2014).

[77] National Institute of Standards and Technology. 2018. *Framework for Improving Critical Infrastructure Cybersecurity.* Gaithersburg, MD: NIST. (April 16, 2018).

[78] National Institute of Standards and Technology. *Cyber-Physical Systems and Internet of Things. NIST Special Publication 1900-202.* Gaithersburg, MD: NIST. (March 2019).

[79] National Institute of Standards and Technology. 2019. *Cybersecurity Framework Smart Grid Profile, NIST Technical Note 2051.* Gaithersburg, MD: NIST. (July 2019).

[80] National Institute of Standards and Technology. 2020. *Draft NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 4.0.* Gaithersburg, MD: NIST. (July 2020).

[81] FERC Staff Cybersecurity Whitepaper 2020.

Cybersecurity Smart Grid Profile. NIST worked closely with the electric power industry in developing the framework, and it is in use by the industry.[82]

Incorporating cyber-physical security into a broader framework or set of metrics for resource adequacy will present challenges:

- The threat and technology landscapes constantly evolve, making it difficult to maintain meaningful standardized metrics.
- The risk – the probability of success and potential consequences – associated with each vulnerability and potential, deterred or thwarted attack may be difficult to assess. The security objective is that events do not affect system operations. Fortunately, we have limited data about successful attacks on which to base assessments.
- For known vulnerabilities and threats, organizations may face differing exposures, different potential consequences, and present different paths by which an event could propagate to the broader power system.
- In this domain, there are both known unknowns and unknown unknowns. For some risks, qualitative assessments may be the state of the art.
- The disclosure of a firm's security metrics itself might provide a roadmap to potential attackers and create a further security risk.
- There is not a standard approach for translating risk into justifications for mitigation. Major industry organizations commented in 2016: "There are currently many resources for improving cybersecurity but there is not a resource available to guide the process of balancing the value of risk mitigation with the risk impact for various stakeholders."[83]

These challenges will make it difficult to develop standard security metrics and allow public reporting on metric achievement. Nonetheless, individual power sector organizations need effective security metrics. The industry can provide an institutional mechanism for validating the appropriateness of each participating organization's metrics and its performance with respect to its security metrics. Such an institution also could become a resource and advocate for continuous improvement.

The 2014 Bipartisan Policy Center report proposed an innovative model for addressing these challenges combining the continuing development of cybersecurity standards with creation of industry led institution promoting enhanced security governance. The report states:

> "A particularly important recommendation concerns the establishment of a new industry-led body, comprising power sector participants across North America and modeled on the nuclear power industry's Institute of Nuclear Power Operations (INPO). Based on experience with INPO, we believe such an organization could substantially advance cybersecurity risk-management practices across the industry and, in doing so, serve as a valuable complement to existing NERC standards. …

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[82] American Public Power Association, Edison Electric Institute, Electric Power Supply Association, Large Public Power Council, National Rural Electric Cooperative Association, and Utilities Telecom Council. 2016. *Electric Power Industry Views on the Framework for Improving Critical Infrastructure Cybersecurity.* (February 23, 2016).

[83] *Ibid.*

> The electric power industry should establish an organization, similar to INPO, that would develop cybersecurity performance criteria and best practices for the entire industry. This new institute should include the full range of participants in the North American power sector, and it should engage in several activities, including (a) developing performance criteria and conducting detailed cybersecurity evaluations at individual facilities; (b) analyzing systemic risks, particularly on the distribution system; (c) analyzing cyber events as they occur and disseminating information about these events; (d) providing technical assistance, including assistance in the use of new cybersecurity tools; and (e) cybersecurity workforce training and accreditation."[84]

Such an organization would complement current institutions that promote information sharing. It could help provide credible evaluations of an organization's security profiles, support an industry wide culture of continuous improvement and adaptation to changing risks, and advance the development metrics that are meaningful in the context of specific utilities and threat environments.

[84] Hayden, M., C. Hébert, and S. Tierney. 2014. *Cybersecurity and the North American Electric Grid: New Policy Approaches to Address an Evolving Threat.* Washington, D.C.: Bipartisan Policy Center.

5
INVESTIGATE POSSIBLE METHODOLOGICAL ENHANCEMENTS INCLUDING FORECASTING

In this section, we suggest new metrics, tools, processes, and market mechanisms that can be used to measure and contribute to the achievement of resource adequacy and supply resilience in the face of high impact understated probability events. We will begin by reviewing metrics that have already been proposed or are in use today and discuss their applicability to the problem and challenges in implementation. Then, we will develop the conceptual framework and theoretical logic for resource adequacy and other supply planning metrics and changes in market design that may contribute to the provision of a resilient supply of electricity.

5.1 Resilience Metrics

To address disruptive common mode events that are not yet fully reflected in resource adequacy, the industry can build on the conceptual framework for developing resilience metrics. Resource adequacy may contribute to supply resilience, while a broader resilience framework considers how to absorb, manage, recover and learn from disruptive events. The NIAC resilience framework is shown in the diagram below.[85] This diagram was developed for general critical infrastructure, but provides a useful way to think about electric sector resilience, as was recognized by the National Academies report on enhancing electric system resilience.[86] Supply resilience is not simply a function of adding and hardening assets. Planning for high impact common mode events can be enhanced by identifying redundant systems, operating procedures that mitigate impacts during an event, contingency planning on how the system can recover, and incorporating lessons learned into revised plans and technology choices. Planners should consider all of the components of the framework in deciding how best to improve resilience and making related investments. In some instances, investment may target multiple components. For example, battery storage may be useful during the event and then after the event if it has black start capability to restart the system.

[85] National Infrastructure Advisory Council (NIAC). 2010. A Framework for Establishing Critical Infrastructure Resilience Goals: Final Report and Recommendations by the Council.

[86] National Academies of Sciences, Engineering, and Medicine 2017. Enhancing the Resilience of the Nation's Electricity System. Washington, DC: The National Academies Press.

