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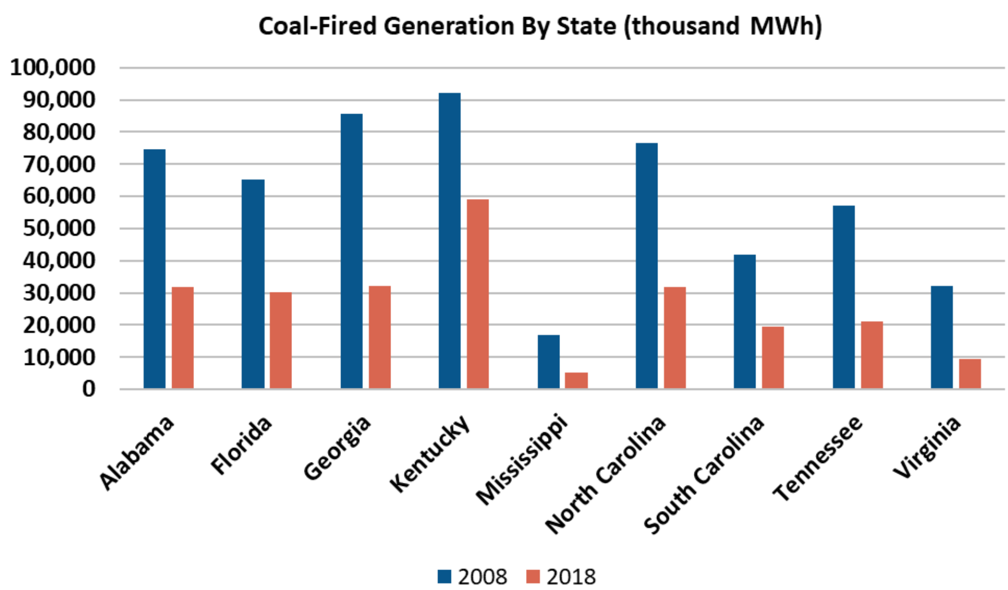
Coal-Fired Power Generation in Freefall Across Southeast U.S.

One-Two Combination of Gas and Solar Is Pushing Historically Dominant Industry Aside

Executive Summary

Historically, the U.S. Southeast[1] has been a stronghold for coal-fired electricity generation. That is no longer the case.

The ready availability of low-cost natural gas has led to a freefall in coal generation across the region over the past 10 years that has outpaced even the national drop in coal-fired generation. This, despite the fact that the area is home to companies such as the Tennessee Valley Authority, Southern Company and Duke Energy—three of the traditionally most coal-reliant utilities in the country. The decline is also noteworthy because the region's utilities are still vertically integrated—controlling generation and transmission—and thus largely shielded from economic pressures like those in fast-changing markets like Texas and the PJM Interconnection,[2] where more competitive generation resources often have an easier route to the market.



Source: EIA data, IEEFA analysis.

[1] In this report, we define the Southeast as including the following nine states: Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee and Virginia.
[2] PJM is the wholesale transmission operator that runs the market serving 13 states and the District of Columbia.

The scope of the collapse is evident in the following graphic, which shows significant decline in each of the nine Southeastern states examined in this report. Even Kentucky, which in 2008 relied on coal for almost 94% of its electricity generation, has seen a significant decrease.

This is just the opening act in what is essentially a two-stage transition that will further erode coal's generation market share in the region over the next five years and beyond—a trend that in several of the states affected could lead to the zeroing out of coal generation. The second act will be driven by solar, which, while still a modest contributor to regional electric output, is poised to grow substantially through the 2020s.

The region has 13.1 gigawatts of installed solar capacity, according to the Solar Energy Industries Association (SEIA), and more than two-thirds of that total is in just two states, North Carolina and Florida. But significant growth is on the horizon. SEIA sees an additional 21.5GW of solar coming online in the region by 2024,[3] an outlook that may be already out-of-date given recent utility and state announcements that are likely to expand the total.

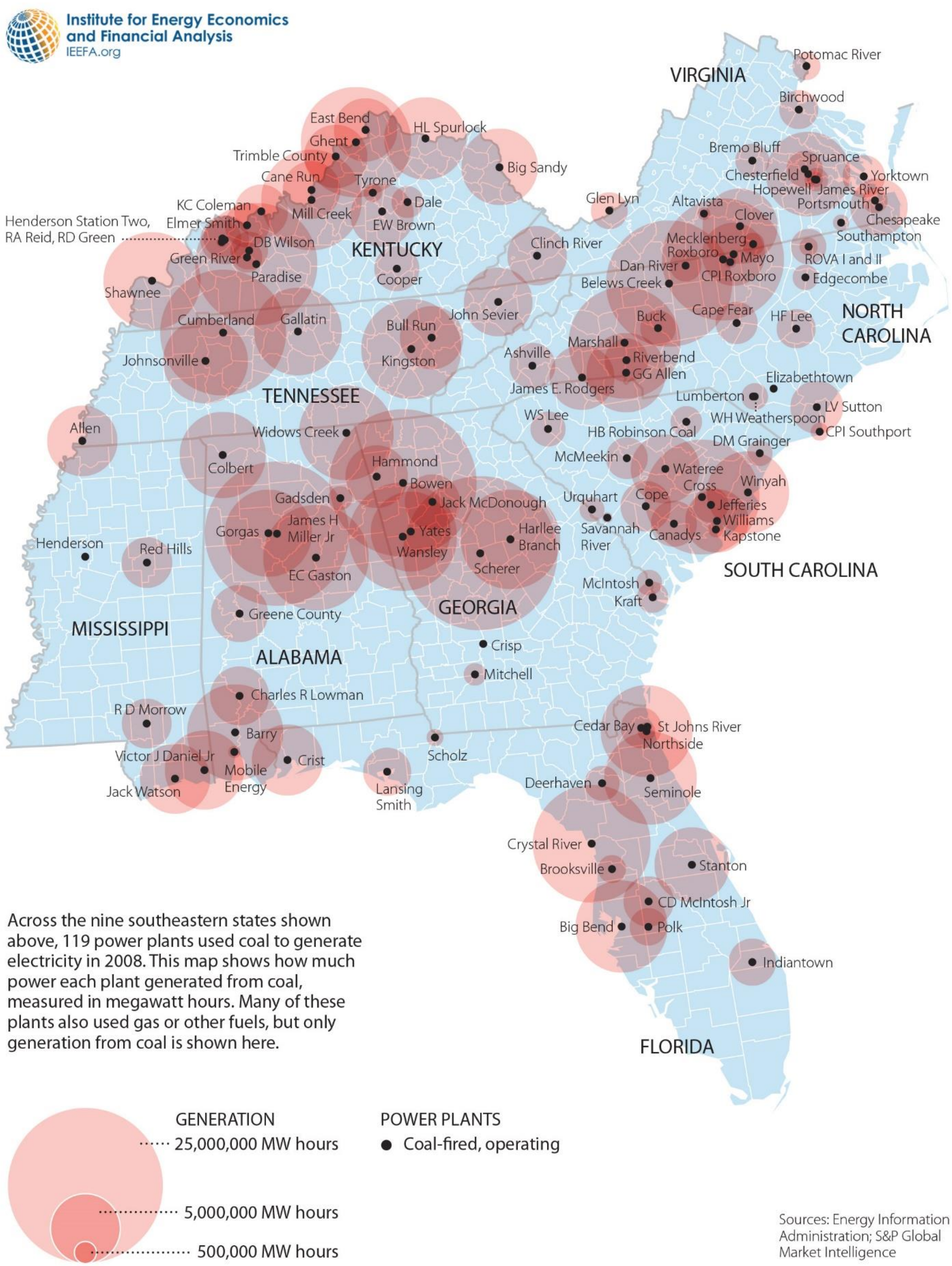
This report—in addition to exploring the impact of the regional solar surge—examines state-specific developments that continue to undercut coal generation, such as the expected completion of Georgia Power's two new nuclear units, the corporate push for renewable energy development in Virginia and other states, and the push by NextEra Energy subsidiary Florida Power and Light to become the nation's leading solar utility.

The future for coal in the region is one of continuing decline, if not complete obsolescence.

[The graphics on the two following pages illustrate the region's transition away from coal, pinpointing the plants and the relative amount of their generation in 2008 and 2018—the change is stark. A graphic circa 2028 will show even less coal generation, by a significant factor, as the report's text explains.]

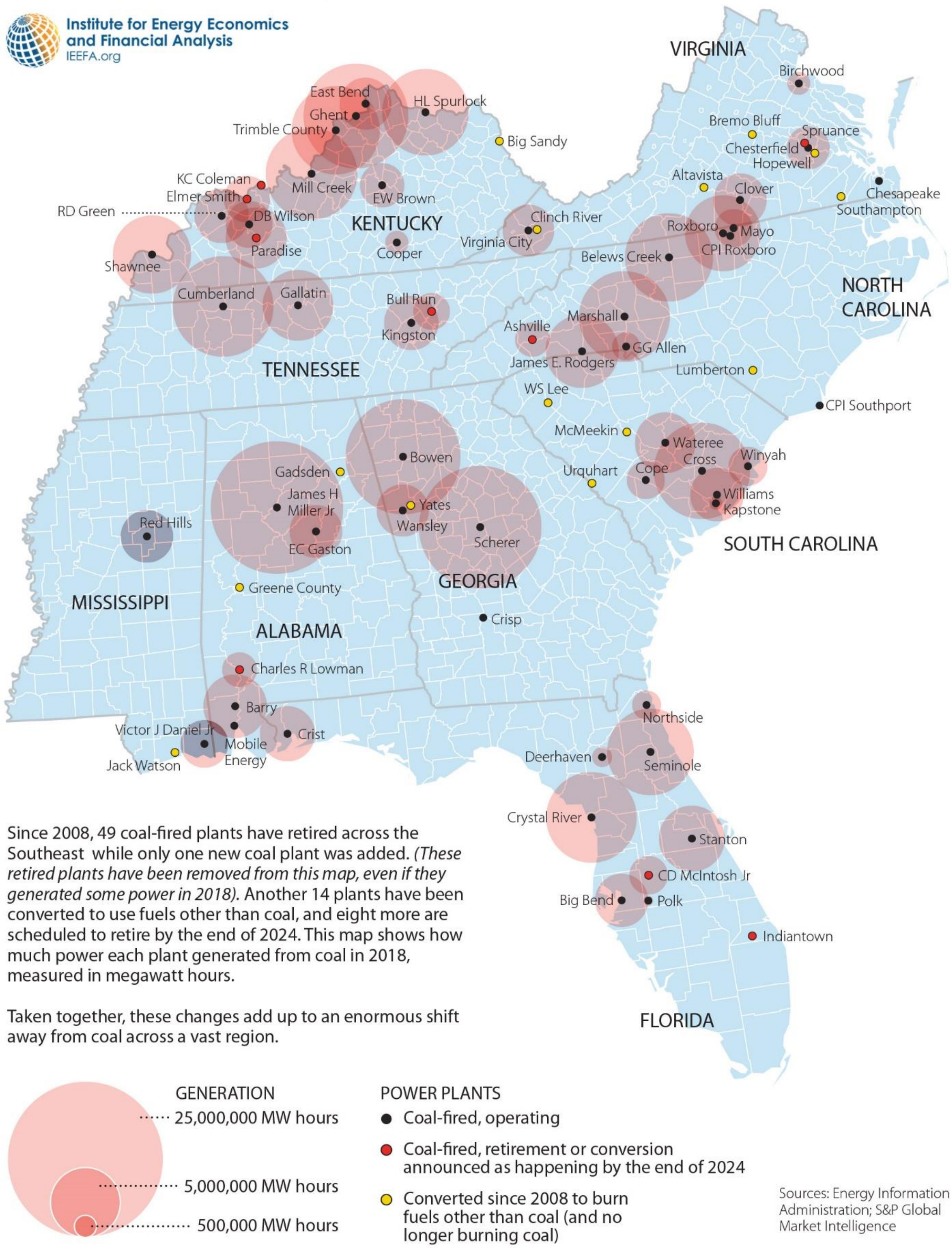
[3] SEIA website. Solar State by State. Accessed September 18, 2019.

