The Water-Energy Nexus in Georgia:

A Detailed Examination of Consumptive Water Use in the Power Sector

Southface and the Southern Environmental Law Center are pleased to present "The Water-Energy Nexus in Georgia: A Detailed Examination of Consumptive Water Use in the Power Sector." Our goals in commissioning this analysis were to clarify the scale and nature of water use by the electric power sector in Georgia and to enrich the ongoing discussions about energy and water regulation and policy in Georgia and the Southeast.

While the study looks both backward and forward in time, the real value of the study is the forward-looking modeling that evaluates the likely future water consumption of the power sector in Georgia and how this "business as usual" water consumption could change depending on different alternative energy pathways possible in the future. In particular, we sought to understand how the use of freshwater resources by the power sector would change if Georgia were to pursue greater deployment of energy efficiency and renewable energy technologies. Given Georgia's continued focus on water resource planning and the pressure imposed on long-term water resource planning by ongoing interstate litigation, we felt it was important to highlight this compelling co-benefit of alternative energy pathways involving clean energy.

We hope this research will be useful and timely to those involved in steering the resource choices of Georgia's electric utilities and those engaged in the effort to protect and enhance Georgia's water resources and quality of life. It would fulfill our highest hopes if the study were to succeed in encouraging stronger coordination between water resource and energy resource planners and regulators in the state.

We want to thank the Cadmus and CNA teams for their excellent analytic work.

Through our involvement in the study design, research and publication, we have formed several recommendations we believe are worth sharing.

1. *The State should invest more in energy efficiency.* Georgia utilities and agencies have implemented modest energy efficiency programs but could do much more. In recent years, energy efficiency programs across the state have saved about 0.3 percent of prior year annual retail sales. Several southern states, such as Kentucky and North Carolina, easily best Georgia's energy efficiency performance. A number of states in the nation regularly achieve five to six times Georgia's level of energy efficiency program savings. We found that an energy efficiency rate of 0.8 percent per year by 2050 in Georgia could avoid the need for 5.5 nuclear power generating units or 42 natural gas generating units. Energy efficiency has advantages over traditional energy supply in that it is a cheaper energy resource for the utility, lowers average customer bills, uses no water, and has no emissions. The low rate of energy efficiency deployment in Georgia suggests that the potential for improvement is significant.
2. *Georgia should increase its rate of renewable energy adoption.* According to the U.S. Energy Information Administration (EIA), in 2015 Georgia had about 220 gigawatt hours (GWh) of

Southface | Southern Environmental Law Center electricity produced by solar photovoltaic (PV) energy, about 0.18 percent of the total. In contrast, Georgia's neighbor, North Carolina, with its more favorable renewable energy policies, had more than six times that amount, and is growing quickly (EIA, 2017b). Though there are plans for significant increases in solar PV in Georgia over the next five years, these additions will still represent a small share of overall generation. However, if the planned additions in Georgia continue at the same rate over the next few decades, they would eventually make a significant contribution to generation and could significantly limit the increases in water consumption that would otherwise occur. If coupled with an energy efficiency program, water consumption in the power sector could decline significantly from the 2015 amounts, a boon for other water use sectors facing increased demand from population and economic growth.

3. *Georgia should develop consistent water withdrawal and water consumption data.* As the old adage says, you can't manage what you don't measure. Accordingly, Georgia should invest more to obtain consistent and reliable data for water use (withdrawals and consumption) in the state. We found that water consumption numbers for regions and sectors across the state were inconsistent and the methods used to develop them were unclear. We believe that addressing this information gap would sharpen the state's already strong water planning efforts.
4. *Georgia should strengthen the State's water-energy planning practices.* In the regional water planning process, Regional Councils must address water quality or water supply constraints through the identification and selection of water management practices. Few, if any, of these water management practices address thermoelectric water withdrawals and consumption, despite the decisive scale of the water use in this sector. We hope that Water Planning Regions can, with the state's assistance, devise strategies to pro-actively address this water planning need. Additionally, we encourage the state to consider ways to better integrate water quality and supply considerations into the energy regulatory process. This could yield important long-term results for the state. If Georgia did integrate these planning processes to identify and promote optimal ways to meet both water and energy needs, it could find opportunities to meet energy demand in ways that save water for other key areas of economic growth, while at the same time protecting and restoring natural stream functions.