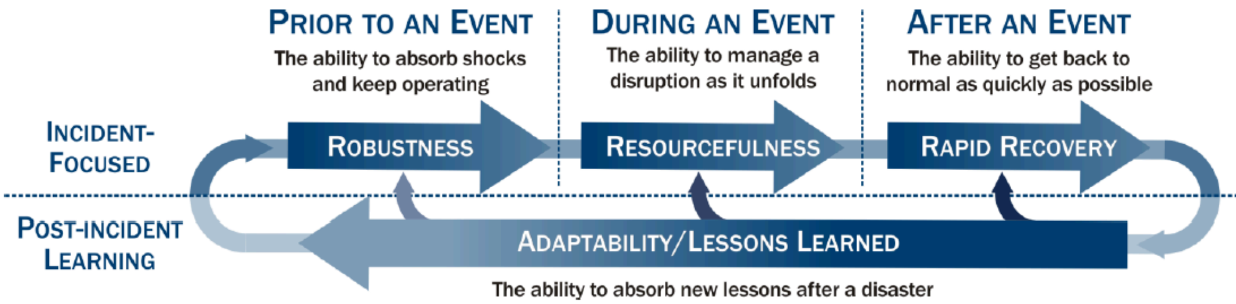

Figure 5-1
NIAC Resilience Construct

Resilience should be measured from the customer's perspective. Measurements may include both metrics of supply performance such as Expected Unserved Energy and economic consequences such as Value of Lost Load or modeling regional economic impacts.

EPRI has been working to develop a framework for evaluating both the physical and financial consequences of extended outages to determine how customers value resilience and monetize the resilience value of utility investments.[87] Such a framework could be used to measure the effectiveness and performance of investments to improve resilience and evaluate how the benefits of such investments can be compared to their costs. In pursuing the development of resilience metrics, EPRI has considered the conceptual approach to energy resilience metrics proposed by Sandia National Laboratories in response to Presidential Policy Directive 21 on *Critical Infrastructure Security and Resilience* (February 12, 2013). The Sandia report recommended a risk- based framework reflecting two fundamental concepts, that resilience is defined with respect to disturbance(s) or threat(s) and that consequences relate to social effects of system performance in addition to system performance itself. It proposed developing and deploying resilience metrics that can be represented as probability density functions of consequences that may result from one or more threats. A metric defined in this manner allows an analyst to understand expected consequences using its mean value, while also identifying the range of possible impacts.[88]

The development of a probabilistic estimation and economic valuation of the potential consequences for each of the disturbances and threats relevant to a particular electric system, including high impact common mode events, represents a fundamental shift from conventional resource adequacy that focuses on meeting an LOLE criterion. While the Sandia report includes illustrative examples, additional analysis is needed to identify relevant events and threats that can have a material impact on supply resilience in different regions, describe their physical

[87] Roark, J. 2018. “Evaluating Methods of Estimating the Cost of Long-Duration Power Outages,” *Frontier in the Economics of Widespread, Long-Duration Power Interruptions: Proceedings from an Expert Workshop.* P. Larsen, A. Sanstad, K. LaCommare, and J. Eto, Editors. Berkeley, CA: Lawrence Berkeley National Laboratory (January 2019); Ela, E., R. Entriken, R. Hytowitz, V. Singhvi, and E. Vittal. 2020. *Power System Supply Resilience: The Need for Definitions and Metrics in Decision-Making.* Palo Alto, CA: EPRI (August 2020).

[88] Watson, J-P, R Guttromsom, C Silva-Monroy, R Jeffers, K Jones, J Ellison, C Rath, J Gearhart, D Jones, T Corbett, C Hanley, and LT Walker. 2014. *Conceptual Framework for Developing Resilience Metric for the Electricity, Oil and Gas Sectors in the United States*. Albuquerque, NM: Sandia National Laboratories, SAND2014-18019.

consequences, assess data requirements and availability, and develop approaches for estimating probability distributions of physical impacts and economic costs for specific power systems.[89]

Differences in societal costs dictate that certain customers must have a higher level of service reliability. Hospitals, police and fire stations, and communication services need to receive priority in both the level of service they receive as well as the rapidity with which service is restore after interruption.

Even within the set of customers who would not be considered critical, there are customers who will value service restoration more than others. For example, during a moderate weather period, residences may place a lower value on electricity than certain industrial processes. Estimates of customers' value of unserved energy can be incorporated into measures of resilience. However, additional research could improve current estimates and evaluate how customer costs change during deep and / or extended service outages.

5.2 Methods for Valuing of Uninterrupted Service

Electricity supports essential services, including water, telecommunications, and transportation; the operations of businesses and industry; the lighting, heating, and cooling that enable modern living; our digital economy and a range of online and mobile applications. Yet, the value that different customers place on uninterrupted service is not consistently quantified by utilities or regulators. A lack of alignment between how customers value uninterrupted electric service and how utilities and regulators value resilience can have significant economic impacts. Understanding the costs that outages with different scopes and durations and occurring at different times impose on customers can help provide the basis for valuing supply resilience.

Determining the value of uninterrupted electric service requires estimating the cost of electric service outages for relevant customer segments. Historically, a variety of approaches have been used to estimate customer outage costs, each with its own set of pros and cons, including:

- **Proxy methods**: This approach uses an observable behavior to estimate the value of outage avoidance. For example, where a customer has purchased back-up generator, the cost of future avoided outages may be expected to equal or exceed the marginal cost of the backup power supply. The purchase of a backup generator would be evidence of "revealed preference" toward avoiding outages. However, proxy methods are available in only limited circumstances, offer little insight about consumer preferences among alternative approaches, and suggest only an upper or lower bound on outage costs.[90]
- **Consumer surplus**: These methods estimate the value of uninterrupted service based upon observations of price elasticity. They are based on an assumption that consumer responses to longer term changes in prices provides useful information on the value lost by a short-term interruption electricity service. These methods have the advantage that they are based on actual observed behavior. However, they have the drawback of relying on an assumed

[89] *Ibid.*

[90] Centolella et al., Estimates of the Value of Uninterrupted Service for the Midwest Independent System Operator Midwest Independent Transmission System Operator (April 2006). Hereafter: Centolella (2006).

correspondence between long- and short-term value estimates. The limited information provided by this approach has severely restricted its use in practice.[91]

- **Reliability demand models**: These models explicitly include the quality of service component. Because U.S. electric reliability levels have been uniformly high, these models have not been applied in the U.S. Their use has been limited only to studies for developing countries.[92]
- **Survey-based methods**: Survey-based methods have become the most widely used approach and are generally preferred over other measurement protocols because they can be used to obtain outage costs for a wide variety of reliability conditions not observable using other techniques.[93] Survey methodologies can be used to examine a wide range of possible conditions under which outages might occur by asking about outages occurring in different seasons, at different times of day, with varying interruption durations, with and without advance notice. In a typical survey, each customer respondent is presented with 3-8 scenarios and asked the costs they would incur for the specific conditions described in each scenario. Using this approach, it is possible to develop results that can be applied to a wide range of utility planning and regulatory policy questions.[94] Properly structured surveys can provide robust content validity in that the customer is in the best position to assess the impacts based upon their experience and requirements. An additional advantage of survey-based methods is that the use of "stratified" sampling can ensure that responses meet the desired precision criteria and are representative of the customer populations of interest and not just those customers who may have experienced a particular outage. Commercial and industrial customers typically are surveyed about the value of lost production, other outage related costs, and outage related savings, after taking into account their ability to make up for any lost production. These direct costs can be classified as fixed, flow and stock costs and modeled for different outage durations.[95] This is known as the "direct worth approach."[96] For residential customers, the vast majority of outage impacts are not directly observable economic costs. As a result, surveys usually inquire regarding residential customers' "willingness to pay" to avoid outages with specific characteristics and / or the amount of compensation they would require to be subject to a scenario involving an interruption of service (i.e., their "willingness to accept").[97]