Electric Generation from Coal, 2008



Electric Generation from Coal, 2018

At plants still operating as of September, 2019



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The Rise of Gas

The dramatic changes in market perceptions about gas since 2008 have been nothing short of remarkable.

A decade ago, fracturing and horizontal drilling were still in early development stages. Gas was seen by electric utilities as a fuel suitable for intermediate and peaking applications but too pricey and uncertain in terms of long-term supply to be used for baseload electric generation.

Today, production in the Appalachian region alone (which includes the Marcellus and Utica shale resources) has climbed to more than 32 billion cubic feet per day[4]—from essentially nothing a decade ago. This has helped fuel a run-up in national output from just over 20 trillion cubic feet (tcf) in 2008 to more than 30 tcf in 2018,[5] a trend that is still accelerating. Supply, clearly, is no longer a problem.

In turn, the supply surge has had a predictable impact on prices. Henry Hub spot prices (used here as a proxy for the industry as a whole) averaged $5.82 per million British thermal units (mmBtu) in the 2000s. The average since 2010 has been $3.39/mmBtu, and for the past four years it has been $2.82/mmBtu; low prices are expected to persist for the next several years.

The upshot is that gas is now many utilities' preferred resource to meet their generation needs, leaving coal behind.

This transition can be seen nationally in the rapid shift from coal-fired generation to gas from 2008 through 2018. In 2008, coal-fired generation accounted for about 48% of U.S. electricity, but by 2018 had fallen to less than 28%, with projections for continued decline by the Energy Information Administration (EIA). In contrast, the gas sector share of the electricity market had climbed from 21% in 2008 to more than 35% by 2018.

Low-priced gas is now utilities' preferred resource, leaving coal behind.

The electricity-generation transition in the Southeast itself has been even more dramatic. In 2008, coal generated 52% of the electricity for the nine states in this study; by 2018 that figure had fallen to 22%. Similarly, gas accounted for 17% of the

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[4] U.S. Energy Information Administration (EIA) website. Drilling Productivity Report. Accessed September 17, 2019.
[5] EIA web site. U.S. Dry Natural Gas Production. Accessed September 17, 2019.

region's electric generation in 2008, but by 2018 that figure had jumped to 44%—a change that has had irreversible impacts on coal.

Focusing on one plant can help illustrate what's happened. The ensuing graph shows capacity factors at Southern Company's Plant Wansley complex located 60 miles southwest of Atlanta. Wansley includes two supercritical coal-fired units owned by Georgia Power that entered commercial service in 1976 and 1978. The two units have identical net summer capacity ratings of 872 megawatts (MW). The complex also includes two combined-cycle gas units owned by Southern that came online in 2002 and have a combined summer capacity of 1,150MW.

From 2003 to 2008, Wansley's two coal units operated at a capacity factor of near or above 80%, while the gas units posted an average annual capacity factor of less than 30%. Gas price declines and a shift in perception about long-term stable supplies that began to take hold in the latter half of the 2000s have turned the operating equation upside down. Over the past five years, the Wansley gas-fired units have posted an average capacity factor of 73.9% and were over 80% in 2017 and 2018. Meanwhile, the coal-fired units have posted average capacity factors of below 30% since 2012, falling below 20% in 2018.

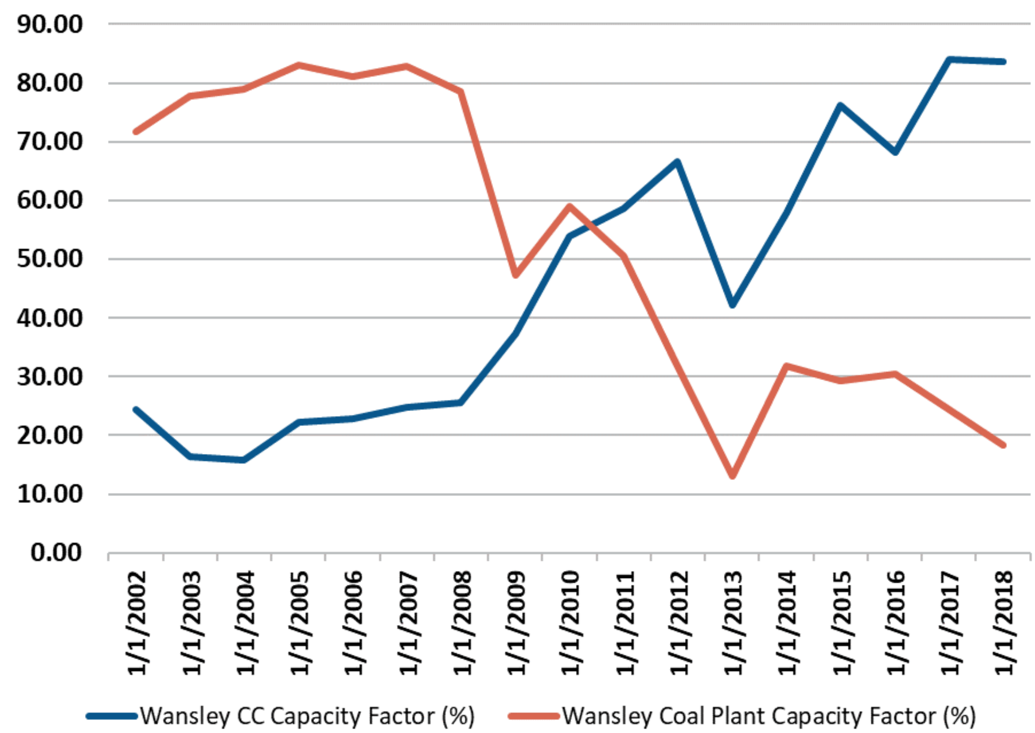
A Note About Capacity Factors

This report uses capacity factors as a proxy for competitiveness, especially when looking at comparable resources such as large coal-fired units and combined-cycle gas turbines. Both forms of generation are designed to run more or less continuously. As a unit's capacity factor rises, it produces more electricity, enabling its fixed costs to be spread over a larger number of units, thus lowering the per-kilowatt-hour price of its generation. Conversely, costs go up as capacity factors decline since there are fewer units to absorb a plant's fixed costs.

Given expectations that plentiful supplies of low-cost gas will persist, coal has increasingly been priced out of the baseload market and is now relegated to intermediate applications that require ramping. These uses strain coal plant equipment and increase costs. The rise in solar generation compounds coal's problems, taking sales during daylight hours and further depressing capacity factors.

All told, 45 utility-scale coal units in the Southeast posted an annual capacity factor of 25% or less in 2018, putting that generation at increasing risk as more renewable capacity (and in the Southeast that means solar) is installed. The death knell for coal could well be sounded by combining solar with storage technology, an increasingly competitive option.

Figure 1: Southern's Wansley Power Plant Complex



Source: S&P data, IEEFA analysis.

Solar Is Coming

The gas capacity goldrush of the past 10 years is being replicated now in the solar sector. In 2008, the annual total of new solar PV capacity installed across the U.S. was just 290MW; last year, installations nationally topped 10.6 gigawatts (GW), a 35-fold increase.[6] The latest forecast from Wood Mackenzie and the Solar Energy Industries Association has installations topping 12GW annually for the next six years (see Figure 1).[7]

In the utility-scale market, Wood Mackenzie and the SEIA say there are 37.9GW of solar PV under development (meaning projects that either are under construction or have a signed power purchase agreement)—a figure that would almost double the 38.9GW of currently operating solar capacity.[8]

Existing solar capacity already is beginning to change the dynamics of electricity markets both nationwide and in the Southeast, with zero-fuel-cost solar taking sales away from coal-fired generation and further undercutting its competitiveness. And much more solar capacity is on the way:

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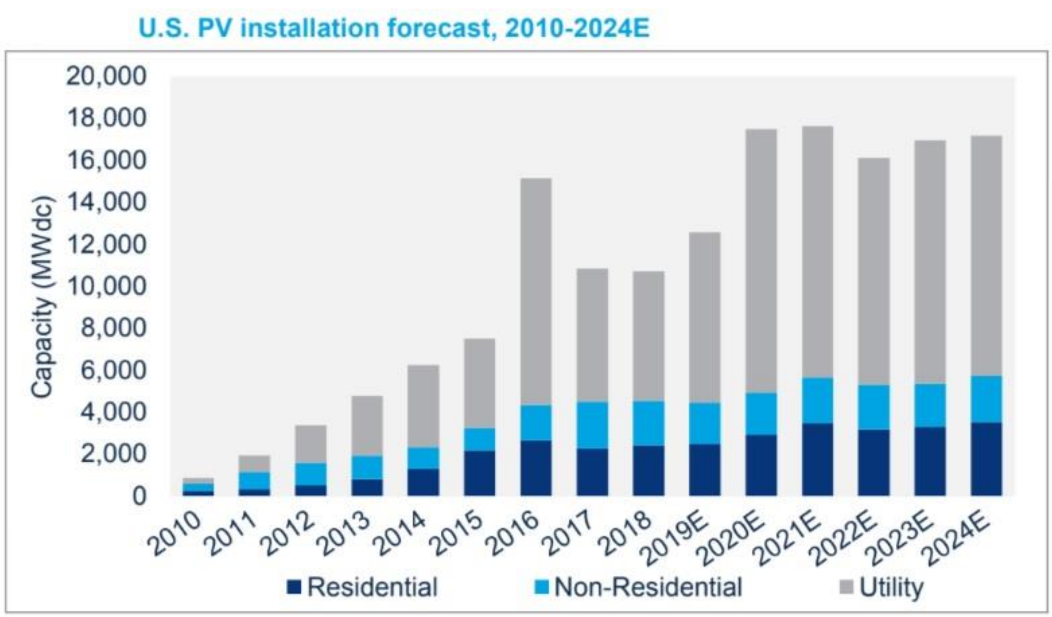
[6] Greentech Media. U.S. Solar Market Insight: 2010 Year in Review. March 10, 2011.
[7] Wood Mackenzie and SEIA. U.S. Solar Market Insight Executive Summary. September 2019, p.16.
[8] Ibid., p. 15.

- In July, Georgia regulators ordered Georgia Power to install 2,260MW of new solar by 2024.
- The three major Florida utilities—Teco, Duke Energy Florida and Florida Power and Light—have plans to install more than 11GW of solar over the next 10 years.
- Santee Cooper, a public power supplier in South Carolina, said in September that it planned to add 1,000MW of solar to its system by 2024.