We thank you for taking time to review this research and welcome any suggestions you may have.

Sincerely,

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April 2018

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Acknowledgments

This research was funded by the Southface Energy Institute and the Southern Environmental Law Center. We would like to thank our colleagues, Lisa Bianchi-Fossati at Southface, and Jill Kysor and Kurt Ebersbach at SELC, for their input and encouragement as well as Ashley Arayas and Andrew Tabas for their help with editing and document layout. We would also like to thank the Georgia Environmental Protection Division, Georgia Power Company, and the Metropolitan North Georgia Water Planning District for their assistance with data and methodology.

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List of Acronyms

ACF	Apalachicola-Chattahoochee-Flint river system
ACT	Alabama-Coosa-Tallapoosa river system
BTU	British Thermal Unit
CO_2	carbon dioxide
CUD	consumptive use database
EIA	Energy Information Administration of the United States (U.S.) Department of Energy
eGRID	Emissions & Generation Resource Integrated Database
EGU	electric generating unit
Georgia EPD	Georgia Environmental Protection Division
MGD	million gallons per day
MMT	million metric tons
MW	megawatt
MWh	megawatt-hour
NGCC	Natural gas combined cycle
NO_x	nitrogen oxides
OT	Once-through cooling
RC	Recirculating cooling
REDI	Georgia Power’s Renewable Energy Development Initiative
Solar PV	Solar photovoltaic
SO_2	sulfur dioxide
TWh	terawatt-hours
UCS	Union of Concerned Scientists
USGS	United States (U.S.) Geological Survey

I. Summary

This report was developed by Cadmus and CNA for Southface and the Southern Environmental Law Center. In it we examine the connection between electricity production in Georgia and the water consumed or lost from such production. This connection is referred to as the water-energy nexus. Electricity generation requires large amounts of water to cool thermoelectric power plants. The volume of water needed by the electric power sector is not merely a function of the total amount of electricity required to meet demand. The way in which electricity is generated also makes an enormous difference. Simply put, different electricity production pathways can have very different implications for water use. Prudent planning requires an understanding and consideration of those implications.

In this report, we provide the results of analysis we completed using an electric power sector model that calculates projected water use. We considered various potential future pathways for Georgia's power sector and using the model, estimated the water requirements, costs, and emissions of carbon dioxide and several air pollutants involved in each pathway. We examined three different load growth projections as well as six alternate future scenarios that include different assumptions regarding energy efficiency, nuclear power, and renewable energy.

We also provide a thorough examination of water consumption factors for Georgia's thermoelectric power plants, reviewing available sources, comparing them, and providing what we believe are the values that best fit the state's fleet. In Appendix B of the report, we review the major power plants in the state and ground these values by comparing our estimates of water consumption with the official reported values available.

In addition to the analysis and modeling results described above, we provide our conclusions derived from them.

II. Water Use and Electric Power Generation

Water is an essential input for power generation, primarily as a means of cooling thermoelectric plants that produce steam to drive turbines. While some water is needed to create the steam to drive the turbines that generate electricity, this steam is generally condensed and recirculated as part of a closed loop. The major driver of water use at thermoelectric power plants is the water needed to cool and recondense the steam after it turns the turbines.

There are two ways that cooling systems for power plants use water and affect water availability: withdrawal and consumption. These terms are defined by the U.S. Geological Survey as follows:

Withdrawal: "Water removed from the ground or diverted from a surface-water source for use." For thermal generation cooling purposes, withdrawn water is used to absorb waste heat and is then discharged back into the environment (Kenny et al., 2009).

Consumption: "The part [portion] of water withdrawn that is evaporated, transpired…or otherwise removed from the immediate water environment (Kenny et al., 2009)."

