Policy Brief
NI PB 17-01
January 2017

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The Uncertain Future of Nuclear Power in the Southeast: Implications of an Aging Fleet for Electricity Sector Planning and Emissions

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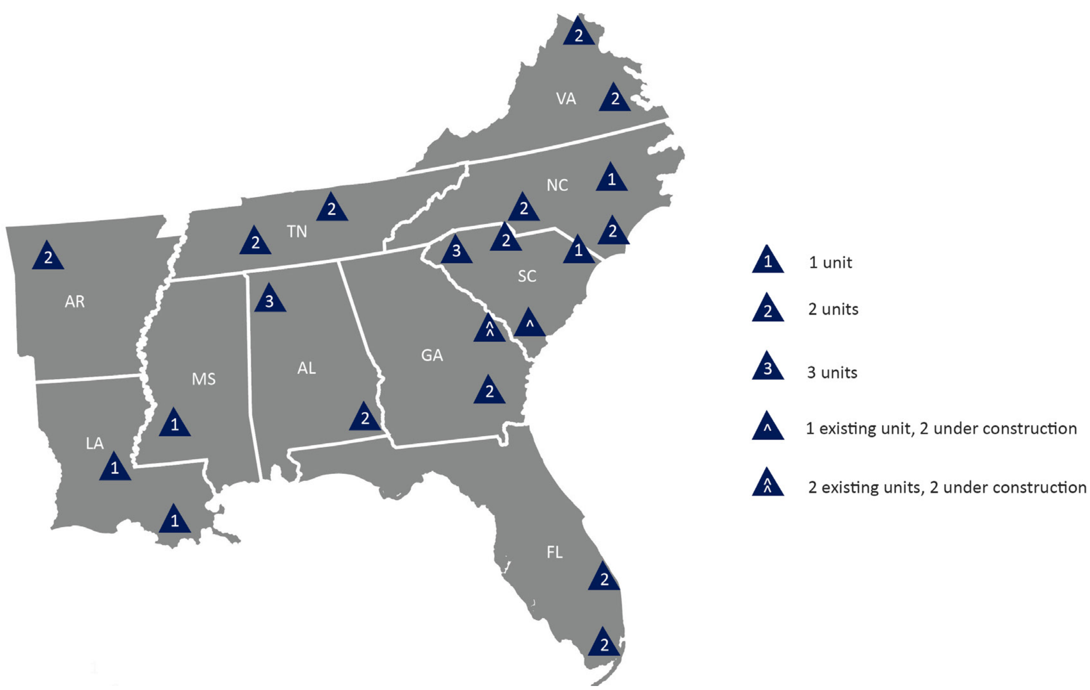
Introduction

Nuclear power plays an important role in electricity generation in the Southeast. Historically, it provides slightly more than a quarter of the region's power and more than 80% of its non-fossil generation. The Southeast—defined here as Alabama, Arkansas, Florida, Georgia, Louisiana, Mississippi, North Carolina, South Carolina, Tennessee, and Virginia—is the only region of the country constructing new nuclear units. Unlike existing nuclear units in other areas of the country, those in the Southeast generally do not face the same market pressures that could lead to their retirement before expiration of their current operating licenses.[1] Nevertheless, utilities, utility regulators, ratepayer advocates, and other stakeholders in the Southeast are likely to face decisions about the long-term operation of existing nuclear units in the next few years if not sooner.

Figure 1. Nuclear power plants in the Southeast



[1] Whitney Herndon and John Larson, "Nukes in the Crosshairs Revisited: The Market and Emissions Impacts of Retirements," Rhodium Group (November 4, 2016), accessed December 21, 2016, http://rhg.com/notes/nukes-in-the-crosshairs-revisited. This analysis includes all existing nuclear units at risk of retirement through 2030. Herndon and Larson confirmed that all potential retirements in the Southeast are due to operating license expiration rather than market forces.

The reason is that the nation's fleet of nuclear power plants is aging. Nearly 45% of existing units are at least 40 years old.[2] The average age of a nuclear power plant in the Southeast is 36 years.[3] Nuclear power plants in the United States are licensed to operate for a 40-year period, after which their operators can apply for a 20-year extension. Beginning around 2030, nuclear units across the country, including in the Southeast, will have been operating 60 years and will require a second license extension to continue operating. Utilities that wish to replace an existing nuclear unit with a new unit must start planning to do so 10 to 15 years before the retirement date of the existing unit.[4] The region's oldest nuclear plants—such as Duke Energy's H.B. Robinson plant in South Carolina, which reaches the end of its 60-year license in 2030—have already entered that planning window.[5]

