ANALYSIS OF STATE POLICY INTERACTIONS WITH ELECTRICITY MARKETS IN THE CONTEXT OF UNECONOMIC EXISTING RESOURCES: A CRITICAL ASSESSMENT OF THE LITERATURE

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About the Report:

In this report, we provide a critical assessment of recent studies on the topic of subsidies for uneconomic nuclear generating resources, and identify a number of problematic assumptions and modeling choices that tend to drive their findings and policy recommendations. In the context of two fundamental principles of market design from economic theory, we examine the inherent problems with subsidies as a policy mechanism. This discussion is then related to studies supporting state intervention through subsidies by pointing out three common flawed assumptions that are inconsistent with the peer-reviewed academic literature. Our purpose is to describe how modeling and data choices influence outcomes and policy recommendations of these studies. The report was supported by PJM Interconnection, LLC.

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Executive Summary

After nearly a century of regulating electric utilities in the U.S. as natural monopolies, many regions have moved to a wholesale market approach for electricity generation beginning in the 1990s. The market-based approach was intended to improve economic efficiency and shift risks away from consumers, based on two fundamental principles from economic theory:

1. **Prices perform a signaling function; they rise and fall to reflect resource scarcity or surplus**. Low market prices signal excess supply and the need to reduce output through the exit of uncompetitive producers. Exit is a natural part of the market process, and allowing uncompetitive producers to exit lowers overall costs in the long run.

2. **Market systems confront investors with the financial consequences of their decisions, shifting the risk away from consumers**. In a market system, investment decisions are made by producers, who can best manage the costs and risks of that investment.

The prospect of retirement by large baseload generation facilities has recently induced actions in several states to provide out-of-market compensation to financially distressed generation resources. Some nuclear plants have requested and been awarded subsidies through "Zero Emission Credits" or similar mechanisms, and the federal government has repeatedly proposed direct involvement in wholesale electricity markets to support both coal and nuclear resources. Subsidies that prevent the exit of uneconomic resources are fundamentally inconsistent with the two foundational principles of market design described above. Specifically, subsidies to a generator in a competitive market are problematic for three reasons:

1. **Subsidies are among the least efficient means to achieve emission reductions.** Economic studies have long shown that pricing activities that internalize negative externalities in ways that are consistent with market competition (via emission taxes or tradeable permit systems) tends to be the most efficient mechanism to penalize pollutant emissions. In contrast, subsidies to specific participants or technology types have been shown to be among the least efficient means to achieve emission reductions, leading to higher costs and lower benefits to society.

2. **Subsidies shift investment risk to consumers.** Electricity restructuring is premised on private investors being able to manage investment risk at the lowest cost. In contrast, subsidies shift the risk of investment in uneconomic generation resources back to the consumers, who ultimately pay the costs of the subsidies.

3. **Subsidies can beget further subsidies.** Subsidies create a precedent whereby firms become more likely to make inefficient investments because they will not ultimately bear the costs for uneconomic decisions. Handing a subsidy to one firm or technology type signals to other market participants that they could receive similar treatment.

A number of recent studies on the impacts of subsidies to existing generation units, particularly nuclear plants, ignore this basic economic logic and conclude erroneously that subsidies will lead to lower overall electricity costs. This report describes how modeling and data choices influence outcomes and policy recommendations from a number of recent analyses. We identify three key modeling fallacies and offer suggestions to the analytical community for correcting these fallacies.

<u>Fallacy 1</u>**: An increase (or decrease) in prices in one electricity market (energy, capacity or ancillary services) implies that overall electricity costs will increase (or decrease).** Markets for energy, capacity and ancillary services products are highly interconnected, and all three influence overall electricity costs. Outcomes in the energy and capacity markets are particularly interconnected, and we show how price suppression in the spot energy market can lead to higher fixed costs.

<u>Fallacy 2</u>**: Retirement decisions occur all at once or not at all, a static analysis comparing these two cases is appropriate, and ignoring market dynamics is acceptable**. The interactions between market outcomes and entry/exit decisions are dynamic and evolve over time under conditions of substantial uncertainty. A rigorous assessment of the impacts of subsidies for uneconomic generation resources must account for the dependence of entry and exit decisions on subsequent decisions by other players in the market.

<u>Fallacy 3</u>**: If a negative externality is present and can be quantified, a subsidy of the same magnitude is the best politically feasible mechanism for restoring market efficiency.** Several studies quantify the air emission impacts of losing nuclear power as a zero-emission resource (including carbon and criteria pollutants). This is an important piece of information, but the magnitude of the externality itself does not suggest that a subsidy is the best mechanism for correcting the externality, even among the politically easier choices.

We complete our report by proposing a tractable analytical framework with well-defined questions and elements that we believe should be included in any analysis of state-level interventions to provide appropriate insights to policy-makers. These necessary elements include accounting for interdependencies between markets, recognizing that entry and exit represent a dynamic process, and comparing alternate options to internalize environmental externalities under uncertain future conditions. Our framing of the state intervention problem, while more complex than existing analyses, can be implemented with current computational methods.

We have not performed our own detailed analysis to be able to sufficiently argue that subsidies for existing uneconomic generators either are or are not warranted. However, our review of the literature to date leaves us concerned that existing subsidy programs are based on an incomplete analysis. The actual cost-benefit calculus to ratepayers and taxpayers in these states may be very different than what existing studies would suggest. In particular, the prevention of exit by uneconomic generation resources through the use of subsidies will likely increase the long-run costs of achieving sustainability and reliability in electric power service.

1. Introduction and Objectives for Study

Electricity policy in the United States is formulated at a number of different levels of government. Interpretations of the Federal Power Act have placed regulatory responsibility for non-discriminatory operation of electric transmission systems in federal hands, with the Federal Energy Regulatory Commission (FERC) being one relevant rule-making authority. This authority has extended to the oversight of organized wholesale markets for electric energy, capacity and other services in those areas of the U.S. that have chosen to implement markets through Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs). Authority for regulating the management of the electric distribution system, including retail rate-making, has been left to the states.

After nearly a century of regulating electric utilities in the U.S. as natural monopolies, many regions shifted to a wholesale market approach for electricity generation, beginning in the 1990s. The market-based approach was intended to improve the efficiency of investment and operations in the power sector, and ultimately reduce costs to consumers by better aligning incentives. Wholesale electricity market designs are based on two fundamental principles from economic theory. First, ***prices in any market signal relative scarcity***. Second, ***markets shift the risk of investing in generation away from the consumer***: producers have the best information about the costs and risks of any investment, and should bear its costs and risks while reaping the benefits of good investments.

The line between rules and regulations affecting electric transmission and wholesale markets and those affecting electric distribution and retail markets may be bright in theory, but is often hazy in practice. Since the adoption of centralized wholesale market structures, states have implemented a number of measures that, whether intended or not, affect outcomes in wholesale markets and overall wholesale market efficiency. Wholesale market structures and rules also have impacts on retail rates. Examples of state-level policy actions that affect the functioning of wholesale and retail markets include the following:

- Renewable Portfolio Standards (RPS) or similar programs, adopted by many states, which mandate that utilities purchase certain amounts of capacity or energy from qualifying sources. At the time of writing, almost all states partially or wholly served by PJM Interconnection (an RTO that operates electricity markets in all or part of 13 states plus Washington DC in the mid-Atlantic and Midwestern U.S.) had some kind of RPS mandate or target in place. States have a number of different policy goals in establishing RPS policies, including carbon emission reduction or other environmental quality goals; economic development through supporting renewable generation industries; or the favored treatment of certain technologies through carve-outs or other retail rate measures (special requirements for solar energy or net metering rules are well-known examples). State RPS programs have impacts on wholesale market outcomes through quantity requirements or other support for specific generation technologies, affecting prices and production decisions.
- Some states have initiated programs to subsidize the construction of new power generation, as a way to influence the mix of fuels and technologies in the system. Connecticut and

Maryland, for example, have encouraged the construction of new natural gas generation capacity by requiring utilities in their states to sign long-term contracts with these sources at a fixed capacity price above the PJM market price. In Maryland's case, the U.S. Supreme Court ruled in 2016 that the program impinged on FERC's jurisdiction to set wholesale rates.

- Many states routinely require utilities to meet retail demand reduction or efficiency targets. These targets may be administered through the rate-making process or the state legislature. Pennsylvania's Act 129, for example, requires utilities to demonstrate annual reductions in retail peak and average load. This action by a single state has been found to have affected wholesale energy market outcomes throughout the PJM territory.
- More recently, as wholesale market prices for energy and capacity have plummeted, the owners of financially distressed generation resources have sought support at both the state and federal levels. Some nuclear power plants have requested and been awarded price supports through "Zero Emission Credits" (ZECs) or similar mechanisms, and the federal government has repeatedly proposed direct involvement in wholesale markets to support both coal and nuclear resources.

To varying degrees, all of these policy decisions and proposals alter the functioning of markets in ways that undermine the fundamental principles on which these markets were designed, such as price formation or risk allocation.

Further, market interventions by states typically do not happen in isolation. States are more likely to adopt RPS policies if their neighbors have also adopted RPS policies (Huang, et al., 2007; Lyon and Yin, 2010; Fowler and Breen, 2013). Moreover, lawmakers or regulators will often look to states that are recognized as leaders in electricity policy for guidance as to whether or how to establish a given policy (Carley and Nicholson-Crotty, 2018). Following the lead of New Jersey and Ohio, states within the PJM region have begun closing their borders to the trade of Solar Renewable Energy Credits (SRECs), which supports prices for solar installers in each state but can also increase costs to consumers (Utility Dive, 2017).

State policies that affect outcomes in wholesale markets are motivated by several factors, including economic development, environmental quality, and costs to ratepayers. The process of policy formation is typically accompanied by evidence and analysis that either supports the policy intervention as being beneficial for stakeholders within their state or opposes the policy intervention as being overly costly, inefficient, or ineffective.

These analyses, whether conducted independently or driven by a specific commercial interest, can have significant influence but are often quite opaque. Many of these studies rely on models, data and other tools that are neither sufficiently described nor adequately documented. While most consumers of these analyses may be less interested in the technical details, these very details are crucial in that they capture model assumptions and restrictions, and lead to the development of representative scenarios. Some of these assumptions may, either intentionally or not, pre-determine the outcomes and findings of the studies that influence policy-makers in whether to support or reject specific policy initiatives.

Our purpose in this report is to carefully examine the analyses of one specific policy issue – price supports for uneconomic generating resources in the PJM footprint –, in order to describe how modeling and data choices influence outcomes and policy recommendations of these studies. Since our purpose here is to improve the understanding of the critical modeling decisions that drive these analyses as a whole, we do not focus on critiquing particular findings of any single study. Rather, we focus on the modeling choices and assumptions that are common across studies of proposed subsidies to existing generators.

Existing studies on subsidies to uneconomic generators have explored one or more of four justifications: 1) environmental benefits, particularly in terms of reducing carbon emissions; 2) fuel security and resilience, such as to extreme weather or fuel supply disruptions; 3) impact on cost of electricity to consumers, often using projected price impacts as a proxy; 4) economic development, especially in terms of some measure of jobs within the state.

In general, the majority of the studies have argued that these subsidies are justified, based on analyses that appear to show relatively little or no cost of such subsidies but large social benefits. This is extremely surprising because decades of rigorous and peer-reviewed economic theory and analysis have shown that subsidies are almost never the preferred mechanism for achieving policy goals. In particular, subsidies directly contradict the two fundamental market principles discussed above, and increase costs in three ways:

- **Subsidies distort price signals, leading to higher costs**. In markets, prices indicate relative scarcity of a resource. Low prices in the long run indicate excess supply, and should provide an incentive for the least efficient producer to exit the market. Preventing that exit will increase overall costs to consumers.
- **Subsidies shift investment risk to consumers**, who will bear the costs of any inefficient investments. In contrast, firms are shielded from the cost of a poor investment, but will still keep the benefits of good investments. Shifting the risk in this way will increase costs to consumers.
- **Subsidies can beget further subsidies.** Because subsidies artificially keep prices low and set a precedent, other firms become more likely to need and seek a subsidy as well, further increasing the costs to consumers over time. Other producers may be compelled to request subsidies because artificially low prices do not cover costs going forward, or in some cases producers may be able to cover costs but engage in "rent seeking," where individual market participants seek to benefit from government decisions at the expense of the consumers.