Thermoelectric power plants employ one of the following three types of cooling systems, with very different implications for water withdrawal and consumption:

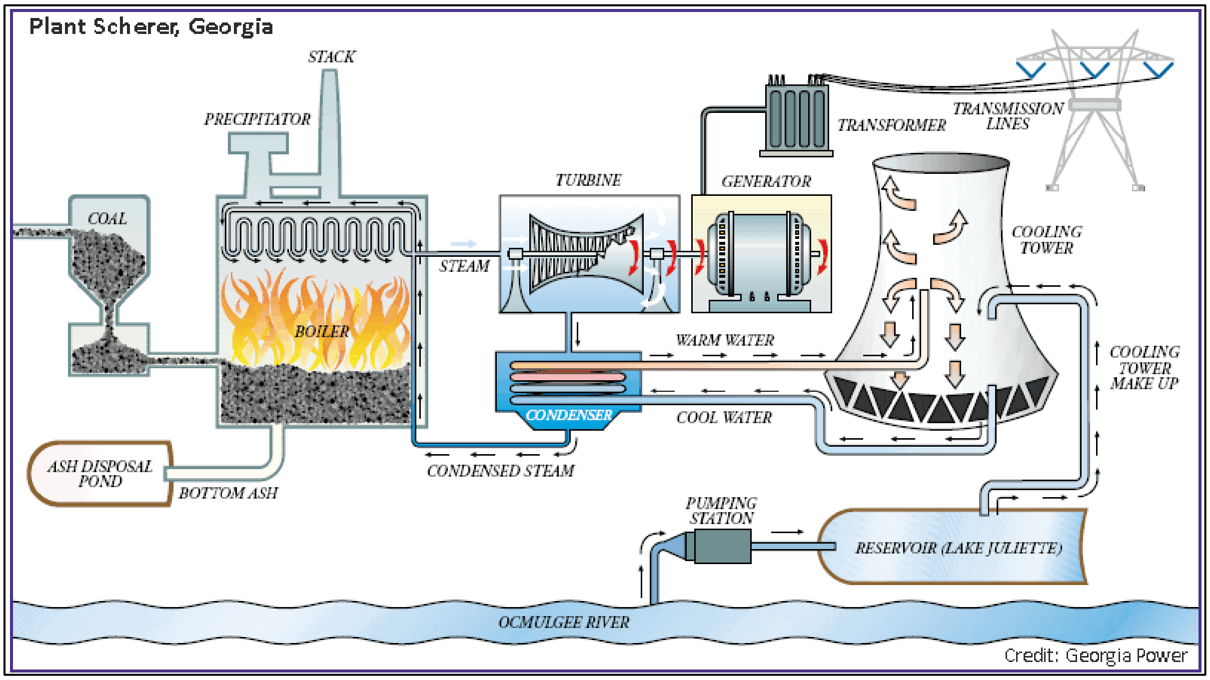
Once-through or **open-loop** systems withdraw water from a source, circulate it to absorb heat, and then return it to the surface water body (Electric Power Research Institute, 2002). These systems withdraw many times more water than recirculating systems, but consume less (Macknick, Newmark, Heath, & Hallett, 2011).

Recirculating or **closed-loop** systems withdraw water and then recycle it within the power system. These systems withdraw less water but typically consume more than once-through or open-loop systems (Electric Power Research Institute, 2002) because they depend upon evaporation rather than dilution to disperse the heat load. Cooling towers are the most common way to evaporate water in these systems, which predominate in the United States.

Dry cooling systems use air flows to remove heat. While dry cooling systems use no water, they do incur an energy penalty during operation as they require electricity to run enormous cooling fans to move large volumes of air. They are more expensive to operate than either once-through or recirculating systems (Mielke, 2010).