The value of uninterrupted service can vary significantly both within and between customer classes. There also can be important differences by region, season, timing and duration of

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[91] These drawbacks include, for example, that a consumer's demand curve and the implied outage cost estimate are impacted by the advance warning that customers receive of a price change. See: Centolella (2006).

[92] Centolella (2006).

[93] Sullivan, Michael J. et al., "How to Estimate the Value of Service Reliability Improvements," Power and Energy Society General Meeting, July 25-29, 2010, available at http://certs.lbl.gov/pdf/lbnl-3529e.pdf.

[94] Sullivan, Michael and Schellenberg, "How to Assess the Economic Consequences of Smart Grid Reliability Investments," A Report for NARUC, November 2010.

[95] Ericson, S. and L. Lisell. 2018. "A flexible framework for modeling customer damage functions for power outages," *Energy Systems.* 11, 95-111 (2020).

[96] Industry practices are described in Electric Power Research Institute, *Outage Cost Estimation Handbook,* (December 1995).

[97] Ibid.

outages.[98] The range of differences in outage costs for different customers is illustrated in part by a widely cited Department of Energy report.[99] Consolidating outage cost estimates from twenty-eight customer value of service studies conducted by ten utilities over the 16-year period from 1989 to 2005, the study finds that the cost of an eight hour outage on a summer afternoon, in 2013 dollars, to be $17.10 for an average residential customer, $4,313 for an average small commercial and industrial customer, and $96,252 for an average large commercial and industrial customer. The duration of the outage impacts customer costs. An increase in outage duration from eight to sixteen hours nearly doubles estimated customer costs to $31.10 for an average residential customer, $7,737 for an average small commercial and industrial customer, and $186,983 for an average large commercial and industrial customer. For short service interruptions, an hour or less, most of the cost to consumers is associated with the initial interruption. An earlier version of this meta-analysis identified outage costs by industry with the cost of an eight hour outage ranging from $41,250 for an average agricultural customer, to $147,219 or average customers in finance, real estate and insurance, and up to $214,644 for an average customer in construction.[100] These are statistical estimates of average impacts. Costs to individual customers will vary.

This meta-analysis[101] provides the basis for the U.S. Department of Energy's Interruption Cost Estimate (ICE) calculator and Guidebook for estimating the cost of service interruptions.[102] These tools have been used by some utilities in reliability planning. However, there are important limitations to the data used to develop these estimates. Approximately half the data comes from surveys conducted prior to 2000. Our reliance on digital technologies and electronic control systems has increased significantly over the last twenty years. No underlying survey data was available from the northeast/mid-Atlantic region and only limited data was available for cities along the Great Lakes. And, importantly for evaluating the value of supply resilience, the study focused on the costs of relatively short power interruptions of up to 24 hours. In longer duration power interruptions, the nature of costs changes and indirect spillover impacts to the larger economy need to be considered.

Longer duration outages may be qualitatively different. Following a survey of valuation experts, Daniel Shawhan of Resources for the Future and Cornell University reports:

> "One principle that could differentiate long from short outages is when safety or sanitation is likely to start to be significantly affected, for reasons that may include extreme indoor temperatures, crime, thirst, food spoilage, and full toilets. These qualitative changes in circumstance matter most to households. For businesses, a power outage is likely to be costly from the start. But for most households, these

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[98] Centolella (2006).

[99] Sullivan, M., J. Schellenberg, and M. Blundell. 2015. *Updated Value of Service reliability for Electric Utility Customers in the United States.* Berkeley CA: Lawrence Berkeley National Laboratory. Hereafter: Sullivan *et. al*., 2015.

[100] Sullivan, M., M. Mercurio, and J. Schellenberg. 2009. *Estimated Value of Service reliability for Electric Utility Customers in the United States,* Berkeley, CA: Lawrence Berkeley National Laboratory.

[101] See: https://www.icecalculator.com/home; Sullivan *et. al*., 2015.

[102] Sullivan, M., M. Collins, J. Shellenberg, and P. Larson. 2018. *Estimating Power System Interruption Costs: A Guidebook for Electric Utilities.* Berkeley, CA: Lawrence Berkeley National Laboratory (July 2018).

> qualitative changes that take time to develop can make an outage much more costly. As a result, the pattern that business losses from a power outage dwarfs household losses, a common finding in estimates of the costs of short-term outages at least in the US, may be less pronounced in future studies of the costs of long-duration outages."[103]

In addition to the direct outage costs that directly impacted customers experience, in a longer duration interruption larger groups will incur indirect costs. Indirect costs occur because businesses and households experience economic losses from other companies, organizations, and institutions not having power. Indirect costs reflect both the loss of vital services and economic disruptions that propagate across firms and industries via market interactions.

Indirect costs include costs incurred by individuals and firms from the absence of public services such as water treatment and emergency services. Indirect costs also include economic disruptions:

- Lost production by firms that are dependent on those directly impacted for essential inputs.
- Reduced production by suppliers of impacted firms to the cancellation of orders.
- Reduced household income resulting from reduced hiring and layoffs and a reduction in dividends by directly affected firms, their customers, and suppliers.
- Decreased consumer spending associated with declines in household income.
- Decreased investment as a result of the lower revenue of firms directly affected, their customers and suppliers.
- Reduced economic activity due to increases in prices associated with a reduction in the availability of products and services.[104]

In longer term interruptions, costs are not limited to the customers within the directly affected utility service territory but may extend to a wider area through economic interdependencies.[105] Longer and deeper outages also may produce adaptations with individuals relocating and firms shifting production activities. Mitigation and post-event adaptation strategies may be able to mitigate a significant portion of the major economic impacts that might otherwise occur.[106] In these cases, the sum of costs to affected individuals and firms may differ from the costs incurred by an impacted geographic community.