In this report, we provide a critical assessment of recent studies on the topic of subsidies for financially distressed generators, and identify a number of common modeling assumptions and deficiencies that tend to drive their findings and policy recommendations. We are most concerned that policy-makers are giving too much weight to conclusions driven by the following three fallacies:

> <u>**Fallacy 1**</u>**: An increase (or decrease) in prices in one electricity market (energy, capacity or ancillary services) implies that overall electricity costs will increase (or decrease);**

> **<u>Fallacy 2</u>: Retirement decisions occur all at once or not at all, a static analysis comparing these two cases is appropriate, and ignoring market dynamics is acceptable;**
>
> **<u>Fallacy 3</u>: If a negative externality is present and can be quantified, a subsidy of the same magnitude is the best politically feasible mechanism for restoring market efficiency.**

The remainder of this study proceeds as follows. In Section 2, we describe the context behind current policy initiatives to support generation resources that are uneconomic in the present market environment. Section 3 reviews in detail the existing studies of subsidies for uneconomic generation, summarizing their approach and findings. Section 4 identifies a number of concerns with assumptions and modeling choices employed to support study outcomes, provides more detail on the three fallacies, and includes a simple numerical example to illustrate one of the fallacies. To be constructive, in Sections 5 and 6 we offer proposals for tractable analytical frameworks with well-defined questions and the elements that should be included to provide credible policy insights. These frameworks can be implemented now with existing analytical tools. Section 7 concludes with a discussion of the key insights and tradeoffs to consider in any policy deliberation, and the modeling practices that we recommend for analyses intended to support policy formulation.

2. *Historical Background and Context of the Electricity Sector*

In this section, we provide a brief review of the major regulatory and technological changes leading to conditions under which there is perceived value to subsidizing specific generators or technologies. This is not meant to be a complete treatment of the topic, but instead serves to highlight the key elements to the current policy debate over interactions between electricity markets and state policies.

Since the early days of electric power, the viability of the business model of selling electricity was challenged by the necessity of large fixed investments (building the network) that a firm must make before serving any consumers. This situation is one of several market failures in electricity, in which a completely unregulated market would lead to socially undesirable outcomes. For the historical context, the relevant outcome was the decision early on that electricity was best managed through a regulated monopolistic approach, in which one company (the electric utility) would be the guaranteed sole provider for a geographic region in order to justify the large investment in the network infrastructure, and state regulators would set electricity rates to be charged at the level of average costs, preventing the utility from overcharging consumers and underproviding service.

By the 1980s in the U.S. and many other developed economies, the price of electricity was rising and concerns emerged that the regulated monopoly paradigm led to inefficient investments by utilities. By the 1990s, there was a trend in North America, Europe, and Latin America to liberalize electricity markets. The primary changes were the unbundling of the formerly vertically integrated utilities (which owned generation, transmission, and distribution) into separate entities, and the creation of competitive wholesale markets for electricity generation. In other words, many different companies own electric generating units, and must compete to provide power in a market where the "consumers" are the distribution utilities.

The central idea of competitive wholesale electricity markets came from the pioneering economic concept of spot pricing of electricity by Fred Schweppe and colleagues (Schweppe et al., 1988). Rather than pricing electricity at its average cost as had been the practice, least-cost provision of electricity would be achieved by having competing units bid into auctions, sorting them in order of increasing generation cost, and setting the price at the bid of the last unit needed to meet demand. All generators selected would receive the same price for that time period. Because electricity demand varies constantly and no large-scale storage is economically feasible, this auction would be repeated periodically (e.g., every hour), and the result would be a price of electricity that varies over the day. Any firm too small to affect the price (i.e., without market power) would tend to bid its marginal cost of production in the auction, because a lower bid would cost the firm money and a higher bid might result in not being chosen. Thus, competitive markets would lead to electricity prices equal to the marginal cost of production, and total costs to consumers would be as low as possible.

In the U.S., the types of power plants used to provide the bulk of electricity include nuclear, coal-fired, natural gas-fired (mainly combined cycle or combustion turbine), hydroelectric, wind, and solar. Although the actual costs of any specific unit vary widely, in general the marginal costs of generation are lowest for nuclear, hydro, wind, and solar units, often next lowest for coal-fired units, higher for natural gas combined cycle units, and highest for natural gas combustion turbines. This trend is largely driven by the fact that fuel costs (if any) dominate the marginal costs of generation, which are in turn the product of fuel prices and the resource's efficiency. In North America, it has generally been true that electricity prices in wholesale markets are strongly influenced by the marginal cost of a natural gas combustion turbine, and therefore roughly proportional to the price of natural gas.

In the initial years of the electricity markets in the 1990s and 2000s, the price of natural gas in the U.S. was relatively high. For example, from 2005 to 2010 the average price of natural gas to the electric sector ranged from $5 to $12 per thousand cubic feet (Mcf). Over the past decade, however, hydraulic fracturing by natural gas developers has allowed the economic recovery of natural gas and oil from shale deposits, which had previously not been cost effective, and dramatically increased the U.S. domestic supply of gas. As a result, since 2014, natural gas prices have fallen to between $2 and $4 per Mcf. Prices have been particularly low at gas trading hubs that lie within gas production areas in the PJM footprint, averaging nearly $1 per Mcf below the benchmark Henry Hub price since 2015.

The impact of lower natural gas prices on the electric power industry has been dramatic. For example, in PJM Interconnection the annual average real time price (LMP) ranged from $40 to above $70 per MWh during 2005-2010, and since 2014 the annual average LMP has been falling to below $30 per MWh. The biggest impact of this decrease in average electricity price has been felt by nuclear, coal, and renewable generators. These technology types tend to have fuel costs that are very low (or zero in the case of wind and solar), but much higher fixed costs. In other words, these types of plants face very large costs every year, repaying the investment and construction costs and the costs of maintaining the plant, regardless of the amount of electricity produced.

The following explanation, while simplified, captures the main dynamics at play. When electricity prices are high, units with high fixed costs and low variable costs (e.g., nuclear) can bid into the energy markets at low marginal costs and, once selected, are paid at the price of the marginal gas unit, which provides more revenue than the plant's variable costs. Out of this net revenue, it pays its fixed costs and, if sufficient, still has profit remaining. However, when electricity prices are low, some of these types of plants are no longer able to cover the fixed annual costs out of the now reduced revenue. Thus, a power plant in this situation loses money by remaining in operation, given its costs and the prevailing market prices.

An important yet missing element in the above description is the additional revenue to generators from capacity markets, which exist in most U.S. RTOs (including PJM). In addition to the energy markets, existing generators and proposed new units not yet built also periodically bid into an auction for providing capacity (the ability to generate, if needed) within some future period.

The period of low electricity prices and the resulting economic challenges to some nuclear generation plants have led to the proposed retirements of some units earlier than originally scheduled. This in turn has led some states to consider a range of actions to keep these plants operating. The most common approach in recent years has been a subsidy to specific units. Numerous justifications have been provided for subsidizing existing nuclear units, including:

- Environmental benefits, particularly as a zero-carbon emitting resource, as well as other air quality benefits;
- Fuel security and resilience, as a hedge against a system too dependent on natural gas and renewable generation;
- Maintaining low wholesale electricity prices and therefore keeping consumer costs of electricity lower; and
- State economic conditions and employment.

One example of a state subsidy for existing generation units is the Illinois Zero Emission Standard (ZES). The ZES was passed by the Illinois General Assembly as Public Act 99-0906, and took effect on June 1, 2017 (Illinois Power Agency Act,: Section 1-75(d-5)). The program aims at procuring zero-carbon emission credits in order to promote non-carbon emitting sources, and is explicitly designed to augment the state's existing renewable portfolio standard by making nuclear units eligible for these credits. The program requires the Illinois Power Authority to procure ZECs for a 10-year period via a bidding process by eligible units. The price of the Illinois ZEC is benchmarked against the estimates of the social cost of carbon from an earlier study of the U.S. Interagency Working Group on Social Cost of Greenhouse Gases (2016), and in 2017 is $16.50 per MWh. The initial round of procurement has selected the Quad Cities and Clinton nuclear plants, among other sources, as recipients of these credits.

Other states have enacted similar ZEC-type programs. New York State approved the Clean Energy Standard in August 2016 to create ZECs between 2017 and 2029, and supports the R.E. Ginna, Nine Mile Point, and Indian Point nuclear plants. This plan is currently being challenged in New York state court. In Connecticut, the state's only nuclear plant, Millstone, was permitted to enter fixed-price contracts with utilities. In May 2018, New Jersey became the fourth state to adopt this approach, establishing a Zero Emission Certificate program to support the state's four nuclear plants, consisting of 4,100 MW of capacity. Other states have considered or are considering subsidy programs that would benefit nuclear plants within their states; similar proposals were examined but did not advance in Ohio and Pennsylvania.

In response to the recent trend of state subsidies to existing generators, some ISOs and RTOs have become concerned about the impact of subsidies on market outcomes. In particular, subsidized units may submit capacity market offers that distort capacity market outcomes, since those offers reflect neither going-forward nor opportunity costs. In March 2018, ISO New England (ISO-NE) proposed a change in the financial assurance requirements for participants in their Forward Capacity Market, which was approved by the FERC. PJM Interconnection has similarly filed a proposal for its capacity market, the Reliability Pricing Mechanism (RPM), with two alternative modifications to mitigate any distortion of price signals resulting from state subsidies.

As with many state interventions in electricity markets, the goals of the ZEC-type programs may be legitimate in the abstract for the public good. However, as with any policy intervention, the positive impacts of the new programs, or benefits, must be weighed against their negative impacts, or costs, whether intended or not. The remainder of this study focuses on state subsidies for existing nuclear generators through ZEC-type programs as a case study for the broader class of state interventions in markets.

3. *Review of Existing Studies of Subsidies for Uneconomic Generation Resources*

As several states have considered subsidies or other forms of support for existing nuclear units, a number of studies have assessed the impact of the retirement of nuclear and coal-fired power plants, and/or the benefits of keeping these plants operating. Some of these studies have used models or data to make quantitative findings about potential impacts, while others have been more conceptual or theoretical. Here, we briefly review each of the studies in terms of the analytical question posed and the approach(es) used. We then summarize the range of findings across the studies about each impact of interest.

3.1 Overview of existing studies

One set of studies on this topic has been performed by The Brattle Group (Berkman and Murphy, 2016; 2017a; 2017b; Murphy and Berkman, 2018). These studies primarily focus on how allowing nuclear generation to close would affect: a) energy and capacity prices within PJM; b) the state in which the nuclear plant is located, in terms of jobs; and c) (in some of the studies) air emissions. They simulate the system for two scenarios where the first scenario has the relevant nuclear plants operating while the second does not include these plants, and report the differences in these two outcomes. In order to address the impacts on energy and capacity markets, most of the reports use a tool proprietary to Brattle called Xpand, a production cost type capacity expansion model, although not all studies were explicit about the modeling tool used. In addition, a commercial input-output based model called REMI is used to estimate "economic impacts", which include jobs and state tax revenue lost if the plants were to shut down. The methods used to assess the emission impacts were not explicitly documented, but appear to rely on quantifying the increase in other fuels used for power generation in the event that nuclear plants retire, presumably using the results of the Xpand model. The analyses rely on published social cost estimates for carbon and criteria pollutants to monetize the air emission impacts of nuclear power plant retirements. These studies do not explicitly advocate for subsidies for the nuclear units.

Another set of studies from IHS Markit (Makovich and Richards, 2017; Makovich and Levitt, 2018) similarly provide quantitative estimates of the impacts on PJM and the U.S. of the closure of nuclear plants, including the impacts on electricity consumers in terms of retail prices, consumption levels and carbon emissions. In addition, these studies emphasize the impacts on resilience of the supply of electricity to disruptive events similar to weather events experienced in 2014 and 2018. The methodology employed is described as a backcasting analysis, in which two scenarios, one with the existing nuclear units and one without, are estimated for the years 2013-2016. However, the authors do not appear to have used a formal numerical model as in the Brattle studies, but have constructed a counter-factual for the nuclear retirement scenario based on off-line calculations and assumptions.

A study by the Nuclear Energy Institute (NEI, 2018) also provides quantitative estimates of the reliability impacts of nuclear retirements. This analysis focuses on assessing the vulnerability of the PJM system to an outage event in the natural gas infrastructure, and on how the retirement of existing nuclear units would affect the impacts on PJM from this type of event. The results are based on simulations performed by ICF and using ICF's proprietary models, including IPM, a production cost generation capacity expansion model, the Gas Market Model (GMM) of the North American natural gas market and pipeline system, and CoalDom, a coal depletion optimization model. In addition, the results for each scenario are augmented with simulations of the peak demand hour using PowerWorld, a commercial software that models the physics of electricity flow over the transmission network to produce estimates of the unserved demand during an event (the loss of load). The study analyzes potential natural gas infrastructure outage events based on historical data and the details of the pipeline system. The modeling portion of the study explores the impacts of one such hypothetical event on the power system, and compares the results under two alternative assumptions about nuclear units, the "policy case" in which existing nuclear units in PJM continue operating, and the "extended case" in which several units retire. The load profiles from 2014 and 2015 are then simulated for each nuclear retirement scenario. The study provides estimated changes in capacity, energy, CO_2 emissions, and unserved demand during the event between the two nuclear scenarios.