As an example of a recirculating or closed-loop system, Figure 1 is a schematic of a coal-fired power plant that uses a cooling tower. On the left, coal is fed into the boiler, which turns water into steam to spin a turbine, which then drives a generator, producing electricity. When the spent steam comes out of the turbine, the excess heat is transferred in the condenser to cooling water, which is then sprayed in a cooling tower, where it evaporates. Flue gas from the boiler also takes away some heat when it is released into the atmosphere via the smokestack. If the system shown instead used once-through cooling, there would be an intake pipe from the river to the condenser and the warmed cooling water would then go immediately back to the environment. Nuclear power plants work much the same way as the recirculating or closed-loop system depicted in Figure 1, except that there is no smokestack. This is one reason that nuclear power generating units use more water than coal units (Diehl, 2013).

Figure 1. Schematic of a coal-fired power plant with recirculating cooling.



Source: USGS.

Figure 2. Georgia Power Company's Plant Vogtle nuclear power plant near Waynesboro, Georgia, showing evaporation from its stacks.

Photo credit: Georgia Power.

For once-through cooling systems water withdrawals may be tens of thousands of gallons per megawatt-hour (MWh) though consumption may be relatively low, while for recirculating systems water withdrawals may be low but consumption relatively high. In addition to the cooling system used, the primary energy source and generating technology greatly affect the amount of water withdrawn and consumed. Natural gas combined-cycle (NGCC) power plants with recirculating cooling systems may consume around 200 gallons per MWh, while the same cooling system for coal power plants might consume about 500 and nuclear power plants about 800 (Diehl, 2014; Macknick et al., 2011).

The nature of thermoelectric water use poses two inter-related water management issues: water quality impacts and consumptive use. Once-through cooling systems consume less water but pose water quality challenges due to the warmer temperature of the discharge water and the release of certain contaminants. Recirculating cooling systems reduce power plants' direct water quality impacts but leave less water available for ecological and downstream uses. This study focuses on consumptive use due to its significance for long-term water resource planning in Georgia. In Georgia, we have estimated that about 153 million gallons per day (MGD) of fresh water are consumed by the power sector.

A Description of This Study

We undertook this study to understand the water use implications of different possible pathways for the electric power sector in Georgia. How might water withdrawals and consumption change in the future under varying assumptions for electricity demand and generation? To do this, we used CNA's Energy-Water Nexus model, calibrated to simulate Georgia's power sector. We then developed energy load and generation scenarios and ran them through the model to estimate water withdrawals, consumption, air emissions including sulfur dioxide (SO_2), nitrogen oxides (NO_x), and particulates, and carbon dioxide (CO_2) emissions. We also used the model to estimate variable, fixed and total system costs including variable operation and maintenance costs as well as amortized capital costs and fixed operating costs.

The scenarios we looked at included three baselines with high and middle load growth projections taken from a study done for the Georgia Environmental Protection Division (Georgia EPD) (Davis, 2016) and a low growth projection from analysis by the Energy Information Administration (EIA) of the U.S. Department of Energy (U.S. Energy Information Administration, 2017b). These baselines used the same assumptions for how electric power would be generated.

We also considered six alternative future scenarios:

1. **High energy efficiency**. Georgia's electric utilities offer residential and commercial energy efficiency programs, but the state's overall energy savings performance remains low. The American Council for an Energy Efficient Economy ranks Georgia 38th in the country in terms of energy efficiency improvements (American Council for an Energy Efficient Economy, 2017). We assumed the implementation of a stronger suite of efficiency programs that reduce electricity demand and thereby require less new energy generation.
2. **More renewable energy**. Currently, renewable energy comprises only about three percent of Georgia's power generation profile, and most of that is hydroelectric power. In recent years, however, Georgia has begun to add more solar photovoltaic (PV) generation. Here, we assumed that solar development would continue at current levels through 2050, although at the time of writing there are no approved additions beyond 2021. Under this scenario, 18% of generation in the state would come from renewable energy by 2050.
3. **Additional nuclear power**. Georgia Power expects to complete two new nuclear generating units, Vogtle 3 and 4, in 2021 and 2022, which will increase current nuclear generation by 50 percent. We include these new units in the baseline forecasts. For this high-nuclear scenario, we assumed that two additional units, which have been under study in Stewart County, are completed in 2034 and 2036. This would double the electricity generation from nuclear energy compared to 2015 levels.
4. **No new nuclear**. Given recent setbacks in the nuclear industry, we also examine the possibility that the two new nuclear units under construction at Plant Vogtle are not completed. Instead, we assume that solar PV contributes at the levels assumed for scenario 2 with natural gas making up any gap in generation.

