Considering Generator Cycling in Resource Adequacy

2018 Technical Update

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Technical Update, January 2019

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THE ELECTRIC POWER RESEARCH INSTITUTE (EPRI) PREPARED THIS REPORT.

This is an EPRI Technical Update report. A Technical Update report is intended as an informal report of continuing research, a meeting, or a topical study. It is not a final EPRI technical report.

NOTE

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The Electric Power Research Institute (EPRI) prepared this report.

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ABSTRACT

In resource adequacy assessments, generator availability is represented using each generator's forced outage rate (FOR). FOR is known to change as a function of how a resource is operated (for example, base load vs. cycling). The purpose of this work is to initially identify whether changing FORs has any material effect on resource adequacy based on the following: a reasonable expectation of the level of variance between potential FORs for generators in the future and rates based on the persistence of historical FORs.Two case studies were conducted using realistic system information to assess a change in FORs for the set of generators most likely to be affected by increased variability and uncertainty. Outcomes from both cases indicated a level of impact that was not greater than existing uncertainties associated with demand or renewable penetration but was still material to the outcome.

The results from this report indicate that assumptions around generator FOR values are material to the outcome of resource adequacy analysis. Additional work is needed in this area to better identify useful assumptions around generator FOR in such studies. The report describes a number of considerations that may be taken into account when carrying out such studies.

Keywords

Generator cycling
Capacity adequacy
Generator
Availability
Reliability
Renewable generation

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EXECUTIVE SUMMARY

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Product Title: Considering Generator Cycling in Resource Adequacy: 2018 Technical Update

PRIMARY AUDIENCE: Bulk system planners, reliability coordinators

SECONDARY AUDIENCE: Regulatory bodies

KEY RESEARCH QUESTION

In resource adequacy assessments, generator availability is represented using each generator's forced outage rate (FOR). FOR is known to change as a function of how a resource is operated (for example, base load vs. cycling). The goal of this project is to determine the:

- Level of materiality that generator reliability parameters have for the outcome of capacity adequacy studies
- Potential scope for under-representation of generator availability by persisting with the approach of estimating generator reliability parameters for future studies based on past performance

RESEARCH OVERVIEW

The purpose of this work is to initially identify whether changing FORs has any material effect on resource adequacy based on the comparison of the persistence of historical FORs into the future against change case where operational impacts are reflected on future FORs. This is demonstrated through two case studies described in Section 3, with background on the analysis methods to be used in Section 2. Based on the outcome of the case studies, recommendations are made in Section 4 as to follow-on actions for both practitioners and researchers.

KEY FINDINGS

- The generator operational profile affects the availability of that resource when considered in resource adequacy calculations.
- In a first case study system with peak load under 7 GW, the effect of incremental FORs for a selection of units that are likely to engage in increased ramping resulted in a 254 MW change in the peak net load case that could be met at the same reliability as the base case. This outcome indicates the potential for the FOR assumption to be material to the outcome of the assessment.
- In a second case study system, the test for materiality was repeated by examining incremental FORs of gas plants more than 18 years old that are likely to experience increased ramping in the future. This outcome showed a difference in peak net load that could be met at the planning standard of 843 MW in a system with a demand peak of 70–80 GW.
- The tests indicated a potential material impact of FOR assumptions on the outcome of the studies. A further detailed review is needed of practices and methods to better estimate and include generator availability in resource adequacy assessments as operational variability and uncertainty increases.

EXECUTIVE SUMMARY

WHY THIS MATTERS

Resource adequacy calculations are often mandated by regulators to determine whether a system has sufficient capacity to meet its needs. Insufficient capacity is often the trigger for investment in resources or retention of aging resources. This report challenges the conventional assumption that historical FORs are sufficiently accurate estimators of future FORs. This assumption may not be appropriate as net load profiles change.

HOW TO APPLY RESULTS

The results from this report indicate that assumptions around generator FOR values are material to the outcome of resource adequacy analysis. Additional work is needed in this area to better identify useful assumptions around the generator FOR in such studies. Section 4 discusses a number of considerations that may be taken into account when carrying out such studies.

LEARNING AND ENGAGEMENT OPPORTUNITIES

- This report was produced through EPRI's Bulk System Integration of Renewables project on flexibility and resource adequacy.
- Several related reports have been released in tandem with this report, the results of which will presented at a January 2019 webcast and in person at the 2019 Transmission Operations and Planning Task Force Meetings, held April 30 – May 1 in Charlotte, North Carolina, USA (contact elannoye@epri.com).

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PROGRAM: 173 Bulk System Integration of Renewables

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CONTENTS

LIST OF FIGURES

LIST OF TABLES

1
INTRODUCTION

Problem Statement

Conventional generators' reliability is known to decrease when additional starts and ramping are carried out by that resource. This has an impact on assumptions for future reliability of those resources in resource adequacy studies which drive capacity markets, resource adequacy proceedings in long term planning and capacity margin notices in operations planning. This task is seeking to determine whether:

- The level of materiality that generator reliability parameters have for the outcome of capacity adequacy studies
- The potential scope for under-representation of generator availability by persisting the approach of estimating generator reliability parameters for future studies based on past performance.

Background

Planning authorities and reliability coordinators conduct assessments of the capacity adequacy of a power system. In specific, this measures the likelihood that a system will have sufficient capacity available from generators to meet the anticipated demand. This can occur on a season ahead [1] to years ahead studies [2] of a given region, under multiple scenarios of consumers' demand or production from hydro and renewable generation. Systems or regions are typically planned to maintain or exceed a capacity adequacy standard, historically equivalent to the expectation of having insufficient generation capacity for one peak load interval out of every peak daily load interval in ten years or a loss of load expectation (LOLE) of 1 day in 10 years.

These studies model the availability of a generator in one of several ways described later. Generator models are populated with probabilities associated with the likelihood that a generator is likely to fail or recover, or to be in a given state. Generation outages are recorded through a North American Electric Reliability Cooperation (NERC) mandated Generating Availability Data System (GADS) [3]. This system enables sufficient historically observed data to be collected to estimate the probabilities of generation availability for a specific class of plant (e.g. F-Frame combined cycle gas turbine).

Low probabilities of generation outage increase how much capacity is typically available, improving capacity adequacy metrics such as the aforementioned LOLE or Expected Unserved Energy (EUE[1]). Conventional generation plant typically exhibit high reliability with availability ranging between 90 and 98% on average for most classes of thermal generation. Maintenance is typically scheduled for the off-peak months of the year so as to avoid the peak stress periods.

Generators are typically ascribed a capacity value which is a measure of the additional demand that a system could serve with the same reliability when it is added to a system. This is also

[1] This can also be called the Expected Energy Not Served (EENS) or the Loss of Energy Expectation (LOEE).

called the Expected Load Carrying Capability of a generator. For example, if a system with a peak load of 6 GW has a starting LOLE of 0.1 days per year, and a 100 MW gas turbine is added with high availability, the new system may be able to meet a demand profile with a peak load of 6.09 GW with similar reliability. This capacity value can be determined through a variety of alternative ways such as by comparison with the addition of perfectly reliable (Equivalent Firm Capacity) or benchmark alternative resources (Equivalent Gas Turbine).

Increased Variability & Uncertainty

When subtracted from a demand profile, the output from variable renewable energy (VRE) such as wind and solar changes the variability and uncertainty associated with net load profile. The net load profile sets the trajectory that dispatchable plant (potentially including the same VRE resources) adjust their operating profile to. The net load profile emerging in many systems at present and in the near future has increased variability associated with it, compared to the demand profile. One metric to measure that change in profile variability is the mileage metric which is the absolute value of the sum of interval to interval changes in the demand / net load level. Figure 1-1 demonstrates this concept stylistically on an example profile, also contrasting with the approach of measuring variability through simple changes in the load level as ramps.

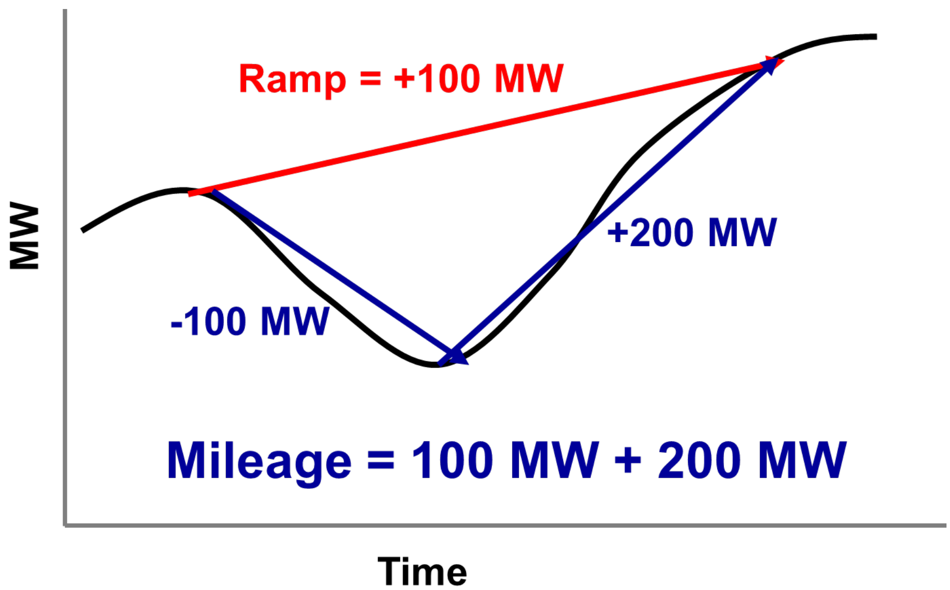


Figure 1-1
Example of a mileage calculation as compared to simple ramp estimation

In Figure 1-2 and Figure 1-3, example mileage calculations are shown for systems with in Europe and the US for both demand (green) and net load profiles (red). Demand values are further to the right on the horizontal axis due to the higher energy requirements, and the mileage is higher for the net load profiles due to the impact of VRE. In some cases, the impact of renewables has a relatively benign impact on mileage (e.g. Denmark, MISO) despite relatively high penetrations of VRE, and in other cases it is more substantial, (e.g. UK and ERCOT).

Even in the case of relatively unchanged levels of mileage as VRE penetration increases, the net load energy served decreases. This in turn means that conventional generators online are at lower average output levels, and as VRE penetration increases, the number of conventional generators online on average also decreases. Several further studies have shown the increase in generator starts and cycling from online to offline and back, or from max to min and back as the penetration of VRE increases.