As this surge of utility-scale solar comes online, the region's remaining coal capacity will be hard-pressed to compete. The industry is further hampered by the age of the region's coal plants—60% of the still-operating capacity in the states covered by this report is at least 40 years old. According to the U.S. Department of Energy's Argonne National Laboratory and the National Energy Technology Laboratory, coal plant heat rates increase with plant age, while plant availability declines.[9] Older plants also tend to have more unanticipated problems requiring more frequent shutdowns. All of these factors raise operations and maintenance costs, increasing the competitive disadvantage of coal-fired generation.

These forces will very likely speed up the transition to solar—and the uptake of solar linked with storage—pushing more and more coal out of the market.

Figure 2: The Outlook for U.S. Solar Installations



Source: Wood Mackenzie Power & Renewables.

[9] See, e.g. U.S. Department of Energy Staff Report to the Secretary on Electricity Markets and Reliability at page 155 (Aug. 2017). Heat rate is a measure of a power plant's efficiency in generating electricity, and plants tend to become less efficient as they age. Plant availability measures the percentage of possible operating hours in which a plant was actually available to generate power.

State-by-State Review

The pages that follow explore trends in each of the nine states separately, identifying operating coal plants and the threats facing them. State-specific issues are highlighted, and tipping points in the transition are examined.

Many of the utilities in the region buy power from and/or own plants in other states—Florida companies own pieces of Plant Scherer in Georgia, for instance. This analysis is focused geographically on where facilities are located, not where the owner/buyer is based. Consequently, some coal capacity is excluded, such as Entergy Mississippi's coal power purchases from corporate partners in Arkansas and Dominion/Virginia Power's ownership of the Mt. Storm Power Station in West Virginia. That said, a broad, rapid and most likely irreversible transition away from coal is clearly occurring across the Southeast.

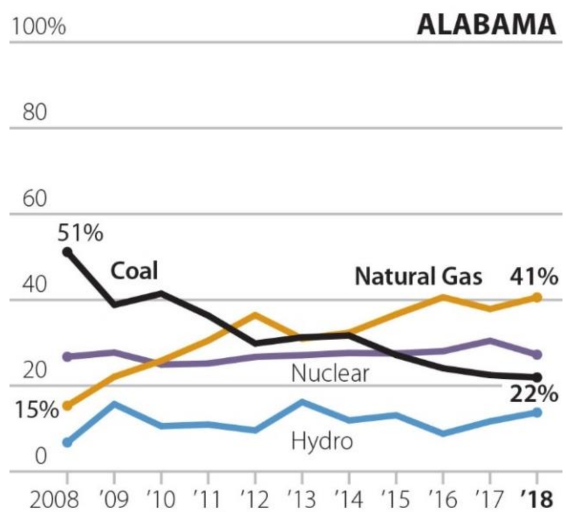
Alabama

Coal's share of the state's overall electric generation fell from 51% in 2008 to 22% in 2018. During the same period, electric use remained relatively flat, falling from 146.7 million megawatt-hours (MWh) in 2008 to 144.9 million MWh in 2018.

During this period, gas-fired generation in the state soared from 21.9 million MWh in 2008 to 58.8 million MWh last year—reducing its share of the state's electricity generation to 41%.

Coal's share of statewide generation has continued to drop in 2019, pushed down by the closure of Alabama Power's Plant Gorgas, a three-unit station with 1,062MW of capacity, earlier this year. Through June, year-to-date coal generation has totalled 12.7 million MWh, down from 16.3 million MWh in the first six months of last year.

Fuel Share for Electric Power Generation (Utility Scale, All Sectors)



Only fuels with 5% or more share in any year are shown.
Source: Energy Information Administration

With the closure of Gorgas, there are now four operating plants in the state:

- PowerSouth Cooperative's three-unit Lowman Plant, with a total capacity of 556MW.
- Alabama Power's two-unit, 1,118.5MW Plant Barry.

- The four-unit, 2,765.9MW Plant Miller, which is owned largely by Alabama Power (PowerSouth owns an 8.1% stake in two of the plant's four units).
- The five-unit, 1,861MW E.C Gaston Steam Plant owned by Alabama Power and Georgia Power. Formerly a coal-only plant, Gaston now burns a significant amount of gas for power generation; its coal consumption dropped from 4.5 million tons in 2008 to 1.2 million tons in 2018.

The Lowman facility won't be around much longer. The co-op's CEO told employees in December 2018 that the plant would close at the end of October 2020.[10] To replace the lost generation, the cooperative is planning to build a new gas combined-cycle plant on the Lowman site. According to Fitch, the cooperative plans to have the new 631MW plant online by 2023.[11]

The outlook for the three other plants is less certain, but the Barry station could be in trouble, particularly Unit 4, a 362MW boiler that came online at the end of 1969. That unit's annual capacity factor has trended down since 2008, from 59% to 26% in 2018. On top of this, Alabama Power recently filed with state regulators for permission to add 2,236MW of new capacity to its system, largely because of what the utility asserts is a need to meet rising demand in the winter.[12] A review of Unit 4's generation during the past several winter seasons does not indicate any such need: From December to February in 2016-2017, Unit 4 posted an average capacity factor of 10.9%; in 2017-2018 it climbed to 25.9%; and then in 2018-19 it dropped to 14.8%. This suggests there is no serious need for additional winter capacity. But assuming new capacity is built, particularly the 743MW combined-cycle gas plant the utility wants to put on the Barry site, it would likely cut further into the need for Unit 4's output.

Alabama Power is seeking to contract five new solar-plus-storage plants.

Another proposal in Alabama Power's recent capacity-addition request is also likely to undermine its coal-fired generation. The company is seeking regulatory permission to contract for five solar-plus-storage plants with a total winter capacity

[10] Power South Energy Cooperative. "Lowman People," CEO column. December 31, 2018.
[11] S&P Global Market Intelligence. Ala. utility plans to close coal-fired plant, citing US EPA coal ash rule. February 1, 2019.
[12] Alabama Power. Petition for a certificate of convenience and necessity. September 6, 2019, p. 28.

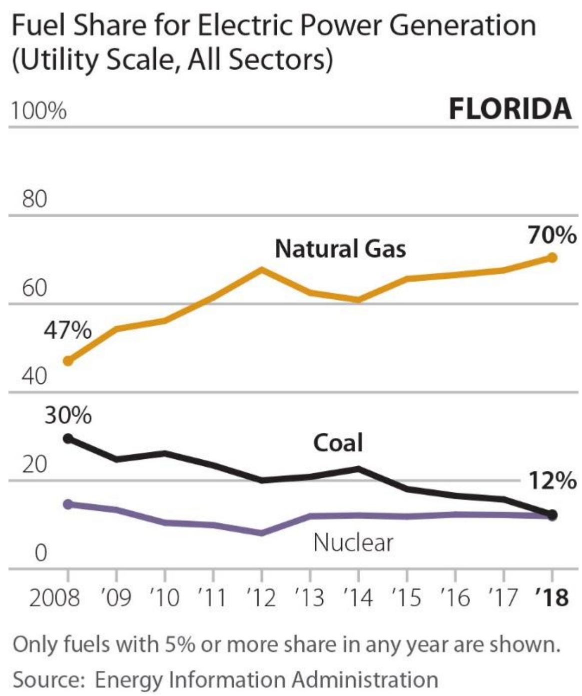
of 340MW (68MW for each site). If built, the facilities would have dispatch costs below that of Plant Barry, where operations and maintenance costs alone were reported at more than $53/MWh in 2018.[13] In contrast, utilities in states that include Arizona, Indiana and Nevada, to name just three, are moving forward with solar-plus-storage projects at prices well below $50/MWh. This example in and of itself may not constitute a market tipping point, but it is a start.

Florida

Gas already was the primary source of electricity generation in Florida in 2008, but the transition away from coal since then has been dramatic, nonetheless.

Overall electric consumption in the state has climbed significantly since 2008, rising more than 11%, from 219.2 million MWh to 244.9 million MWh in 2018. None of that increase went to coal. In fact, coal generation fell from 65.1 million MWh in 2008 to just over 30 million MWh in 2018, reducing its share of the state's generation to 12%.

This decline is likely to continue in 2019, with coal generation through June having dropped to 9.7 million MWh, down 30% from the comparable year-earlier period.



There still are nine operating coal plants in the state, with a total installed capacity of 7,883MW. But a large portion of that capacity is already slated for closure, while the rest is threatened by the quickly growing interest among Florida's utilities in tapping into the renewable resource that gave rise to the state's "Sunshine State" nickname.

The state's remaining coal-fired capacity includes:

- Florida Power and Light's Indiantown Cogen Facility, a 330MW unit scheduled to close in March 2020 but that has generated power only once since the end of 2017;

[13] S&P Global. Barry Power Plant Profile. Accessed September 24, 2019

- Deerhaven Generating Station, a 252MW unit owned by Gainesville Regional Utilities that came online in 1982;
- Unit 3 at the C.D. McIntosh plant, a 342MW unit owned by the city of Lakeland and the Orlando Utilities Commission that is scheduled to close in 2024;
- Stanton Energy Center, a two-unit, 896MW plant jointly owned by the Orlando Utilities Commission, Florida Municipal Power Agency and Kissimmee Utility Authority;
- Crist Plant a four-unit, 924MW facility owned by Gulf Power, now a subsidiary of FPL parent NextEra Energy;
- Jacksonville Electric Authority's two-unit, 586MW Northside Generating Station;
- Seminole Electric Cooperative's 1,309MW Seminole Generating Station, where one of two units is scheduled to close in 2022 when the co-op completes work on a new combined-cycle gas plant;
- Duke Energy's two-unit, 1,422MW Crystal River plant;
- Teco's four-unit, 1,602MW Big Bend Power Station;
- Teco's 220MW integrated gasification combined-cycle unit at the Polk Power Station.

Of this remaining coal-fired generation, plans have been announced to retire an additional 2,094MW of capacity by 2024, which will cut the state total to 5,789MW.

More capacity reductions—beyond those—are coming.

The numbers above do not account for the conversion to gas of the Crist Plant in northwest Florida. The utility is already working on constructing a pipeline to bring gas to the plant, which it estimates will be completed by late 2020. Construction of a combined-cycle gas plant, pegged by the company at roughly 950MW of capacity, would follow, with completion estimated for 2021. In NextEra's investor-day presentation earlier this year, CEO Jim Robo said the plan at Gulf Power was to cut its carbon dioxide emissions rate from the current 1,679 pounds/MWh to 1,060 lbs./MWh by 2021[14] – a level that can only be reached by ending coal combustion at Crist. (Gulf Power's other coal-fired capacity, a 50% stake in Plant Daniel in Mississippi, is discussed below, but no changes can be made at that plant until 2024.)

Teco's Big Bend Power Station is also being converted in part to run on gas. Teco received approval from state regulators this summer to convert one of the four units

[14] NextEra. Energy Investor Conference presentation. June 20, 2019, p. 30.

at Big Bend from coal to gas. That conversion is supposed to be complete in 2023. Linked with the approval to convert Unit 1, which came online in 1970, Teco will shutter Unit 2, a similarly sized unit, with 385MW of net summer capacity.