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[103] Shawhan, D. 2019. "Using Stated Preferences to Estimate the Value of Avoiding Power Outages: A Commentary with Input from Six Continents," *Frontiers in the Economics of Widespread, Long-Duration Power Interruptions: Proceedings from an Expert Workshop.* P. Larsen, A. Sanstad, K. LaCommare, and J. Eto, Editors. Berkeley, CA: Lawrence Berkeley National Laboratory.

[104] Sue Wing, I. and A. Rose. 2018. *Economic consequence analysis of electric power infrastructure disruptions: an analytical general equilibrium approach.* Berkeley, CA: Lawrence Berkeley National Laboratory. Hereafter: Sue Wing and Rose 2018.

[105] Sullivan, M., M. Collins, J. Shellenberg, and P. Larson. 2018. *Estimating Power System Interruption Costs: A Guidebook for Electric Utilities.* Berkeley, CA: Lawrence Berkeley National Laboratory (July 2018).

[106] Rose, A., F. Oladosu, and S. Liao. 2007. "Business Interruption Impacts of a terrorist Attack on the Electric Power System of Los Angeles: Customer Resilience to a Total Blackout," *Risk Analysis*, 27(3); Sue Wing and Rose 2018.

EPRI and other researchers have been evaluating and further developing methods for valuing resilience and the impacts on long-duration outages.[107] EPRI has been evaluating the use of Discrete Choice Experiments (DCE) to gather information on customer preferences and macroeconomic modeling to assess the indirect costs to service interruptions.[108] DCE, which can provide respondents detailed choices, may offer a better elicitation method for establishing the cost of extended outages.[109] And, there are examples of its use.[110] However, there have been questions regarding the reliability of DCE results.[111] At this point, there is not an expert consensus on a preferred methodology for eliciting consumer preferences.[112] Direct outage costs for business customers is often based on surveys enumerating such costs. Macroeconomic modeling of indirect costs, "has appeal because it is consistent with the nature of severe events, the impacts are extensive and of long duration, and affect not just those directly impacted." However, this such modeling has extensive region-specific modeling requirements.[113] Additionally, macroeconomic models can estimate a variety of metrics including impacts on employment, personal income, and tax revenues. EPRI should continue to evaluate and as appropriate develop tools to support the application of these methodologies in valuing the economic impacts of long-duration outages.

5.3 Operational Physical Models of Natural Gas Pipeline Networks

As discussed in Section 4.2, natural gas supply interruptions represent extreme common mode events that significantly influence resource adequacy of many regional electrical systems in the United States. The common mode affecting generating facility is the common limitation of natural gas availability to a group of generating unit served by the same subsection of a

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[107] Maitra, A. and B. Neenan. 2017. *Measuring the Value of Electric System Resiliency: A Review of Outage Cost Surveys and Natural Disaster Impact Study Methods*. Palo Alto, CA: Electric Power Research Institute; Roark, J. 2019. "Evaluating Methods of Estimating the Customer Cost of Long-duration Power Outages," *Frontiers in the Economics of Widespread, Long-Duration Power Interruptions: Proceedings from an Expert Workshop.* P. Larsen, A. Sanstad, K. LaCommare, and J. Eto, Editors. Berkeley, CA: Lawrence Berkeley National Laboratory, Hereafter Roark 2019. See also other portions of: Larson, P., A. Sanstad, K. LaCommare, and J. Eto. 2019. *Frontiers in the Economics of Widespread, Long-Duration Power Interruptions: Proceedings from an Expert Workshop.* Lawrence Berkeley National Laboratory (January 2019).

[108] EPRI. 2017. *Measuring the Value of Electric System Resiliency: A Review of* Outage *Cost Surveys and Natural Disaster Impact Study Methods*. Palo Alto, CA: Electric Power Research Institute; Mills, E, and R. Jones. 2016. "An Insurance Perspective on U.S. Electric Grid Disruption Costs," *The Geneva Papers on Risk and Insurance – Issues and Practice,* Vol. 41, No. 4; Larson, P., A. Sanstad, K. LaCommare, and J. Eto. 2019. *Frontiers in the Economics of Widespread, Long-Duration Power Interruptions: Proceedings from an Expert Workshop.* Lawrence Berkeley National Laboratory (January 2019).

[109] Roark 2019.

[110] Ozbafli, A. & Jenkins, G. P., 2016. Estimating the willingness to pay for reliable electricity supply: A choice experiment study. *Energy Economics,* Volume 56, pp. 443-452.

[111] Weimar, M. "Discussion on 'Evaluating Methods of Estimating the Customer Cost of Long-duration Power Outages,' " *Frontiers in the Economics of Widespread, Long-Duration Power Interruptions: Proceedings from an Expert Workshop.* P. Larsen, A. Sanstad, K. LaCommare, and J. Eto, Editors. Berkeley, CA: Lawrence Berkeley National Laboratory; Rakotonarivo, O., M. Schaafsma, and N. Hockley. 2016. "A systematic review of the reliability and validity of discrete choice experiments in valuing non-market environmental goods," Journal of Environmental Management. 183:98-109.

[112] Sullivan et al. 2018.

[113] Roark 2019.

constrained pipeline network. The critical probabilistic driver affecting pipeline constraint is weather. The most typical effect of the weather on pipeline constraint is at coldest days in winter when electric generators compete for limiting pipeline capacity with other natural gas end uses, primarily for residential and commercial sector heating. However, a significant, growing and weather driven demand for pipeline capacity may occur in other seasons. Serving high summer electric loads by peaking plants or the need to support fast ramping of conventional generation replacing weather-driven renewable resources may bring the pipeline segment to the edge of its operational capability[114].

Furthermore, as mentioned in 4.2, most natural gas supply interruptions are not caused by physical events (ruptures / leaks) but are operational. In sum, to properly assess the effect of extreme common mode events on resource adequacy, it may be necessary to include in the assessment framework a suitable representation of operational interactions between gas and electric systems under probabilistically changing weather conditions.