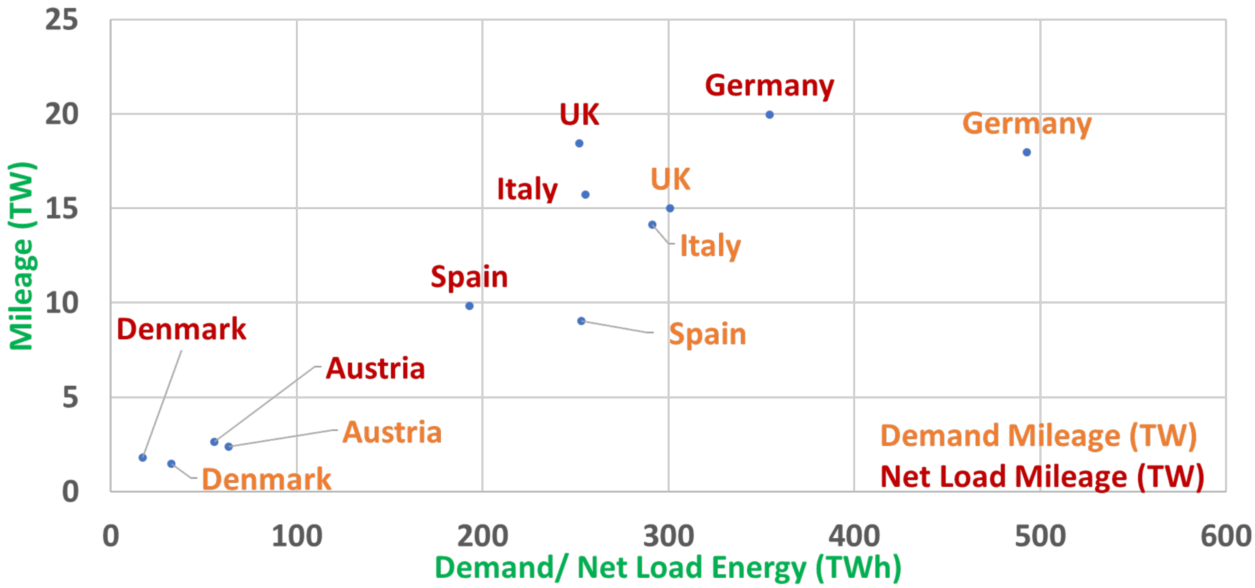


Figure 1-2
Changes in demand and net load mileage for European systems (TW), as a function of demand and net load served (TWh) in 2017. Data source: transparency.entsoe.eu

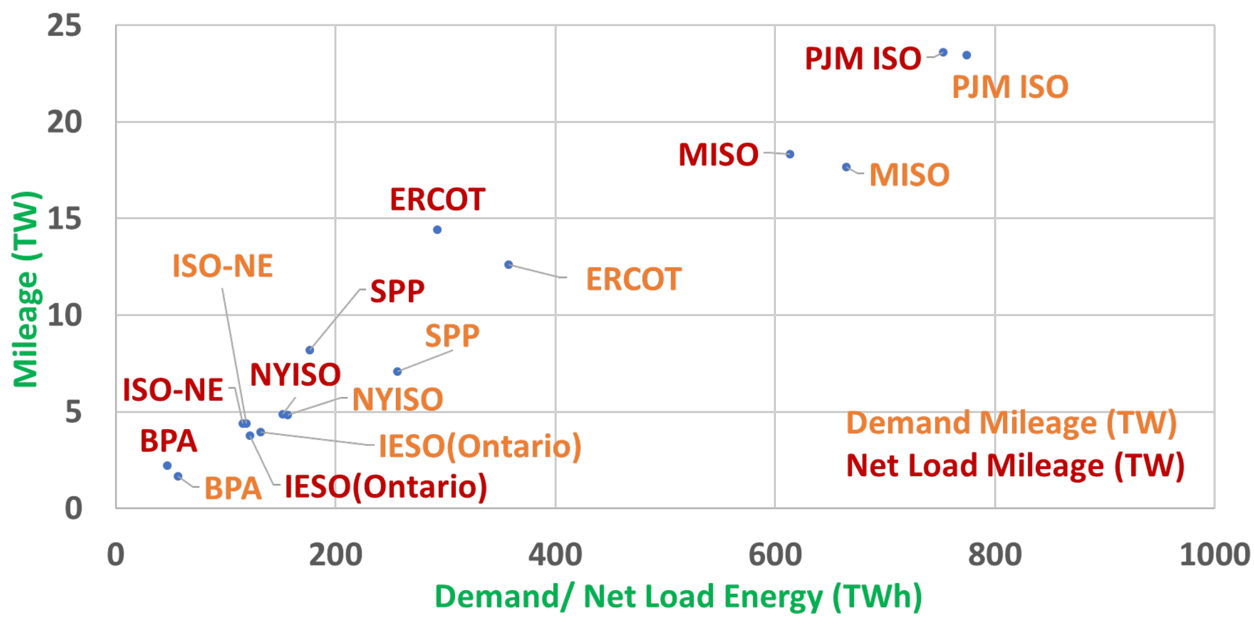


Figure 1-3
Changes in annual demand and net load mileage for US systems (TW) as a function of demand and net load serves (TWh) in 2017. Data source: ABB Ventyx Velocity Suite, FERC Form 714 Filings

Taking the example of the German system, by dispatching conventional generation according to the net load profile rather than the demand profile, resources alter their output by an additional 2 TW while serving 70% less energy demand. If the effect of the management of variability was concentrated on a set of generators, this results in the shift of over 2 GW of generation from being based loaded on average to cycling offline to online each day. In practice, this shift affects a wider range of generating resources

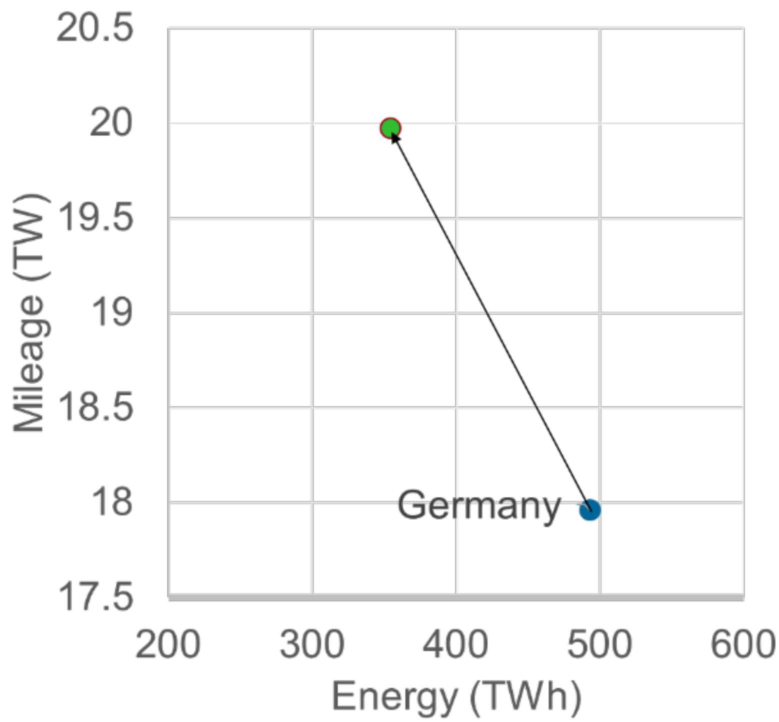


Figure 1-4
2017 German Mileage and Energy for Demand (Blue) and Net Load (Orange)

Cycling and Reliability

Analysis of historical generation availability data indicates a relationship between the mode in which a generator is operated, its age and its reliability. As conventional generators start more often the reliability of those generators typically decreases from that of a base-loaded unit. Furthermore, generators also exhibit a U-shaped relationship between the age of a generator and its forced outage rate (i.e. less reliable at the start and end of life, most reliable in the middle). These relationships are further explored in the next chapter. Given the fact that generator reliability is known to change as a function of age and operational mode, coupled with the fact that generator mileage is increasing for each resource, a question arises as to how these facts are represented in practice.

Significance of Issue

Assumptions around generator reliability affect several key parts of long-term planning for power systems. Most obviously, the representation of each generator's availability in capacity adequacy assessments directly affects the determination of whether a system meets an established resource adequacy criterion. In some systems with capacity margins that are close to the criterion, this may influence the decision to invest in new resources or to adjust plans for the retirement of generators.

Furthermore, generation capacity adequacy is coupled with flexibility assessment and transmission adequacy.

Scope of this Work

The purpose of this work is to initially identify whether changing forced outage rates based on a reasonable expectation of the level of variance between potential forced outage rates for generators in future and those used based on persistence of historical forced outage rates has any material effect on resource adequacy. This is demonstrated through two case studies in Chapter 3, with background on the analysis methods to be used in Chapter 2. Based on the outcome of the case studies, recommendations are made in Chapter 4 as to required follow on actions for both practitioners and research.

2
OPERATIONS FEEDBACK INTO PLANNING

Capacity Adequacy Studies

Purpose of Studies

Capacity adequacy studies hold varying degrees of importance in each system but are broadly applied to give a view as to whether a system has sufficient generation to meet expected demand levels in future years. In certain cases a statutory requirement is enforced to ensure capacity adequacy and in other cases the outcomes of the analyses are for more informational purposes.

The decisions influenced by the outcome of capacity adequacy studies include clearing of capacity markets where they are present, strategic capacity reserve procurement, creation of programs to leverage demand response or other new technologies as capacity resources, generation retirement and investment.

Modeling Uncertainties

Through the course of long-term system planning, engineers must consider a wide range of uncertainties which affect the process of determining needs for new generation, or the risks associated with capacity retirements. These uncertainties have different effects in terms of magnitude and profile of risk. These include:

Demand

Demand projections in terms of growth or decline as well as the profile (daily, seasonal) of consumer’s potential demand will change. This is affected by a variety of factors including economic, device adoption and climate. Increasingly, price sensitivity of demand plays a larger role in affecting the demand for capacity, indicating that the demand for energy will be dependent on the cost of producing power at that time, such as participation in demand response programs. Uncertainty around demand is a significant factor which needs to be addressed in capacity adequacy assessment.

Renewables

The capacity and production from wind and solar power is a significant and increasingly critical factor in resource adequacy assessments. This includes both utility scale and residential scale renewables. This requires forecasting of the capacity of technology installed in the study horizon which may be affected by policy or increasingly, customer supply preferences. Furthermore, the production from the installed renewables is dependent on climate conditions which has inter-annual and seasonal variations and is correlated with demand due to the same underlying drivers being present.

Hydro Power

Similar to renewable capacity, hydro generation presents a large uncertainty for capacity adequacy assessment given the variability in annual hydrological inflows. System planners in hydro rich system have considerable experience with analysis of such annual variation. However, use of hydropower is changing as the net load profile evolves to integrate the impact of renewables. As this occurs assessment of available energy may change but capacity to mitigate short duration peak conditions may be less affected for most systems where hydro is not the dominant feature of the generation mix.

Generation availability

The next uncertainty is related to whether generators are unavailable due to planned or forced outages of the generating equipment. This is the uncertainty typically addressed by assessing the availability of generators taking into account their historical or projected failure rates. Modeling of this uncertainty is the focus of this report and is discussed in the next section.

Fuel availability

In certain systems, the availability of fuels for generators is an uncertainty that is studied as part of the capacity adequacy process. In winter peaking systems with substantial gas generation and end consumer gas fired heating, planners may study uncertainties related to the availability of gas from pipeline or storage facilities as well as the availability of fuel switching to secondary options such as distillate.