By the early 2020s, in other words, an additional 1,694MW of coal-fired capacity in Florida will be retired, bringing the total down to roughly 4,000MW, which in fact still may be an overstatement. The new combined-cycle gas turbine being built at Big Bend will have 1,090MW of capacity and, like so many of the region's other combined-cycle units, will likely operate at a high annual capacity factor once fully operational. This is certain to put additional economic pressure on the two remaining coal-fired units at Big Bend. Already, the annual capacity factors at Big Bend Units 3 and 4 have dropped from more than 70% in the early 2010s to 45%-55% recently. Further, Teco is moving forward with plans to build 600MW of solar capacity in its service territory, generation that will draw sales directly from the utility's coal generation due to its lower cost.

Coal-fired capacity in Florida will continue to be retired, bringing the total down to roughly 4,000MW.

FPL's 30-by-30 program, under which the utility has committed to build roughly 10GW of new solar capacity by 2030, clearly constitutes a tipping point for solar (and coal) in the Sunshine State.

The state lagged in solar installations until 2018, when Florida utilities added 876MW of new solar to the grid—a 200% increase from 2017.[15] Of this, almost 600MW was installed by FPL, with Teco adding 144.8MW and Duke Energy Florida, the state's other major utility, bringing 74.9MW online.[16]

That uptick came before the FPL 30-by-30 announcement in January 2019, which has markedly changed the landscape. Last year, FPL projected that 4GW of new solar would come online by 2027; now the target is 10GW by 2030—a number that will serve a sizable portion of the state's expected growth in the coming decade.

It also could dampen FPL's interest in retaining its 76.36% ownership stake in Plant Scherer Unit 4 in Georgia, which came online in 1989. That facility, operated by

[15] SEPA web site, accessed Sept. 23, 2019, https://sepapower.org/knowledge/sepas-2019-solar-snapshot-report-finds-floridas-solar-market-is-flourishing/
[16] Ibid.

Georgia Power, has a net summer capacity of 858MW. Jacksonville Electric Authority owns the remainder of the unit.

Elsewhere in Florida, Duke Energy has committed to installing 700MW of solar by 2022, Teco is aiming for 600MW and Gulf Power has announced plans for 225MW of new solar, with the first 74.5MW project expected online in early 2020. Those figures probably understate the total coming to market. Marlene Santos, Gulf Power's president, said at the NextEra investor-day gathering that her utility, "similar to the strategy employed at FPL… will look for additional solar investments to reduce fuel and O&M expense."[17]

The second driver pushing Florida coal aside, and older gas units as well, is the rapid decline in costs for solar-plus-storage applications and the utility sector's increased interest in such uses. Here too, FPL, using expertise developed by NextEra, is in front of other Florida utilities.

The company announced in March that it planned to use battery storage and linked solar capacity to enable it to retire two large, aging gas turbines at its Manatee Power Plant. These two units, which came online in 1976 and 1977, each have a net summer capacity of 812MW but have not been producing anything close to their full capability for years. According to S&P data, the plant's annual capacity factor has not exceeded 20% in the last 10 years, although there have been occasional months when one unit or the other topped 30%.

The new Manatee Energy Storage Center, which is scheduled to come online in 2021, will have a capacity of 409MW and be capable of supplying 900 MWh of electricity, FPL said. It will be paired with the company's existing 74.5MW Manatee solar farm, which began operating in 2016.

The Manatee facility is not a one-for-one replacement of the existing gas units, but in combination with other battery systems and solar plants it is planning across the state, FPL says it will be able to replace the 1,600MW-plus of generating capacity and save customers more than $100 million in the process.[18] In this sense, the project will serve as a proving ground for the concept that replacing fossil fuel generation, whether coal or gas, with cleaner generation can be done without compromising the security or stability of electric supplies while at the same time saving money.

Georgia

The transition under way in Georgia is especially noteworthy because the state is home to Southern Company, whose operating subsidiaries relied on coal for 70% of their electric generation through the mid-2000s. Further, as late as 2017, Southern CEO Tom Fanning was still saying he didn't think carbon dioxide was the primary cause of climate change.[19] Just a year after that, the company announced plans to be

[17] Op. cit., NextEra Energy Investor conference presentation, June 20, 2019, p. 107.
[18] FPL press release. Plan to build the world's largest solar-powered battery. March 28, 2019.
[19] CNBC. Like the new EPA chief, Southern Company's CEO doesn't see CO2 as main reason for climate change. March 28, 2017.

carbon-free by 2050. Georgia Power, the largest of Southern's utility units is likely to be coal-free (if not carbon-free) much sooner than that.

The change in Georgia generation over the past 10 years is similar to that seen in other states in the Southeast. Coal, which accounted for 63% of the state's electric generation, now produces just 25% of the total, and this share will shrink more in the near future.

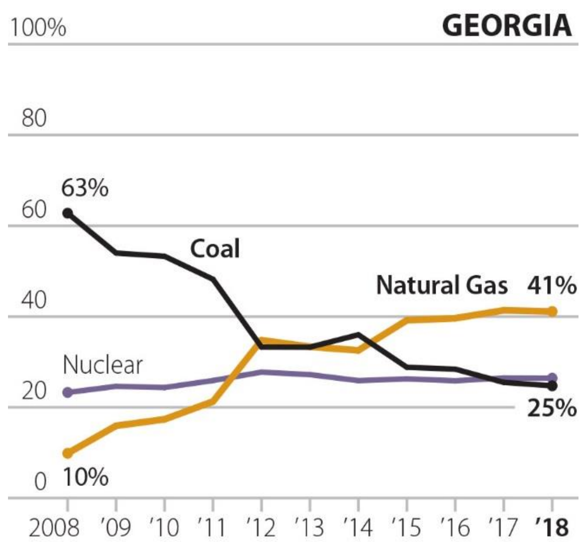
Coal, which accounted for 63% of Georgia's total electric generation, now produces just 25%.

Just three coal plants remain in operation in the state, including two of the three largest plants in the U.S. They are:

- the four-unit, 3,392MW Plant Scherer;
- the four-unit, 3,200MW Plant Bowen; and
- the two-unit, 1,744MW Plant Wansley.[20]

Two other Georgia Power plants with a total capacity of 982.5MW were officially retired this past July as part of the utility's recently approved integrated resource plan (IRP). Those plants, the single-unit Plant McIntosh (142MW) and the four-unit Plant Hammond (840MW), had long ago stopped playing a major role in the utility's power mix. McIntosh, for example, had essentially been offline since the end of 2015, operating with a capacity factor of less than 2% from 2016-2018 and generating power only once in 2019. Similarly, Units 1-3 at Hammond had largely been out of the mix since 2014, with each of them recording capacity factors of less than 10%. All of those units have been offline entirely since September 2018. Unit 4 (the largest of the four, at

Fuel Share for Electric Power Generation (Utility Scale, All Sectors)



Only fuels with 5% or more share in any year are shown.
Source: Energy Information Administration

[20] In addition to these five plants, there are two smaller coal plants in the state. Plant Crisp is a 10MW facility that has not generated any power since 2017. The 83.8MW Savannah River plant is capable of burning coal, but its primary fuel source is petroleum coke.

510MW) was used somewhat more often, but only once recorded an annual capacity factor above 20% since 2012.

Plant Wansley appears headed in the same direction as Hammond and McIntosh. Its capacity factor averaged from 65% to 83% from 2000-2008, but it has trended downward ever since. By 2012, Wansley's annual capacity had fallen to just under 32%, and it has never subsequently risen above that level.

The challenge for coal in Georgia going forward is two-fold. First, Georgia Power will be bringing the Plant Vogtle 3 and 4 nuclear power units online in the early 2020s. The two units, using Westinghouse's AP1000 design have a nameplate capacity of 1,117MW each. Georgia Power owns 45.7% of the project (or about 1,021MW of capacity); the other owners are Oglethorpe Power Corporation (30%), Municipal Electric Authority of Georgia (MEAG) (22.7%) and Dalton Utilities (1.6%). When these two much-delayed, over-budget generating facilities come online (currently scheduled for November 2021 and 2022, respectively) they will run, if possible, 24/7 and, in doing so, push other baseload units out of the dispatch queue except on the highest of demand days.

This will be a problem for Georgia Power's remaining coal-fired facilities, particularly its wholly owned Plant Bowen. In its latest IRP, which came out this year, the utility noted that the plant, especially Units 1 and 2, is already facing "economic challenges."[21] Given this, the company said it plans "to minimize future investment in these units." Some investment will be required, "due to maintenance and environmental mandates, [but] the company intends to defer major retrofit projects and optimize implementation of projects necessary to manage the near-term availability of these units."[22]

In other words, while it is going to keep the units up and running, the end is in sight and may well occur when the utility's new nuclear reactors come online. If not then, certainly by December 2023, which is the latest date for compliance with the Environmental Protection Agency's new limits on effluent releases from steam electric power plants (the so-called ELG rule).

Plant Bowen's problems have been building for some time. Through the 2000s, the plant consistently posted a capacity factor above 70% and frequently higher than 80%, including in 2010 when it recorded a high of 82.39%. The fracking-generated gas revolution began to affect operations after that, however, and since 2011, the plant has never posted a capacity factor above 55%.

The viability of Plant Bowen is also going to be undercut by the significant amount of new solar that Georgia Power is bringing online in the next five years. The company currently has 1,500MW of renewable capacity in operation and is developing an additional 1,600MW, all of which—because of its lower cost—will be dispatched ahead of power from Bowen and other coal plants in Georgia.

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[21] Georgia Power. 2019 IRP, Docket #42310, Section 1-7, Unit Retirements. December 27, 2018, p. 1-7.
[22] Ibid., Section 10-5, Future Uncertainty, p. 10-70.

As part of its just-approved IRP, Georgia Power will bring an additional 2,260MW of solar capacity online by 2024, 2,000MW of utility-scale capacity and 260MW of distributed, smaller-scale facilities.

In total, the company says it will have 5,390MW of renewable generation online by 2024. Coupled with the new Vogtle capacity and expectations of continued no- or low-load growth in the state, that could be the end of Bowen.

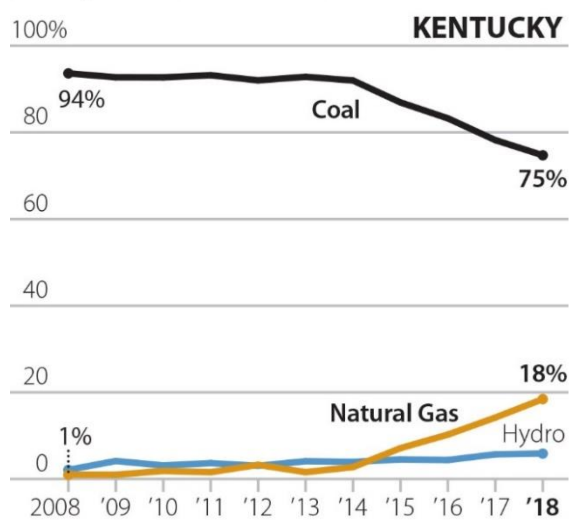
In total, Georgia Power says it will have 5,390MW of renewable generation online by 2024.

What impact these developments will have on the Plant Scherer is harder to project because of the many different companies that own a piece of that plant, but it is worth noting that MEAG's share of the new Vogtle units will give it roughly 491MW of new capacity, a little less than the amount it owns at Scherer. Similarly, essentially one entire unit at Scherer (25% of Unit 3 and 75% of Unit 4) is owned by NextEra subsidiaries in Florida that are moving rapidly away from coal toward solar (see the previous section on Florida). In short, the outlook for Scherer isn't bright, although it may end up being the state's last plant standing.