To properly represent interactions between gas and electric systems, the physical model of the pipeline network should be capable of simulating the effect of the linepack, the dynamic relationship between the flow of compressible gas in pipes and gas pressure, and as functions of operation of compressor stations. These are known as *transient* models of pipeline operation. To address reliability problems, these models should be capable of not just simulating the system given pre-defined compressor settings but also of assessing the feasibility of natural gas deliveries required for reliable operations of served power plants. On a cold day, the underlying demand for gas supply to serve heating loads requires that some sections of the pipeline operate at the lower end of their pressure bound. Although that pressure may be sufficient to support a steady flow of gas to generating units, it may become insufficient for ramping needs of peaking and shoulder units resulting in fuel supply interruption at these times of need. The same problem may occur under normal weather in a system with a significant penetration of intermittent renewable resources. A weather driven drop in renewable output would create a sudden need for generator ramp. Even though gas turbine units are very flexible and have high ramping capability, concurrent ramping of multiple generating units served by the same pipeline segment could require pipeline support that is physically infeasible. The feasibility assessment would take into consideration engineering constraints, such as maximum and minimum pressure bounds for individual pipes and operating envelopes for compressors.

Feasibility assessment problems would require the use of *transient optimization* models[115]. Until very recently, transient optimization of real size pipeline networks was considered computationally intractable. New methods for solving these problems discovered at Los Alamos National Laboratory (LANL) are a game changer in this field, providing the capability for optimizing real size networks in a matter of minutes[116]. LANL developed Gas Reliability

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[114] INGAA, Interstate Natural Gas Pipeline Efficiency, 2010. https://www.ingaa.org/file.aspx?id=10929

[115] Finding a feasible solution is effectively an optimization problem in which the objective is to find a solution minimizing violations of feasibility constraints. If the solution with no violations is found, the problem is deemed feasible.

[116] A. Zlotnik, M. Chertkov, and S. Backhaus, "Optimal control of transient flow in natural gas networks," in 54th IEEE Conference on Decision and Control, Osaka, Japan, 2015, pp. 4563–4570.

Analysis Integrated Library (GRAIL)[117], an open-source software package for transient optimization, which could be used to assess feasibility.

5.4 Using Physical Models to Simulate Gas – Electric Interactions and the GECO Project

In this section, we provide a summary of the GECO project as a demonstration of the existing capability to model gas-electric interaction as operational decisions affecting two physical systems. That approach possibly with some modifications could be used to properly assess the impact of fuel shortages as extreme common mode events on resource adequacy of the electric system.

The majority of gas supply interruption events are attributed to operational issues rather than to physical failure in gas delivery infrastructure. While the physical system could be capable of accommodating fuel supply needs of generating units, market design and operational rules in place are preventing electric and pipeline operators from finding such a feasible regime.

Consider the schematics of gas-electric interactions shown in Figure 5-2 which depicts the distinct but inter-related decision processes followed by electric and natural gas networks in scheduling their operations. The schematics reflects the scope and timing of decision cycles per FERC Order 809.

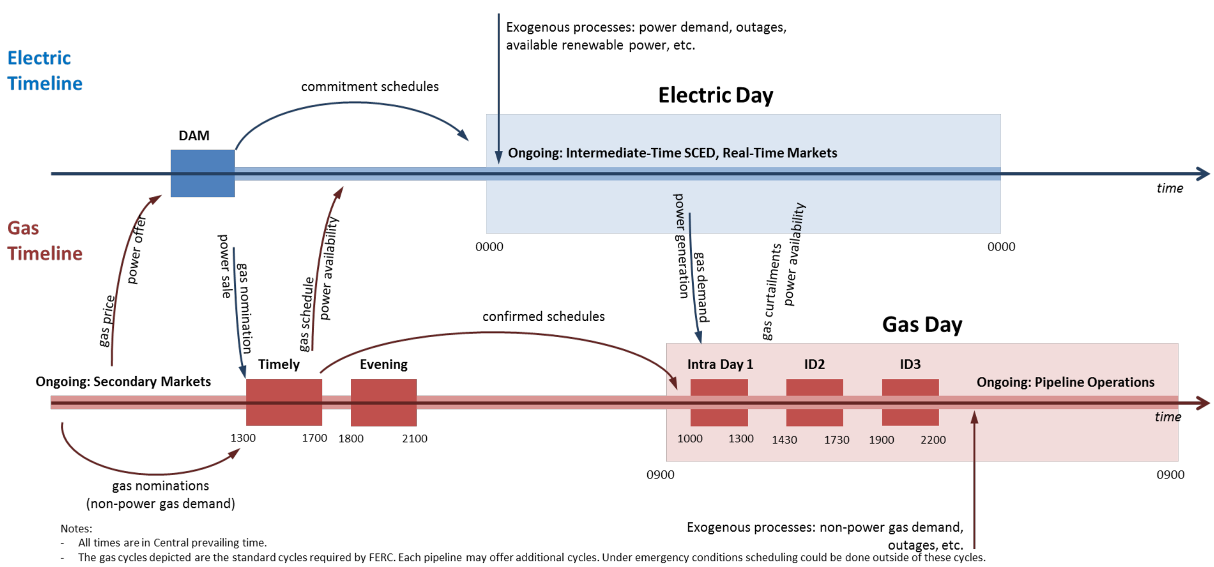

Figure 5-2
Schematics of Gas-Electric Interactions[118]

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[117] LANL, "Gas Reliability Analysis Integrated Library (GRAIL)," https://github.com/lanl-ansi/grail.

[118] A. Rudkevich, A. Zlotnik, P.Ruiz, E. Goldis, R.Tabors, R.Hornby, S. Backhaus, M. Caramanis, A. Beylin, R. Philbrick. "Market based Intraday Coordination of Electric and Natural Gas System Operation." Proceedings of the 51st Hawaii International Conference on System Science, Hawaii, January 2018.

In both the electric and natural gas markets there are a succession of highly intricate decision cycles. side. A gas-fired generating unit looking to operate the next electric market day (which begins at midnight) needs to submit an offer to the Day-Ahead market by 10:30 AM Eastern Time of the previous day The asset manager for the generating unit would already have lined up gas supply and delivery. The supply will be arranged at a bilaterally negotiated price at a pipeline receipt point. Shipment of gas from the receipt point to the delivery point on the pipeline would be arranged on a firm basis through the capacity release mechanism or on a non-firm, interruptible capacity basis. The result is a preliminary supply arrangements that includes gas prices. Although not backed up by a delivery guarantee, these prices inform electric generators in terms of their bides into the day-ahead (DA) electricity market. As is evident, this process exposes the transacting parties to a wide range of risks that could be avoided with improved market signals.

Post the DA market clearing and the financially binding operational schedule for electric generators is determined, the individual generators have only enough time to make delivery nominations with the pipeline for the next gas day. Daily deliveries quantities are essentially guaranteed under the condition that the nominations are confirmed in the Timely and/or Evening cycles on the gas side. Even if confirmed, the quantities needed by the generator may be different from those preliminary arrangements and the difference must then be settled between the parties.