5. **High energy efficiency and more renewable energy**. For this scenario, we combined scenarios 1 and 2.
6. **High energy efficiency and 35 percent renewable energy**. Several studies by the U.S. Department of Energy project that renewable energy could comprise 33 to 59% of U.S. power generation by 2050 (Cole, 2016; U.S. Department of Energy, 2015). Here we assume a combination of the level of energy efficiency used in scenario 1 and enough new solar PV to generate 35% of load.

What We Learned

We provide the full analytical results from our modeling in later sections of this report. Here we summarize what we learned:

1. A wide range of outcomes for water withdrawals and consumption are possible for the power sector in Georgia depending on electricity demand and how it is met. While higher demand certainly means a greater need for power generation, meeting that demand with nuclear, coal, natural gas, or solar energy will result in much different water use profiles for the state.
2. By avoiding the need for new generation, energy efficiency reduces water use, carbon dioxide emissions, air emissions, and total system cost. Reductions in demand through various efficiency and conservation programs have the benefit of permanently reducing demand, thereby avoiding the need for new generation investments and their associated water use, CO_2, and other air emissions. Energy efficiency can produce net savings for the user, and even at the upper end of costs, is less expensive than new generation.
3. Cost-effective generation options are available to meet demand while reducing water use, CO_2, and air emissions. The costs of solar energy, wind energy and batteries are declining rapidly (Cole, 2016). These technologies, though currently used in relatively miniscule amounts in Georgia, have lower capital and operating costs than nuclear energy and are not far from natural gas or coal generation costs (U.S. Energy Information Administration, 2016a). Solar PV and wind are financially viable now, and the cost of storage is coming down. In the timeframe we considered in this report (2015 to 2050), these options are expected to become even more cost competitive, bringing with them significant health and environmental benefits as well.
4. While it appears that Georgia is currently on a pathway toward greater water consumption because of the coming completion of two new nuclear generating units, that outcome is not inevitable. Greater deployment of energy efficiency and renewable energy could help to counterbalance those increases in water use.
5. Despite its increased water use, nuclear power provides multiple benefits in the form of reduced emissions of CO_2, SO_2, NO_x, particulates, and mercury when compared to coal generation, and CO_2 and NO_x when compared to natural gas generation. However, it is also the most expensive generation option to develop.

III. Water Resources in Georgia

Georgia is blessed with rich water resources, including more than 44,000 miles of perennial rivers and streams (Georgia Department of Natural Resources, 2015) as well as highly productive aquifers. The state's surface waters comprise 14 river basins including the mountainous Coosa River, the powerful Savannah River and several blackwater rivers like the Suwanee, the Ogeechee, and the Satilla, which flow through Georgia's coastal plain (see Figure 3). Because the Eastern Continental Divide runs the length of Georgia, the water in seven of these basins flows to the Gulf of Mexico, while the water in the other seven flows to the Atlantic Ocean. Georgia shares most of these surface water resources with its neighbors. Eleven of Georgia's 14 river basins flow into Alabama, Florida, South Carolina, or Tennessee (Lawrence, 2016). This fact has led to interstate conflicts over water use between Georgia and other states, particularly Alabama and Florida. These legal challenges continue today (Hallerman, 2017; Southern Environmental Law Center).

South Georgia, below the Piedmont, also boasts significant groundwater sources that supply the bulk of drinking water and irrigation water in that part of the state. This study, however, focuses on Georgia's surface water resources because the state's rivers and lakes supply nearly all the cooling water for Georgia's thermoelectric power plants.