A fourth set of studies responds not to the proposed subsidies but rather to the proposed changes to capacity markets by PJM and ISO-NE, as described in Section 2 (Willig, 2018; Bialek and Unel, 2018). Both studies are theoretical and conceptual, and do not provide quantitative estimates. The main question in these studies is whether PJM's proposed adjustments to its capacity market in response to state subsidies are justified. Both studies implicitly offer arguments about the benefits and costs of state subsidy programs for existing nuclear units, as well as qualitative assertions about the relative impacts on market prices and CO_2 emissions. Note that PJM's proposal to FERC was denied on June 29, 2018 (FERC, 2018a).

Many of the existing studies have focused on nuclear power plants and the explicitly negative impacts that the closure of these plants would have on state-level electricity costs and air emissions, as well as regional power grid resilience. Some studies considering these same issues have questioned whether closing nuclear power plants would have substantial effects on cost, environmental or resilience outcomes. Tsai and Gülen (2017) model the shutdown of nuclear power plants and find that these shutdowns do not necessarily increase carbon emissions at the state or regional level. Blumsack (2018) models capacity and energy market outcomes (but not air emissions) in PJM associated with nuclear power plant shutdowns in Pennsylvania under a range of gas-fired generation investment scenarios, and finds that market outcomes in PJM are more sensitive to the prevailing gas generation investment scenario than the nuclear shutdown scenarios. Some RTOs (PJM Interconnection, 2017a; ISO New England, 2018) have also addressed the issue of system resilience to natural gas outages without directly addressing economics or environmental impacts. PJM's analysis suggests that its footprint could bear a much larger share of gas-fired generation without substantial impacts on system reliability. ISO New England's analysis suggests that its power grid is less resilient in the face of fuel supply interruptions, and this resilience risk would be exacerbated by nuclear power plant retirement.

Two other studies of this issue have considered whether some of the nuclear plants that have announced retirement and requested subsidies are in fact unprofitable, and if so by how much. Monitoring Analytics (2018) estimated the net revenue of all existing nuclear plants in PJM (along with other new and existing plant types). Their analysis shows that some of the nuclear units had a negative net revenue by 2017, depending on the assumed operating costs. In contrast, a similar analysis by Energyzt Advisors (2018) of New Jersey nuclear plants estimates that these units will remain profitable even in the absence of any subsidy. The main difference between these studies is that the Energyzt study includes existing hedging contracts as an additional source of revenue to the plants, which is not considered by any of the other analyses. This study also projects PJM market prices and other changes after 2020 that would keep these units profitable after the current hedge contracts expire.

Finally, one notable study by Resources for the Future (Shawhan and Picciano, 2017) examines the proposal by the U.S. Department of Energy to subsidize existing nuclear and coal generation resources in some parts of the U.S. to enhance resiliency. This study applies the E4ST model of the U.S. power sector to perform a cost-benefit analysis of the proposed policy, considering power sector costs and environmental damage costs. In contrast to many of the studies above, the E4ST model has been documented in several peer-reviewed articles and is available for free use online. The authors examine several alternative scenarios, including the proposed subsidy applied to both nuclear and coal plants, only nuclear, and only coal plants.

3.2 General findings by the existing studies

Next, we provide a summary of the range of findings across the studies, grouped by the specific outcome of interest.

3.2.1 Environmental benefits

Nuclear power plants offer certain environmental advantages relative to fossil fuels because they produce no associated air emissions during power production, and low life-cycle air emissions (Sovacool, 2008). Support programs that keep unprofitable nuclear units from retiring may lead to a reduction in CO_2 emissions, relative to a scenario where such plants are replaced by natural gas or other fossil generation. Reductions in emissions of other air pollutants may be an additional benefit.

While it is natural to expect that the replacement of zero-carbon power generation with fossil fuels would increase emissions of CO_2 and other air pollutants, the studies to date on uneconomic nuclear power plant retirements yield different results depending on the models used. The studies by the Brattle Group estimate that nuclear retirements in Pennsylvania, Ohio and New Jersey would lead to an increase in CO_2 emissions in the PJM region by between 9.3 and 37.6 million metric tons per year. The NEI study assumes that 19.4 GW of nuclear (about 58% of installed generating capacity, as of 2016) retires prior to 2023, earlier than these plants' operating permit would require. This study estimates that CO_2 emissions would increase by 78 million metric tons annually. The IHS study of PJM (Makovich and Levitt, 2018), which assumes 32.8 GW of nuclear retirements, estimates an annual increase of 100 million metric tons of CO_2. Shawhan and Picciano (2017) estimate that the DOE profit guarantee, if it lasted from 2020 to 2030 and were applied only to nuclear resources, would reduce CO_2 by 70 million tons in 2025, 40 million tons in 2035, and result in a net increase of 3 million tons in 2045; this suggests that the carbon reduction benefit is relatively short-lived. The study also estimates that the impact of subsidizing both nuclear and coal over this time frame for results in a 4 million ton reduction in CO_2 in 2025, but a net increase of 23 million tons in 2045.

The Brattle reports include estimates of increases in the emissions of SO_2, NO_x, PM_{10}, and $PM_{2.5}$ as consequences of nuclear retirements for each case analyzed. Shawhan and Picciano (2017) estimate the impacts of the nuclear-only case on SO_2 and NO_x emissions to be a decrease in 2025-2035 and an increase in 2045.

Willig (2018) and Bialek and Unel (2018) do not quantify the avoided CO_2 emissions by keeping the nuclear units operating. However, both reports argue that the financial challenges for nuclear units in current markets are either entirely or in part tied to the carbon externality. Both studies also highlight emission taxes or prices as the first-best policy solution, but point out that political constraints make this very difficult to implement in the U.S. Willig's argument for corrective subsidies relies on the assertion that a subsidy could, in principle, be designed efficiently to address the externality without introducing distortions. The argument for subsidies by Bialek and Unel is more nuanced in that it acknowledges that subsidies are not a socially efficient solution but a second-best option. Specifically, in the presence of an externality and given the inability to impose a carbon price, subsidizing cleaner units through RECs, ZECs, and similar programs may increase efficiency. Along similar lines, Morgan et al. (2018) argue for a federal R&D focus on next-generation nuclear power, rather than explicit support for existing reactors or other low-carbon technologies that have been economically threatened.

3.2.2 Resilience

In the context of power systems, resilience is seen as the ability of the power grid to mitigate the impact from, adapt to, and recover from a range of catastrophic events (FERC, 2018b; Sandia National Laboratory, 2018; Electric Power Research Institute, 2018). The power sector has long estimated reliability, usually measured in terms of electricity demand not met or the probability of demand not being met with respect to unplanned outages within the power system, such as a generator or transmission line unexpectedly becoming unavailable. The concept of resilience, in contrast, refers to maintaining the ability of the grid to deliver desired services in the face of external disruptions, such as extreme weather or an interruption of fuel supply.[1] Differing definitions of resiliency exist in the literature. One aspect of resiliency, the ability of the grid to still provide energy to consumers during a disruptive event, resembles reliability but considers sources of disruption outside the power system. Many studies, including those referenced here, restrict their attention to this aspect of resilience. Other aspects, such as recovery of the system after a catastrophic failure, are less relevant to the issue of existing nuclear generators, and will not be considered further in this report. As in the studies reviewed here, this report will use "resilience" to refer to maintaining reliability in the context of external disruptions.

[1] A third concept, "survivability" (Talukdar et al, 2003), refers to the ability of any system – not limited to the power grid but also encompassing distributed energy resources and storage – to continue to provide critical services when faced with major contingencies.

Some studies analyze the impacts on power system resilience arising from the retirement of nuclear facilities. The IHS report (Makovich and Levitt, 2018) estimates the impact in terms of the cost to replace the equivalent resilience as the retired nuclear capacity. They assume that the equivalent resilience can be achieved by natural gas call options. Based on this approach, they estimate an increase in average annual cost of $714 M.

The NEI study (NEI, 2018) has resilience as its primary focus. They estimate the impact of a major disruption in the natural gas supply over a 60 day event under either 2014 or 2015 load profiles for PJM. In their scenario assuming that all nuclear units continue operation, they report no unserved demand. In their scenario assuming 19.4 GW of nuclear capacity retire prematurely, they estimate the impact of the event in terms of maximum loss of load in any hour of 8,754 MW (17% of PJM Mid-Atlantic estimated winter peak) in 2014 and 10,889 MW (22% of PJM Mid-Atlantic estimated winter peak) in 2015; 34 days and 20 days with lost load in 2014 and 2015, respectively; and 280 hours and 209 hours of lost load in 2014 and 2015, respectively.

3.2.3 Prices and consumer costs

Some studies have estimated the impact of retirement of nuclear units on wholesale electricity prices, retail electricity prices, costs to consumers, and the change in economic net benefits to consumers. In general, these studies find that the price of electricity increases with the retirement of nuclear units.

The Brattle studies estimate the impact on wholesale energy and capacity prices (combined effect) in PJM and to individual states for several different scenarios of how many nuclear units retire. The estimates include an increase in the wholesale energy price in PJM of $1.84/MWh from 4,745 MW retiring, $1.30/MWh from 4,108 MW retiring, and $4.09/MWh from 9,649 MW retiring. The impacts on the price in Pennsylvania range from an increase of $4.78/MWh per MWh to an increase of $1.77 per MWh; in Ohio estimates range from $1.07 to $2.43 per MWh; and in New Jersey, one estimate of an increase of $4.99 per MWh. The IHS analysis of PJM (Makovich and Levitt, 2018) reports an increase in the average annual retail electricity price of 13%, and the analysis of the U.S. (Makovich and Richards, 2017) reports an increase of retail prices by 28.3%. The energy price increases in the Brattle studies are consistent with one scenario analyzed in Blumsack (2018), where nuclear power plants retire but are not replaced by any additional generation. In contrast to the Brattle and IHS studies, Willig (2018) implicitly argues that the continued operation of nuclear units will not suppress capacity market prices, and asserts that PJM’s proposed modification would unnecessarily raise capacity prices. Willig also asserts that buyer-side market power is the only justifiable rationale for an intervention in capacity markets, which further implies that a subsidy does not cause distortions in capacity prices. Bialek and Unel (2018) also challenge PJM’s proposed changes to its capacity market design on the basis that there is currently no empirical evidence that a subsidy to correct an externality would inefficiently suppress capacity prices; they identify the need for analyses of energy and capacity markets of the type proposed later in this paper.

In the Brattle and IHS reports, the estimated price increases from nuclear retirements are accompanied by corresponding estimated increases in the cost of electricity. The Brattle studies show increases in the annual cost of electricity from nuclear retirements of $1.5B (Ohio and Pennsylvania), $1.1B (New Jersey), and $3.4B (Pennsylvania) to PJM. The IHS analyses project average annual increases of $9.3B to PJM (Makovich and Levitt, 2018) and $114.2B to the U.S (Makovich and Richards, 2017). Their PJM study also reports a loss in consumer benefits between $5-12 billion dollars per year, due to the combination of higher retail prices and lower consumption of electricity. It is unclear how these studies calculate impacts on electricity retail prices, without explicitly accounting for the rate-making process by which each state sets the retail electricity rates for each consumer class.

4. Problematic Assumptions and Modeling Choices in the Existing Studies

Most of the recent studies on the impacts of subsidies to existing generation units appear to make a strong and consistent case that the closure of currently uneconomic plants will cause individual states or regions to experience higher production and consumer costs, higher CO_2 and other pollutant emissions, greater vulnerability to disruptions leading to power outages, and a loss of jobs and weaker economy. Many studies proceed further in either implying or asserting that out-of-market supports to these units are justified. The alternative scenario in which nuclear units remain in operation (due to the subsidies) avoids all of the above costs, and does not appear in these studies to have any downside. In some of the studies, there is a more nuanced assertion that because of pre-existing market failures, a subsidy to non-carbon emitting resources would have benefits (eliminate social costs of pollution) that may outweigh any costs.

The purpose of this present study is not to critique any specific finding cited above, or one specific model or technique used. Nevertheless, the analyses all make a number of important and problematic assumptions and modeling choices to support their conclusions – choices that influence the conclusions of these studies in substantive ways, and therefore require careful scrutiny.

In this section, we examine problematic assumptions and modeling choices found in many of the studies reviewed in Section 3. Our discussion proceeds as follows. First, we highlight two fundamental principles of market design from economic theory. In the context of these principles, we examine the inherent problems with subsidies as a policy mechanism, and relate this discussion to studies supporting state intervention through subsidies by pointing out three common flawed assumptions (or fallacies). We then present a simple numerical example to illustrate one of the fallacies. Finally, we enumerate several additional methodological shortcomings of many studies in Section 3, and discuss how these choices may influence findings and outcomes.

4.1 Fundamental market principles

Section 2 briefly reviewed the history of regulation of the electric power sector till the introduction of competitive wholesale generation markets. Up until the 1990s, and still today in some states, electric utilities were guaranteed to recover all of their prudently incurred costs plus earn a "reasonable" return on equity (i.e., the value of capital assets). This was achieved by setting the electricity rates for consumers at levels that would provide the desired revenue to the utilities.