Measurement Approaches

Given the long history with the application of capacity adequacy studies around the world, several approaches have been developed to measure the capacity adequacy of a system. While the essence of comparing the availability of generating capacity to the expected demand is preserved among all of the approaches, there are slight differences between the methods and metrics calculated. The methods typically follow two camps: a Closed Form and Simulation Based Form.

Closed Form

In this approach a distribution of the available generating capacity at given time. This distribution is formed for a given region based on the availability models for each resource. These models reflect the probability of the resource changing between operational availability states. Typically, two states are considered: available and unavailable, as shown in Figure 2-1, but other configurations are possible (Figure 2-2).

In this approach, the probability of the resource's capacity being available or unavailable can be determined to build the model. Rather than calculation of failure or repair rates (i.e. transitions from one state to another), direct estimation of the time spent in the state is carried out. This gives a probability of being in the available or unavailable state. The forced outage rate commonly referred to is typically the probability of being in the unavailable state rather than a *rate* in the strictest sense of events per unit of time. Several derivative versions of the forced outage rate (FOR) are found across industry and mandated for reporting in GADS, including the Equivalent Forced Outage Rate (EFOR) which includes time spent partially de-rated, or the Equivalent Demand Forced Outage Rate (EFORd) which indicates the probability of being unavailable when a resource could have otherwise been needed for demand [4]. These are based on definitions for reliability metrics set out in IEEE Standard 762 - 2006 [5].

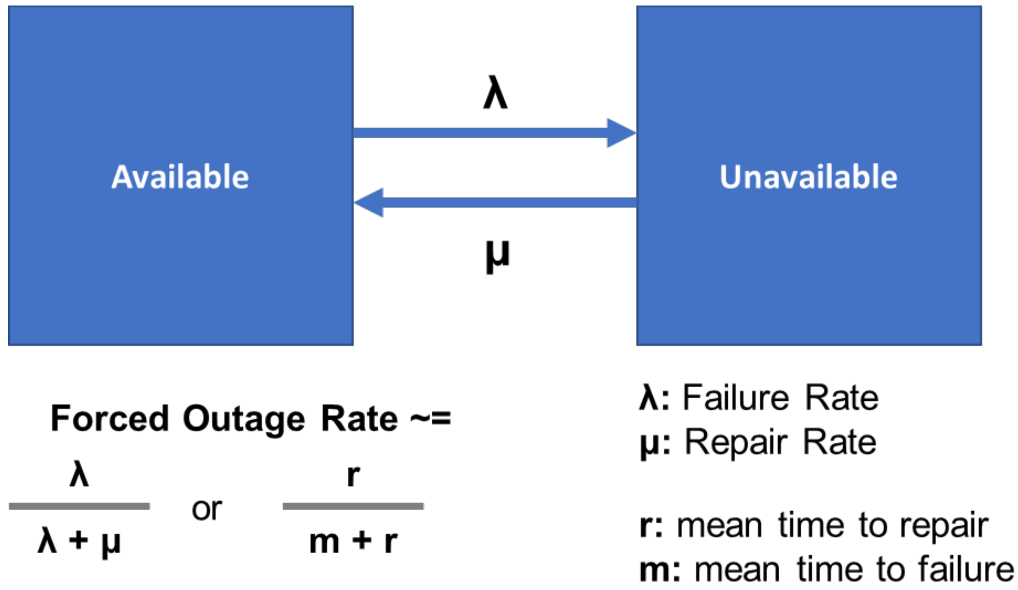


Figure 2-1
Two state generator model used in capacity adequacy assessments

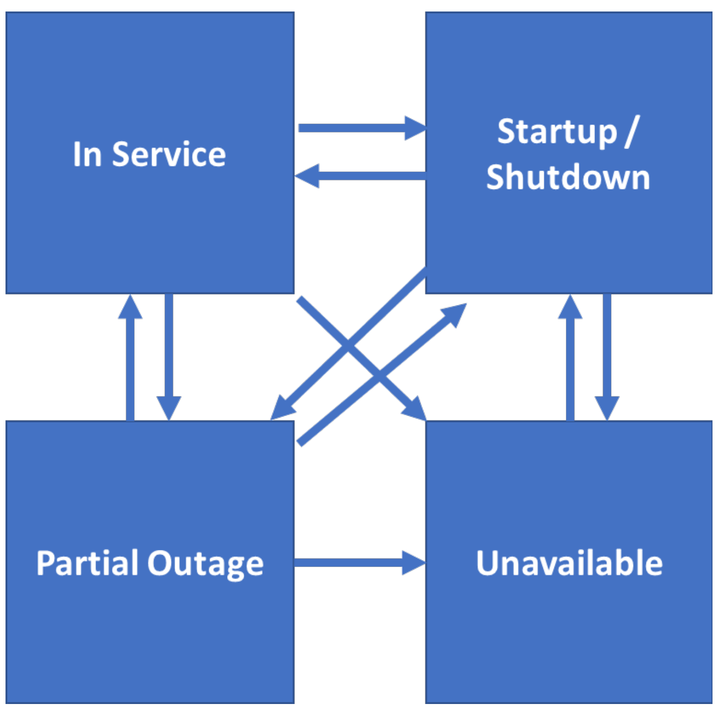


Figure 2-2
Multi-state generator availability model example

For most purposes, the two state model with estimations of the probability of being in each state has been justified for the demand profile, given two key assumptions holding:

1. Times of peak risk of having insufficient capacity are predictable to the point that planned or maintenance outages resulting in partial derating are moved away from the peak periods and will not affect the risk calculation

2. The risk of generator startup failure is not sufficiently large to give rise to concerns about capacity shortfalls during morning load pickup ramps.

There are anecdotal examples of periods when capacity risk emerged due to one of those two conditions not holding were experienced in short consecutive events in PJM. The first is the temperature sensitivity of demand leading to demand forecast errors arising. This can occur during the shoulder months in spring and fall when generation and transmission assets in many systems takes a planned outage. In the first case in PJM in September 2013, a heatwave giving rise to higher than normal demand, coupled with asset outages led to high price events and some load shedding [6]. Furthermore, during the Polar Vortex event affecting the eastern seaboard of the US in January 2014 substantial generation unavailability existed for a variety of reasons, including failure at start up [7].

Following this method, two state distributions for each generator are determined as follows:

State	Capacity	Probability
0	0	EFORd
1	Rated Capacity	1-EFORd

These models are then convolved together consecutively to form the probability distribution function and cumulative distribution function of available capacity in a system. These distributions are shown for a test system in Figure 2-3. This function is used to calculate whether there is at least a given amount of capacity online at each time which can be used to determine reliability metrics.

Simulation Based Method

In the simulation-based method multiple implementations are possible. In the simplest form, sequential draws of generator capacity are generated using Monte Carlo simulation and resource failure and repair rates. By simulating the state of generators over a sufficiently long period, this approach is shown to converge on the closed form approach using the available capacity distribution.

These methods can be further extended to consider factors beyond the availability of generation or transmission. Further elaboration of these methods is possible and often exploited. One version of this is to combine planned outage schedules with Monte Carlo generated forced outage draws and then to economically dispatch the generation resources according to the net load time series.

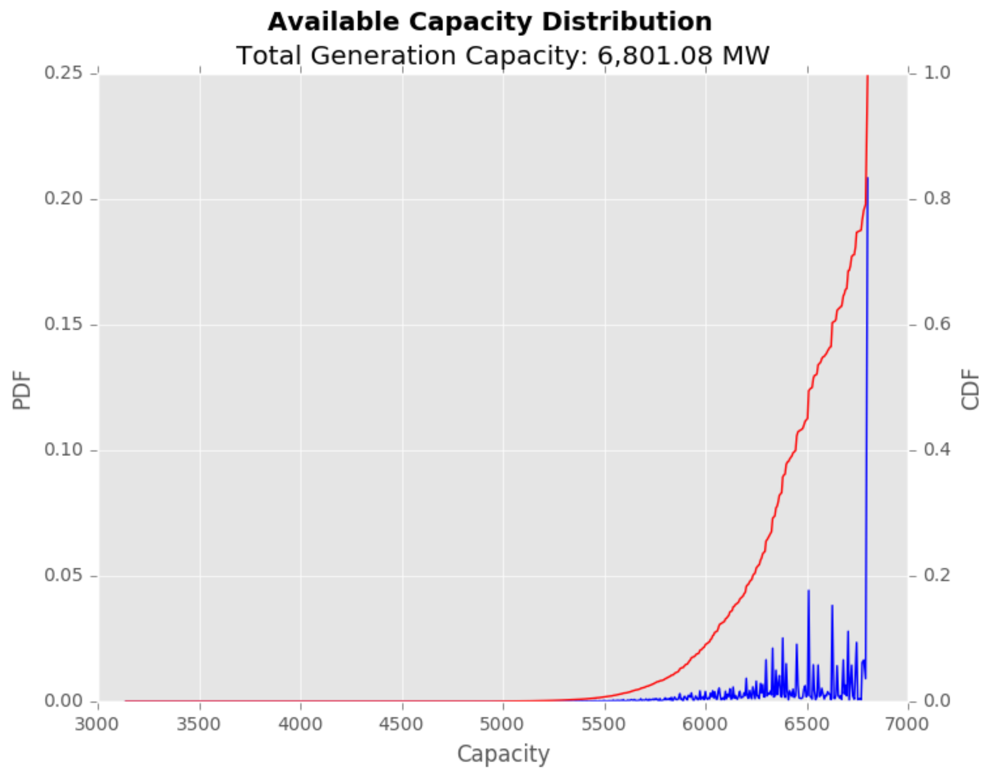


Figure 2-3
Probability Density Function (PDF) and Cumulative Density Function (CDF) of available capacity for test system with peak net load ~6GW

Limitations to Each Approach

The closed form and simulation form each have their own benefits and drawbacks. Three of the main drawbacks the closed form methods over the simulation-based methods are the relative increase difficulty in analyzing discrete events and the reliance on accurate estimation of EFORd (EFOR adjusted for periods when the resource is in demand).

Closed form methods build the probability distribution based on an estimation of resources' availability during periods of demand for that resource. Without dispatching the system this is typically estimated based on historical operational profiles for the resource. However, as demand profiles change and variability and uncertainty increase, that estimation of operational need changes in a way not necessarily related to the merit order position of the resource given inter-temporal or energy limited constraints which increasingly affect the dispatch of generation in systems with growing variability and uncertainty.

Figure 2-4 demonstrates how the closed form approach (denoted *must-run* in the figure's legend) compares with the simulation approach (denoted *economic commitment* in the same legend). In this example, the EFORd were estimated based on the operation of resources at a planning reserve margin of 20% and persisted across the studies at other reserve margins. Due to the varying coincidence between the capacity shortage risk periods at different reserve margins and the closed form EFORd estimation of the LOLE diverges from the simulation based assessment which uses constant estimations of the probability of failure.