When deliveries needed by the generator are not confirmed because of pipeline capacity limitations, generators face significant financial exposure because they are obligated to deliver power even though they have no gas to produce it. This financial exposure is from two factors: generators may need to acquire under-delivered power in the real-time market and also may be facing nonperformance penalties if the electric under-delivery occurs at the time of scarcity when physical reliability of the system is challenged. Even when the daily delivery quantity is confirmed, the pipeline typically expects that gas will be taken in equal quantities in each hour of the gas day (a ratable quantity). Generators respond to the quantities needed by the power system that are seldom equal every hour (are non-ratable) and as a result the pipelines may or may not be able to accommodate the flow requests.

Most fast-start combined cycle generators and gas turbine peaking facilities are not committed in the DA market with the result that these units are most often scheduled through the hourly reliability updates or close to the real-time market. These "last minute" decisions do not fit into the existing gas market decision cycles. For these generators, which are critical for maintaining reliability of the electric service and providing essential ancillary services, there is today no transparent mechanism on the gas side under which they can purchase gas and schedule delivery as needed. Operational problems on the pipeline may be caused by sudden ramps required by these generators. If these generators receive no gas, it will jeopardize the operational reliability of the electrical grid will be jeopardized while delivering the gas may jeopardize the reliability of the pipeline system.

Efforts today are focus on development of coordination mechanisms proposed to widen the scope of operational information exchanges between the two sectors as well as on readjusting the timing of exchanges[119]. While these measures are helpful, to achieve an significant improvement in efficient joint operations will require the timely exchange of both physical and pricing data, with price formation in both markets being fully consistent with the physics of energy flow.

The market design and modeling of gas-electric interactions have been the focus of the Gas – Electric Co-Optimization (GECO) Project funded by ARPA-E in 2016 – 2019[120]. The project objective was is to develop methods, model, algorithms and an associated market design for a dramatically improved coordination and / or co-optimization of wholesale natural gas and electric physical systems and economic markets on a day-ahead and intra-day basis. The outcome of that project was the development of modeling tools combined in the GECO Machine used as an engine in the GECO ENELYTIX cloud-based modeling environment. The GECO serves as a simulator of gas – electric interactions modeled as user-controlled decision cycles. On the electric side, GECO Machine used the Power Systems Optimizer (PSO) by Polaris Systems Optimization[121]. The Gas System Optimizer (GSO) is LANL's GRAIL adapted for the coordinated use with PSO. Coordination is managed by the *Kordinator* module developed by Newton Energy Group

GECO ENELYTIX was used to compare the status quo gas-electric coordination with the implementation of the intra-day Gas Balancing Market (GBM) designed to improve pipeline capacity utilization by combining transient optimization methods with the auction-based market mechanism for managing pipeline deliveries on an economic basis. The Gas Balancing Market (GBM) as proposed is a critical element for economically efficient gas-electric coordination. It provides for the timely exchange of both physical and pricing data between participants in each market, with price formation in both markets being fully consistent with the physics of energy flow. Physical data would be intra-day (e.g., hourly) gas schedules (burn and delivery). Pricing data would be bids and offers reflecting willingness to pay and to accept. Location-based gas prices would be obtained using optimization of transient pipeline flow models. Inputs to the pipeline optimization problem include prices that power plants are willing to pay for gas, as derived from nodal electricity prices that are produced by power system optimization. GBM would allow market participants to trade deviations from approved ratable schedules in the Timely and Evening Cycles.[122]

5.5 Incorporating Weather Scenarios into the Analysis of Gas – Electric Interactions

As mentioned earlier, weather dynamics represent the major driver behind the inter-dependency between fuel supply interruptions serving gas-fired generating units along with the demand for natural gas and demand for electricity net of variable generation. As we discuss in our recommendations, incorporating weather scenarios into probabilistic analysis is another essential

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[119] MITEI. (2013) Growing concerns, possible solutions: The interdependency of natural gas and electricity systems. [Online]. Available: http://mitei.mit.edu/publications/reports-studies/growing-concerns-possible-solutions

[120] Newton Energy Group, "Gas Electric Coordination," https://arpa-e.energy.gov/technologies/projects/gas-electric-co-optimization

[121] http://psopt.com

[122] A. Rudkevich, A. Zlotnik, P.Ruiz, E. Goldis, R.Tabors, R.Hornby, S. Backhaus, M. Caramanis, A. Beylin, R. Philbrick. "Market based Intraday Coordination of Electric and Natural Gas System Operation." Proceedings of the 51st Hawaii International Conference on System Science, Hawaii, January 2018.

component of resource adequacy assessment in general and specifically with respect to gas-electric interactions. Each spatially and temporally consistent weather scenario can be translated into a scenario for electricity demand, electric generation and non-electric natural gas demand, wind and solar resource availability and output, as well as transmission capabilities based on dynamic line ratings. When such a scenario is combined with a standard, non-weather-related scenario of generator outages, the gas-electric modeling system could evaluate a simultaneous capability of two systems to provide non-interrupted service to both gas and electric customers. By simulating a large number of weather/outage combinations, it will be possible to assess the reliability of the combined system.

5.6 Data Availability Issues

Reliability and production costing modeling of power systems is broadly used within the electric industry. Significant amounts of U.S. data on electric generating capacity, demand patterns, interchange flows, outages statistics are available in the public domain. Various organization develop ready-to-use modeling datasets and provide them to interested parties on a commercial basis.

Very little parallel data exists on the natural gas side. Topology of interstate pipelines could be obtained from FERC as Critical Energy Infrastructure Information (CEII) under FERC Form 567. However, such information is provided on a pipeline- by- pipeline basis with no standard electronic format[123] and presently no tools are available to digitize this information to make it usable for analytic and modeling purposes. Information on natural gas consumption is also lacking granularity in time and location. Data may exist within pipeline organizations on a pipeline-by-pipeline basis but is not publicly available. To the best of our knowledge, there are no pipeline industry analogs of GADS,[124] DADS[125] and TADS[126] programs maintained by NERC, that are publicly available and used in the electric industry in reliability, planning and operational studies. These are significant impediments to the development of robust modeling tools. Data problems could be solved but would require investment in data science methods and statistical analyses.

5.7 Potential Improvements in Extreme Weather Event Forecasting

The weather community has made steady, consistent progress towards improved forecast accuracy over the past decades. On average, forecast skill has improved 0.5% per year on an absolute basis (if skill for a defined timeframe and boundary is 70% today, skill will be 71% two years later). This skill improvement is driven by improvements across multiple dimensions:

1. Improved physics equations in numerical weather processing models, and greater implementation of ensemble modeling.

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[123] In contrast electric network topology is available in Siemens PSS/E format which is standardized and readable by most power flow applications and by text editors.