One of the primary causes of inefficiency and higher costs under this system was shown to be the perverse incentive to utilities to over-invest in capital, particularly in the form of large expensive generation facilities, while providing no incentive to reduce costs (Averch and Johnson, 1962). In the search for a better alternative, many turned to the idea of competitive markets for generation. Wholesale electricity market design is based on two fundamental principles from economic theory:

<u>Principle 1</u>: Prices perform a signaling function; they rise and fall to reflect resource scarcity or surplus.

The key mechanism that allows markets to function is price. Price serves to communicate the relative scarcity of a resource to all market participants. When prices are high, that signals to firms to produce more or to new firms to enter the market. Conversely, low market prices signal an excess supply of resources and the need to reduce output through the exit of a producer in the long run. Entry and exit are necessary for markets to function properly, and are natural parts of the market process. Interventions that prevent exit of uncompetitive producers from the market will cause price suppression and result in excess capacity levels. Ultimately, such policies will increase overall costs to consumers.

Price signals drive firm decisions in wholesale markets for electricity generation. Prices create an incentive for any firm to reduce costs, when possible. They will also tend to drive the system to an efficient level of investment by incentivizing entry when capacity is insufficient, and exit of the least competitive producers when there is excess capacity.

One important caveat is that this theoretical result assumes that markets are operating efficiently and that prices are capturing all relevant information. In the presence of a market failure, prices are distorted and could be sending inefficient signals – and in reality, nearly all markets suffer distortions to some extent. If these distortions are large enough, regulatory interventions may be justified, but not all interventions come with equal benefits and costs. We discuss this issue in Section 4.2.

Nevertheless, the fundamental principle of price signals in an idealized efficient market is a useful starting point for this discussion. Some proponents of subsidies argue their necessity as a correction for other distortions. Because a subsidy for one resource type will further distort prices in an already inefficient market, the costs imposed on society by this policy must be weighed against its benefits, and these costs are properly measured according to the benchmark in this principle.

<u>Principle 2</u>: Market systems confront investors with the financial consequences of their decisions, shifting the risk away from consumers.

In a market system, investment decisions are made by producers, who have the best information about both the costs and the risks pertaining to that investment. Part of the purpose of the market system is to shield consumers from the risk of poor investment decisions and shift that risk to investors who are best positioned to manage this risk at the lowest cost. If a producer is uneconomic and not competitive, it should retire in the long run. Interventions that prevent economic retirement ultimately shift costs and risks back to consumers.

Under the regulated cost-of-service approach, consumers relied on the regulators to act on their behalf and prevent utilities from recovering the costs of uneconomic investments in higher rates. In many cases, however, regulators allowed utilities to recover the costs of poor investments. Competitive electricity markets were created as a way to eliminate the perverse incentive to invest in capacity to inflate the capital base, by shifting the risk of that investment back onto the firm.

These principles of price signals and risk allocation are the basis for the expectation that competitive markets will provide electricity to consumers at the lowest costs.

4.2 Inconsistency of subsidies with market principles

In the context of these market principles, subsidies present fundamental and inherent problems as a mechanism for policy intervention. One of the major deficiencies in many studies of subsidies for uneconomic generation is that they ignore or deny the inevitable disadvantages of imposing a subsidy within a market system. In particular, subsidies are likely to lead to higher costs to consumers in the long-run in the following three ways:

1. **Subsidies are among the least efficient means to achieve emission reductions.**

Economic studies have long shown that pricing activities that internalize negative externalities in ways that are consistent with market competition (via emission taxes or tradeable permit systems) tends to be the most economically efficient mechanism to achieve emission reductions (Pigou, 1932).

In contrast, subsidies to specific units or technology types have been shown to be much less efficient than market-based mechanisms at correcting negative externalities. This well-known result in environmental economics (Baumol and Oates, 1988; Gruber, 2016; Kolstad, 2000) has been bolstered by both theoretical treatments (Galle, 2012; Goulder and Parry, 2008; Metcalf, 2009; Nordhaus, 2013; Stavins, 2002; Xepapadeas, 1991) and empirical studies of actual subsidy programs (Borenstein, 2012; Ito, 2015; Khanna, et al., 2008).

Subsidizing cleaner producers results in artificially lowering prices in the short term, which increases consumption to the extent that demand is elastic. Because other producers still contribute to the externality, which remains unpriced, this in turn increases the polluting activity (Metcalf, 2009; Ito, 2015) if those other producers are inframarginal. If the firms contributing to externalities are marginal, they may be pushed off the margin by the subsidy, thus reducing the externality (Fell and Kaffine 2018). The demand for electricity in the short run is generally price inelastic; in this case the targeted subsidy still lowers prices, but the primary welfare impact is in the form of lower producer surplus. In the long run, subsidies tend to discourage exit and lead to an inefficient level of capacity, which may result into higher levels of pollution from the industry as a whole (Kolstad, 2000). Subsidies are also almost never technologically neutral, and therefore create additional distortions (Metcalf, 2009; Borenstein, 2012).

Some of the support for subsidies arises from the political difficulty of implementing carbon prices or other pollution fees as first-best solutions to environmental externalities. The subsidy is thus viewed as being better than leaving the externality unaddressed. If the only two policy options were politically infeasible pollution taxes or targeted subsidies, then this argument may well be correct. In reality, however, externalities may be addressed through multiple policy levers. Targeted subsidies would be economically justified only if they were the most efficient of all politically feasible options. Whether this is the case, and even whether the benefits of targeted subsidies exceed their costs, has not been empirically considered in the literature on interventions to support uneconomic power generation resources.

Overall, the consistent finding from economics is that a price/tax to correct an externality improves market efficiency, while a subsidy creates numerous price distortions that can undermine its original intent. Therefore, subsidies are fundamentally inconsistent with efficient price signals in market design.

2. Subsidies shift investment risk to consumers.

Providing a subsidy to uneconomic generation of any type imposes an additional and very important cost on consumers, who face the costs of the subsidies in the form of higher rates and/or higher taxes. Subsidies that prevent economic retirement inherently shift risk away from producers. As a result, subsidies are fundamentally inconsistent with the goal of shifting investment risk away from consumers.

3. Subsidies can beget further subsidies.

A third cost imposed by providing subsidies is that they create incentives for future investments whose risks are partially or wholly borne by consumers. Economists refer to this situation as moral hazard, whereby firms become more likely to make inefficient investments because they will not ultimately bear the costs when investments are uneconomic, but will reap benefits when investments are successful.

The concern is that state subsidies may lead to a cascading sequence of actions by market participants and states that could undermine economic efficiency in regional electricity markets. If a particular firm or technology is provided with a subsidy, this sets a precedent that might make other firms seek subsidies, potentially replacing competition in the markets by "competition to receive subsidies" (Monitoring Analytics, 2017). If prices are artificially depressed by a subsidy, other resources are starved of the revenue they need, and will also in time be forced to find some other source for this revenue outside the original market design.

Further, since subsidies are provided at the state level while firms compete across the entire RTO footprint, a subsidy for units in one state distorts the market environment for generation owners in other states. This could incent other states to respond by seeking to provide similar subsidies to their own generation sector. Such behavior is likely to impact operations and investment decisions in energy and capacity markets run by multi-state RTOs, possibly resulting in economic inefficiencies. In almost all of the studies surveyed, the cost of market interventions appears to ignore the subsequent impact of a market intervention on the decisions of other generation owners and states in the next time periods. As a result, the impact of a market intervention for a single firm may be significantly higher in cost than projected by ignoring these dynamics.

This concern is in fact heightened by arguments in favor of targeted subsidies for nuclear units. This argument is that current markets are already distorted because of multiple interventions, e.g. tax credits for renewable power generation that artificially suppress energy prices at low levels. These price distortions are then used to justify a subsidy. However, a subsidy will simply exacerbate the original distortion, further suppressing energy prices. These cumulative distortions may then be used to provide a basis for the next regulatory intervention on behalf of the next resource type, which now has insufficient revenue from the suppressed prices, using this very same argument. There is a potential for a significant imposition of cost on the system through these dynamics, a consequence that has not been considered in the existing static analyses of preserving nuclear resources.

The logical result of a dynamic process of subsidies creating conditions for more subsidies is, at its limit, a return to cost-of-service regulation. If most resources in a system are subsidized, market prices no longer provide a valid signal. Producers would respond to the subsidies, and not to market prices, when making decisions. In the long run, all generation would be reimbursed its full cost plus a guaranteed rate of return, and consumer costs would increase. The long-run potential impact of short term subsidies appears to have not been considered by most studies on the impacts of subsidies to existing generation units.

4.3 Three common fallacies in existing studies of nuclear subsidies

Many analyses of subsidies for uneconomic generation ignore the basic economic logic discussed in the previous section. This results in an underestimation of the costs of subsidies to weigh against any benefits. Three flawed assumptions (or fallacies) are either present in the analyses themselves or are implicit in readers' minds as a result of the way in which the studies are framed. These fallacies contribute to the perception that this body of literature provides evidence in favor of subsidies.

Fallacy 1: An increase (or decrease) in prices in one electricity market (energy, capacity or ancillary services) implies that overall electricity costs will increase (or decrease).

Organized electricity markets are made up of multiple markets for distinct, complementary products – energy, capacity and ancillary services markets. Each of these performs a separate function and corresponds to matching supply to demand over a different time scale. Capacity markets were designed to address generation resource adequacy, to ensure that grid operators have sufficient capacity to meet anticipated demand a year or more in advance. Spot markets for energy (day-ahead and real-time) ensure that enough existing capacity is available to balance supply with anticipated demand one day or one hour in advance. Ancillary services are designed to provide grid operators with resources to match demand and supply on even shorter time-scales (minutes to seconds), and to handle unexpected contingencies.

While each of these markets serves a different function, they are highly interconnected. The same market participants may allocate capacity from the same resource to different energy or ancillary services markets, depending on where they expect the greatest returns. The energy and capacity markets are particularly strongly interconnected. A decline in spot energy prices signals some combination of low fuel costs and a substantial supply of generation or other resources with low marginal costs. Inframarginal rents (revenues minus variable costs) would decline in this situation. To the extent that low spot prices arise because of excess supply, this would likely lead to an increase in capacity prices at some point in the future. Potential new resources will postpone entering the market because there is less revenue to capture in the energy market, and some existing resources may exit the market if combined rents in the spot energy and capacity markets are not sufficient to cover costs going forward. Both of these mechanisms will tend to push capacity prices higher.

Projecting outcomes from one market, such as the energy prices, onto overall retail rates, or even just the generation portion of the retail rate, is misleading. Lower prices in spot energy markets do not necessarily translate into lower overall wholesale costs or lower overall retail bills. In contrast, many of the analyses of subsidies project the price in one market (e.g., spot energy prices), and assume that those outcomes determine retail rates. This is misleading, because lower prices in one market do not necessarily correspond to lower overall wholesale costs or lower retail bills to consumers. Suppressed energy prices should not be confused with low costs to consumers. A rigorous assessment of the impacts of subsidies for uneconomic generation resources must consider costs across market services as a proxy for electricity rates, not wholesale market energy prices or capacity prices. In Section 4.4, we illustrate this point through a simple numerical example.

Fallacy 2: Retirement decisions occur all at once or not at all, a static analysis comparing these two cases is appropriate, and ignoring market dynamics is acceptable.

Exit decisions for uneconomic resources generally do not happen in large steps, but rather in dynamic increments. Decisions by one firm about one plant at one time will influence market outcomes, and therefore future decisions of all other firms thereafter. For example, the retirement of one uneconomic generator will cause energy and capacity prices to clear at higher levels in subsequent auctions. This changes incentives for the remaining units to retire. In particular, revenues to the remaining plants increase, and a plant that was uneconomic under the previous price regime may now be competitive. Most studies use a simplified scenario in which all retirements occur *en masse* or assume that subsequent retirement decisions are unaffected by the exit of other plants. As a result, the number of nuclear plant retirements that are modeled may be very different from the number of plants that are actually economically threatened or will be threatened within the next several years. Monitoring Analytics (2018) has estimated that four nuclear power plants in the PJM footprint may be economically threatened to the point that they would be expected to retire in the near term.

Entry decisions are also dynamic in nature but, as seen from recent PJM capacity markets, entry can occur in larger steps as multiple new entrants (especially natural gas) try to take advantage of the same favorable investment conditions (low cost of borrowing, low fuel costs) to capture the same rents. The interconnected and sequential nature of the energy and capacity markets is another reason for the gradual and evolutionary nature of entry and exit decisions. Entry or exit will impact capacity market outcomes, which will then feed forward into energy market outcomes. Based in part on those energy market outcomes, participants will determine going forward costs and capacity market strategies for the following auction. This series of decisions effectively repeats itself. A single uneconomic period for a resource will seldom itself lead to a decision to exit.

Some studies do not claim that these nuclear plants would retire at the same time, and rather, the studies simply compare two idealized scenarios (one with nuclear and one without). The potential problem is that the negative impacts illustrated in that comparison may be extremely unlikely to occur, precisely because once one of the plants retires, the conditions change for the remaining plants.