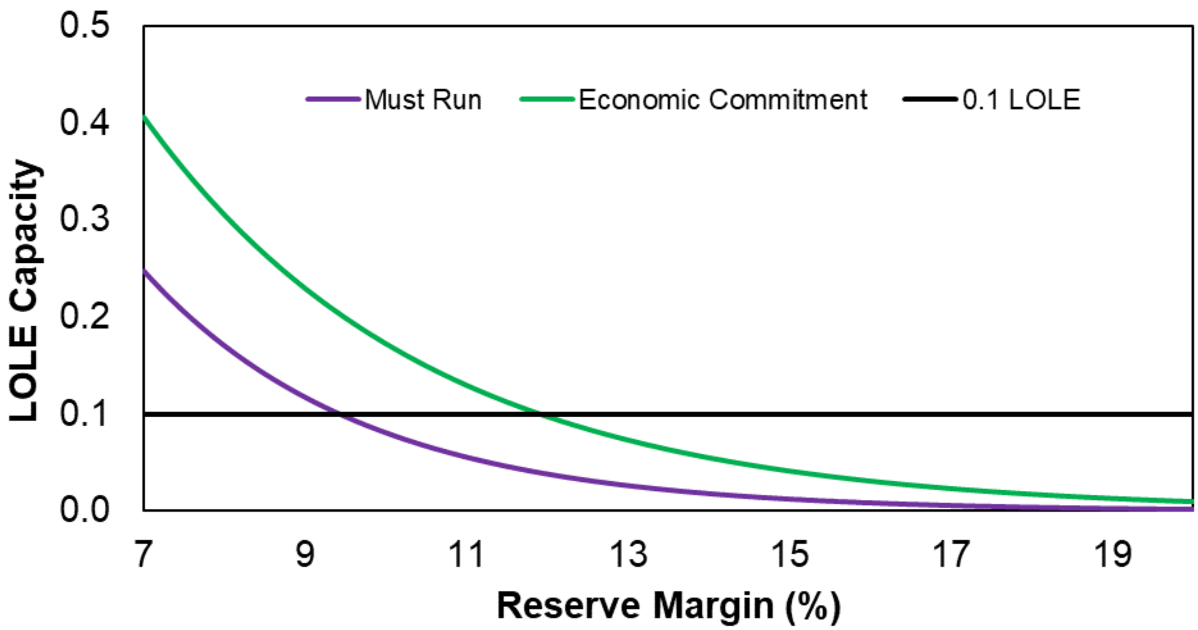


Figure 2-4
Comparison of LOLE evaluated using economic commitment simulation approach and closed form approach denoted "must run" at different planning reserve margin levels for test case. Source: Astrape Consulting

The second area drawback is related to the operational constraints of units and the discrete and inter-temporal constraints governing their operation. For resources such as battery energy storage, fuel limited conventional generation or demand response, the maximum export capacity from those resources is not uniform across the year and may be a function of their operational profile. Simulation models can reflect these constraints, the changing available capacity and establish operational states which are associated with various failure modes (e.g. startup failure) which is possible, but to a less accurate degree with the closed form methods coupled with the estimation of operational states.

Metrics

Several metrics are calculated according to either method however the simulation-based method is better able to capture discrete capacity shortage events as compared to the closed form approach. However most of the commonly used metrics can be calculated by both approaches.

Loss of Load Expectation – LOLE

The loss of load expectation is the expected number of periods over a defined horizon that the system is likely to have insufficient capacity. This is typically given as daily peak load hours per year (1 day in 10 years). The loss of load expectation is usually calculated based on an assessment of the probability of the loss of load at each daily peak load period over a course of a year's time series or longer.

Loss of Load Hours – LOLH

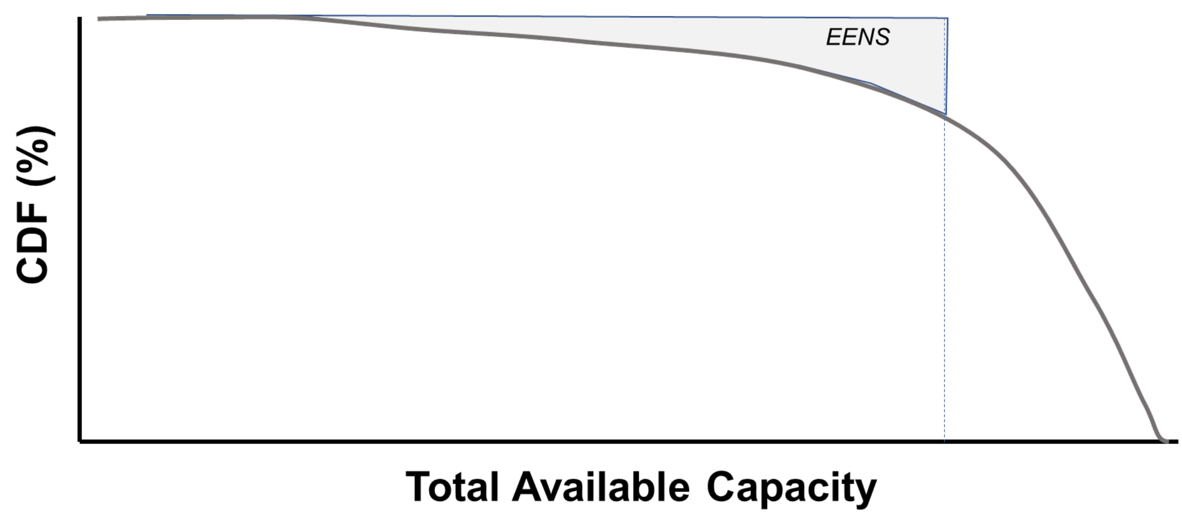
The loss of load hours is the expected number of hours per year when a system is likely to have insufficient capacity. This is typically given as an hours per year value (usually 2.4 hours per year or similar). The LOLH is the expected value of the probability of loss of load measured in each hour over a time period of a year or longer.

Loss of Load Events – LOLEv

The loss of load events is the expected number of loss of load events per year. A loss of load event can be defined in different ways but are typically discrete consecutive periods when a system has insufficient capacity. Since this is a discrete calculation, this is better suited to simulation-based assessment methods, but calculation with closed form methods are also possible with the addition of heuristics to denote capacity shortage events (e.g. number of consecutive hours when LOLP is greater than a threshold value).

Expected Unserved Energy – EUE

This is the expected amount of energy that cannot be served due to inadequate capacity being present in the system at each interval across a year. This is more readily estimated with simulation based methods, but it is possible to estimate EENS using the closed form methods. EENS is the preferred method in some systems as the basis for justifying investments as the frequency related metrics such as LOLE do not capture the magnitude of the risk of a capacity shortfall [8].



How Does Cycling Change Generators' Availability?

EPRI conducted a review of generator outages reported in the NERC generator availability data system (GADS) in 2018 to understand the impact of operational behavior on the reliability of a conventional generating resource. While it can be reasonably expected that increased starting and stopping of a resource, as well as ramping of resource's production level between minimum and maximum generation may give rise to wear and tear, this can result in two material effects on resource availability: the need for some combination of maintenance and / or increased unavailability of a generator through forced outage. The latter effect was the target of the GADS analysis.

The results of the analysis of availability data from 1980 to 217 for US coal plants showed that as the number of starts per year increased, so too did the unit's EFOR, for units of almost all age brackets (Figure 2-5). Units built in the last 15 years, and the last 5 in particular, experienced this effect to a lesser extent. This may be due to a combination of improved materials and processes as well as fewer cumulative starts having been accumulated over the lifetime of the unit.

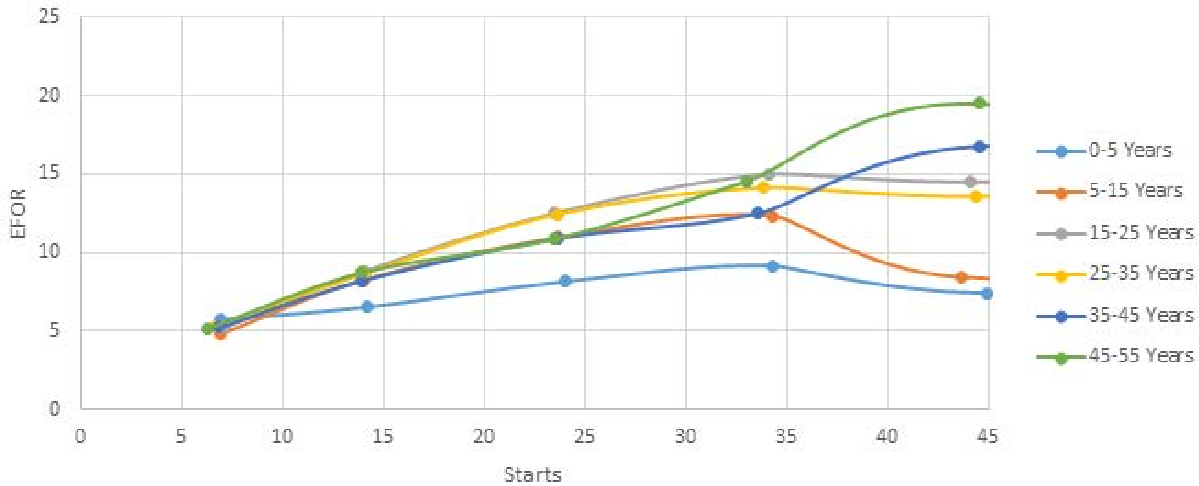


Figure 2-5
Average EFOR by number of annual starts and age bracket of coal plants in the US. Based on data from NERC GADS 1980-2017

The majority of the almost 90 GW of US supercritical coal plant fleet were built before 1980 (Figure 2-6) with a similar trend for subcritical plants (mostly before 1990) giving an age profile greater than 35 years for most cases. While these units are nearing retirement age, they continue to play a significant role in the provision of capacity to the grid.