The 60th birthdays of existing nuclear plants are also beginning to appear in utility long-term planning horizons, forcing utilities and utility regulators to make assumptions about the plants' long-term operation. For example, Duke Energy's 2016 integrated resource plan (IRP) assumes that H.B. Robinson retires at 60.[6] In contrast, Dominion Virginia Power's 2016 IRP assumes a second operating license extension for its existing nuclear units in Virginia.[7]

Although utilities and utility regulators need to begin planning for the potential retirement of the region's nuclear plants, they face at least four uncertainties: (1) how many units will seek a second license extension, (2) what requirements must operators meet to apply for and receive a second license extension, (3) what investments will individual plants need to make to receive such an extension, and (4) what capacity would replace units that do retire.[8] These uncertainties add to the existing planning challenges of a rapidly evolving sector with increasing natural gas dependence, increasing penetration of variable renewable generation (including distributed solar), difficult-to-predict future demand, and potential requirements to significantly reduce carbon emissions.

This policy brief explores the electricity planning challenges presented by the Southeast's nuclear units that are approaching the end of their initial extended operating license (i.e., units 40 to 60 years old) in 2030 and beyond. It begins with a brief overview of the role of nuclear power in the Southeast and the status of Nuclear Regulatory Commission (NRC) guidelines for operating license extensions from 60 to 80 years. It describes how the uncertainty surrounding the future of existing nuclear factors into the current planning process in the Southeast and how that uncertainty interacts with the other planning challenges facing utilities and regulators in the region. It concludes by identifying opportunities for states to begin planning for decisions related to the ongoing operation or replacement of existing nuclear capacity.

Nuclear Generation in the Southeast

As of December 2016, the Southeast has approximately 38 gigawatts of nuclear capacity and another 4.5 gigawatts (GW) scheduled to enter service around 2020.[9] Although nuclear represents a relatively small fraction of generating capacity in the region as compared with coal and natural gas (69 and 142 GW in 2015 respectively), it provides a large fraction of power because nuclear units typically have low operating costs and operate at approximately 90% capacity factors.[10] Since 2000, nuclear has consistently provided 25–28% of generation in the Southeast. Over that period, nuclear has provided 80–85% of the region's non-fossil generation, which includes hydropower, biomass, wind, and utility-scale solar (Figure 2).

[2] Of the nation's 99 currently operating nuclear power units, 44 entered commercial operation between 1969 and 1976. See NRC Datasets, "Commercial Nuclear Power Reactors –Operating Reactors" (updated 11/02/2016), accessed December 21, 2016, http://www.nrc.gov/reading-rm/doc-collections/datasets/.

[3] This information is based on EPA's NEEDS database version 5.15, https://www.epa.gov/airmarkets/power-sector-modeling-platform-v515, which was accessed December 21, 2016.

[4] American Physical Society, "Renewing the Licenses of the Nation's Nuclear Power Plants," (2013).

[5] Duke Energy Progress, "North Carolina Integrated Resource Plan," (2016) at 46.

[6] Ibid.

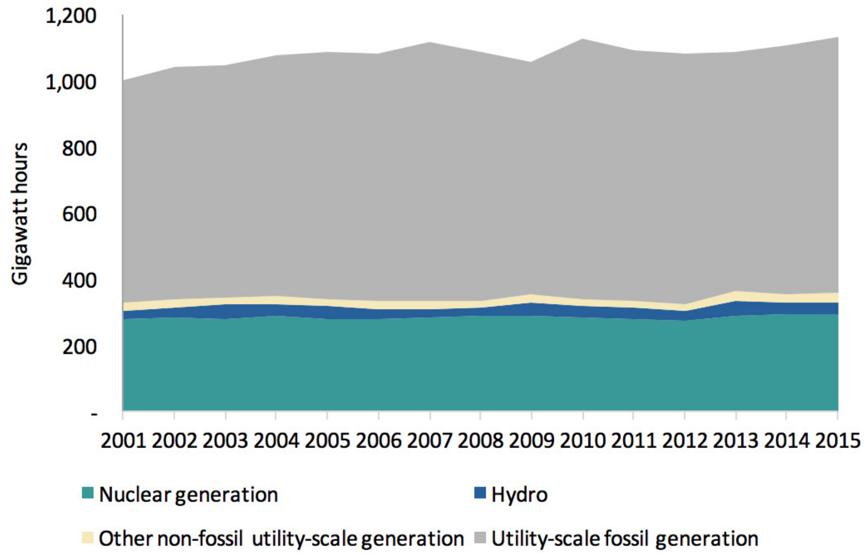
[7] Dominion, "Dominion Virginia Power's and Dominion North Carolina Power's 2016 Integrated Resource Plan," (2016) at 12.

[8] An example of a major capital expense to operate a nuclear unit for 80 years is the potential need to replace the unit's steam turbines. If a nuclear plant operator or Nuclear Regulatory Commission determines that a major component such as steam turbines need to be replaced for a unit to continue operating past 60 years, the cost of extending the life of that unit would significantly increase relative to that of a plant that requires only continued maintenance and could cause the plant owner not to seek approval for a second operating license extension.