Kentucky

Kentucky seems like an outlier, at first glance, but even in this coal-dominated state, similar shifts are occurring, albeit at a somewhat slower pace. In 2008, the state generated 92.1 million MWh of electricity from coal, 94% of its total electricity needs. By 2018, coal generation had dropped by 36%, to 59.1 million MWh and accounted for 75% of the state's total generation. While this is a higher percentage than any of the other states included in this report, the trend is as unmistakeable in Kentucky as it is elsewhere across the Southeast.

Fuel Share for Electric Power Generation (Utility Scale, All Sectors)



Only fuels with 5% or more share in any year are shown.
Source: Energy Information Administration

Gas accounts for the change. In 2008, gas generated less than 1 million MWh of electricity, totalling just 1% of the state's total power generation. By 2018, gas-fired electricity output had risen to 14.6 million MWh, accounting for 18.4%.

Today, 14 coal plants are operating in Kentucky, but that number is somewhat misleading. The total includes the following plants:

- Unit 3 at the Tennessee Valley Authority's (TVA's) Paradise Fossil Plant. The utility's board of directors has voted to close the 971MW unit in 2020. The other two original units at the station, totalling 1,230MW, were closed in 2017.

- The two-unit Elmer Smith Power Plant owned by the city of Owensboro. The city decided in 2017 to close both units, totalling 399.8MW, with Unit 1 scheduled for a June 2019 closure while Unit 2 is slated to stop operating in 2023.

- The three-unit, 443MW K.C. Coleman Generating Station, owned by Big Rivers Electric Corporation, has not generated any power since 2014 but is not technically retired. It is listed as "out of service" in official documents.

- A second Big Rivers plant, the single unit 65MW R.A. Reid facility, was retired in June 2019. It had not generated any power since 2014.

Of the state's remaining plants:

- East Kentucky Power Cooperative owns two: The two-unit, 341MW J. Sherman Cooper Power Station and the four-unit, 1,346MW H.L. Spurlock Station.

- Big Rivers owns the single-unit, 417MW D.B. Wilson Generating Station and the two-unit, 454MW R.D. Green Generating Station.

- Kentucky Utilities owns the four-unit, 1,919MW Ghent Generating Station and the single-unit, 409MW E.W. Brown Generating Station.

- Louisville Gas & Electric (LG&E) owns the two-unit, 1,243MW Trimble County Generating Station and the four-unit, 1,465MW Mill Creek Generating Station.

- TVA owns the nine-unit, 1,206MW Shawnee Fossil Plant.

- Duke Energy Kentucky owns the single unit, 600MW East Bend Plant.

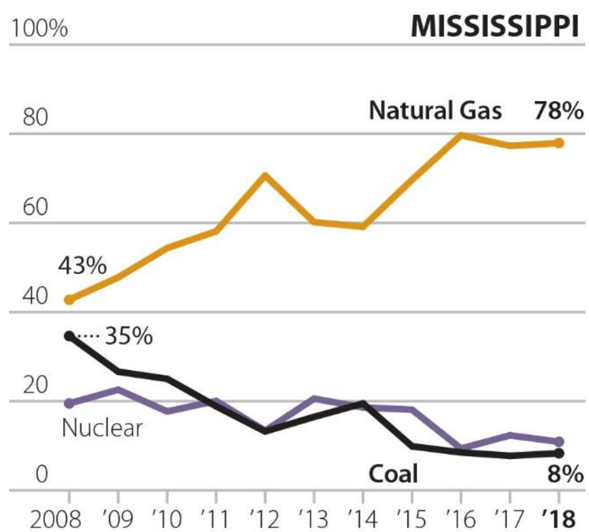
Kentucky Utilities and LG&E, which own 5,034MW of the state's coal capacity, are both operating units of PPL Corporation, a holding company that also owns PPL Electric in Pennsylvania and Western Power Distribution in the United Kingdom. In January 2018, PPL announced plans to cut its CO2 emissions by 70% from 2010 levels by 2050. According to the corporation, among the measures that will be needed to reach that goal "include replacing Kentucky coal-fired generation over time with a mix of renewables and natural gas while meeting obligations to provide least-cost and reliable service to customers."[23]

While Kentucky is clearly still the most coal-dependent state in the region, change is coming.

Mississippi

Total electricity generation in Mississippi is the lowest among the nine states in the Southeast, despite having grown 30% since 2008. However, none of this new demand has changed the outlook for coal generation in the state: Since 2008, coal output has dropped from 16.7 million MWh to 5.28 million MWh in 2018. This decline has resulted in coal's share of state generation falling from 35% a decade ago to 8%.

Fuel Share for Electric Power Generation
(Utility Scale, All Sectors)



Only fuels with 5% or more share in any year are shown.
Source: Energy Information Administration

Over the same period, gas-fired generation has risen significantly, from 20.6 million MWh to 49.4 million MWh in 2018. More gains by gas are on the horizon.

One of the few coal-fired power plants in the state, the two-unit, 360MW R.D. Morrow Generating Station, owned by wholesale energy provider Cooperative Energy, closed at the end of 2018. Cooperative Energy is replacing the coal capacity with a 540MW gas combined-cycle unit that is due online in 2023.

Cooperative, which is the power supplier for 12 member co-ops in the state serving more than 431,000 meters—like other utilities—is moving to embrace the rapid changes occurring across the utility sector, noting in its 2018 annual report: "This era in the electric utility industry should be seen as a strategic inflection point in the evolution of an industry that has remained essentially unchanged during modern times. This is still an era when utility size matters, but efficiency and flexibility matter more."[24]

[23] PPL Corporation. 2018 Sustainability Report. p. 19,
[24] Cooperative Energy. Positive Energy Annual Report 2018, p. 17.

As part of its shift and emphasis on flexibility, the company is buying two Wärtsilä 31SG reciprocating engines that will help integrate greater intermittent energy loads into its system. According to Wärtsilä, the engines can operate continuously at 10% load and ramp to full power in two minutes. Plus, the company says, it is the most efficient four-stroke engine in the world, at more than 50%.[25]

The cooperative says the Wärtsilä engines will help ensure the safe integration of its new 100MW solar farm when it comes online in 2022. Cooperative Energy also buys solar power from an existing 52MW PV facility.

With the Morrow plant retired, just two operating coal-fired power plants remain in Mississippi: Plant Daniel and Red Hills Power Plant.

The single unit 440MW Red Hills facility is a merchant generator that sells power under a long-term contract to TVA. The plant's ability to cycle (it has posted monthly capacity factors below 20% and above 90% in the last 12 months) and its low cost (S&P estimates its 2018 O&M expenses at $18.40/MWh) likely will safeguard it until the power supply contract expires in 2032.

We're at an inflection point in the evolution of an industry that has remained essentially unchanged during modern times.

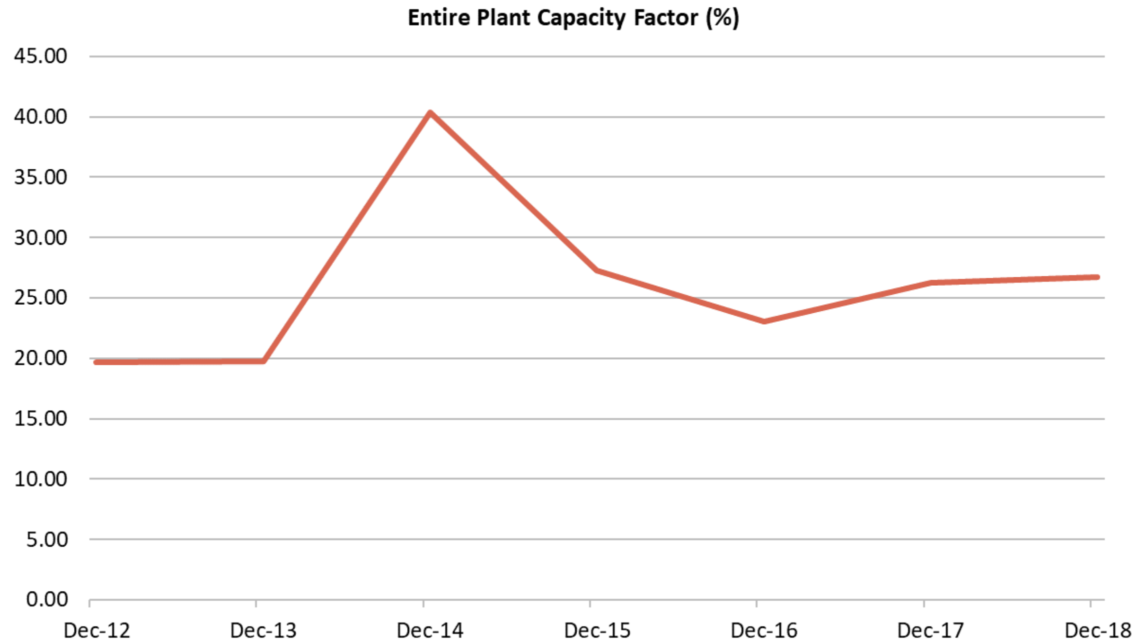
The two-unit, 1,004MW Daniel facility faces a far more uncertain future. The plant is owned by Gulf Power and Mississippi Power, with each utility owning 50% of both generating units. The ownership split did not matter previously since both utilities were units of Southern Company. However, NextEra's purchase Gulf Power at the end of 2018 changed the dynamic.

In Gulf Power's latest Form 1 filing with the Federal Energy Regulatory Commission, the company said the two utilities "have committed to seek a restructuring of their 50% undivided ownership interests in Plant Daniel such that each of them would, after the restructuring, own 100% of a generating unit." The filing included this kicker: "On January 15, 2019, the company provided notice to Mississippi Power that the company [Gulf Power] will retire its share of the generating capacity of Plant Daniel on January 15, 2024."[26]

The Gulf Power/Mississippi Power ownership agreement gives Mississippi Power the option to purchase the Daniel unit for $1, but whether the company (or its corporate parent) wants the plant is an open question. Certainly, it would not appear that the Mississippi utility needs the capacity, as Figure 2 illustrates. For the preceding seven years, the capacity factor at Plant Daniel has averaged just over 26%, and hit 40% on only one occasion.

[25] Wärtsilä website. Wärtsilä 31 Engine Family.
[26] NextEra. Gulf Power FERC Form 1, Accessed from investor web page. September 23, 2019.

Figure 3: Generating Performance at Plant Daniel



Source: S&P data, IEEFA analysis.

Utility-scale solar uptake has been slow in Mississippi, but there are indications of interest by the state's three major utilities: Entergy Mississippi, Mississippi Power and Cooperative Energy. Mississippi Power now has four solar sites in its generation mix, totalling 156.4MW of capacity. Entergy Mississippi signed a deal late last year for 100MW of solar capacity that will be built by Sunpro Solar and is slated for completion in 2022. And, as mentioned above, Cooperative Energy currently buys 52MW of solar capacity and is bringing an additional 100MW online in 2022.