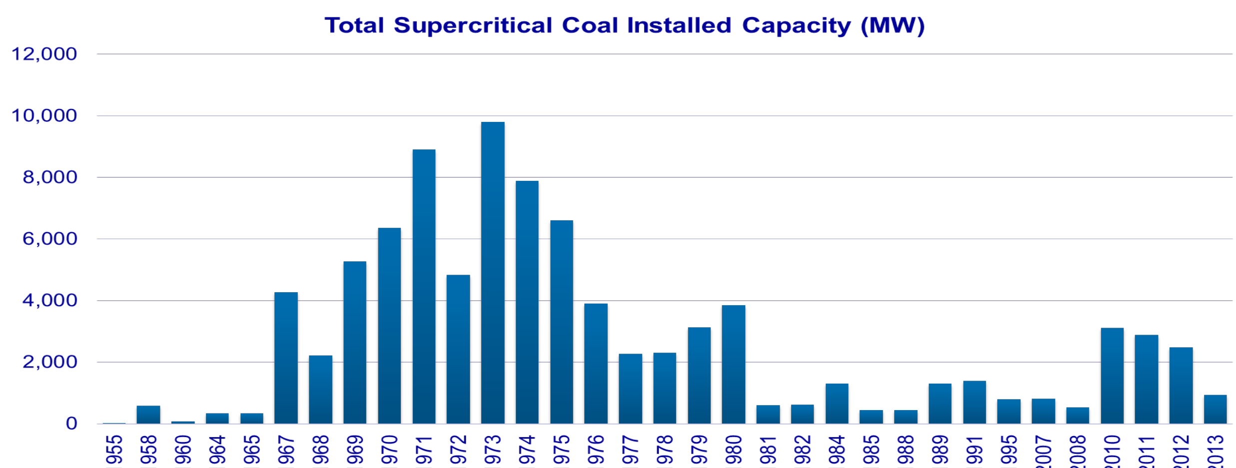


Figure 2-6
Age profile of US supercritical coal plants. Source: EIA

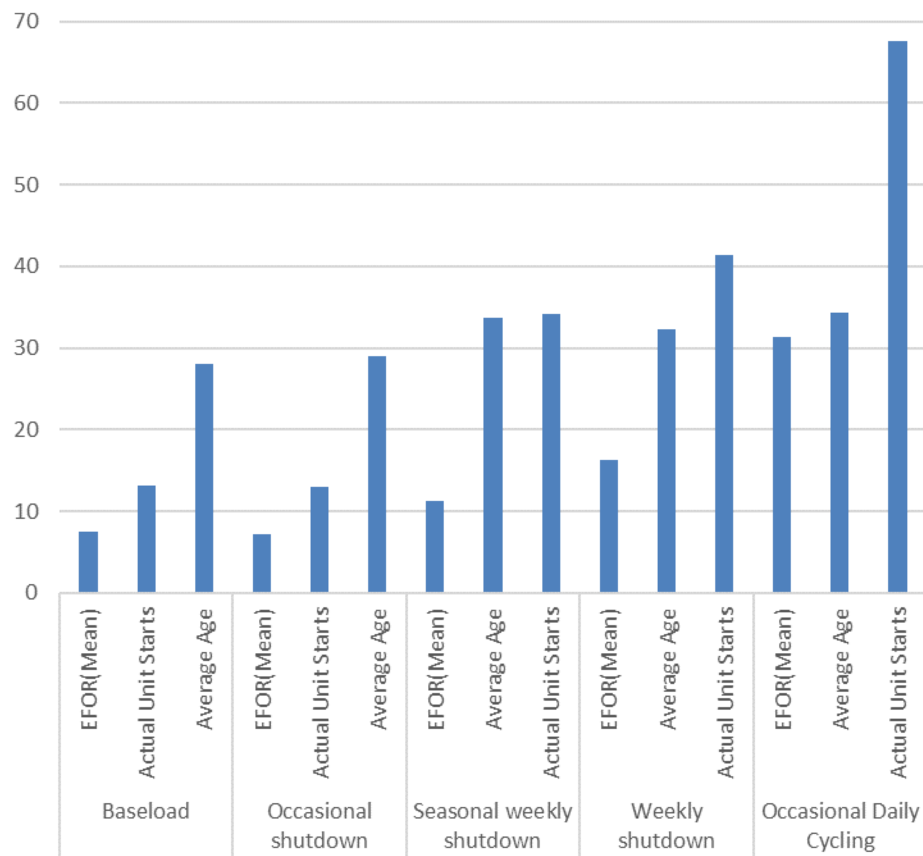


Figure 2-7
Average Age, Annual Starts and EFOR for forced circulation boiler units by operational profile. Data source: NERC GADS

Looking at the coal fleet with forced convection boilers, and the differing operational modes they operate in, a substantial difference between the EFOR can be seen between units operating in a primarily baseloaded operational mode and those which cycle more frequently. Units that operate with extended shutdown, such as seasonal weekly shutdowns, have an average age of just under 34 years, similar to the weekly shutdown group that has an average age just under 33 years. However, the latter group completes 6 extra starts on average but has an EFOR 5% higher than the seasonal weekly starting group.

A similar EPRI study in 2013 [9] conducted a review of outage statistics of coal and CCGT units in Europe, examining the link between the age and operational profile of the resource. The trend for CCGT units followed that of coal units, with reliability decreasing as the mode shifted between base loaded units and cycling units. The analysis also showed a quadratic relationship between plant age and reliability for both base loaded and cycling units, indicating a bedding in effect of resources after construction and then a degradation of reliability after reaching a maximum at 12 years in-service (Figure 2-8)

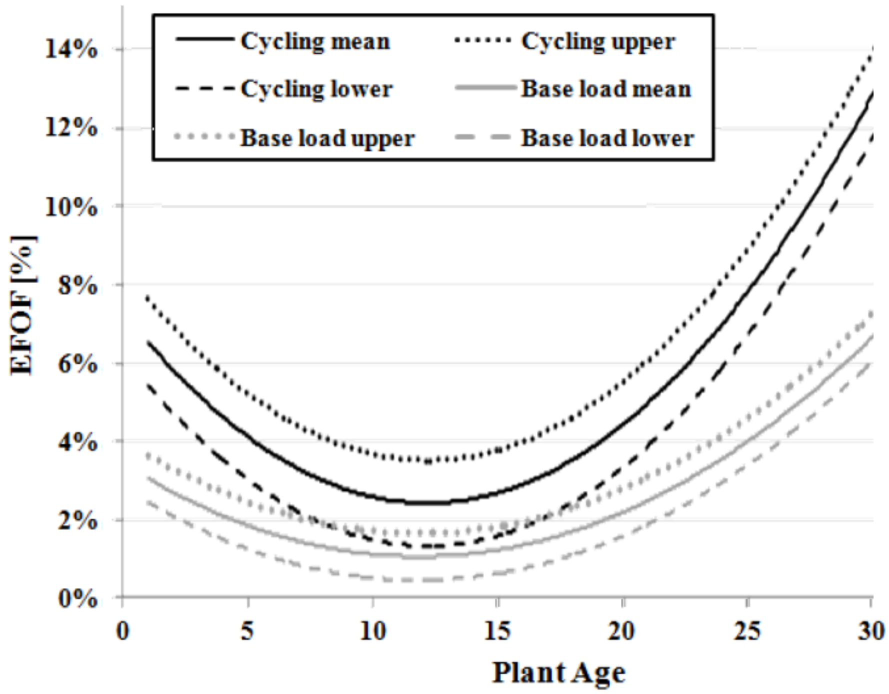


Figure 2-8
Equivalent Forced Outage Factor (EFOF) of Combined Cycle Gast Turbines (CCGT) based on sample data set of European generartors. Source: EPRI, Impact of Cycling on the Operation and Maintenance Cost of Conventional and Combined-Cycle Power Plants 3002000817, 2013

Similar studies conducted as part of the National Renewable Energy Laboratory (NREL)'s Western Wind and Solar Integration Study – Phase 2 indicated similar trends and costs associated with generator cycling in the assessment of cycling impacts conducted by Intertek Aptech in support of a study evaluating the cost of generator cycling on system production costs. The report noted that cycling costs did include an estimation of the EFOR impact on the operation of the plant and included the estimated additional costs of replacing the energy from units due to increasing forced outage rates. The study also mentioned that cycling costs were difficult to evaluate given the effect that maintenance had on both costs and availability noting that an increase in maintenance improved availability, but increased cost [10].

Implication for Resource Adequacy Assessment

Based on the analysis of the forced outage rate impact of cycling on generator availability, it is reasonable to infer that future availability of such generating plant is dependent both on a plant's natural ageing mechanisms as well as the operational profile of the plant across time, notwithstanding the potential improvements in plant management that are possible to mitigate both of those impacts. As outlined in the opening section, plant reliability indices that are used in resource adequacy assessments are typically based on assessments of historical performance of a group of resources, which is based on historical operating profiles in turn.

Knowing the impact of cycling exists, there are a set of key questions related to addressing this gap in practice:

- How can the future availability of a plant be estimated?
- Are those estimations of FOR likely to be any more accurate than current estimations?
- How significant is the impact of understating the availability of conventional generation to resource adequacy when resource cycling increases substantially?

Each of these questions require effort to understand in practice but are all contingent on the answer to the third question. If the effect of the forced outage rate is insignificant on the outcome of the analysis, then no further action may be required into the future. As such this is the highest priority question resolve from the outset and is the subject of the remainder of this report.

Assuming a material impact on the outcome of capacity adequacy evaluations, the next question is the question related to the estimation of plant availability when its availability is dependent on its operational profile. In this case it is clear that estimation of the profile is necessary for the range of forecasted scenarios that may be realized in the planning horizon. This implies the need for a production cost simulation based approach to assessing the operational profile of the resources, giving further support to the use of simulation based approaches to resource adequacy assessment. The concluding section of this report outlines how the process could be updated to consider such effects and research needs to bring this assessment into practice.

The following chapter now focuses on establishing the level of materiality surrounding the assumed forced outage rate of generating resources to resource adequacy calculations through two case study systems experiencing increasing variability due to the integration of variable renewable energy resources.

3
CASE STUDIES

Case Study 1: Medium Sized System

The first case study system is a medium sized system with peak demand in the 6 – 7 GW range and with relatively weak interconnection with other systems. This interconnection is not depended upon for capacity adequacy in this study but is present in reality. The system has substantial renewable generation, with wind generation producing 20% of energy demand in 2017. A 40 month-long historical wind generation and demand data set was available for analysis for the system, along with the capacities and forced outage rates used for resource adequacy assessment. Installed wind generation capacity in the system varied across the time period. In order to assess the impact of the assumption around historical generation forced outage rates persisting into the future, a three-step process was conducted:

1. Measure a system's reliability metrics in the base case for a variety of scenarios
2. Identify resources whose operational profile may change to a degree that historical FOR assumptions may not hold. Update to conservative estimates of new generators' FOR
3. Re-measure the system's reliability with the updated generator FOR.

It should be noted that the objective here is to identify whether assumptions around FOR are material to the outcome, not necessarily yet to forecast the impact of various renewables penetrations and operational scenarios on resource adequacy. In this case the first step was to assess the capacity adequacy of the system under the initial FOR conditions. Several scenarios were generated from the original data to assess the base case under different conditions and reliability levels. These scenarios were created by incrementing and decrementing the demand and renewables profiles around historical. Renewable generation was scaled from the original installed capacity of close to 1.1 GW to up to 3.3. GW in five steps. Similarly, demand projections were varied around the profile by a range of 5% in 1% steps.

The system consisted of 58 generating units. Over half of the system's conventional generating capacity came from natural gas combined cycle gas turbines with the remainder coming from a mix of coal plants, gas turbines, and a small amount of hydro and pumped storage plants also included. 93% of the plant had a FOR equal to or less than 5% in the base case, reflecting the mid-life age of many of the CCGTs.

To start the process the LOLH was measured for the system on an annualized basis by measuring the LOLP in each interval given the convolution of each generator's two-state capacity availability distribution using the closed form approach discussed in the previous chapter. Figure 3-2 shows the distribution of net load throughout the year using one of the base case scenarios. In the figure, the red histogram of net load shows the frequency of net load periods at a given level. The net load is the demand not served by wind generation. The blue dots indicate the loss of load probability (LOLP) at that same net load level. For this base case scenario, the LOLH was relatively low, indicating high reliability of the system. As would be expected, LOLP increases as net load increases, but the system has a very high likelihood of meeting demand at levels below 5,500 MW in this case.