[9] Nuclear capacity data from the EPA's NEEDS database version 5.15.

[10] Natural gas and coal generation tend to operate at capacity factors well below 90% on average. 2015 Southeast coal and natural gas capacity estimates from NEEDS version 5.15 database.

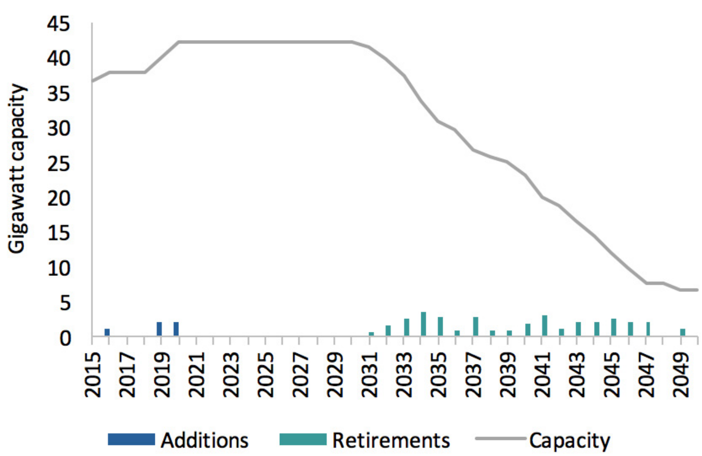
Figure 2. Historical generation in Southeast



Source: EIA Electricity Data Browser, http://www.eia.gov/electricity/data/browser/.

The nuclear fleet in the Southeast is relatively old.[11] Of the 38 existing units, 33 have been in operation at least 30 years, and 16 units, at least 40 years. Thus, if all existing nuclear units in the Southeast were to retire after 60 years of operation, the region's nuclear capacity would quickly drop off after 2030 (Figure 3). By the end of 2040, some 45% of nuclear capacity in the region, including units currently under construction, would be retired. By 2045, some 72% would be retired. Yet Southeast utilities have only three new reactor applications under review at the NRC and two applications that recently received NRC approval.[12] Given the lack of new unit applications and the long lead time required to build new units, the Southeast is unlikely to maintain its 2020 nuclear capacity if many existing units retire after operating for 60 years.

Figure 3. Southeast nuclear capacity assuming a 60-year lifetime



Source: EPA NEEDS database version 5.15, https://www.epa.gov/airmarkets/power-sector-modeling-platform-v515.
Note: This figure reflects the assumption that no new units, other than those currently under construction, are built. It does not include planned or potential unit uprates.

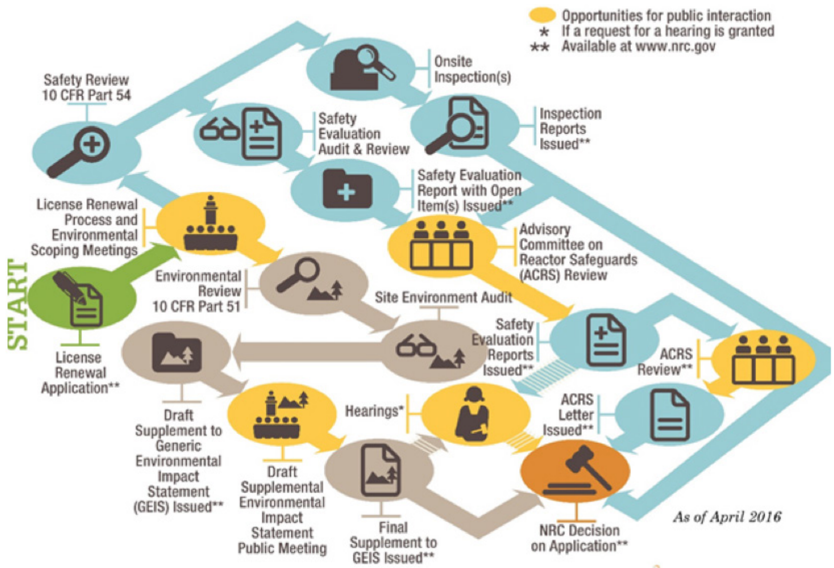
[11] For comparison, the average capacity-weighted age of natural gas combined cycle plants in the Southeast, according to information gathered from NEEDS database version 5.15, is 13 years.