North Carolina

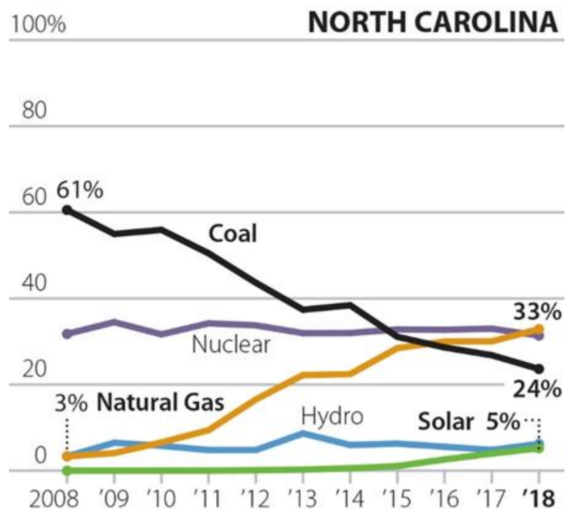
Electricity generation in North Carolina has grown slowly since 2008, from 126.2 million MWh to just over 134 million MWh in 2018. Over that same period, coal generation has plummeted, from 76.6 million to 31.6 million MWh. Further reductions are in store for 2019, with generation for the first six months at just 12.1 million MWh, more than 4.5 million MWh below last year's levels.

As the chart indicates, much of coal's lost market has been taken by gas, where generation has soared from 4.1 million MWh in 2008 to more than 44 million MWh last year. But it is worth noting that solar has seen a significant increase as well, climbing from essentially zero to 5% of the statewide total in 2018—making North Carolina the only Southeast state to derive that much of its electricity from solar.

These trends are certain to continue, particularly given that there are only seven coal plants still operating in the state (all owned by Duke Energy), and one of those, the two-unit, 378MW Asheville Energy Plant, will be retired by the end of the year once Duke brings its new combined-cycle gas plant in western North Carolina online.[27] The six remaining plants are:

- The five-unit, 1,098MW G.G. Allen Steam Station. Unit 5, the newest at this facility, came online in 1961; the unit's 2018 capacity factor was 14.4%. The other four units at the plant all posted capacity factors of less than 10% for the year. Units 1-3 are slated to close at the end of 2024;
- The single-unit, 727MW Mayo Plant;
- The four-unit, 2,058MW Marshall Station;
- The two-unit, 2,220MW Belews Creek Station;
- The four-unit, 2,439MW Roxboro Plant;
- The two-unit, 1,388MW James E. Rogers Energy Complex, formerly known as the Cliffside Station.

Fuel Share for Electric Power Generation
(Utility Scale, All Sectors)



Only fuels with 5% or more share in any year are shown.
Source: Energy Information Administration

The performance of these Duke plants makes it clear that coal is no longer the utility's mainstay generation resource. For example, at Mayo, which is relatively young, at 36 years old, annual capacity factors have trended down steadily since 2008, when the plant ran more than 75% of the time. By 2018, Mayo's capacity factor had dropped to 22.8% as Duke limited use of the plant to periods of higher demand in the winter and summer and ramped operations down significantly (or stopped generating entirely) during the lower-demand months in the spring and fall.

In addition, at three of its remaining plants, Marshall, Belews Creek and Cliffside, Duke is planning renovations that will allow for the burning of gas in addition to coal—a move that almost certainly will lead to lower coal consumption across the utility's system. At Cliffside, the one plant where the retrofits have been completed, coal consumption fell 34% in the first six months of 2019 compared to the same

[27] There are four smaller, non-utility plants in the state with the capability to burn coal: Two had no generation in 2018; a third, owned by a paper company, burned just under 250,000 tons of coal last year; and the fourth, 28.7 MW unit owned by the University of North Carolina-Chapel Hill, only operated 20% of the time during the past 12 months.

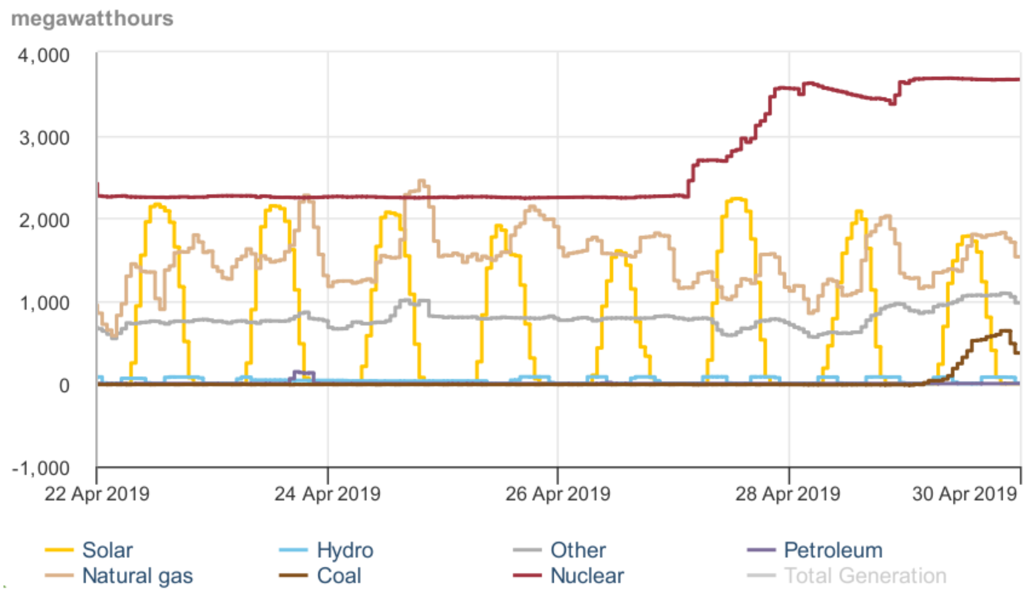
year-earlier period, from 1,248,913 to 821,525 tons.[28] Declines at the other two plants are likely as Duke completes their gas-enabling retrofits.

The two charts that follow show another problem facing Duke's coal-fired plants—the rise of solar generation. The first chart, from a week during the shoulder month of April, shows that there was essentially no coal generation in Duke's eastern region (the service territory of Duke Energy Progress where the Mayo plant is located). Ten years ago, when there was no solar (and less gas), much if not all of that generation would have been coal-fired. The second chart shows a week in the high-demand month of August. Here, coal is clearly back in the mix, but it is worth noting that much, if not all of the generation in yellow (the solar output, which totalled just over 105,000 MWh for the week), would have been supplied by coal 10 years earlier. Further, this transition is happening with 5,601MW of installed solar capacity in the state.[29] Given that at least an additional 4,000MW of new solar is planned through 2024,[30] the challenge to coal is only going to become more acute.

Solar has climbed from essentially zero to 5% in 2018—the only Southeast state to derive that much from solar.

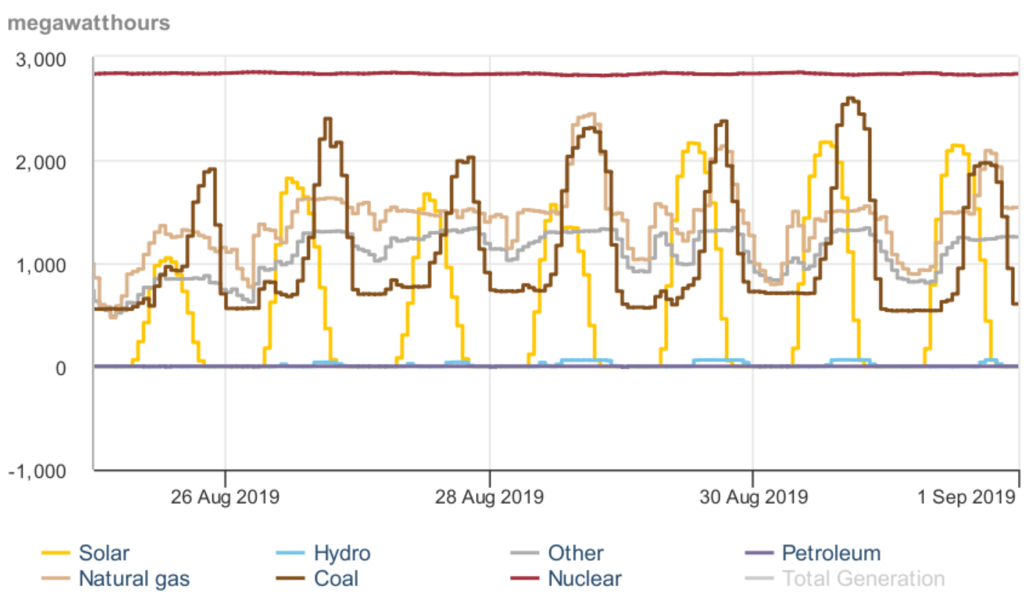
[28] S&P data.
[29] Solar Energy Industries Association. North Carolina Solar through Q2 2019. Accessed September 18, 2019.
[30] Ibid.

Figure 4: Duke Energy Progress East (CPLE) Electricity Generation by Energy Source, April 22-29, 2019



Figures 4&5 Source: EIA's Hourly Electric Grid data browser.[31]

Figure 5: Duke Energy Progress East (CPLE) Electricity Generation by Energy Source, August 25-31, 2019



[31] EIA. Hourly Grid Monitor. This EIA data is newly available to the public.

Declines at Duke's other plants (Cliffside, Roxboro, Belews Creek and Marshall) have not been quite as pronounced as at Mayo, but the drop-offs are notable. Of the 12 individual units at those plants, only three (Marshall Units 3 & 4 and Cliffside Unit 6) posted a capacity factor of more than 50% in 2018. Six of the other units, including three at Roxboro, posted capacity factors of less than 30% in 2018, meaning that they were cycled on a regular basis, something they were not designed to do.

If asked to name the top three or four states for installed solar capacity, most people would probably get number one correct: California. Most would mention Southwestern states as runners-up. But North Carolina in fact has the second-largest total of installed solar capacity in the U.S., at more than 5,600MW as of the second quarter of 2019. Virtually all of this capacity was installed in the last four years, and its impact on the North Carolina electric grid is beginning to be felt, as shown in the two charts above.

Much more is on the way. SEIA estimates that more than 4,000MW will come online in North Carolina in the next five years, and this forecast may well understate the trend. In the 2018 IRPs Duke filed in North Carolina for its two utilities (Duke Energy Progress and Duke Energy Carolinas, both of which also serve customers in South Carolina), the company said it would be adding more than 2,300MW of solar to its systems by 2023. Since then, the utility has said it plans "to more than double its current solar capacity in North Carolina and South Carolina to 7,000 megawatts during the next five years."[32]

That new capacity will further reduce the need for coal-fired generation in the state—and save money in the process. In announcing plans earlier this year for 600MW in 14 new solar projects solicited through the state's Competitive Procurement of Renewable Energy program, Duke said those projects alone would save ratepayers $375 million in the first 20 years of operation.[33]

Notably, North Carolina has the second-largest total of installed solar capacity in the U.S.