Some of the studies that we reviewed, notably those using a formal capacity expansion model (Brattle and NEI), do have one type of dynamic process modeled explicitly to determine what new generators are selected to be built to replace the lost nuclear capacity. Both the IPM model (NEI, 2018) and the Xpand model (e.g., Berkman, and Murphy, 2016) will develop enough capacity to maintain reserve margin requirements and to meet load, taking the entire time horizon into account, so retirements and additions of all other plant types are made over time, not all at once. However, these models primarily determine investment decisions under relatively idealized least cost assumptions, and neglect additional contextual factors likely to influence these decisions in reality. In fact, the interactions between market outcomes (prices and risks) and investment decisions (entry and exit) are highly dynamic and evolve over time under conditions of substantial uncertainty.

<u>Fallacy 3</u>: If a negative externality is present and can be quantified, a subsidy of the same magnitude is the best politically feasible mechanism for restoring market efficiency.

Several studies quantify the air emission impacts of losing nuclear power as a zero-emission resource (including both carbon and criteria pollutants). The studies then proceed to draw the conclusion that, because there are benefits to eliminating the market failure, the proposed policy of a subsidy is necessarily justified.

This equivalence is incorrect and misleading. There is a vast economic literature on alternative regulatory instruments for correcting negative externalities, and the costs and benefits are not the same across these instruments (e.g., Baumol and Oates, 1988; Fischer and Newell, 2008; Goulder and Parry, 2008; Nordhaus, 2013; Stavins, 2002). Potential regulatory approaches for achieving carbon reductions include:

1. Mandating emission rates from each individual resource or each type of resource,

2. Imposing an aggregate cap on emissions across sources while allowing individual emitters to trade allowances,
3. Imposing a price per unit of emissions,
4. Subsidizing non-emitting sources through fixed payments or production tax credits,
5. Mandating that a share of energy must come from specific types of sources, and
6. R&D tax credits for investing in non-emitting generation technology.

Each of these mechanisms differs in terms of the costs imposed on consumers/citizens, and in the fraction of the externality that is corrected (i.e., the benefits). The consistent finding across the studies cited above is that, relative to pricing the emissions, subsidies and other mechanisms create distortions in prices that undermine the original goal or impose other costs on consumers.

It is reasonable to consider the political feasibility of different instruments among the tradeoffs. Although a per unit price correction may be the preferred solution in an ideal setting, this is not always possible. However, it is also important to quantify the relative costs and benefits of each mechanism, and in particular to estimate the distortions (costs) that could result from a subsidy targeted at a single technology type or at individual plants. The political difficulties in implementing carbon taxes do not necessarily mean that targeted subsidies are a second-best alternative, or even the best alternative among all politically feasible choices. This may be true in some circumstances, but policy-makers need to be presented with evidence that this is the case.

Finally, some studies never explicitly state that a subsidy is recommended. However, the implicit framing of comparing the outcomes between one scenario with the existing nuclear units and one without has the effect that many readers will quickly jump to this conclusion. Indeed, this set of studies have been used in political debates as evidence that subsidies are a good policy choice. In such a situation, the fallacy is not in the study but what many readers bring to it. However, analysts have a responsibility to consider the implications of simple framing and explicitly clarify what readers can and cannot conclude.

The benefit from correcting a market failure is an important piece of information. However, the economics literature is clear: the magnitude of the externality itself does not suggest that a subsidy (or any specific mechanism) is the best solution. This false equivalence between the importance of addressing a given externality and the desirability of a proposed policy correction, absent a comparative analysis, should be avoided.

4.4 Numerical illustration of Fallacy 1

The discussion above described a fallacy in several studies that higher energy prices or capacity prices in electricity markets necessarily mean higher costs to consumers, and conversely that lower prices equate to lower consumer costs. In this section we present a simple numerical example to illustrate the flaw in this equivalency.

The Model: The example presented here is a stylized adaptation from an actual utility system in the United States. The system on which this is based is not a competitive wholesale market, but it is a relatively small (therefore transparent) system with a representative mix of generation types typical of other larger RTOs and ISOs. Specifically, our example system consists of the nuclear, coal-steam, natural gas-steam, natural gas combined cycle, natural gas combustion turbine, solar PV, and wind generation sources. We have made modifications to the size, number, and costs parameters of the units to protect the identity of the actual operator, and rely on assumptions for each technology that are broadly representative of units currently in operation. The detailed assumptions about all generators and the data sources are provided in Appendix A.

We use a unit commitment and dispatch model to simulate this system, the type of model used to schedule and dispatch units a day in advance, and is used for clearing many day-ahead energy markets in RTOs. The model solves for the generator online status and output levels over the 24-hour horizon that minimizes total cost to meet forecast demand. It enforces several constraints on how units can be scheduled, such as that units are either offline (output is zero) or online but generation must be between its economic minimum and economic maximum, constraints on how quickly a unit can increase or decrease it output (ramping), the minimum amount of time a unit must be offline after a change, and the minimum amount of time required to bring a unit online that has been off. The costs considered in this model are the variable costs of each generating unit, fuel costs and variable operations and maintenance (O&M), and the costs incurred each time a unit starts. The model also assumes that nuclear units are must-run at their nominal output level, and that solar and wind generation are also must-run (no spillage) using a historical hourly pattern of generation. The model has been calibrated and validated using hourly observed demand, solar generation, and wind generation from 2015 and 2017, and the simulations presented here use the 2017 values for the entire year. The detailed formulation and assumptions for this model are given in Appendix A, and the code and data used are archived at (https://github.com/mortpsu/PSUSubsidyStudy) for maximum transparency.

The Experiment: To illustrate the relationship among prices, total costs, and excess capacity, we construct a simple example using the model described above. We simulate the system for every day of 2017, assuming the historical hourly demand, solar, and wind; we refer to this as the "Base" scenario. We then construct an alternative case, "+200N", in which a second 200 MW nuclear plant is also in the system and is also considered must-run. The simulation of 2017 is then repeated for this second scenario, but the dispatchable fossil units are now being used to meet a smaller portion of the load (demand minus renewable and nuclear generation).

In this example, we assume that generators participate in a competitive wholesale market, and that generators have no market power (i.e., they bid their true marginal costs, which are the basis of computing the economic (optimal) dispatch). The model solution provides the resulting hourly generation of each unit, the clearing price for each hour, and the variable costs of each unit at each hour.

The hourly energy price is generally lower for the case with the additional 200 MW of nuclear capacity. With a variable cost of $2/MWh, this unit displaces higher cost units in the system, and lowers the clearing price for many of the hours of the year. The average price is $36.70 in the base case, and falls to $34.83 with the additional 200 MW of nuclear. The full distribution of prices over the year for both cases is given in the Appendix.

As explained previously, the energy prices alone do not reflect the full private cost of providing electricity. The total system cost is the sum of all variable costs (here represented by the results of the model), the fixed O&M costs for each resource, and any annual payments for capital investments, which may be either the original construction costs or the costs of upgrades to units. In order to see the impact of the additional nuclear unit on total system costs, we assume values for fixed O&M for all units, and annualized capital costs for some units.

In particular, for both nuclear units (the existing unit and the hypothetical second unit) we assume \$200/KW-YR of fixed O&M costs. In addition, we assume that some upgrade is necessary at the second unit, which is what makes it uneconomic at the prevailing prices. We assume an additional cost of \$90/KW-YR, equivalent to an overnight cost of \$1000/KW (or 20% of a new construction), which requires an annual cost of \$18M using a WACC of 8% and a 30-year economic lifetime. Under these assumptions, the total cost of this unit, assuming it operates at a high capacity factor, is \$36.25/MWh. The Nuclear Energy Institute published the costs of operating nuclear plants in the U.S. (Nuclear Energy Institute, 2017), and found that the U.S. average in 2016 was \$33.93/MWh, but the average for single-unit plants was \$41/MWh and for multi-unit plants was \$31/MWh. Thus, this hypothetical plant is slightly above the U.S. average, but well within the range of costs of existing plants. More details on all assumptions for fixed and capital costs are provided in the Appendix.

The resulting total cost and its components for both cases are given in Table 4.2. Consistent with the lower energy prices shown above, the total variable costs of producing electricity are reduced with the additional 200MW of nuclear generation by about \$28.8M, or 20%. The tradeoff is the additional cost of maintaining the second nuclear unit, both its fixed O&M and the amortized capital investment for upgrades and life extension. The increase in total fixed costs across the system is about \$36.0M, for a net increase in total system cost of \$15.7M.

However, this still does not capture the full private cost of this scenario. With the lower prices resulting from the additional nuclear capacity, the hypothetical 200 MW unit is uneconomic. Assuming the existence of a capacity market and a representative capacity price of \$80/MW-day, using recent clearing prices in PJM's Reliability Pricing Mechanism in recent years as a reference (PJM, 2018), this unit would lose about \$11M for the simulated year. In the absence of a subsidy, this plant would not likely continue to operate going forward. To simulate a subsidy, we assume the current price of the ZEC program in Illinois of \$16.50/MWh. At that price, the nuclear plant would receive over \$27M per year, enough to make it profitable. However, the full private cost of electricity consists of the total fixed and variable costs plus the subsidy (borne by the taxpayers/consumers), for an increase in total cost of \$15M + \$27M = \$42M.

We generalize this example by running additional cases to the two discussed, for a total of five scenarios based on the total capacity of nuclear generation in the simulated system: 0 MW, 200MW, 400MW (actual current capacity), 600MW, and 800MW. The impact on variable, fixed, and total costs are shown graphically in Figure 4.1. For the system modeled here, we observe that variable costs decrease with increased nuclear capacity while fixed costs increase. The best proxy for consumer costs is the total cost of this system, the sum of variable and fixed costs. In this example, total costs are lowest for 400MW of nuclear capacity (the baseline system). Beyond this level, incremental fixed costs exceed the reductions in variable costs. Increasing the amount of nuclear generation in a system will lower variables costs (and energy prices), but will ***not*** necessarily always lower total costs.

The main point of this simple example is that, although ***energy prices are higher*** without the second nuclear unit, ***total costs are actually lower***. The best proxy for electricity rates to consumers is to consider total system cost, not just a single revenue (or cost) stream in isolation, such as wholesale market energy prices or capacity prices.

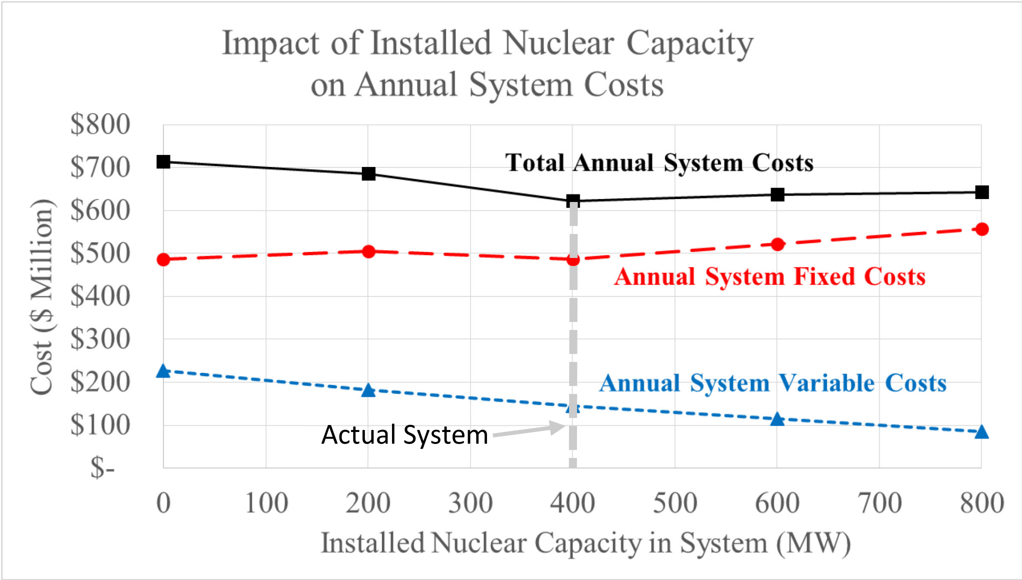
Several caveats to this example should be provided in light of previous sections. This simple analysis does not conclude that the subsidy either is or is not appropriate. We have not estimated the change in CO_2 emissions between the scenarios, nor attempted to value them. This example is deliberately restricted to considering the private costs. The objective here is not to assess whether a nuclear unit is justifiable when considering the carbon externality. We simply illustrate that low energy prices do not indicate low system costs (and thereby low consumer prices).

Moreover, we have not included many of the other elements in the analysis that would be required to draw any such conclusions, including alternative mechanisms for correcting the externality and other potential sources of CO_2 reductions which may be lower cost, or the critical dynamic response of the system over time in terms of new investments and other retirements of other plants and technology types. A more detailed analysis with these features would be a useful contribution to the policy debate, but is beyond the scope of this report.