[12] For a map of current applications, see NRC, "Location of Projected New Nuclear Reactors," (updated December 9, 2016), accessed December 20, 2016, http://www.nrc.gov/reactors/new-reactors/col/new-reactor-map.html. The NRC recently approved Levy units 1 and 2 licenses. See, NRC, "Issued Combined Licenses for Levy Nuclear Plant," (updated November 2, 2016), accessed December 21, 2016, https://www.nrc.gov/reactors/new-reactors/col/levy.html. Duke Energy has announced that it is not proceeding with the Levy project. See, David Adams, "Duke Energy Shelves Major Nuclear Project in Florida," Reuters (August 1, 2013), accessed December 21, 2016, http://www.reuters.com/article/utilities-duke-levy-idUSL1N0G227O20130802. In December the NRC issued combined licenses for Lee units 1 and 2. See, NRC News, "NRC Issues New Reactor Licenses to Duke Energy for William States Lee III Site in South Carolina," (December 21, 2016), accessed December 21, 2016, https://www.nrc.gov/reading-rm/doc-collections/news/2016/16-075.pdf.

Overview of Second Operating License Extension

The NRC licenses and regulates nuclear power plants under the Atomic Energy Act, which grants it authority to issue initial operating licenses for a period of 40 years and to extend those licenses.[13] NRC regulations provide that a license extension shall not exceed 20 years.[14] NRC regulations governing license extensions were developed for initial extensions from 40 to 60 years. These regulations, which include separate safety and environmental reviews, focus on identifying aging effects that could impair plant operations and on demonstrating that those effects will be adequately managed.[15]

Figure 4. NRC operating license extension process



Source: Backgrounder on Reactor License Renewal, http://www.nrc.gov/reading-rm/doc-collections/fact-sheets/fs-reactor-license-renewal.html.

The NRC is developing guidance for second extension applicants and NRC staff to apply the existing regulatory framework to so-called subsequent (second) operating license extensions from 60 to 80 years, with a goal of finalizing that guidance in summer 2017.[16] In 2016, the NRC released draft guidance identifying technical challenges to operation beyond 60 years and emphasizing industry's responsibility to address those and other aging management issues.

Key aging management issues pertain to material degradation, especially related to primary system metals, welds, and pipes; concrete and containment structures; electrical cables; reactor pressure vessels; and buried piping.[17] Research by the Department of Energy's Light Water Reactor Sustainability program and the Electric Power Research Institute's Long-term Operations program that has informed the NRC guidance identifies no generic technical barriers to long-term operation, assuming adequate aging management practices.[18]

The Nuclear Energy Institute, a nuclear industry trade organization, estimates that preparing an application for submittal will take approximately two years.[19] NRC regulations specify that if a plant operator submits a complete application at least five years before expiration of its operating license, the plant can continue operating pending a final decision from the NRC.[20] Therefore, many operators are likely to begin preparations for a second (subsequent) license extension at least seven years before its license expires.

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[13] Atomic Energy Act, U.S. Code (2133(c)).

[14] Requirements for Renewal of Operating Licenses for Nuclear Power Plants. Code of Federal Regulations, § 54.31(b).

[15] Ibid.

[16] For the subsequent license renewal (SLR) process, NRC staff are preparing two main guidance documents: the Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report, which provides guidance for SLR applicants as well as the NRC staff's generic evaluation of plant-aging management programs and which establishes "the technical basis for adequacy," and the "Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants," which provides guidance to NRC staff reviewers of applications. See NRC, "Subsequent License Renewal," (updated December 9, 2016), accessed December 21, 2016, http://www.nrc.gov/reactors/operating/licensing/renewal/subsequent-license-renewal.html.

[17] American Physical Society, supra note 4 at 4.

[18] Ibid.

[19] Nuclear Energy Institute, "Second License Renewal Roadmap" (2015) at 7.

[20] Agency Rules of Practice and Procedure. *Code of Federal Regulations.* § 2.109(b).

Electric utilities Exelon and Dominion have already notified the NRC of plans to submit a second license extension application for their Peach Bottom and Surry nuclear plants in 2018 and 2019, respectively.[21]

Existing Utility Planning Process in the Southeast

All states in the Southeast use traditional, cost-of-service, electric utility regulation for investor-owned utilities in their states. Whereas all power plant costs must be recovered through energy markets in restructured states, approved capital costs are passed through to customers in the rate base in states with cost-of-service regulation. This practice allows traditionally regulated utilities, compared with power plant owners in restructured states, to make investments and capacity decisions on the basis of longer time frames.

Although specific requirements vary by state, long-term electric utility planning in the Southeast is typically done through integrated resource planning. IRPs are the long-term planning documents submitted by regulated utilities to their respective state utility commissions. These plans map out portfolios of generation capacity additions, demand-side energy management programs, and other investments to meet forecast demand for 15 or more years. IRPs typically compare multiple portfolios of investments—combinations of baseload, peaking, and intermittent renewable capacity additions as well as demand-side management programs, purchase contracts, and transmission and distribution investments—across multiple scenarios that represent different potential futures. Electric utilities typically select a preferred portfolio on the basis of the portfolio that has the lowest total system operating cost. Additional considerations for determining a preferred portfolio include fuel diversity as well as qualitative and quantitative risk factors.