All told, Duke is required to secure 2,660MW of renewable energy under the competitive procurement program in slightly less than four years. A second round is scheduled for later this year, and even Duke acknowledges that bid prices are likely to fall (pushing customer savings up). Commenting on the first-round results, Rob Caldwell, senior vice president and president of Duke Energy Renewables & Business Development, said: "As solar energy expands in the Carolinas, the competitive bidding process will lead to better prices and more geographic diversity

[32] Winston-Salem Journal. Duke Energy increasing its solar capacity by 20 percent; it will save customers $375 million over 20 years, company says. April 21, 2019,
[33] Duke Energy news release. Competitive process yields Carolinas' biggest one-day collection of solar projects ever; significant savings for Duke Energy customers. April 17,2019.

of projects. This will enhance Duke Energy's efforts to promote a cleaner energy mix at lower prices for customers."[34]

These rapid changes have not gone unnoticed at the North Carolina Utilities Commission. Last month in a proceeding regarding the Duke utilities' 2018 IRPs (and that of Dominion Energy North Carolina, which serves electric customers in the northeast corner of the state), the commission voiced concern about Duke's assumption that its coal plants would continue to run "until they have been fully depreciated."[35]

The commission noted, "Today's capacity factors for these plants are substantially lower than the historical capacity factors of the plants. It does not appear from the information in the IRPs that DEC and DEP have fully considered early retirement of any of these coal plants by replacing their contributions with other alternative generation resources or with energy efficiency (EE) and demand-side management (DSM) resources."[36]

The commission, as a result, ordered Duke to prepare an analysis "showing whether continuing to operate each of its existing coal-fired units is the least-cost alternative compared to other supply-side and demand-side resource options, or fulfils some other purpose that cannot be achieved in a different manner."[37]

It will be difficult for Duke to show that its coal assets are still the least-cost alternative given the deteriorating performance at those units, the sharp drop in solar costs and, crucially, the rapid uptake of battery storage, particularly when linked with solar (covered in greater detail in the Florida section above.)

South Carolina

Electricity generation in South Carolina has declined slightly since 2008, falling 2.2% to just under 100 million MWh annually. During that same period, coal generation has collapsed, dropping 53% from more than 41 million MWh in 2008 to less than 20 million MWh in 2018. Year-to-date data indicate further declines in 2019, with coal-fired generation through June down more than 23% from a year ago.

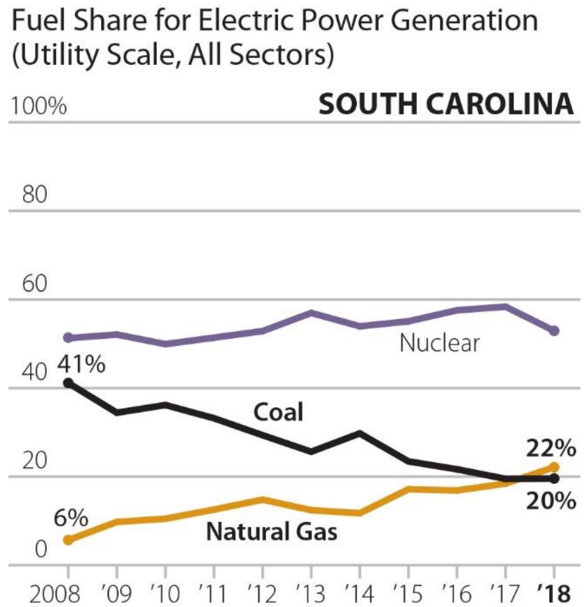
During this period, five coal plants in the state have been closed and two others converted to run on natural gas. As with the region's other states, these retirements have been driven by a surge in cheaper gas generation, which has jumped from 5.9 million MWh in 2008 to just over 22 million MWh in 2018.

The result is that only five coal-fired plants are now in operation in South Carolina, two owned by Santee Cooper, the state-owned public power utility, and three by

[34] Ibid.
[35] State of North Carolina Utilities Commission. Docket No. E-100 Sub. 157.
[36] Ibid.
[37] Ibid.

Dominion, which completed its purchase of South Carolina Electric & Gas earlier this year. These remaining five are:

- The four-unit, 1,150MW Winyah Generation Station owned by Santee Cooper;
- The four-unit, 2,375MW Cross Generating Station, also owned by the state utility;
- The single-unit, 415MW Cope Power Station owned by Dominion;
- The two-unit, 684MW Wateree Power Station owned by Dominion; and
- The single-unit, 605MW Williams Power Station, also owned by Dominion.



Only fuels with 5% or more share in any year are shown.
Source: Energy Information Administration

There will not be five for much longer, however. Santee Cooper announced plans in September to close its Winyah facility, saying it will retire Units 3 and 4 at the plant in 2023 and Units 1 and 2 in 2027. Capacity factors at each of the four Winyah units have been trending down since 2008 and were at or below 20% in both 2017 and 2018. That performance has persisted in 2019, with none of the units operating above 20% through June.

Performance at Santee Cooper's other plant, the Cross facility, has been better, particularly at Unit 4, but here it is noteworthy that the utility has mothballed Unit 2. The 570MW unit had operated sparingly since 2013 and was taken offline in early 2017. It was used again this past winter but has been offline since February.

Concerns about the cost of power from these two plants have been raised by Santee Cooper's largest customer, the Central Electric Power Cooperative, a wholesale electric provider that supplies the state's 20 distribution co-ops (which serve a total of 700,000 meters). CEPC President and CEO Robert Hochstetler has pushed for a review of the plants, arguing that Santee Cooper's rates are too high. "I know there are lower-cost options right now," Hochstetler said earlier this year.[38]

Such concerns, and the new outlook provided by Mark Bonsall, Santee Cooper's recently appointed CEO, have clearly had an impact, with the utility also announcing

[38] S&P Global Market Intelligence. Santee Cooper will study alternatives to operating 556-MW Cross coal unit. January 29, 2019.

plans to build 1,000MW of utility-scale solar by 2024 and to phase in 200MW of battery storage from 2024-2028.

While this war of attrition for coal has progressed, solar has slowly been taking hold in the state. Installed solar capacity totals 830MW, but considerable growth is expected in the years ahead. SEIA projects that 1,651MW will be added in the next five years, but that forecast likely is out of date given Santee Cooper's recent announcement and the passage this spring of H3659, which was dubbed the Energy Freedom Act. Among a host of provisions, the bill did away with the state's existing 2% cap on net energy metering, potentially opening the door for a wave of new rooftop solar installations in the years ahead.

Santee Cooper has announced plans to build 1,000MW of utility-scale solar by 2024 and 200MW of battery storage from 2024-2028.

In addition, the legislation established a process under which larger customers "shall have the right to select renewable energy facility and negotiate directly with the supplier on the price to be paid by the customer for the energy, capacity, and environmental attributes of the facility."[39] This could prove to be a popular option for many larger commercial and industrial customers looking to fulfil their renewable energy purchase obligations and sustainable governance mandates. As discussed in more detail in the Virginia section, corporate access to renewable energy is increasingly becoming a requirement for doing business in a utility's service territory.

The legislation also directs the state's utilities to incorporate a number of measures in their long-term planning that are likely to lead to greater solar adoption. In particular, utilities must include "resource portfolios developed with the purpose of fairly evaluating DSM, supply-side, storage, including low-med-high cases for adoption of renewable energy and cogeneration, EE, and demand response" in their IRPs.[40]

On top of all this, Cypress Renewables, one of the largest solar developers in the U.S. and a major player in the South Carolina market, opened what it said was the state's largest solar farm in late August, the 106MW Palmetto Plains project. The company also has begun construction on a second project nearby, the 100MW Project Huntley, expected to enter commercial service in 2020.

With demand growth pegged to remain flat, the influx of new solar and the state's recent legislation, the outlook for the state's remaining coal plants is not bright.

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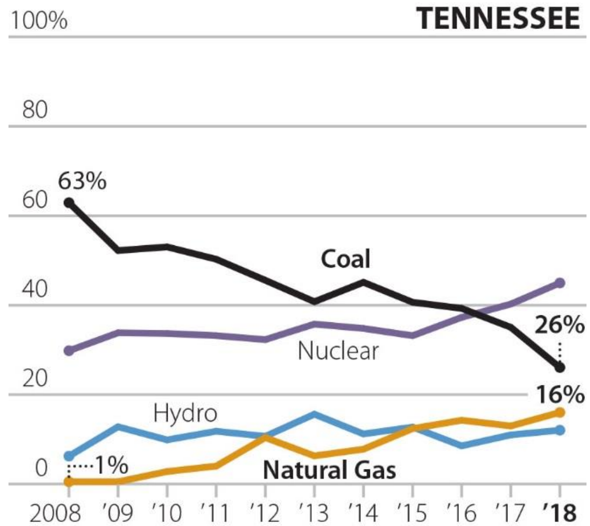
[39] SEIA. South Carolina H3659 Overview. May 2019, p.2.
[40] Op cit., p 4.

Tennessee

Tennessee is the land of the Tennessee Valley Authority, which has moved aggressively away from coal over the past decade, both by adding three combined-cycle gas units in the state with more than 2,600MW of capacity and by bringing the 1,122MW Unit 2 at its Watts Barr Nuclear Plant online. These developments, coupled with falling electricity demand, have cut significantly into coal-fired generation.



Only fuels with 5% or more share in any year are shown.
Source: Energy Information Administration

In 2008, coal-fired generation totalled 57.1 million MWh; by 2018 it had tumbled to 20.9 million MWh. Year-to-date numbers indicate that coal generation will drop again in 2019, with output falling 3.5 million MWh below 2018's totals through June.

Four coal plants are operating currently in the state,[41] although the writing is on the wall for one of them. The four are:

- Bull Run Fossil Plant, a single 870MW unit that TVA has announced it will close in 2023. Its capacity factor in 2018 was 18%, down from more than 50% in 2008.
- Gallatin Fossil Plant, which has two units of 225MW and two of 263MW. All four units came online in the 1950s.
- Cumberland Fossil Plant is a two-unit, 2,470MW plant. Both units entered commercial service in 1973.
- Kingston Fossil Plant is a nine-unit plant, four of which are rated at 132MW while five come in at 174MW. All nine entered commercial service in the 1950s.

In its decision to close Bull Run (announced at the same time the utility said it would close Paradise Unit 3, a 971MW coal plant in Kentucky), TVA said the move was

[41] The Tennessee Eastman company also operates a multi-unit power plant at its Kingston facility that has a total nameplate capacity of 194.3MW. It has burned an average of 1.3 million tons annually at the facility since 2012.

economically driven. The two facilities are "medium-high cost" and have high equivalent forced outage rates, an industry measure of reliability. The result, TVA said, is that they are "ineffectively operating on the margin."[42]

TVA considers Cumberland a baseload unit, noting that the two units are low cost and reliable. Still, it is clear that the region's flat electricity demand and the influx of both new combined-cycle gas and nuclear capacity is having a negative impact on demand for the plant's electricity. The annual capacity factor at Unit 1 dropped from 69% in 2008 to 41.5% in 2018, calling into question its baseload designation by the utility.

The Gallatin and Kingston facilities are now used by the utility to meet load swings and are considered by the utility to be medium-cost facilities with good reliability. Still, given their age, replacement of these units most likely will be needed in the not-too-distant future.

It does not constitute a true tipping point, but the recent IRP[43] approved by TVA's board of directors certainly points in the right direction. The IRP does not bind the utility, but it does call for the addition of at least 1,500MW of solar in its service territory by 2028 and perhaps as much as 8,000MW. The IRP also calls for the addition of up to 2,400MW of battery storage in the next 10 years. These two provisions could be transformative for TVA. For starters, the utility has essentially zero solar on its system, owning just one 1MW unit at its Allen gas plant. Even if it only meets the low end of its 2028 goal, that new capacity is going to take market share from the utility's coal plants, putting them under increasing economic stress.