Table 4.2: Total electricity costs with and without additional nuclear capacity

	Total Variable Costs	**Total Fixed Costs**	**Total Costs**
Base Scenario ($ million)	$ 144.1	$ 486.5	$ 622.1
Additional 200MW Nuclear ($ million)	$ 115.3	$ 522.5	$ 637.8
Change from Base Case ($ million)	- $ 28.8	$ 36.0	$ 15.6
Change from Base Case (%)	-20%	7%	3%

Figure 4.1: Changes in variable, fixed, and total costs from additional nuclear capacity



4.5 Additional modeling deficiencies in the existing studies

In addition to the three fallacies described in Section 4.3, there are other problematic gaps in either the models or the assumptions in many studies of out-of-market payments to uneconomic resources that affect their conclusions or make it difficult to determine whether their conclusions are well-founded. In this section, we highlight four more areas of concern across these studies:

- Assumptions about the current state of the electricity market;
- Appropriate constraints in the models to determine what resources substitute for retiring nuclear units;
- Treatment of uncertainty;
- Transparency of assumptions and methods.

4.5.1 Current state of the electricity market

Many critical assumptions in the studies discussed in Section 3 pertain to the current state of electricity markets and the regulatory environment in which they operate. For example, one common assumption is that the current operating capacity levels in the electricity markets are at or near the efficient level. In other words, there is neither an excess nor a shortage of supply of capacity. Some previous studies of this question implicitly assume that electricity markets and their complementary regulatory structures are currently perfectly economically efficient, except for the environmental externality. Under this assumption, one would therefore almost necessarily find that maintaining the current fleet (after subsidizing the carbon-free generation so that it does not retire) is economically efficient, while the alternative scenario with premature retirements appears to be a worse outcome that imposes costs on the system and on the consumer. Note that other studies reviewed acknowledge that current capacity and price levels may be inefficient due to multiple market failures.

In fact, most observers of the electric power sector in recent years would make a starkly different argument: namely, that current markets have excess generation capacity. For example, in 2016, PJM had an Installed Reserve Margin (IRM) of 16.6% (PJM 2017b), in contrast to the industry standard recommended by the North American Electric Reliability Corporation (NERC) of 15% (NERC, 2018). A well-functioning market would move to an equilibrium by having the least efficient firms exit the market. In other words, the pressure on some units to retire is the logical consequence of the market functioning, as intended, and a regulatory intervention that prevents such exit may result in an inefficient outcome. Thus, what the analysis assumes about the current state of the market can critically affect whether that analysis will conclude that current generation should be maintained.

In contrast, most studies present a potentially false and misleading choice between a world with efficient energy markets except for a carbon externality, which is perfectly corrected by the subsidy, and a world where only the carbon distortion remains and outcomes are worse. No other mechanisms to balance the competing objectives have been explored. Consequently, this omission may well lead the policy audience to conclude that these are the only choices.

4.5.2 Constraints affecting dispatch decisions

Claims about the various impacts from nuclear retirement depend critically on what technologies (if any) will replace them in producing electricity. Section 4.3 discussed factors that determine the long-run adjustment of electricity markets, and problematic assumptions related to ignoring market dynamics. Here we discuss the factors that determine the short-term response of the system, in which substitution must occur from the remaining existing set of generators or with new construction that is already underway or near completion.

In the short run, the generation from resources exiting the market will be replaced by generation from other existing resources, as determined by the dispatch process. Many of the studies reviewed include an explicit dispatch or day-ahead/real-time market model featuring a simple least-cost dispatch routine. The concern with this approach is that it does not accurately capture how generation is selected and dispatched, either in competitive wholesale markets or in regions served by vertically integrated utilities. Focusing on only the short-run substitution with existing capacity, some examples of constraints that consistently cause actual dispatching decisions to deviate from an idealized least cost solution include:

- *Transmission constraints*: Power flows over the transmission network are governed by Kirchhoff's laws. Unlike physical commodities, one cannot direct electrons to use one path or another through the network. Transmission lines also have physical limits on the amount of power that can be transferred, and normal operations remain below upper limits to leave margins for safety. Furthermore, as power is transferred across a transmission line, losses occur; consequently, rarely is demand met from generators a long distance away in the network when closer generators are available.
- *Limits on generator dynamics*: The majority of thermal generation technologies rely on steam turbines or combustion turbines to convert mechanical energy to electrical energy. The thermodynamics of these processes exhibit thresholds, below which stable output cannot be produced. As a result, most generator types are either "OFF", with a power output of zero, or "ON", producing power between minimum and maximum output levels, where the minimum is generally significantly above zero output. Further, there is a substantial cost and time delay in changing a unit from "OFF" to "ON". As a result, generation is not scheduled from cheapest to most expensive within each time window (e.g., each hour), neglecting the time before and after. Rather, units to be ON must be scheduled in advance by looking out over a sequence of hours chronologically to find a set of units that can feasibly meet the variations in demand within their constraints at least cost.
- *Reliability considerations*: Over the past half century, the North American electric power sector has created a complex and sophisticated set of institutions and processes for ensuring reliable electric power (i.e., if a power plant, transmission line, or other component is unexpectedly unavailable, demand can still be met within a target). The North American Electric Reliability Corporation (NERC) sets standards for the amount of acceptable unserved energy, and these targets are translated into common practice in system operations. Such practices include maintaining reserves, additional generators

available to provide power if needed on short notice, or keeping the amount of power flowing on a transmission line below its physical limit in case more flow was needed to address an outage. Typically, a large portion of the operating reserves needs to come from "spinning", or units that are already on and producing power, but not at their maximum (or minimum) output level to allow for rapid adjustment.

- *Environmental regulations*: The complex set of environmental rules for air emissions from power plants from state, regional, and federal government that share jurisdiction, as well as the physical requirements of typical air pollution reduction technologies found within modern power plants, can further limit the usage of the least-cost generators first; in effect, the bidding order changes as a result of environmental regulation. These constraints may also be dependent on the specific location (e.g., an ozone non-attainment zone) or a particular day (season or weather dependent). Ignoring such constraints leads to vastly differing solutions.

The above constraints on actual system operations often result in a dispatch of generators that differs significantly from a pure "economic dispatch" that chooses the least cost units one at a time, each used to its maximum, until demand is met for that hour. For example, several studies using capacity expansion models are based on simplified operations that neglect generator dynamic constraints. This could lead to magnifying the projected difference in energy prices between systems with more or less nuclear capacity. A unit commitment model, that dispatches generation within these constraints, tends to have much smaller changes in energy prices than simpler economic dispatch models. Omitting these constraints could unintentionally magnify the perceived benefits of preserving nuclear generation.

The concern with the majority of the existing studies is that their methods neither consider the above constraints nor document what system properties are considered (see Section 4.5.4). These studies use simple calculations that cannot account for the physical dynamics of the power system, or use generation expansion models that tend to omit or highly simplify these processes. In the absence of a rigorous treatment of the power system's physical constraints, the strong assertions by some studies about what technologies will replace nuclear units or what the costs would be without the nuclear units appear unfounded.

4.5.3 Uncertainty

Another important gap in most analyses reviewed in Section 3 is the representation of risk and uncertainty. Two of the Brattle reports that we reviewed considered alternative scenarios of future natural gas prices, but many did not account for uncertainty or alternative market outcomes in any way. Although natural gas prices and availability represent an important source of uncertainty that should be considered, there are several other sources that have not been considered and could alter the estimates and findings of the analyses. Here we provide two examples:

- *Impact on prices*: Much of the benefits associated with out-of-market interventions are a consequence of the projected decrease in energy and capacity prices. However, the computation of energy and capacity market prices is reliant on a host of firm-specific information (such as outages, availability (especially for renewables), and operating costs) as well as fuel prices and demand. The majority of these parameters are not known by independent analysts, and this uncertainty will necessarily propagate to prices. As a consequence, the quantitative estimates of price changes and impacts on social welfare are far more uncertain than they are presented in the studies, as are the projected benefits as well.

- *Resilience analysis*: Some of the studies assert that power system resilience to disruptions is either one of many important benefits of continued nuclear operations or the single most important benefit. These resilience benefits, measured in these studies as reliability metrics, are often cast in the form of reducing the risk of large-scale outages due to natural gas supply disruptions. The historical likelihood of a blackout being triggered by a fuel supply disruption is vanishingly small – around 100 times less likely than being struck by lightning.[2] As regional power grids become increasingly reliant on natural gas, the future risk of a fuel supply disruption triggering a blackout may well increase. Such an assessment, however, should be framed explicitly around risk and uncertainty, and must guard against only exploring favorable scenarios (leading to a conclusion that there is no problem) or only exploring extreme unlikely scenarios (leading to a conclusion that the problem is severe and costly proposals that may be unjustified). In the absence of rigorous exploration, the selection of the disruptive scenario can unintentionally pre-determine the conclusion of the analysis.

4.5.4 Lack of transparency, false sense of precision, misleading or restricted framing of choices

Finally, many studies discussed in Section 3 are characterized by a pervasive lack of transparency. Several of them present quantitative estimates of impacts based on their models or calculations. Yet, many of the critical assumptions and methodological details that drive the estimates have been insufficiently documented. For example, the Brattle studies rely on their proprietary models such as Xpand, yet no documentation is provided either in the study or on an accessible site. Similarly, the basis for the results from the IHS studies appears to be spreadsheet calculations rather than a numerical simulation/optimization model. These analyses have significant potential to influence major state or federal policy decisions. We believe that models and other calculation methods should ideally be open-source, or at a minimum include thorough documentation that a knowledgeable third party could utilize in reproducing the analysis and results. Those endeavoring to inform policy makers should be extremely cautious of studies using conclusions drawn from undocumented proprietary "black-box" models.

[2] The annual likelihood of being struck by lightning is approximately 7×10^{-5}. Analysis by the Rhodium Group suggests that the share of customer-hour interruptions caused by fuel supply disruptions is 7×10^{-7}. Such events, when they have happened, have nearly always been due to fuel supply problems at coal-fired power plants. See https://rhg.com/research/the-real-electricity-reliability-crisis-doe-nopr/. This figure should be taken with some care. Because fuel delivery systems do not have centralized reliability coordinators or the same stringency of incident reporting requirements as the electric power grid, it is possible that incidents affecting fuel delivery to power plants are under-reported. Even if that is the case, however, existing data suggest a very low likelihood of a widespread power outage being caused by fuel delivery issues. See Freeman et al. (2018).

A second general observation is that the studies that provide quantitative estimates use numbers with a high level of precision that imply a surprising amount of confidence. Given the range of uncertainties, these numbers can communicate more precision and confidence than could be justified by the methods used. Ideally, uncertainty analysis, as described above, would allow ranges of possible impacts to be estimated, and any robust qualitative result could be more easily and convincingly identified. In the absence of that, the conclusions drawn should be far more circumspect and cautious than generally observed.

The final general point reiterates an observation from the above discussions, but is important to emphasize here. A well-meaning and serious analyst, faced with representing an enormously complex system and probably tight deadlines, will make simple and understandable choices. For example, the analyst may choose to model only two scenarios, one with nuclear units and one without, under a small number of possible conditions, compare the results between the two scenarios and offer the conclusions. While understandable, to the mind of the non-analyst audience, the two scenarios will unconsciously frame a choice between only those two possible futures. If one future is clearly preferable, it appears to justify a proposed action that may or may not be warranted in reality.

A more informative approach would consider a broader range of options to achieve a particular goal, and would consider the impacts from each option under several possible alternative future conditions. In the absence of similar more rigorous analysis, conclusions and recommendations should be far more circumspect, and the alternatives not explored should be clarified to provide appropriate context. However, at a minimum, analysts have some responsibility to consider what could be inferred by a simple analytical framing. If they do not believe, for example, that their study should be taken as evidence to support a direct subsidy, they should state this. Much of the support for state programs has relied on this literature as evidence. If this is not the intention of study authors, clarifications within the public debates would be helpful.

Our assessment of the body of literature to date does not lead us to conclude that existing nuclear units should not be kept operating, nor does it lead us to conclude that a subsidy to achieve this is unwarranted. Our point is that the studies reviewed here, whether they appear to support or oppose state intervention, make their claims with a level of precision that cannot be justified. In Section 5 and 6, we discuss proposals for analytical frameworks with elements that should be included to provide appropriate insights.

5. *Proposed Questions for Framing an Analysis of Subsidies*

Public policy decisions, such as a subsidy for an existing nuclear plant, must balance many competing objectives on behalf of the public good. Analyses to inform these decisions, however, need to be well framed, bounded, and clearly defined in order to be useful and valid. Often, analyses of a potential policy proposal or issue can focus on one or a subset of the relevant considerations. Many analyses of state subsidy programs discussed in Section 3 are incompletely framed and inadequately comprehensive, in that they address many different objectives but none of them thoroughly.