A major challenge for integrated resource planning and electricity capacity planning in general is that what is optimal can vary widely, depending on the modeled future scenario. A portfolio that is least cost in a future with low fossil fuel prices, no carbon restrictions, and minimal technology change may be very high cost in a future with high fossil fuel prices, stringent carbon emission limits, and large advances in technologies such as wind, solar, and battery storage.

Future of the Existing Nuclear Fleet in the Southeast and Electricity Planning Challenges

The potential for the large-scale loss of nuclear generation in the Southeast is one part of a broad array of planning challenges facing utilities, utility regulators, consumer advocates, and other stakeholders in the region. These challenges stem from both the major changes that have occurred in the electricity sector over the past 10 years and the potential for even greater change, driven in part by changing technology. The large size of existing nuclear units and the long lead times for both relicensing existing nuclear units and building new nuclear units increases the complexity and consequence of planning challenges facing the region; much can change in 5 to 15 years, and investment and regulatory decisions about individual nuclear power plants affect large increments of both generation and capacity.[22] How decisions about the existing nuclear fleet interact with other specific planning challenges facing the region is described below.

Increasing Natural Gas Dependence

Low natural gas prices, combined with low capital costs for new natural gas units and low emissions of carbon dioxide and other pollutants relative to coal generation, have spurred a major increase in natural gas generation in the Southeast over the past decade (Figure 5). Natural gas combined cycle (NGCC) units, which have higher efficiency and lower capital costs than new coal units, represent the majority of new baseload capacity added in 2016 and under construction in the region.[23]

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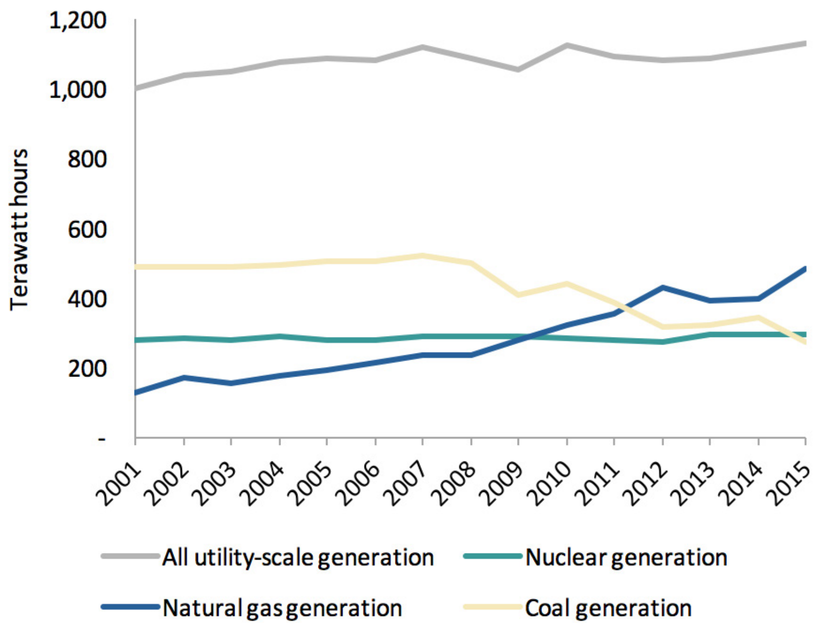
[21] NRC, "Subsequent License Renewal," (updated December 9, 2016), accessed December 21, 2016, http://www.nrc.gov/reactors/operating/licensing/renewal/subsequent-license-renewal.html.

[22] Nuclear units are often about 1 gigawatt in capacity—equal to the maximum capacity of coal units and natural gas units but much more than the capacity of typical energy efficiency, renewable energy, and natural gas investments. This reduces the impact, both positive and negative, of any single investment or regulatory decision, relative to the loss or retention of an existing nuclear unit or such a unit's replacement with a new nuclear unit.

[23] Capacity addition data from Electric Power Monthly released October 25, 2016, by EIA, accessed December 21, 2016, http://www.eia.gov/electricity/monthly/#tabs_unit-4. NGCC plants are natural gas plants that operate at a high efficiency and that can serve as baseload generation, similar to coal and nuclear. As seen in Table 1, the levelized cost of new coal with partial carbon capture is significantly higher than that of new NGCC units. EIA's *Annual Energy Outlook 2016* does not include new coal without carbon capture, but in *Annual Energy Outlook 2015,* new coal without carbon capture has capital costs approximately triple those of new NGCC units. EIA, "Annual Energy Outlook 2015," (2015).