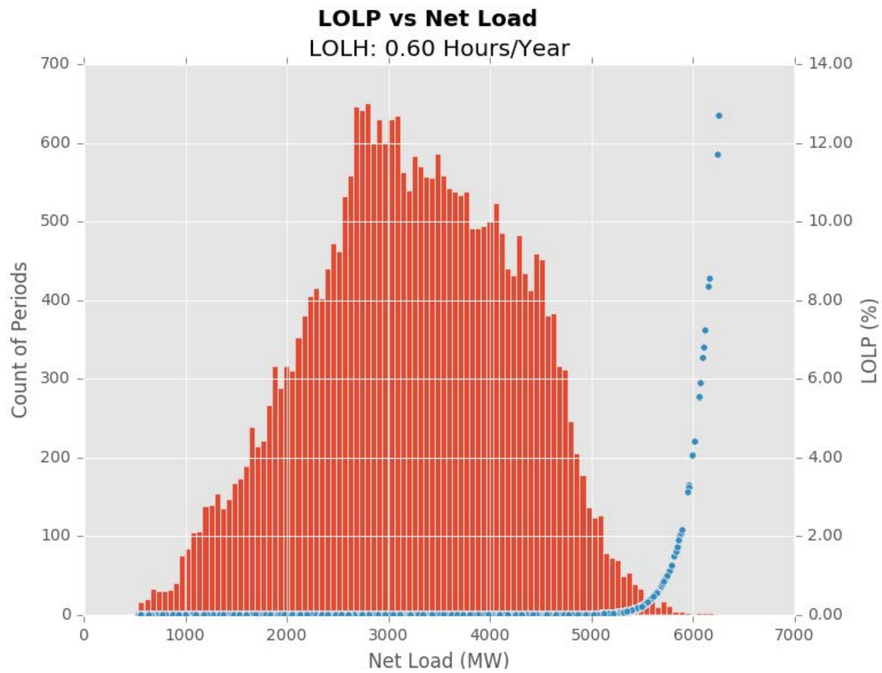


Figure 3-1
LOLP (blue dots) and frequency (red columns) by net load bin for base case (Case 1)

Figure 3-1 summarizes the outcome from the base case analysis for the combination of scenarios of demand and wind generation studied in the base case according to the LOLH recorded for each scenario according to the peak net load in that scenario. The colors of the dots indicate the penetration of wind generation in energy terms in the scenario, ranging from just under 9% to almost 30%.

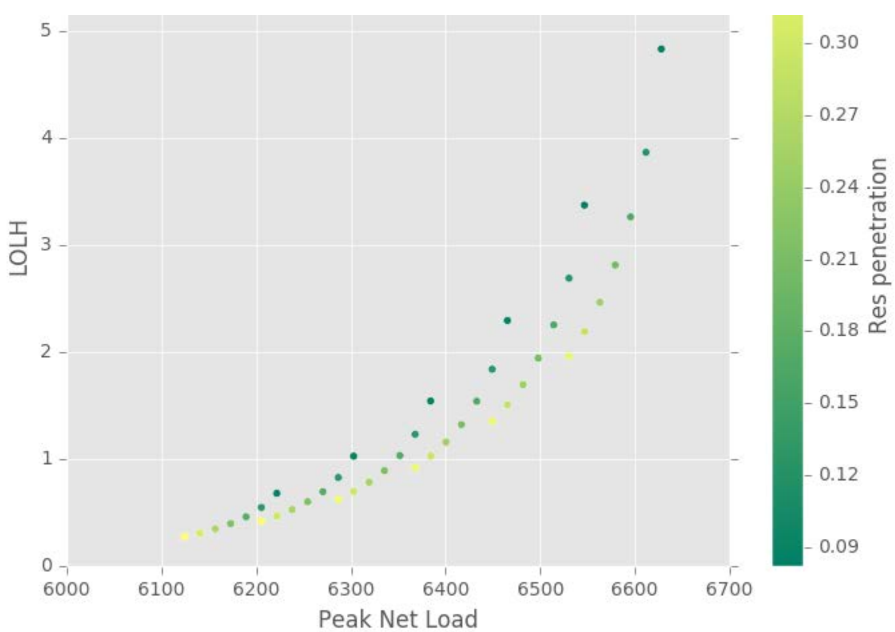


Figure 3-2
LOLH for each studied combination of demand and renewables, indicated by peak net load. Color denotes renewable penetration as a factor (max 1).

The goal of assessing multiple scenarios was to develop a picture of the reliability frontier around the reliability standard. Taking a LOLH standard of 2.4 Hours per year this could be reached in different ways with differing combinations of demand and renewables. In this case, scenarios with three different demand forecast base cases each combined with differing renewables profiles were seen to be close to the 2.4 hour LOLH margin. This approach also helps to give context of the uncertainty associated with generator FOR against that of the net load forecast for the target horizon. By comparing the base case reliability frontier with the adjusted case frontier, the effect of the FOR assumption can also be determined as a function of the reliability standard.

Having established the base case reflecting conventional practice, the next step is to generate an alternative estimation of the forced outage rates that may be more likely to occur at higher penetrations of renewable generation. As mentioned, this process is ideally iteratively carried out between simulation of generators' operational profile and reliability assessment. As the goal here is to first test materiality, an estimation of the range of this potential impact is taken. Should this turn out to be material to a system, the next question relates to how best to establish estimations of future generator availability.

Figure 3-3 shows the result from an analysis of CCGT reliability as a function of equivalent hot starts (EHS). EHS is a normalization technique as damage mechanisms from cold, warm and hot starts are not equal. A simplifying ratio is approximately 1 cold start: 1.5 warm starts: 2 hot starts: 9 load follows (min to max ramp). Cold starts typically occur more two days after shutdown and asset cooling sets in, giving rise to thermal fatigue and other chemistry changes in the plant that do not occur over to the same extent over shorter shutdown periods.

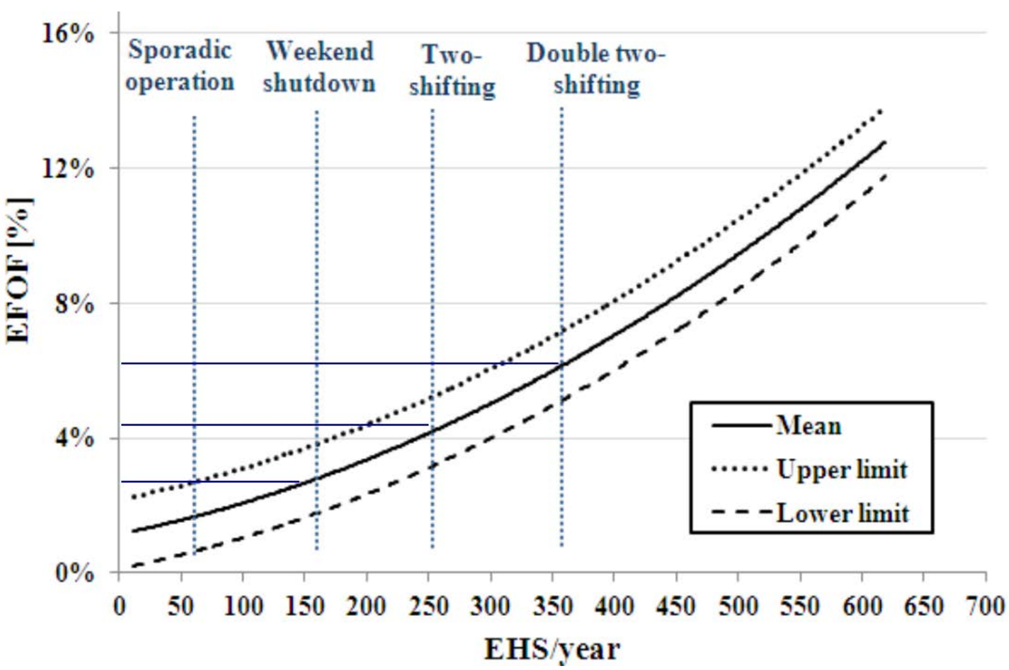


Figure 3-3
Effect of a generator's equivalent hot starts per year on a generators' equivalent forced outage factor. Source: EPRI, Impact of Cycling on the Operation and Maintenance Cost of Conventional and Combined-Cycle Power Plants 3002000817, 2013

The previous chart indicates that as EHS increases, generation reliability decreases in a non-linear manner. Furthermore, both aging and operational profile effects occur simultaneously but it is the latter that is the focus of this study. As a test for materiality, it was assumed that the several CCGTs and coal units in the fleet may shift classification in operating mode from weekly starting to daily starting or daily starting to double two-shifting (starts for morning peak and evening peak, or daily on/off cycle with load following in the middle of the day) in a future high renewables scenario, based on their relative position in the merit order.

As an approximation of the relationship shown in Figure 3-3, it can be seen that that transition incurs a degradation in performance of approximately 1.5%. This penalty was applied to the forced outage rates of the selected units as summarized in Table 3-1. This approach does not match the operational profile of the units to the scenarios but does test for the level of impact on results. This addition to the FOR does not include the effect of plant aging.

Table 3-1
FOR Adjustments to base case

Plant	Capacity (MW)	Original FOR (Case 1)	Adjusted FOR (Case 2)
Plant33	480	4.0%	5.5%
Plant51	445	3.4%	4.9%
Plant50	435	2.7%	4.2%
Plant46	415	2.0%	3.5%
Plant48	404	7.0%	8.5%
Plant47	389	3.6%	5.1%
Plant49	343	7.0%	8.5%
Plant27	285	4.7%	6.2%
Plant28	285	4.5%	6.0%
Plant29	285	4.7%	6.2%
Plant8	258	3.6%	5.1%

When the same demand and renewables scenarios are generated for the new system with updated forced outage rates, and hence generation availability distribution, the risk of insufficient generation increases for each net load level, as shown in Figure 3-4. When the scenarios are aggregated together to form the same frontier as determined previously for the base case, the difference in the peak system net load which can be carried at equivalent reliability levels can be seen. The two frontiers are plotted on Figure 3-5, with the base case (Case 1) frontier denoted in green dots, and the updated FOR case (Case 2) denoted in blue dots. Curve fits were applied to each case's frontier with a reasonably tight fit for both cases (R^2 values of 0.97 for case 1 and 0.90 for case 2). The curve fits allow for approximate estimation of the peak load carrying capability that the system cannot meet with the same level of reliability due to the impact of the forced outage changes.

Evaluated at the planning standard of 2.4 hours per year, the effect of the forced outage assumption changes equates to 254.7 MW for this system. This is the number which will be used to estimate materiality. Evaluated at 1 hour per year LOLH, this increases to 263 MW. The decision as to whether the outcome is material or not needs to be taken in the context of the other uncertainties in the system and the consequence of not examining the uncertainty.