One way to improve the clarity of the debate over this issue is to be explicit about what type of analysis is proposed for any given study. The specific analytical question then indicates the most appropriate method (or methods) that should be employed, and the critical elements that should be included in the analysis. Here, we briefly outline several distinct questions that could be framed for an analysis of existing nuclear subsidies. In the next section, we present a proposed modeling framework that could address two of these example questions and examine the implications of state subsidies to uneconomic resources on short-run operations and long-run investment decisions across a regional electricity market.

Q1: Long-Run Electricity Cost Impacts of Subsidies

The Question:

What is the long-run impact on the total cost of electricity, and indirectly the cost to consumers, from subsidizing an existing generation unit or set of units?

Necessary Elements:

A rigorous analysis of this question must account for the variable costs of generation *and all fixed costs* associated with maintaining the entire physical infrastructure. It also must consider the long-term dynamics over a reasonable horizon (e.g., 10 years). The analysis would most likely take the form of comparing the cost outcomes between two alternative scenarios: one in which the unit targeted by a subsidy does receive a subsidy, and one in which it does not. The analysis should not exogenously specify one hypothetical change in investment (i.e., a nuclear plant retires or does not retire), and then assume exogenously how the rest of the system will respond to this change. There are many possible evolutions of the mix of generation capacity under both scenarios, with plausible alternatives including other plants retiring, new investment in any of several possible technologies, or a reduction in the net generation capacity. Additional dynamic processes that are important to consider are the potential responses over time by other units to seek subsidies, and decisions by neighboring states to enact subsidies of their own plants. The analysis should include an appropriate representation of relevant system constraints, such as regional transmission constraints, which affect the dispatching of generation to meet demand and in turn influence the investment and retirement decisions of all units. The revenue from the relevant markets, including capacity markets, energy markets, and ancillary services markets should be considered, along with any subsidies or other revenue streams, in the investment and retirement decisions. Because of the many uncertain factors that impact the cost of the system over long-run horizons, a study that explicitly treats these uncertainties is more likely to be useful than an analysis that is restricted to only one or a few of the many plausible futures.

Limitations and Boundaries:

An analysis that estimates the cost impacts does not necessarily need to also address the potential benefits of a proposed subsidy. Environmental emissions, system resiliency, and broader economic impacts are not required for this narrowly framed analysis of cost. Conversely, a study of the type proposed here need not imply that a proposed subsidy is not desirable. It would simply provide a credible estimate of the range of possible cost impacts, which policy makers must weigh against any benefits estimated from other analyses or sources. One other limitation is that, under current regulatory institutions for electricity in the U.S., giving a precise estimate of the final impact on the cost to the consumer would be extremely difficult. The reason is that many states in the U.S. maintain a regulated cost-of-service approach for the distribution side, in which they set the rates that distribution utilities can charge their customers. The regulatory rate-setting process is difficult to model objectively, and details vary across states. What can be reasonably estimated is the total cost of the wholesale electric power system, which is a major determinant of total retail electric bills. Careful estimates of the entire wholesale electricity cost are informative about the ultimate consumer burden that will be faced, even if such estimates do not capture the whole story.

Q2: Cost-Effective Carbon Reductions

The Question:

What is the least cost way for a state or coalition of states to achieve a targeted amount of reductions in greenhouse gas emissions electric power generation?

Necessary Elements:

This type of question is a cost-effectiveness framing. It takes the objective, an amount of emission reductions to achieve over a time period, as given from some other process or consideration. This approach should consider all possible policy mechanisms to achieve the reduction, and estimate the cost of each approach. As discussed in Section 4.3, possible mechanisms for carbon reductions include mandating emission rates (technology standards) for individual units or for technology classes, aggregate emission limits with tradable emission allowances ("cap-and-trade"), pricing the externality and requiring all producers to pay ("carbon tax"), subsidies for technologies with lower emissions, mandating generation from low emission technologies (Renewable Energy Standards), and tax credits for R&D to produce lower emission technologies. All such instruments should be compared within a consistent and rigorous framework for assessing cost. In the absence of explicitly considering alternative approaches, it is incorrect and misleading to argue that any one of the above policy approaches is justified.

The analytical framework for assessing costs of each approach must include all the elements described above for Q1. However, the question posed here requires additional elements. Estimated effects go beyond the direct cost of electricity, because higher costs will induce substitutions in production and consumption across many other sectors in the economy, in turn affecting consumer welfare. The analysis must account for these other feedbacks, which may increase or decrease the ultimate cost, and which may clarify the relative advantages of one approach for emissions reductions over alternatives. Finally, the social cost estimate should attempt to include an estimate of the total burden to ratepayers and/or taxpayers, and should make some effort to distinguish how much of this burden would fall on each group.

Limitations and Boundaries:

This type of analysis does not address whether the targeted emission reduction is appropriate to maximize consumer welfare, or whether greater or lower reductions are more desirable. Economically efficient levels of emission reductions are better addressed using economy-wide modelling approaches, because there are other sources of emissions beyond the electricity sector. It also does not address other potential benefits, such as system resiliency or economic growth within the state. These objectives would require many additional elements and considerations for a proper treatment. However, the suggested approach would be informative and credible for deciding which policy approach to pursue and what the likely cost to consumers would be.

Q3: Cost-Effective System Resiliency

The Question:

What is the least cost approach to ensure that the power grid is resilient (i.e., maintains reliability) to external disturbances in addition to internal contingencies?

Necessary Elements:

Power system operators have long designed and managed systems to achieve a target level of reliability, as measured by the probability that demand will not be met over some time horizon. The potential causes of reliability problems that are considered were traditionally internal to the power system, such as the unexpected loss of a generator or transmission line and/or higher than expected demand. Increasingly, operators and policy-makers are concerned about events external to the power system that can lead to some demand not being met. Such events include extreme weather events (e.g., severe cold or heat, hurricanes, extended drought), events in connected infrastructures or markets (e.g., loss of a major gas pipeline, major communications blackout), or terrorism. Like reliability in its traditional sense, the resilience of the power grid to external disturbances is a question of risk assessment and management, and needs to be couched in those terms specifically.

Historically, the risk of interruptions instigated because of generation inadequacy or fuel supply problems is extremely low; most interruptions stemmed from failures or contingencies internal to the power grid (such as transmission line failures). There is a legitimate question as to whether an evolving mix of generation fuels/technologies is more likely to contribute to an increased risk of interruptions in some way – whether through external mechanisms, such as over-reliance on a single fuel delivery infrastructure, or internal mechanisms, such as a decline in system inertia or reactive power supply. If that is indeed the case, then there are many possible generation technologies, as well as transmission upgrades, that can achieve a desired target for reducing the risk of interruptions. For example, in addition to nuclear plants, the power grid could become more resilient to disruptions in the gas transmission system through the use of coal or nuclear technologies, increasing on-site storage of natural gas, requiring dual-fuel capabilities for gas units, energy storage technologies, and more robust demand-response markets. A more holistic analysis would inform the least cost way of achieving the desired level of risk reduction. It is misleading and inappropriate to limit technology options (to nuclear resources or any other technology) simply to draw inference about the value of those options.

Limitations and Boundaries:

Given the complexity of representing multiple interconnected infrastructures and markets, any analysis of this type will necessarily need to limit its scope to a subset of the possible causes of unmet demand to be tractable. The analyst will need to be explicit about what types of events are and are not considered, and the limitations of capturing all possible future events with any finite set of scenarios. Nevertheless, such analyses could be quite informative to a range of stakeholders, and more such efforts are likely to emerge in the coming years.

6. *Proposed Framework for Assessing the Impacts of Subsidies on Electricity Markets*

We conclude our discussion in this study with the presentation of a potential framework to better assess the implications of state subsidies to uneconomic nuclear resources on short-run operations and long-run investment decisions across a regional electricity market. This preliminary framework represents a pathway towards addressing the first and second research questions posed in Section 5, without adopting any of the fallacies that have been pervasive in existing studies of market impacts. Our proposed framework can be implemented by experienced analysts using existing computational tools, and as such has immediate potential to improve the information given to policy-makers considering interventions in regional electricity markets. Our framework accommodates the following elements:

- S*trategic decision-making in a game-theoretic framewor*k: Our framework recognizes that states and generating firms that own and operate power plants make interdependent strategic decisions. When a state chooses to subsidize a plant or a set of plants, the decision-making problem of non-subsidized nuclear firms and other generation owners in subsequent periods changes, and competing states, faced with a possible shortfall in surplus, may choose to respond with their own subsidies. Strategic state and firm decision-making may be examined in a non-cooperative, game-theoretic framework. This will provide insights into the cascading sequence of actions in response to unilateral state policy interventions, and more accurate assessments of costs and benefits associated with these interventions.

- *Entry and exit*: Adding a temporal dimension to the model is also essential to adequately capture player reactions. In particular, an analysis of the impact of state interventions on electricity markets should allow for endogenously determined entry and exit (investment) decisions in these markets for all resources.

- *Treatment of uncertainty*: As noted above, two of the Brattle reports reviewed in our study consider alternative scenarios of future natural gas prices. Several other sources of uncertainty have not been explicitly considered, but may alter estimates and findings of the analyses. For example, uncertainty may arise from intermittent renewable generation, generator outages, and level of demand.

- *Fidelity of models*: A key challenge in building electricity market models consists in developing a representation of the underlying transmission network that is sufficiently realistic to provide useful insights. As discussed, ignoring network restrictions likely leads to solutions that are inconsistent with actual dispatching and investment decisions in electricity markets, and thus provide poor estimates of the costs of an intervention.

These elements lead to a dynamic game-theoretic framework that is complicated by the presence of discreteness (arising from the need to model entry and exit decisions) and uncertainty. Corresponding to this game are multi-period stochastic equilibrium models of firm and state decision-making in a regional electricity market. Equilibrium models consist of sub-models for individual players (in our setting, generating firms, states, and the RTO) and a set of market clearing conditions linking player decisions. There has been significant progress in developing algorithms and heuristics for the computation of equilibria in such games. In some instances, this entails combining optimality conditions for player sub-models with market clearing conditions, leading to large-scale computational problems which may be solved using available algorithms. In other instances, the player sub-models have to be maintained as optimization problems, e.g. if they are characterized by nonconvexity arising from discreteness due to entry/exit decisions. Equilibrium models search for a set of solutions to the player sub-models (subject to expectations about how the rest of the market will react if each player changes its decisions) that satisfy optimality conditions for each player and market clearing conditions. Ideally, the resulting solutions identify an equilibrium of this game (if one exists, and assuming that the utilized schemes can indeed compute such an equilibrium).

Key features of the proposed modeling framework reflect salient aspects that are likely to affect market outcomes and assessments of costs and benefits, but have received limited attention in earlier studies. The models will: (i) endogenously determine subsidy, entry and exit decisions; (ii) recognize the dynamic nature of how decisions are made in electricity markets; (iii) compare alternate options to achieve a particular goal (i.e., internalize environmental externalities), and quantify efficiency and welfare impacts associated with each option under uncertain future conditions; (iv) estimate total costs of wholesale electricity generation (a major determinant of final costs to consumers, as discussed in Section 5) to more accurately assess the costs of generation support decisions; (v) account for multiple sources of uncertainty; (vi) capture essential features of electricity systems (e.g., transmission constraints). In an effort to facilitate a constructive dialogue toward effective policy coordination between states and regional system operators based on consistent market principles, it is important that all models, calculation methods and network data developed for this purpose are made open-source to allow for independent evaluation and replication of results.

Finally, we should note that this preliminary modeling framework does not directly incorporate the least cost avenues to meeting resilience requirements, in the sense of maintaining reliability in the face of external disturbances such as weather, fuel supply disruption, etc. While one may compute *ex post* reliability metrics by considering failures, a more fundamental question is how one may provide incentives to market participants and transmission owners to ensure that an overall resilience requirement is met. This remains a focus of ongoing and future research.

6.1. Model Description

In the following, we describe the key features of the proposed game-theoretic models.

6.1.1. Model components

(1) *Network*: The models are defined over an electricity network that consists of several nodes and transmission lines. Each node may house one or more generation plants belonging to possibly differing firms. The network spans multiple states in the same RTO footprint.

(2) *Exogenous demand*. Each node in the network is characterized by a time-varying and uncertain demand trajectory over a finite number of periods. Demand should be satisfied by aggregate nodal sales of power in each period.

(3) *Players*: Players in the game include generating firms, states, and the RTO. Every player maximizes an expected payoff over a finite horizon and subject to constraints (e.g., network constraints for the firms and the RTO, budget constraints for the states). Generating firms that own power plants are assumed to be price-takers and make production, entry and exit decisions to maximize current and expected future profits from participating in the RTO capacity and energy markets. States maximize the sum of consumer surplus and producer surplus for all economic agents in the state (i.e., generating firms and consumers), and in some periods may choose to provide subsidies to financially distressed nuclear units for subsequent periods. Finally, the RTO maximizes transmission surplus subject to network constraints, and is responsible for the determination of energy and transmission prices in the network at every period. Decisions may be continuous (e.g., generation level at a plant) or discrete (e.g., exit/entry decisions).