Figure 3. Major river basins of Georgia.

Source: Georgia Department of Community Affairs.

Water Uses in Georgia

As in other states, the primary uses of water in Georgia include public water supply, agricultural irrigation, industrial processes, and thermoelectric cooling water. For the latest year available, 2010, total water withdrawals in Georgia were estimated by the United States Geological Survey (USGS) at 4,670 MGD, with the thermoelectric sector withdrawing the most, followed by public water supply and crop irrigation. Table 1 shows total water withdrawals in the state by sector. Of the total, about three-quarters are from surface water, and one-quarter is from groundwater. The thermoelectric sector accounts for 44% of total water withdrawals, almost all of it from surface waters (Lawrence, 2016).

Water withdrawals in Georgia declined between 1980 and 2010, mostly due to less use for thermoelectric cooling as power generation has shifted from once-through to recirculating cooling systems (Lawrence, 2016). USGS no longer reports water consumption, however, so it is difficult to know how overall water use may have changed recently among the various sectors; this will be an issue worth tracking going forward. For the thermoelectric sector, it is very likely that water consumption has gone up and will continue to do so as most of the once-through cooling units are retired or will be retiring, electricity demand is growing, and two new nuclear units that will use towers for cooling are slated to come online in the next decade.

Table 1. Water withdrawals (MGD) in Georgia in 2010.

Category	Water Withdrawals			Deliveries from Public Supply	Total Use	Surface Water Returns
	Groundwater	Surface Water	Total			
Public supply	248	873	1,121	--	--	--
Domestic	107	0	107	634	731	--
Commercial/public use	2.1	>1	2.7	209	212	1.2
Public supply system losses	207	289	495	108	603	405
Public wastewater treatment	--	--	--	182	182	--
Mining	17	>1	17	--	17	24
Irrigation-crop	576	170	747	--	747	--
Irrigation-golf courses	22	33	55	3	58	--
Livestock/aquaculture	6	73	79	--	79	2
Thermoelectric power	3	2,043	2,046	--	2,046	1,081
Total	1,189	3,481	4,670	1,125	4,675	2,225[2]

Source: (Lawrence, 2016).

[2] The values provided by Lawrence in this column are incomplete and do not add to the total.

Water Supply Challenges in Georgia

While Georgia enjoys, on average, more than 50 inches of rainfall per year, the state continues to struggle with water supply challenges, both natural and anthropogenic. Over the last few decades Georgia has experienced several episodes of significant drought, including:

- The 1987-1989 drought, during which streamflows in north Georgia reached the lowest levels in the 20th century;
- The 1998-2003 drought, which threatened public water supply in many parts of the state; and
- The 2007-2008 drought, which saw the levels of water supply reservoirs plummet around the state, including at Lake Lanier, which reached its lowest recorded level.

If the historical record is any indication, Georgia will continue to grapple periodically with the challenge of significant drought.

On top of these episodes of natural water shortage, legal wrangling over Georgia's surface water resources casts a long shadow over Georgia's water supply planning efforts. Georgia remains locked in ongoing litigation with Alabama and Florida over the use of water in the Apalachicola-Chattahoochee-Flint (ACF) and Alabama-Coosa-Tallapoosa (ACT) river systems. In part, the litigation hinges on whether Georgia leaves enough water in these river systems to protect ecosystems and aquatic life, including several endangered species, and to support downstream uses. This interstate struggle took on a new dimension with Florida's lawsuit directly against the state of Georgia, which was heard by the U.S. Supreme Court on January 8, 2018. The urgency of this water sharing challenge comes to the fore during periods of drought like those described above.

Water supply challenges are not limited to the western part of the state. Georgia's coastal communities rely on the Floridan aquifer for much of their municipal and industrial water supply, and the future supply of usable groundwater in the region is uncertain. Heavy use of the aquifer has led to saltwater intrusion, which has already compromised municipal use of the aquifer in parts of Georgia and South Carolina. In response, the Georgia EPD has directed coastal communities to lessen their use of the aquifer. The ongoing management of saltwater intrusion may require decreased reliance on the Floridan aquifer for coastal Georgia counties, with resulting shifts to surface water sources.