TVA has essentially zero solar on its system… new solar capacity is going to take market share away from the utility's coal plants.

But more important is the potential for linking the new solar with storage, as FPL is doing by retiring its Manatee gas units in Florida (see the Florida chapter for additional detail). The use of solar and storage to retire old coal and gas units is also being implemented in Nevada and California.[44]

Combining the two resources would make perfect sense for TVA, particularly to replace part, or perhaps even all, of its aging Kingston coal units. Five of the nine

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[42] TVA. President's report to the board, Feb. 14, 2019, p.17.
[43] TVA. Environmental Stewardship Integrated Resource Plan. 2019.
[44] See IEEFA report: Advances in Electricity Storage Suggest Rapid Disruption of U.S. Electricity Sector. D. Wamsted. June 2019.

Kingston boilers, Units 5-9, all rated at 174MW and online since 1955, posted annual capacity factors of less than 20% in 2018.

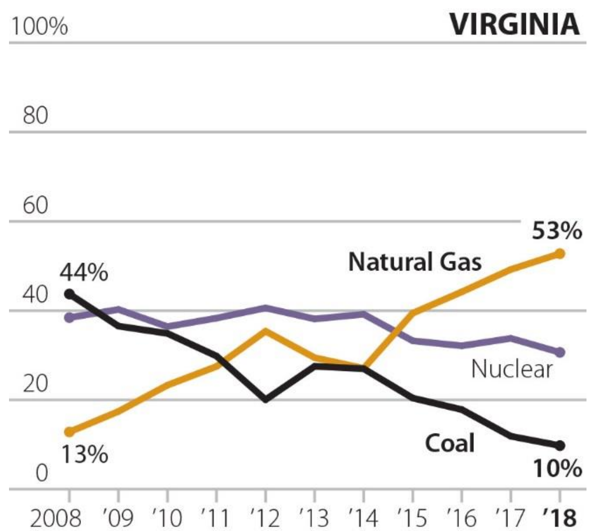
TVA is also beginning to address the growing interest among U.S. corporations for access to clean energy. In a deal announced last year, TVA said it would build 377MW of new solar capacity, 250MW at a site in Alabama and 127MW at a Tennessee location, to provide electricity for a new Facebook data center being built in Huntsville, Ala. Being able to use renewable energy to supply operations is a key driver for companies in the high-tech industry (see the section on Virginia for more detail) and, increasingly, for companies across the board. For example, Tennessee is host to three major automobile manufacturing sites, with GM, Volkswagen and Nissan all producing vehicles in the state. Two of these three companies, GM and VW, have explicit plans to source all their electricity needs from renewable energy by 2050, with GM saying it is already 20% of the way toward meeting that goal. Clearly, TVA needs to be planning to meet this growing demand, and the sooner the better.

Virginia

Electricity generation has grown notably in Virginia over the past decade, from 73.2 million MWh to 95.4 million MWh, an increase of just over 30%. Coal generation has not benefitted, however; in fact, it has plummeted, replaced by gas.

Total coal generation in the state in 2008 was just under 32 million MWh, 44% of the statewide total. By 2018, coal generation accounted for just 10% of the statewide total, producing 9.3 million MWh out of 95.4 million MWh overall. At the same time, gas surged, climbing from almost 9.5 million MWh in 2008 to more than 50 million MWh in 2018, accounting for 53% of the state's generation.

Fuel Share for Electric Power Generation
(Utility Scale, All Sectors)



Only fuels with 5% or more share in any year are shown.
Source: Energy Information Administration

At present, five coal plants are operating in Virginia: [45]

- Spruance Cogeneration Plant, a two-unit facility with 105MW of capacity owned by Ares Holdings;

[45] Dominion also owns the Mt. Storm coal-fired power plant in West Virginia. That three-unit plant has a net summer capacity of 1629 MW; Unit 1 came online in 1965, Unit 2 in 1966 and Unit 3 in 1973.

- Birchwood Power Facility, a single 238.4MW unit jointly owned by General Electric and Electric Power Development;
- Clover Power Station, a two-unit facility with 877MW of capacity jointly owned by Dominion and Old Dominion Electric Cooperative;
- Chesterfield Power Station, a two-unit, 1,006MW facility owned by Dominion;
- Virginia City Hybrid Energy Center, a 610MW single unit owned by Dominion Energy.

Of these, the two Spruance units are operating in name only; neither has generated any electricity since March and neither has posted a capacity factor of more than 9% in the past 12 months. The units are slated for deactivation in January 2020.

The future of the other four plants is not certain, but for at least three—Birchwood, Clover and Chesterfield—economic challenges and changing market dynamics could lead to their closures in the not-too-distant future.

The Birchwood facility, for example, is a merchant plant selling power to Dominion under a long-term contract that expires in 2021. Whether the utility is interested in extending that agreement is unknown, but with operations and maintenance costs estimated by S&P at almost $60/MWh, it is almost certain the utility could buy cheaper power on the market. Further, the unit's capacity factor in the last four years has not averaged more than 26%, and has been at or below 10% for the first six months of 2019.

Chesterfield and Clover also look to be heading toward retirement, particularly in light of their recent performance. The two remaining units at Chesterfield are old, the 336MW Unit 5 came online in 1964 while the 670MW Unit 6 began operating in 1969. They now operate only infrequently. Unit 5's capacity factor in 2018 was just over 22% and, to date in 2019, it has posted an average capacity factor of 14.9%, with its only extensive use coming in June. The story at Unit 6 has been even worse; the unit's 2018 average capacity factor was just under 18.5% and to date in 2019 it has posted an average of 8.5%, again with the only real generation to date coming in June.

Rapidly growing corporate preference for renewable energy is likely to drive the remaining coal plants in Virginia into retirement.

The Clover generating station is newer, with its units having come online in 1995 and 1996, but there has been a noticeable decline in both units' generation since 2017. Unit 1 dropped from a capacity factor of almost 70% in 2016 to just 38.3% in

2018, while Unit 2 fell from 71.8% to 37.2%. Here it is worth noting that the company's Brunswick combined-cycle gas plant came online in 2016 and posted a capacity factor of just under 65% in 2017 and 2018.

The force that is likely to drive the remaining coal plants in Virginia into retirement is the rapidly growing corporate preference for renewable energy, particularly by Internet companies such as Google, Facebook and Amazon, among others. The state, especially the northern tier, serves as the host for at least 45 data centers, and analysts estimate that roughly 70% of the world's Internet traffic runs through these facilities.[46]

These centers require 800MW of power,[47] and increasingly, their owners want all that electricity to be green. That desire was made public earlier this year in an open letter urging Dominion and other suppliers to adopt green electricity supply technologies:

"As data center providers, customers, and colocation service providers with operations in Virginia, we prefer electricity that is generated by clean, renewable energy. We are writing to express concern regarding the restated intentions of energy providers to meet our energy demand with expensive fossil fuel projects."[48]

The 10 signatories[49] also made note of their importance for future load growth in Virginia and argued that their "interests should be taken into account in decisions regarding the future of the region's energy infrastructure." They went on to say that Dominion's current integrated resource plan fails to do this.

Dominion is well aware of the sector's importance, having noted in the same IRP that data centers have been a driver of growth in its service territory and that it continues to see "significant interest" from data companies wanting to locate and/or expand in Virginia. It is also worth noting that Dominion expects growth in its commercial sales segment (which includes the aforementioned Internet-sector firms) to account for 67% of its overall growth through 2033[50]—so clearly it has a keen interest in taking such concerns seriously.

Statewide, solar is still a small player, accounting for just over 1% of Virginia's 2018 generation. For its part, Dominion currently has 132MW of solar capacity in operation and another 240MW under development. In addition, it has three direct contracts, with Facebook, Amazon and Microsoft, for an additional 220MW of capacity, 140MW of which is already online while the other 80MW is still being developed.

[46] Virginia Economic Development Partnership. Data Centers. Accessed August 22, 2019.
[47] Ibid.
[48] Open Letter to Dominion Energy from tech companies. May 8, 2019.
[49] Adobe, Akamai Technologies, Apple, AWS, Equinix, Iron Mountain, LinkedIn, Microsoft, Salesforce and QTS.
[50] Dominion. 2018 Integrated Resource Plan. May 2018, p. 19.

But this is about to change. The company's current plans call for the construction of at least 3,000MW of solar by 2022. The company also said during its investor-day presentation March 25, 2019, that it expected to spend $1.1 billion on offshore wind, $1 billion on pumped hydro storage and $500 million on "renewable enabling combustion turbines" by 2023.[51]

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Beyond these plans, Gov. Ralph Northam in September signed an executive order setting a state goal of having 30% of its electricity come from renewable energy by 2030. As part of this effort, the order calls for building 3,000MW of new solar and/or onshore wind in the state by 2022 and an additional 2,500MW of offshore wind by 2026.

Following the governor's announcement, Dominion issued a blockbuster notice of its own: committing to installing 2,640MW of offshore wind by 2026, the largest such project announced to date in the U.S. As proposed, the utility would bring the new capacity online in three phases of 880 MW each, starting in 2024.[52]

Taken together, these renewable investments are bad news for the state's remaining coal plants.

Conclusion

Coal-fired electricity generation in the Southeast has fallen far, and fast. And there is no sign that the decline is going to stop. Year-to-date numbers for 2019 continue to show significant decline in coal generation in the Southeast: Through July, generation is down 18.9% from the comparable period a year ago.

In 2008, there were 119 plants using coal to generate electricity in the Southeast, and another started commercial service in 2012. During the last decade, 50 of those plants have retired, and at least another eight will be fully retired by 2024—essentially half in 15 years. And this does not include plants like Winyah in South Carolina, which is scheduled to close two of its four units in 2023, with the other two set to retire by 2027. On this point, 2027 should be considered the long odds chance; increasingly, both in the Southeast and nationwide, utilities are moving up announced coal plant retirement dates as more and more renewable energy comes online. These retirements numbers also do not factor in the plants being converted to be able to burn both gas and coal, as Duke is doing in North Carolina. These conversions generally have led to sharp reductions in coal use.

[51] Dominion. Investor day general session. March 25, 2019.
[52] Dominion Energy press release. Dominion Energy Announces Largest Offshore Wind Project in US. September 19, 2019.

Solar is just starting to have an impact on generation in the Southeast, but this is going to change quickly. There currently are 13,1GW of installed capacity in the region—but projections show that an additional 21.5GW will be added to the grid in the next five years. This capacity will pull generation from coal plants, enhancing the serious competitive pressures already facing the region's remaining coal-fired generation. These pressures will only grow more intense as the region's utilities and independent developers link solar with battery storage, providing a dispatchable, zero fuel cost, and clean resource.

Corporations are another major driver in this transition Tech sector companies were once at the vanguard of the push for green energy resources, but now corporations across the spectrum increasingly are demanding access to clean energy to meet their sustainability goals. This will be a source of consistent pressure on the region's utilities to continue (and even speed up) their transition to cleaner generation resources, with coal being the first casualty.

Combined, these developments are going to lead to continued erosion of coal's market in the Southeast, and even its demise in many of the states examined here.

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