(4) *Time horizon*: Each player makes decisions over a finite time horizon of multiple periods. Importantly, some decisions (like production decisions) are made at every stage, while others (like investment decisions and subsidy decisions) are made less frequently.

6.1.2. Baseline

We assume that electricity may be supplied by several generator types in each state. Every firm makes generation decisions at each plant during every period, subject to network and generator constraints and market clearing conditions. Each plant has an associated marginal cost and may receive a subsidy affecting its energy and capacity market revenues. For example, in the energy market the production subsidy may be added to the price received on each unit sold (as in Fischer and Newell (2008)), or the firm's marginal cost may be reduced by the per unit subsidy amount. Existing firms decide at every period whether to exit the market, based on the aggregate profits over the remaining horizon. In addition, firms may decide to enter the market, if the cost of entry is lower than the expected benefits over the time horizon.

A state that does not offer a subsidy in one period may choose to do so in subsequent periods, when faced by diminishing surpluses of power producers in the state. In effect, the subsidy decision is endogenized and is a consequence of market interactions.

By defining the optimization problem for each player in the game (i.e., generating firms, states and RTO), and clearing conditions for both energy and capacity markets, we may solve for the equilibrium that determines the optimal economic dispatch and entry/exit decisions at every stage. In addition, we may compute economic efficiency in the regional electricity market and state surpluses. We will calibrate our model to ensure that nuclear units operate at an economic loss in the baseline. Further, as noted above, estimating total costs would allow us to more accurately assess the costs of generation support decisions associated with our equilibrium solution.

6.1.3. Policy interventions

The formulation of the baseline model will allow for a range of generating firms (each of whom may or may not be subsidized), endogenous entry, exit and subsidy decisions, and multiple sources of uncertainty. Further, the model will be simulated under alternate policy options to achieve a particular goal (i.e., internalize environmental externalities), and efficiency and welfare impacts associated with each option will be evaluated under uncertain future conditions. Two policy options of particular interest in the context of our analysis are state subsidies to nuclear resources and an RTO-wide carbon pricing scheme.

Option 1: Subsidies. The provision of state subsidies affects the optimization problems of players in the multi-period stochastic equilibrium model. First, we consider the period in which one state provides a subsidy to one nuclear plant in the state. The subsidy positively affects the revenue of the subsidized firm, and thus changes the objective of its optimization problem relative to its non-subsidized competitors. Further, the optimization problem of the subsidizing state now accounts for the cost of the subsidy to consumers, while the social welfare max problem of the non-subsidizing states is unchanged, relative to the baseline. In subsequent periods, the player problems in the game are modified in several ways. First, firms that own and operate financially distressed, non-subsidized nuclear plants may also obtain a subsidy. Second, the subsidizing state may choose to provide a subsidy to other nuclear plants, and non-subsidizing states may choose to provide a subsidy to one (or more) nuclear units within their state, in an effort to maintain competitiveness within the regional electricity market. After defining the optimization problem for each player and market clearing conditions, we will solve for the equilibrium as discussed above, and calculate efficiency and welfare implications associated with market outcomes.

Option 2: Carbon Pricing. We may compare market outcomes and efficiency/welfare implications of Option 1 with those obtained under an alternate market mechanism that corrects environmental externalities through the application of an RTO-wide carbon pricing scheme. The goal is to illustrate, through numerical simulations on the same network, that carbon pricing represents a more cost-effective approach for correcting environmental externalities than subsidies for carbon-free resources.

7. *Discussion of Key Insights and Cautions for the Current Regulatory Debates*

This report has provided a critical assessment of recent studies on the question of whether states should award price supports through subsidies to uneconomic generation resources, particularly financially distressed nuclear power stations. Most of these studies make the case that preventing the proposed retirement of some nuclear units earlier than originally scheduled is in the interest of the consumers. Some explicitly support the idea of subsidies for these plants. Other studies do not discuss subsidies and simply compare outcomes with and without the plants of interest, which implies to some readers that subsidies are desirable, whether this was the intention of the analysts or not. This set of analyses appear to have significantly influenced the debate on this topic in several mid-Atlantic and Midwestern states in recent years. However, our examination raises serious concerns that the current body of work does not represent a good empirical basis for current policy decisions due to several theoretical and methodological deficiencies.

Drawing on foundational principles from economic theory, this report describes how providing effective incentives for operations and investments in electricity markets relies on price signals and the allocation of investment risk to private investors. A subsidy will rarely, if ever, be a preferred mechanism for achieving emission reductions. Further, a subsidy will increase costs by distorting price signals and shifting investment risk back to consumers, who will ultimately bear the costs of any inefficient investments. Finally, subsidies can beget further subsidies, and producers may engage in “rent seeking” behavior to benefit from government decisions at the expense of the consumers.

Several recent studies have ignored this basic economic logic, and instead concluded that subsidies would result in lower costs to the consumers. We highlight three fallacies that are found in some studies and implied by the framing of other studies, and collectively favor subsidies:

- An increase (or decrease) in prices in one electricity market means that overall electricity costs will increase (or decrease);
- Retirement decisions occur all at once or not at all, static analysis comparing these two cases is appropriate, and ignoring market dynamics is acceptable;
- If a negative externality is present and can be quantified, a subsidy of the same magnitude is the best politically feasible mechanism for restoring market efficiency.

None of these assumptions is correct, and all have the effect of making subsidies appear to have lower costs and higher benefits than is likely the case. Other modeling deficiencies in these studies include an unsatisfactory treatment of physical system constraints, unsatisfactory or altogether missing treatment of the significant uncertainty in projecting outcomes from the power system years into the future, and a notable lack of transparency about assumptions and methods.

We have not performed our own detailed analysis to be able to sufficiently argue that subsidies for existing uneconomic generators either are or are not warranted. Reducing carbon emissions and other pollutants are worthy goals, but there are alternate ways to achieve them. Similarly, power system resilience (intended as the system’s ability to deliver power in the face of external disruptions, such as extreme weather or an interruption of fuel supply) is important, and many resources can contribute to improving resilience. There are good reasons to believe that keeping existing nuclear units operating longer, even if electricity costs are increased, could be part of a solution to achieving environmental or resilience objectives. If nuclear generation is an important component of the system, it is not clear what the best mechanism is, among those that are politically possible, to ensure their continued operation. In the absence of a rigorous, careful analysis, we cannot draw definitive conclusions at this time about either the role of nuclear generation or the appropriate regulatory and market design.

Our review of the literature to date leaves us concerned that existing state subsidy programs are based on incomplete analysis. The theoretical and methodological flaws of these studies are serious and pervasive. It is likely that the long-run costs to consumers of these policies will be much higher than suggested, the benefits will be far lower than promised, and that better means to achieve these goals have been left unexplored.

Going forward, the research community should engage in clearly formulated, rigorous, and transparent analysis grounded in economic and engineering principles to compare alternate policy options for achieving a power system that is economically efficient, reliable, resilient, and has minimal environmental impacts. By exploring several market, regulatory, and technological designs and their tradeoffs across these objectives, such studies would provide a better basis to inform policy decisions by legislators and regulators.

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Appendix A: Numerical Model Documentation for Section 4.4

A.1: Model Formulation

The model used for the numerical simulation in this report is a standard unit commitment model, which chooses the least cost commitment schedule (i.e., which generators are on and which are off) and dispatch, subject to operational constraints. The model is implemented as a Mixed-Integer Linear Program (MILP), using the formulation in Morales-España et al. (2013a; 2013b). A variation on this model has been published in Craig et al. (2016). This section provides the precise model formulation.

Table A.1 defines the sets, parameters, and variables of the model. The equations of the model are given below in (A.1 – A.10). The objective function (A.1) of the unit commitment model is to minimize the total cost of the system, subject to the constraints defined in (A.2-A.10). The total cost is defined as the sum of operating costs and startup costs over all generators in all hours.

$$\min z = \sum_{g,t} \left[p_{g,t} * C_g + v_{g,t} * SU_g \right] \tag{A.1}$$

Subject to:

$$\sum_{g} p_{g,t} = D_t \qquad \forall t \tag{A.2}$$

$$w_{g,t} = p_{g,t} - u_{g,t} * P_g^{MIN} \tag{A.3}$$

$$w_{g,t} \le u_{g,t} * (P_g^{MAX} - P_g^{MIN}) \tag{A.4}$$

$$-RL_g \le w_{i,t} - w_{i,t-1} \le RL_g \qquad \forall t \ge 2 \tag{A.5}$$

$$u_{g,t} = u_{g,t-1} + v_{g,t} - y_{g,t} \qquad \forall t \ge 2 \tag{A.6}$$

$$1 - u_{g,t} \ge \sum_{\tau > t - MD_g}^{t} y_{g,\tau} \qquad \forall t \in [MD_g, T] \tag{A.7}$$

$$u_{g,t} \ge \sum_{\tau > t - MU_g}^{t} v_{g,\tau} \qquad \forall t \in [MU_g, T] \tag{A.8}$$

$$SR_t \le \sum_{g} \left[u_{g,t} * P_g^{MAX} - p_{g,t} \right] \tag{A.9}$$

$$p_{g,t} \le P_g^{MAX} \tag{A.10}$$

Constraint (A.2) specifies that the sum of all generation in each hour must meet the demand for that hour. This formulation does not allow for non-served energy. Constraints (A.3-A.4) define the auxiliary variable w, which represents the generation output above its minimum load. The ramping limit (A.5) is defined in terms of the change in w between consecutive hours. Constraint (A.6) defines the relationship between the commitment state u, the startup variable v, and the shutdown variable y. The minimum down time constraint is defined in (A.7), while the minimum uptime constraint is defined in (A.8). Constraint (A.9) ensures that the spinning reserve target, which is assumed to be 8% of demand, is met across all generators that are online. The capacity constraint of each generator is defined in (A.10). The model is implemented in GAMS (GAMS, 2018), and solved with CPLEX 12 (IBM, 2018).

Table A.1: Sets, Parameters and Variables in Unit Commitment Model

Sets	
t	hour of week, $t \in T$
g	generator, $g \in G$
Parameters	
D_t	demand in hour t [MW]
SR_t	system spinning reserves in hour t, equal to 8% of system demand in hour t [MW]
RL_g	ramping limit (up and down) for unit g [MW]
P_g^{MIN}	minimum power output of unit g [MW]
P_g^{MAX}	maximum power output of unit g [MW]
SU_g	start-up cost for unit g [$/start]
MD_g	minimum down time for unit g [hours]
MU_g	minimum uptime for unit g [hours]
C_g	variable cost for unit g [$/MWh]
Variables	
z	total system cost [$]
$p_{g,t}$	total power output of unit g in hour t [MW]
$w_{g,t}$	power output above minimum load of unit g in hour t [MW]
$u_{g,t}$	binary variable indicating unit g is operating above its minimum load in hour t {0,1}
$y_{g,t}$	binary variable indicating unit g is shut down in hour t {0,1}
$v_{g,t}$	binary variable indicating unit g starts up in hour t {0,1}

A.2: Case Study

The example presented in this report is a stylized adaptation from an actual utility power system and balancing authority. The system on which this example is derived is not a competitive wholesale market, but it is a relatively small (therefore transparent) system with a representative mix of generation types typical of other larger RTOs and ISOs. Specifically, our example system consists of the generation resources as described in Table A.2 below. The data for the generation resources and their attributes were obtained from the IRP for this utility, but we state the generic assumptions for this example in the table here. The costs assumed here are generic costs from the Energy Information Administration (EIA, 2018a), and should be considered as representative of these types of units. We assume the price of coal is \$1.89/MMBTU and the price of natural gas is \$3.12/Mcf, from EIA fuel price data (EIA, 2018b).

Table A.2: Generation Resources for Example System

Name	**Fuel**	**Prime Mover**	**Total Capacity (MW)**	**# of Units**	**Variable O&M (\$/MWh)**	**Fixed O&M (\$/KW-YR)**	**Full Load Heat Rate (BTU/KWh)**
NUC-1	Nuclear	Steam	400	1	2.0	90	-
COAL-1	Coal	Steam	690	2	1.9	35	11,000
COAL-2	Coal	Steam	320	2	1.9	35	9,800
NGCC-1	Natural Gas	Combined Cycle	350	2 CT/ 1 CA	4.8	24	7,600
NGCC-2	Natural Gas	Combined Cycle	290	1 CT/ 1 CA	4.2	24	7,500
GAS-ST	Natural Gas	Steam	220	3	3.1	20	12,700
CT-1	Natural Gas	Combustion Turbine	60	1	20.8	16	12,000
CT-2	Natural Gas	Combustion Turbine	220	1	5.0	16	10,100
CT-3	Natural Gas	Combustion Turbine	60	1	20.9	16	11,900
CT-4	Natural Gas	Combustion Turbine	220	1	5.0	16	10,600
Additional Nuclear Unit	***Nuclear***	***Steam***	***200***	***1***	***2.0***	***90***	***-***