Figure 5. Historical natural gas, coal, and nuclear generation in the Southeast



If natural gas prices continue to align with the U.S. Energy Information Administration's (EIA) Annual Energy Outlook projections, natural gas is likely to be the least-cost dispatchable new build resource in the Southeast and nationally. According to EIA estimates of the levelized cost of new generation coming online in 2022 and 2040, NGCC units are the lowest-cost dispatchable resource across the country (Table 1).[24] The low cost of new NGCC plants likely means that retiring nuclear units will be replaced, in large part, by NGCC capacity. The low cost of new gas generation also makes it difficult for utilities to receive utility commission approval for new nuclear units; EIA's levelized cost estimates are 32% to 46% higher for nuclear units than NGCC units. Similarly, low natural gas prices will factor into the decision to invest in a second license extension because retiring and replacing existing nuclear units with NGCC and other resources may be lower cost than relicensing.

Table 1. EIA-estimated range of levelized cost of new generation entering service in 2022 and 2040 in 2015$/MWh across different regions of the United States

	2022			2040		
	Minimum	Average	Maximum	Minimum	Average	Maximum
Coal w/CCS	$129.9	$139.5	$162.3	$116.9	$125.8	$144.3
NGCC	$53.4	$58.1	$67.4	$53.9	$57.6	$65.5
Nuclear	$99.5	$102.8	$108.3	$90.2	$90.3	$97.6
Biomass	$81.5	$96.1	$115.6	$62.4	$78.7	$105.5
Wind (non-dispatchable)	$35.4*	$56.9*	$70.9*	$39.0	$58.8	$70.1
Solar (non-dispatchable)	$51.6*	$66.3*	$97.7*	$50.9*	$65.5*	$96.5*

Source: http://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf.
Note: Prices of coal with carbon capture and storage reflect the assumption that 30% of CO_2 emissions are captured.
*Includes federal tax incentives.

[24] According to EIA estimates, geothermal is the least-cost dispatchable resource, but it is very limited in availability by geography. The Southeast does not have good geothermal resources. EIA, "Levelized Cost and Levelized Avoided Cost of New Generation in the Annual Energy Outlook 2016," (August 2016), accessed, December 21, 2016, http://www.eia.gov/forecasts/aeo/pdf/electricity_generation.pdf.

Although market conditions are favorable to increasing natural gas generation, increasing natural gas dependence can create risk for utilities and ratepayers because natural gas prices tend to be volatile relative to other fuels and in the past have proved difficult to forecast for extended periods of time.[25] Additionally, natural gas is harder to store than other fossil fuels and uranium, making it more vulnerable to supply disruptions. Fears of overdependence on natural gas are often raised by utilities and cited in planning and investment decisions.[26] The potential retirement of existing nuclear plants in the Southeast would likely increase dependence on natural gas and its associated risks. Unanticipated retirements of existing nuclear units—for example, a nuclear unit operator's unexpected failure to seek or be granted a second operating license extension—may force utilities in the region to default to natural gas because lead times to build new gas plants are shorter than those for coal and significantly shorter than those for nuclear units.[27]

Carbon Regulatory Risk

With a change of administration at the federal level and legal challenges to the Clean Power Plan, near-term national limits on carbon dioxide emissions for the electricity sector are uncertain.[28] Despite the legal and political uncertainty, electricity planning tends to take a long-term view of potential climate regulation because the sector has a long planning horizon and power plants operate for 30 or more years.[29]

Concerted efforts to reduce the risk of climate change are likely to require significant reductions, on the order of 80% or more, of carbon dioxide emissions from the electricity sector. A loss of the major source of zero carbon generation in the Southeast would make any efforts to reduce emissions from the sector more difficult. The construction of new nuclear capacity, the primary zero-carbon baseload replacement option, is expensive relative to other generation options and would likely reduce funding available to reduce emissions from other sources in the sector. Wind and solar are intermittent and therefore are not an exact replacement for existing baseload generation without significant balancing resources; these resources would most likely be natural gas plants. If retiring nuclear is replaced with natural gas generation, carbon emissions would increase.[30] Unanticipated nuclear retirements could create major gaps in plans to reduce emissions in the region.