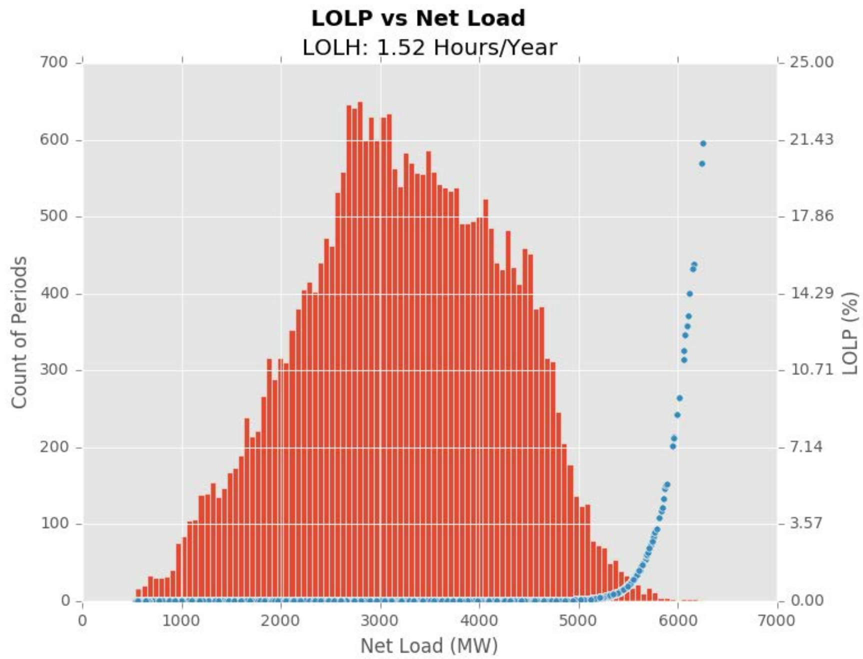


Figure 3-4
LOLP (blue dots) and frequency (red columns) by net load bin for adjusted FOR case (Case 2)

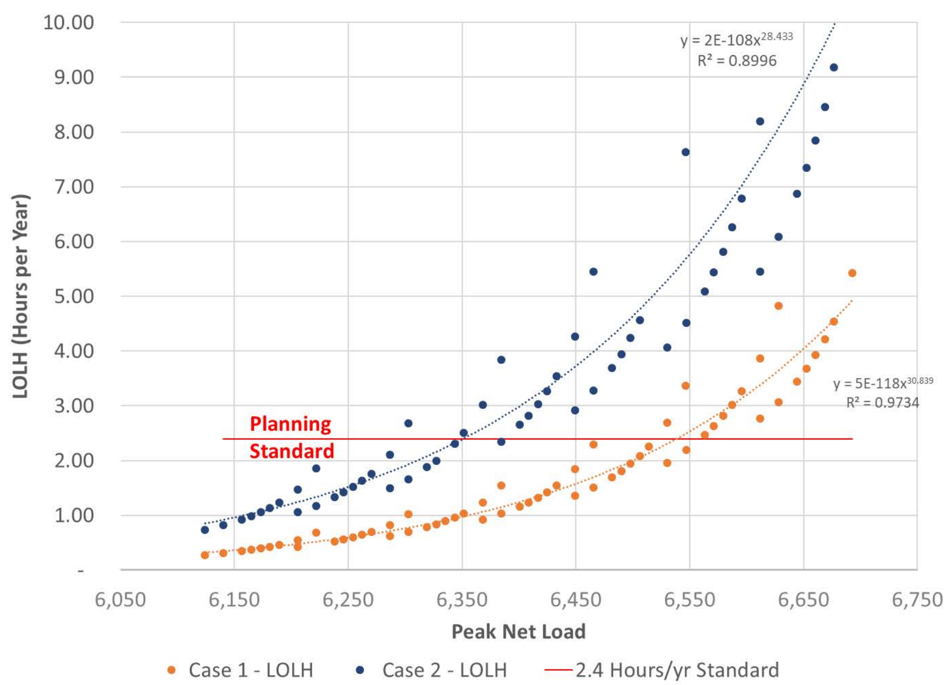


Figure 3-5
LOLH by scenario for base case (Case 1) and adjusted FOR case (Case 2) for medium system.

Case Study 1 Outcome Discussion

In this system with a peak demand between 6 and 7 GW, the effect of the assumption affects the planning capacity margin by approximately 3.5%. If such a system ran a capacity market or capacity remuneration mechanism with a sufficiently long-term horizon such that the operational profiles of generators were likely to change substantially from historical, this may become material to the outcome of the analysis. If such mechanisms have shorter horizons, but significant renewable integration or relative volatility in fuel prices are foreseen in the short term, assessments of appropriate EFOR assumptions may place a greater emphasis on more recent observations of plant reliability than a more uniform approach that may be taken otherwise.

In terms of the magnitude of uncertainty, FOR assumptions here proved to be likely less than the uncertainty associated with peak demand, climate impacts (temperature, wind, irradiance or precipitation) or renewable integration uncertainty, but may play a role in influencing marginal investment or retirement decisions none the less.

Case Study 2: Large Interconnected System

The second case study focuses on a larger system with conventional generating capacity nearing 80 GW and a peak load in the range of 70-75 GW. Like the previous system, this case study also has a considerable wind generation resource in its service territory (approximately 16 GW). Conventional generation is comprised of a mix of natural gas, coal and nuclear units. A one year period of data was available for consideration. Furthermore, the system has a significant amount of customer sited generation which may be used for back up generation, energy or ancillary services. This was treated as perfectly available capacity given the small nature of each individual device and the independence of the failure modes of each. Figure 3-6 shows the distribution of available capacity through both the probability distribution function (probability of that amount of capacity being available, blue) and the cumulative distribution function (probability of at least that amount of capacity available, red).

The study process followed is the same as in the first case study system, first by assessing the base case and finding the reliability frontier, then by incrementing the forced outage rate for a selected set of generation and finally to rerun the analysis to identify the impact of the assumed FOR on the outcome. Similar to the previous case study, the LOLP is non-zero only at the highest observed net load levels, greater than 68 GW. The LOLE in the system in the study year is substantially below the LOLE standard observed by that system.

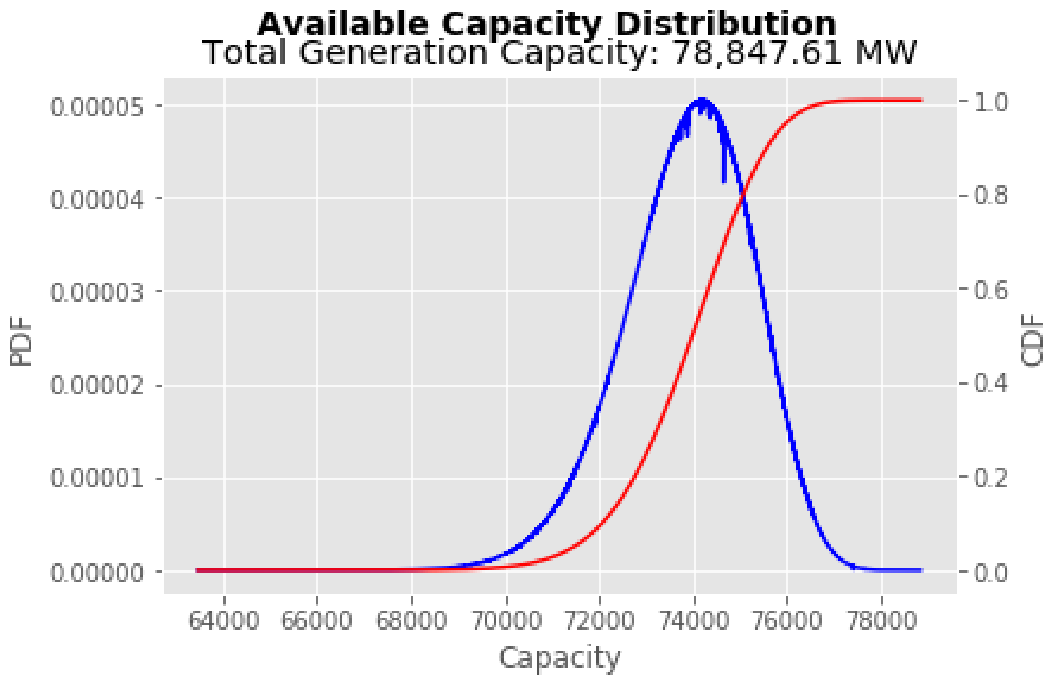


Figure 3-6
PDF and CDF of available generating capacity in the case study system

The LOLH frontier is constructed again by adjusting the demand and renewables scaling levels to obtain a picture of how the reliability changes around the reliability standard. In order to do so, the original demand profile was scaled to add up to 20% by peak demand and renewables scaled linearly by between 0 and 100%. These are obviously beyond the range of forecast uncertainty that is likely in a system over the coming years but is required to develop the frontier around the planning standard point as the system had more capacity in the study year than would have been required to maintain an LOLH of 2.4 Hours per year. This frontier is shown for the base case in Figure 3-8.

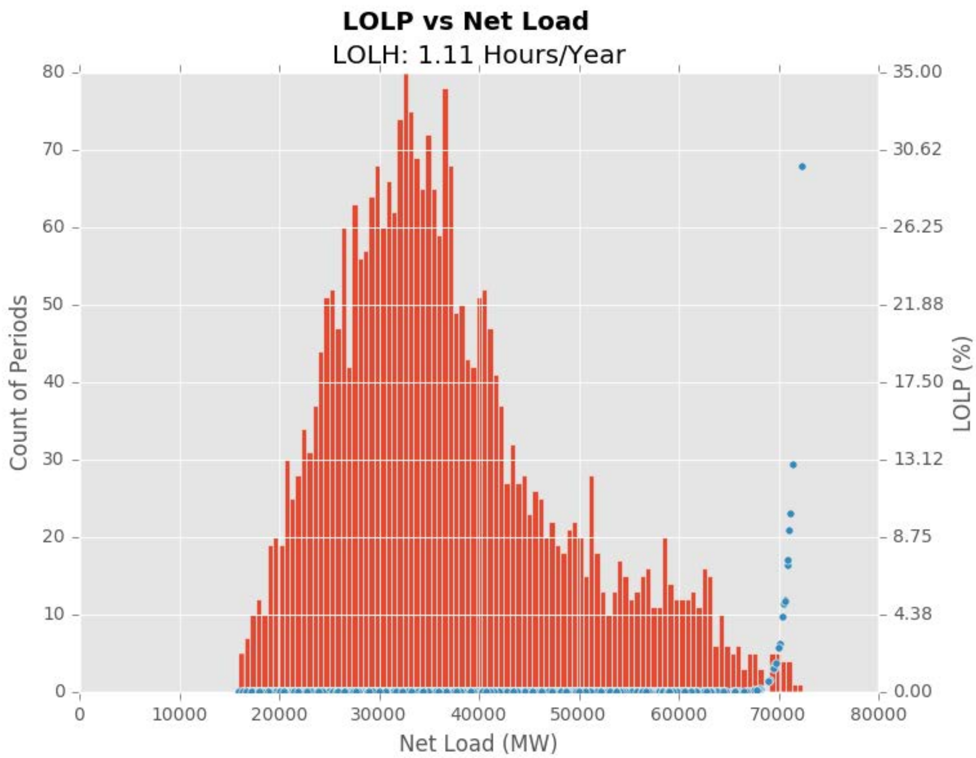


Figure 3-7
LOLP (blue, right) and net load level frequency (red column, left) for medium load, low renewables base case scenario for second case study system