These problems will likely be exacerbated by population growth. The state currently has a population of 9.9 million people. The Governor's Office of Planning and Budget estimates that Georgia's population will top 12 million people by 2030, and be almost 15 million by 2050 (The Governor's Office of Planning and Budget, 2015), intensifying the demands on its water resources.

Additionally, recent studies have suggested that climate change may negatively affect Georgia's water supply. The U.S. 2014 National Climate Assessment (NCA) addressed water conflicts in the

Apalachicola-Chattahoochee-Flint and the potential for climate change to worsen those conflicts. It concluded that the "basin is likely to experience more severe water supply shortages, more frequent emptying of reservoirs, violation of environmental flow requirements (with possible impacts to fisheries at the mouth of the Apalachicola), less energy generation, and more competition for remaining water" (Georgakakos, 2014).

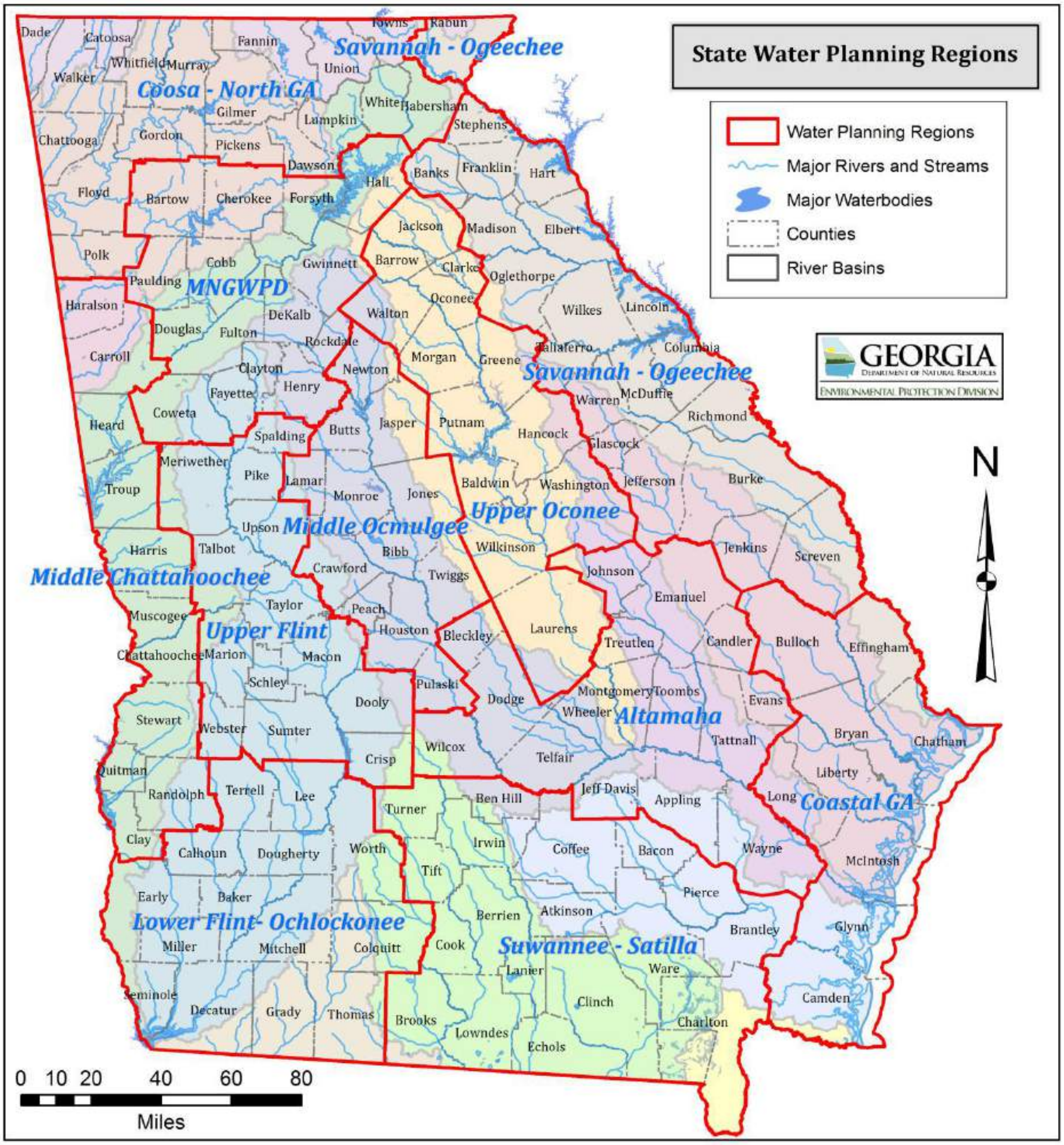
Across the state, climate change is likely to lead to changes in precipitation patterns, with larger, wetter, and more frequent rainfall events. The implications for Georgia's water resources include both more flooding during extreme events, and longer periods without rain, leading to greater potential for drought (U.S. Environmental Protection Agency, 2016). The average amount of rainfall may not change much though, from an increase of up to 2.5 percent in the southeastern part of the state by 2060, to a drop of 5 percent in the northwest (Georgakakos, 2014). Higher temperatures could exacerbate these problems, however, as there will be larger losses to evaporation and transpiration under warmer conditions. In addition, higher temperatures will lead to more electricity demand, and so increase the need for thermoelectric cooling water and its resulting consumption (U.S. Environmental Protection Agency, 2016).