Technology Change and Demand Uncertainty

Declining costs for renewable generation, especially solar, have introduced new generation resources into the Southeast. Solar capacity in the region has risen from just 3 MW in 2008 to 2,484 MW as of September 2016; another 1,407 MWs are under construction.[31] Although the majority of solar capacity in the Southeast is utility scale, distributed solar is growing. And although most projections indicated a continued decrease in solar installation costs, the scale and pace of this decrease are uncertain. The National Renewable Energy Laboratory projects future costs of new solar installations for a range of solar resources (strength of solar insolation) in its Annual Technology Baseline. For an average solar resource, the 2016 Annual Technology Baseline projects that the levelized cost of new utility-scale solar PV in 2040 will

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[25] Center for Climate and Energy Solutions, "U.S. Natural Gas Overview of Markets and Uses," (May 2012), accessed December 21, 2016, https://www.c2es.org/docUploads/natural-gas-markets-use.pdf. This paper provides an overview of the historical volatility of natural gas prices and the difficulty of forecasting prices. Knittel et al., "Natural Gas Prices and Coal Displacement: Evidence from Electricity Markets," MIT Center for Energy and Environmental Policy Research (October 1, 2015), accessed December 21, 2016, http://web.mit.edu/knittel/www/papers/Coal_latest.pdf. Figure 3 in this paper shows higher historical volatility of natural gas prices relative to coal.

[26] For example, see Progress Energy, "Progress Energy Florida Files Annual Nuclear Cost-Recovery Clause Projections with the Florida Public Service Commission," (May 1, 2012), https://www.progress-energy.com/company/media-room/news-archive/press-release.page?title=Progress+Energy+Florida+files+annual+nuclear+cost-recovery+clause+projections+with+the+Florida+Public+Service+Commission&pubdate=05-01-2012. The author states that Florida's generation mix is more than 60% natural gas and "overdependence on any one fuel source can expose customers to potential fuel cost spikes and supply disruptions…expanding utilities' nuclear generation capabilities helps…reduce these risks."

[27] If a new natural gas plant requires new pipeline capacity, lead times can increase considerably.

[28] Amanda Reilly, "Rule's Demise Looms, but How Trump Will Ax It Remains Unclear," *Greenwire* (November 9, 2016), accessed December 21, 2016, http://www.eenews.net/stories/1060045517 (*subscription).*

[29] The Duke Energy Carolinas 2016 IRP includes a carbon tax and a system-wide CO_2 cap scenario. The Duke Energy Progress 2016 IRP reflects the same scenarios. The Georgia Power 2016 IRP includes two carbon tax scenarios. The TVA 2015 IRP includes a decarbonized future scenario.

[30] Whitney Herndon and John Larson, supra note 1.

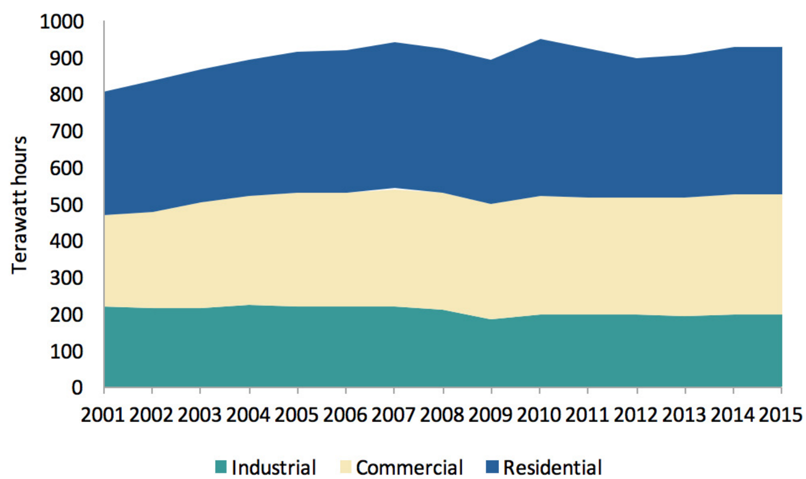
[31] For state-level solar capacity data, see "EIA Electricity Data Browser,"accessed December 21, 2016, http://www.eia.gov/electricity/data.cfm#gencapacity.

range from $35/MWh on the low end, to $55/MWh for the baseline, to $114/MWh for the high end.[32] The low estimate is well below EIA's levelized cost estimates for solar and other resources, and the high end exceeds EIA's levelized cost estimates for new nuclear (Table 1). This uncertainty, which also exists for other emerging technologies like battery storage, increases the uncertainty surrounding the relative cost of generation options in the future both for new builds and the cost competitiveness of existing resources like nuclear.

Declining technology costs also add to the uncertainty surrounding electric utility sales. In addition to utility-scale solar, distributed solar—which has a wide range of cost reduction pathways—is also growing in the Southeast and could significantly affect utility sales.[33] Decreased sales due to distributed generation or other factors reduce the ability of utilities to spread capital costs across each kWh of sales and can increase electricity rates. Other technological advancements, like vehicle electrification, could create a significant new demand source for the sector. The development of grid-level battery storage could profoundly change the electricity sector, introducing additional uncertainty into planning. The EIA and major Southeast IRPs project electricity sales growth in the region, but retail sales have been roughly flat over the last decade (Figure 6).[34]

The potential loss of nuclear as a major baseload source in the region under demand uncertainty creates a number of challenges. If utility sales remain flat, capital costs to replace existing nuclear would not be spread across a growing sales base. If retail sales increase, the loss of baseload generation would potentially be more manageable because of greater sales but would still require major investments beyond those needed to meet demand growth. The long lead times for second relicensing and for replacing existing nuclear units with new nuclear units is challenging because technology change is a major source of the uncertainty surrounding demand growth. Technology advances can drive major changes in electricity generation and sales within the lead times for relicensing existing nuclear units and for building new nuclear units.