[124] NERC Generation Availability Data System (GADS). https://www.nerc.com/pa/RAPA/gads/Pages/GeneratingAvailabilityDataSystem-(GADS).aspx

[125] NERC Demand Response Availability Data System (DADS) https://www.nerc.com/pa/RAPA/dads/Pages/default.aspx

[126] NERC Transmission Availability Data System (TADS) https://www.nerc.com/pa/RAPA/tads/Pages/default.aspx

2. Greater computing horsepower as well as the advent of cloud computing and greater communications bandwidth.
3. A much broader set of physical and remote sensors (both airborne and ground/ocean based) that give us far denser, more accurate, and more real-time data sets to depict initial conditions that are the starting point for all numerical weather models.
4. Improved post-processing of model output using statistics.

Leveraging the above improvements, one of the most interesting evolutions is the transition from "determinative" weather forecasts (the high temperature today will be 78 degrees) to "probabilistic" forecasts (there is a 25% chance that the high temperature today will exceed 85 degrees). These probabilistic forecasts are intended to show a full range of potential weather outcomes (from the lowest possible forecast outcome to the highest). In more sophisticated implementations, one hundred weather system scenarios are created for each location wherein the weather forecasts for all variables under each scenario are internally consistent. In the energy industry, the obvious application is to run all one hundred scenarios through demand and supply (wind and solar) forecast systems to see the impact of each scenario on changes in anticipated energy demand and supply. This translation of probabilistic weather system forecasts into probabilistic energy demand and supply scenarios is especially important as the impact of weather on energy demand and supply is non-linear.

A critical if not the most critical impediment to improvement in forecasting of high impact events is a lack of basic data on the outage events themselves. The issue of insufficiency in outage data is not unique to extreme weather but is common to the availability of consistent outage data at the customer level. With the encouragement of the IEEE Distribution Reliability Working Group and research teams at Lawrence Berkley Laboratory, there has been a push to collect increasingly consistent reliability data from individual utilities.[127,128] This has led the Energy Information Agency in 2013 to adding a Reliability category for information in the *Annual Electric Power Industry Report*.[129]

While these efforts have moved forward, only with the subtraction of two files reporting System Average Interruption Frequency Index (SAIFI) information is it possible to arrive at a crude estimation of the impact of extreme events. The IEEE and the EIA report SAIFI that includes "Major Event Days (MED)" along with SAIFI that excludes MED. Netting the two results in a measure of MED that includes, and in all likelihood is dominated by the more significant, i.e., more widespread and often longer duration events. While it is possible to see trends in MED and imply the relationship to extreme events, the increase in occurrence of major events combined

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[127] See: "IEEE Benchmark Year 2020 Results for 2019 Data," 2020 Distribution Reliability Working Group Virtual Meeting, https://cmte.ieee.org/pes-drwg/wp-content/uploads/sites/61/2020-IEEE-DRWG-Benchmarking-Results.pdf

[128] Eto, Joseph; LaCommare, Kristina; Sohn, Michael; Caswell, Heidemarie, "Evaluating the Performance of the IEEE Standard 1366 Method for Identifying Major Event Days" in submission.

Joseph H. Eto, Kristina H. LaCommare, Heidemarie C. Caswell, David Till, "Distribution system versus bulk power system: identifying the source of electric service interruptions in the US," IET generation Transmission & Generation, February 2019.

Peter H. Larsen a, Megan Lawson, Kristina H. LaCommare, Joseph H. Eto, "Severe weather, utility spending, and the long-term reliability of the U.S. power system, Elsevier *ENERGY*, 2020.

[129] EIA-861 data file. https://www.eia.gov/electricity/data/eia861/

with the combinatorial reality of major events occurring concurrently creates a need for a new approach to collection of information on high impact events.

There are multiple implications for power systems planning for extreme events as a result of this evolution in the capabilities of the weather forecasting community. The first is that, for long term planning, there is an ability to forecast forward the growth in frequency, intensity and extent of extreme events – recognizing the need to plan for the increasing scale of impact in the future rather than for what has just occurred. For example, referring back to Figure 4-2, anyone using a ten- or thirty-year average to determine the frequency of billion- dollar events is going to be under-stating the probability of occurrence on a go-forward basis. Clearly, the most recent five years is dwarfing the frequency and $ impact of 2010-2014 or earlier decades. In addition, the rising trend in frequency and intensity suggests each ensuing five year time period will see higher frequency than the most recent five year period. The second is to continue to separate out the short-term response planning from the long term to incorporate the additional information that multiday, geographically detailed, probabilistic weather forecasting can provide.

Events that will have a major impact on electrical infrastructure are not random. With data tracking and statistical analysis these events and their severity can be seen as a spatial and temporal probability distribution. A standardization / classification of extreme events that includes the definition of the underlying weather information that creates the extreme event is needed to create the information that utility planners can used to develop strategies (investment and behavioral / market) that will improve the reliability and resilience of the power system.

As we discuss in section III above, extreme weather is generally defined as weather events that are unusual (10% outliers) compared to the climatological averages. The impacts of these events upon the electric power system differ in terms of the human cost and the physical infrastructure costs. Weather events are or should be classed as extreme based on their type, intensity, and duration for a given location.

5.8 Probabilistic Analysis of Near Real Time Economic Value of Resource Adequacy

The Department of Energy ARPA-E program has established and funded a program entitled PERFORM that will develop a range of alternative approaches to handling the uncertainty in short term operational planning. One of those projects, Stochastic Nodal Adequacy Pricing (SNAP) was initiated in late September of 2020 by Tabors Caramanis Rudkevich.[130] Focused on the use of stochastic weather data, SNAP will develop the modeling capability to economically

[130] See description listed here: https://arpa-e.energy.gov/technologies/projects/stochastic-nodal-adequacy-platform-snap and presentation at the 2020 FERC Technical Conference *Increasing Real-Time and Day-Ahead Market Efficiency and Enhancing Resilience through Improved Software* https://www.ferc.gov/sites/default/files/2020-06/W1-4_Tabors_et_al.pdf.