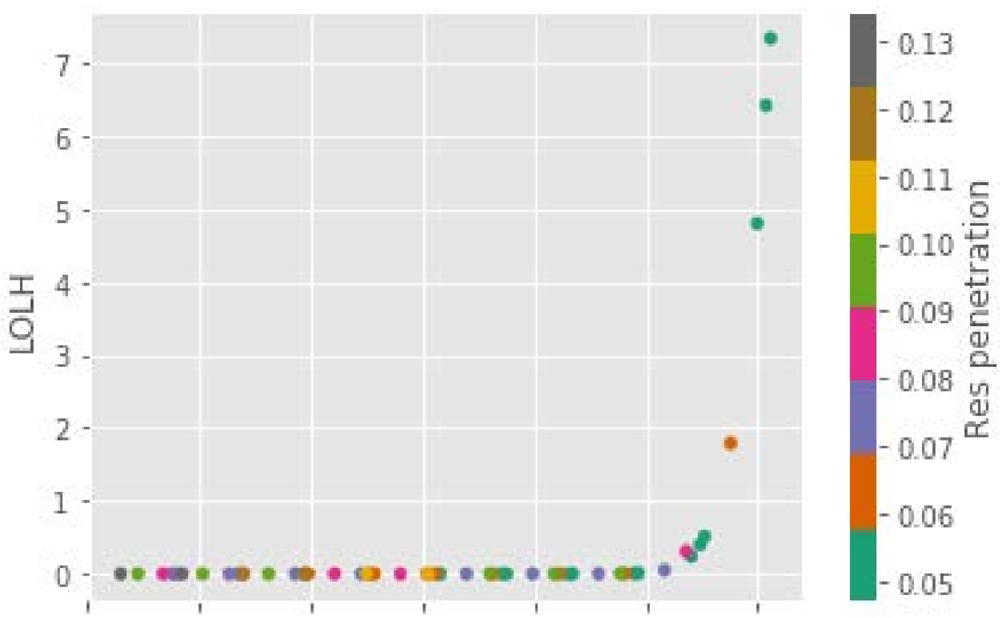


Figure 3-8
LOLH frontier by scenario for second case study system, with scenarios denoted by peak load and penetration of wind energy (color)

As with the previous case study, there are many ways in which the level or materiality could have been tested for a given system. In this case it was determined that there was a considerable penetration of gas fired generation at or near 20 years of age and likely mid merit in economic dispatch order. These units would likely bear the brunt of additional flexible operations, starting and cycling more frequently. Similar to the previous case where an increment was added to the assumed forced outage rates, a 2% increment was added to the existing unit forced outage rate for these older gas generation units.

Repeating the process of analyzing the multitude of scenarios, the new LOLH frontier is determined as shown in red in Figure 3-9. The same curve fitting process is completed and evaluated at the planning standard of 2.4 Hours per year. For this set of scenarios in the case study system, the effect of the change in FOR on the selected units equated to 843 MW difference in the peak load carrying capability of the system at the same reliability level. While this amount is more than three times larger in MW terms than the first case study system, it is three times smaller in terms of percentage of installed generating capacity (1.1% of installed generating capacity).

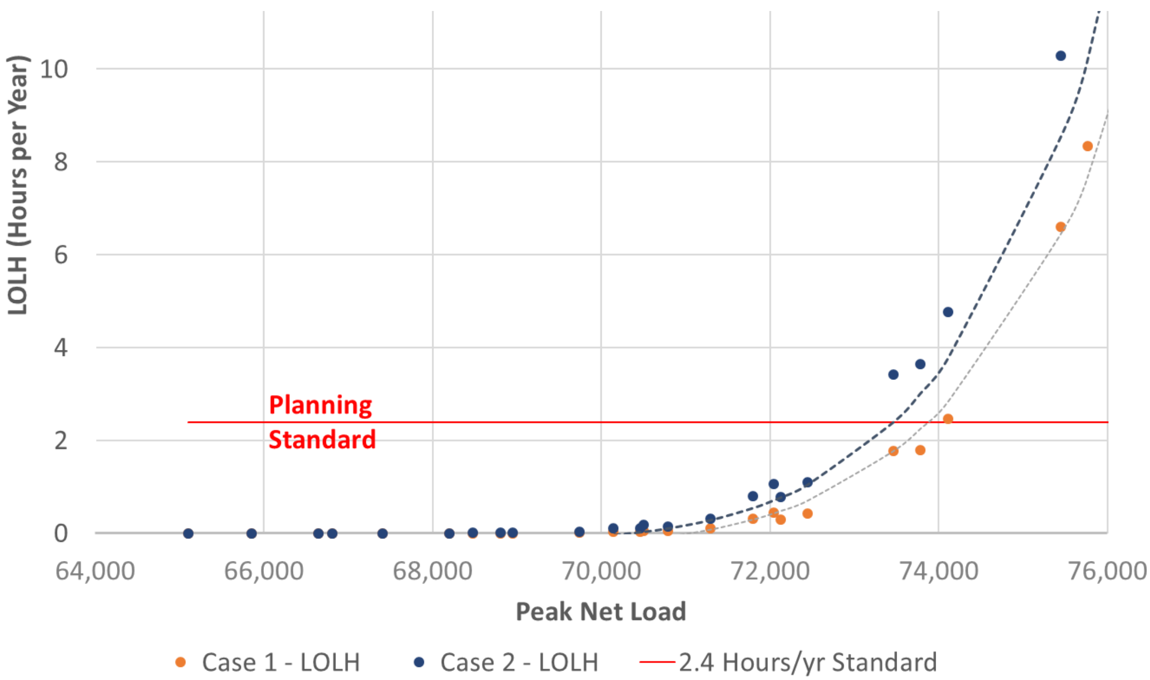


Figure 3-9
LOLH frontier for multiple scenarios associated with the base case (Case 1 , Blue) and the adjusted FOR case (Case 2, Red) for the second case study system

Case Study 2 Outcome Discussion

The judgement as to whether the impact of the FOR on the system depends on the other uncertainties present in the system. In this example, modeled peak demand forecast uncertainty lay in the region of 1-2 GW in recent years, which while larger than the FOR assumption does not completely overshadow the risk. Similarly, assumptions around the penetration of installed renewable generation is of a similar level of uncertainty as the FOR changes made in this case study system over a short time frame. Therefore, while not the most severe uncertainty FOR assessment does warrant consideration as part of the resource adequacy process.

4
CONCLUSION

Summary of Objectives

The objective of this study was to understand whether the effect of changing generator operational profiles means on generation availability is a potentially material consideration for resource adequacy assessments. Previous studies of generation reliability and availability with differing operational profiles have on the availability of different types of conventional generating plant. By increasing the number of starts and cycles that plants complete, the additional wear, tear and fatigue that components face a combination of a commensurate increase in plant maintenance requirements and reduction in availability is experienced.

While studies have been completed to examine how cycling costs impact the operation of a system in terms of O&M charges associated with a cycle, less focus has been placed on the impacts of reduced availability (either planned or unplanned) on the capacity adequacy of a system. The report sought to identify if a change in generator FORs which could reasonably be expected as a result of operational profiles changing when conventional generators and low marginal cost renewable generation meet demand.

Case Studies

Two case studies were carried out on real systems using data that was considered in previous resource adequacy studies. Both systems had a significant and increasing penetration of wind generation, largely thermal generation fleet and relatively weak interconnection with other areas. The first case study system had a smaller peak demand (6-7 GW range) compared to the second which had a peak demand in the 70-80 GW range.

A base case analysis of system reliability was run reflecting the initial assumptions for generator FOR which were based on historical generator or class equivalent performance. A change case was carried out to increment the FOR for a subset of generators that may be more likely to cycle in future due to their estimated position in the merit order. The increment was based on estimated mean change in FOR for a change in operational mode from largely base load operation, to weekly or daily starts.

The main question in each of these case studies was to understand in qualitative terms whether the assumption around the FOR of a subset of resources that are likely to cycle more in future are material to the outcome of the analysis.

Limitations of the Studies' Findings

There are two key limitations to the case studies' findings that should be considered:

1. The set of generators whose forced outage rates were adjusted to reflect the impact of increased cycling induced unavailability were based on an estimation of the types of technologies impacted upon by increased renewable penetration, and not detailed production cost simulation.

   Justification for approach: the goal of the task was to identify whether the effect was material or immaterial to the result as a basis to judge whether additional work should be carried out to first ascertain the fleet-wide operational profile impact and second the resource adequacy impact.
2. The adjusted generator FOR remined constant throughout all of the scenarios evaluated for the change case and did not change as a function of renewable penetration.

   Justification for approach: the change in MW terms of wind generation across the scenarios within each case was rather small, limiting the overall number of generators with substantially different operating profiles.

Key Findings

Both case studies showed that for the change cases, the updated FOR showed impacts on the peak load that could be carried at the same reliability level equivalent to 3% and 1% of generating capacity in either case study, equating to 250 MW and 850 MW, respectively. While relatively small in numerical terms, taken in the context of the uncertainties that are assessed in each system in the resource adequacy assessment process, the FOR impact ranks below that of the uncertainty associated with demand (2 GW range for the latter case study) and installed renewable generation, over a sufficiently long horizon where there is uncertainty associated with uptake of grid connection offers. The magnitude of the FOR assumption may also be sufficiently large to influence marginal decisions around the retirement or retention of generating capacity.

As a result, the key conclusion from this report is that the process of developing the assumptions around future generation availability should take into account anticipated operating conditions and plant ageing on a unit by unit or class by class basis.

In season ahead or for shorter horizons, generator availability statistics will likely remain relatively static compared to recent observations, but for study horizons that are 3 years ahead when substantial build out of renewables or retirement of generation is expected, expected FOR values may adapt.

Next Steps to Enable

There are several key questions for resolution to enable better estimates of generator availability to be used:

1. How should future plant operating profiles be estimated for resource adequacy studies?
2. How can predictive models of resources' FOR be built based on a combination of historical plant specific and resource class performance?
3. How can the substitutional effects of maintenance and forced outage be estimated for consideration in planning studies?

As an initial attempt to reflect this issue, planning engineers may be able to leverage information from production cost simulations of future scenarios to compare expected plant profiles with current operational practice. For units experiencing a transition between operational modes, average statistics, such as those shown in Figure 2-8, can be used to estimate a reasonable change in plant availability that could be experienced by such a change.

In general, the trend of increasing interaction between operational and planning decision making requires a more detailed approach in studies. As discussed in Chapter 2, while simulation-based methods for assessment of resource adequacy do offer the potential to incorporate dynamically changing risk of unavailability, most applications of this assume constant failure rates. The next step to reflect operational impacts on resource availability is to test this addition in practice. This would require the development of more advanced models of generation availability to be conducted to inform such a process. EPRI proposes to consult members on these topics in advance of determining next steps for 2019.

5
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