Figure 6. Historical retail electricity sales in the Southeast



Source: http://www.eia.gov/electricity/data/browser/.

Planning for the Future of Existing Nuclear Units

As utilities, regulators, and other stakeholders face decisions about the future of the existing nuclear fleet, state policy makers may wish to consider opportunities to address this uncertainty in utility commission proceedings or state energy plans. As this policy brief has described, decisions about whether to extend the operating licenses of existing nuclear plants—and which resources should replace any retiring capacity—will come at a time of significant uncertainty regarding future electricity demand and the pace and scale of technological change and a time of increasing natural gas dependence. Because no existing nuclear plants have gone through the second relicensing process and the requirements for doing so are not yet

[32] NREL, "Annual Technology Baseline and Standards Scenarios," (2016), accessed December 21, 2016, http://www.nrel.gov/analysis/data_tech_baseline.html.

[33] The referenced solar capacity is utility-scale solar capacity. The EIA estimate for distributed solar in the Southeast is 474 MW. EIA, "Electric Power Monthly," (November 29, 2016), accessed December 21, 2016, http://www.eia.gov/electricity/monthly/.

[34] The Dominion Virginia Power 2016 IRP projects 1.5% annual load growth. Georgia Power Company's 2016 Energy and Load Forecasts projects 1.2% annual load growth through 2035. The EIA's *Annual Energy Outlook 2016* projects 0.8% national electricity sales growth without the Clean Power Plan and 0.8% to 1.1% regionally.

final, it is difficult to predict how many existing plants will seek and receive operating license extensions. This uncertainty, combined with ongoing changes in the electricity sector and long lead times for both second relicensing and construction of new nuclear create significant planning challenges for utilities, state utility regulators, consumer advocates, and other stakeholders.

Planning for the Future of Nuclear Power in Commission Proceedings

One obvious venue for states to begin planning for the future of existing nuclear capacity is within utility commission proceedings. Throughout the Southeast, these commissions regulate investor-owned utilities, approve (or disapprove) utility capital investments, and oversee integrated resource planning. State utility commissions can establish formal or informal proceedings to learn more from existing nuclear plant owners about their current plans for units reaching 60 years. In these proceedings, commissions can request preliminary cost estimates for the continued operation of existing units past 60 years as well as information on potential technical and licensing challenges. In addition, state commissions can take action to ensure that planning processes such as integrated resource planning look far enough into the future to capture potential retirements and include scenarios that reflect the range of potential futures for existing nuclear units reaching 60 years of operation. For example, IRPs that present 15 years of modeling results (through 2030 or 2031) do not capture most potential retirements in the next 20 years. Presenting the results of modeling through 2035 or 2040 would give commissions a better picture of the potential impact of retirements if the IRP includes a range of retirement scenarios.

Planning for the Future of Nuclear Power in State Energy Plans

Additionally, outside of utility commission proceedings, states may wish to consider the ongoing role of nuclear generation in state energy plans. State energy plans provide a vision for energy policy and technology development and deployment. This vision serves as a resource for state governors, legislators, agencies, state utility regulators, and businesses to help prioritize policy directives, regulatory actions, utility planning, and investments. The planning process typically includes a significant role for stakeholder engagement and consensus building, providing a non-regulatory forum for examining the impacts of potential nuclear retirements on a state's generation mix and emissions as well as for examining how those impacts are likely to shape state energy goals. Moreover, a state energy plan can include strategies to mitigate the effects of potential retirements, for example by expressing a policy preference to retain existing nuclear capacity that is safe to operate, increasing the deployment of other zero-emission resources, or establishing goals related to the deployment of advanced nuclear technologies.

Acknowledgments
The authors wish to thank Whitney Herndon with the Rhodium Group, Anthony James with the South Carolina Office of Regulatory Staff, Robert Trokey with the Georgia Public Service Commission, Tina Taylor with the Electric Power Research Institute, Mike Franklin with Duke Energy and Nicholas Institute colleagues Martin Ross and Brian Murray for their thoughtful comments on the paper.

Citation
Hoppock, David, and Sarah Adair. 2017. “The Uncertain Future of Nuclear Power in the Southeast: Implications of an Aging Fleet for Electricity Sector Planning and Emissions.” NI PB 17-01. Durham, NC: Duke University. http://nicholasinstitute.duke.edu/publications.

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