While not directly related to resource adequacy, EPRI is also part of a PERFORM award led by NREL titled, "An Integrated Paradigm for the Management of Delivery Risk in Electricity Markets: From Batteries to Insurance and Beyond." The work is focused on delivery risk in operational time frames through development of DER risk scores and a flexibility auction. https://arpa-e.energy.gov/technologies/projects/integrated-paradigm-management-delivery-risk-electricity-markets-batteries value the resource adequacy contribution of renewable and fossil generation and transmission, and price that adequacy nodally against VOLL. SNAP provides the probabilistically weighted value to resource adequacy for each resource, the value to consumers at each node of resource adequacy and the contribution of the transmission system to the provision of resource adequacy.

6
KEY RECOMMENDATIONS

The objective of Section 6 is to build upon the prior discussion and conclusions to develop a set of recommendations, a roadmap for enhancing resource adequacy with extreme events including further data development and detailed analyses and methodological development to improve the understanding of and planning for response to high impact events in both the long and short term. These recommendations are divided into those associated with weather, events associated with fuel security – specifically interruptions in the supply of natural gas, improving capacity value calculations, and using new techniques for resource planning that account for high impact common mode events.

1. **Develop scenarios by region of high impact common mode events (both more and less likely events), and estimate the probability distributions of the scenarios' physical impacts and associated economic costs.**

As part of the project, build a catalog of external events that have a sufficiently high cost and probability to merit consideration for regional scenarios in terms of resource planning; this should include events with moderately high cost and high probability of occurrence as well as events with a high potential cost and somewhat lower probability. The type of events, their cost, and their probabilities will vary by region. For example, wildfires deserve the most consideration in the West, while natural gas disruptions incur the highest impact in New England. Scenarios that are deemed to be significant would be prioritized for further analysis.

2. **Coordinate the development of regional Value of Loss Load (VOLL) studies, including updating and extending available estimates of customer outage costs, estimating the distribution of outage costs in different customer groups and addressing how outage costs may change during widespread and/or long-duration outages.**

In addition, support the development of regional models for estimating the economic impacts of long-duration outages. This initiative should address gaps in the regional coverage of recent outage cost studies, consider the specific types of widespread and long-duration events that may be relevant in each region, and enable estimates of the indirect economic impacts of extended service interruptions. EPRI should seek to standardize study methodologies and support the use of best practices.

3. **Model the gas-electric interactions that occur over natural gas and electric physical infrastructures to incorporate the effects of natural gas supply interruption on power system resource adequacy.**

The modeling framework would combine an operational physical model of natural gas pipeline network with a physical model of electric network typically used in production costing planning studies. That model would be capable of explicitly simulating the effects of common mode failures such as loss of pressure on the availability of gas fleet and utilize this information in resource adequacy assessment.

The framework would incorporate a probabilistic weather – driven model of regional spatially distributed natural gas and electricity demand and availability of variable wind and solar generation.

The model of the gas pipeline network would evaluate physical availability of natural gas delivery to serve electric generation. The model of the electric network would assess the adequacy of the power system subject to gas availability determined by pipeline physics and by the gas – electric interaction dynamics.

A substantial effort should be placed on the development of regional gas – electric modeling datasets with particular emphasis on overcoming challenges associated with collecting pipeline data. A New England region would be a good starting point for this effort for two reasons:

- New England pipeline network is constrained, and natural gas availability is a real problem in that system and therefore the model would be useful for electric and natural gas system planners.
- Digitizing pipeline topology serving New England could be accomplished with a relatively modest effort.

4. Develop a classification system of disruptive weather events that includes intensity, geographic scope, and duration that is directly targeted for use by the U.S. electricity market.

While certain types of storms (e.g., landfalling tropical cyclones) could use a single set of thresholds across the nation for measuring severity (e.g., the Beaufort scale), this proposed classification system would consider regional variations where relevant (e.g., the National Weather Service uses a regional storm impact index to accommodate the fact that six inches of snow in Buffalo causes less impact than six inches of snow in Atlanta). Geographic scope (how much population or how many square miles are impacted) would be considered, as would the duration of the weather event. These weather events would be directly correlated to outage data measured by number of customers with interrupted service, and total outage minutes for each event. Once these data are collected and analyzed, explicit weather scenarios by region will be defined with thresholds for high impact disruptive weather events defined by weather type. Ideally, this project would be conducted in collaboration with NERC and EIA.

5. Develop the concept of Value of Load at Risk (VLAR) for the electric utility industry that would be the analogue of Value at Risk in finance in order to provide a probabilistic dollar value for unserved energy.

This would address the shortfalls in ELCC, specifically the need for performance metrics surrounding reliability and resilience that measure unserved energy and the economic impacts that result. Whether focused on resource adequacy or more narrowly on responses to high impact events that disrupt the supply of power, the challenge is the development of a universally applicable metric or set of metrics that reflect the frequency, duration and depth of potential outages, the probability of different outage states, and the resulting economic costs to customers and society given the portfolio of generation assets and responsive loads available to utility planners.

The development of VLAR will need to build on the mathematics and modeling of the financial services industry. It will extend VAR with an objective to focus on the performance of an electric asset portfolio as opposed to the return from financial instruments. The goal will be to develop an economic metric that reflects the stochastic / probabilistic nature of VLAR.

6. **Develop resource planning models that use stochastic mathematical programming which would allow us to incorporate extreme events directly into the optimization. The stochastic framework will provide important insights into how to develop resilient resource plans.**

Since many externally driven high impact events do not happen often, planning cannot be done assuming that such an event will happen with a high frequency. These events would be represented by “states of the world” that have low probability weights. An optimal solution would take into account the possibility of a high cost events and hedge them within the resource plan.

The stochastic model’s objective function would be the minimization of the present value of the sum of expected capital cost, operating and maintenance cost, fuel cost, and unserved energy cost or for widespread long-duration events expected macroeconomic impacts. Unserved energy costs represent customers’ willingness to pay for energy and could be specified as several steps reflecting different customer classes. In an optimal solution, the unserved energy component should be modest in most states of the world. In states that represent extreme events, however, unserved energy costs (or macroeconomic impacts) could be high.

With today's capability to do parallel computation in a cloud environment, solving what would have been an infeasibly large problem a few years ago is now straightforward.

The model’s reporting function should record detailed results for all states of the world in a database. It would then be possible to investigate how the optimal solution performed in each state of the world. The reporting function should also summarize (and produce distributions for) high-level results such as production cost, unserved energy, unserved energy cost, carbon and other emissions across state of the world. This will facilitate further analysis of states of the world that had a high impact on the optimal resource plan.

The model and its reporting function could also be utilized to perform scenario analysis. If a resource plan was proved as an input (rather than determined by the model), the model’s state-of-the-world subproblems would calculate key parameters for the input system for future years.

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