Water Resource Management in Georgia

In the early 1990s, the Georgia General Assembly passed the River Basin Management Planning Act, starting the state down the path of statewide, coordinated water planning, well ahead of other states. In 2001, the legislature ramped up metropolitan Atlanta's water planning efforts with the creation of the Metropolitan North Georgia Water Planning District, or Metro Water District. The Metro Water District develops comprehensive regional and watershed-specific water resource plans for 15 counties and more than 90 municipalities in the Atlanta metropolitan area. Since its inception, the Metro Water District has incorporated aggressive mandatory water conservation measures as part of each of its 5-year water supply plans.

In 2004, the Georgia General Assembly expanded the scope of regional water planning in the state with the passage of the Comprehensive Statewide Water Management Planning Act. This established a comprehensive water planning process that created an additional ten water planning regions and councils (in addition to the Metro Water District) and culminated in the adoption of regional water plans for all ten regions in November 2011. The regional plans developed by these councils estimate future water demands and determine how they will be met. Figure 4 shows how these planning districts align with Georgia's river basins and counties.

Figure 4. Georgia's State Water Planning Regions and Major River Basins.



Source: Georgia EPD.

Note: MNGWPD stands for Metropolitan North Georgia Water Planning District.

As part of this study, we reviewed the water plans for the regions that have the highest current demand for thermoelectric cooling water. The Savannah-Upper Ogeechee Region is the region with the highest water use for thermoelectric cooling in the state, due to the nuclear units located there (Plant Vogtle Units 1 and 2). The region's water planning council's report shows nearly a doubling of both withdrawals and consumption from 2010 to 2050, from 60 MGD to 133 MGD for withdrawals, and 44 to 85 MGD for consumption (Savannah-Upper Ogeechee Water Planning Council, 2011). The next largest region is the Altamaha, which shows almost no change. The Altamaha Council reports withdrawals as 51 MGD and 33 MGD for consumption (The Altamaha Council, 2011). For both of these regions and the others we reviewed, the values from 2020 to 2050 were static, with any adjustments occurring between 2010 and 2020.

The regional water plans relied in part upon a 2010 study for the Georgia EPD by Davis and Horrie (2010) that projected statewide withdrawals for thermoelectric cooling at 2,361 MGD and consumption at 198 MGD. This study was updated by Davis in 2016 and estimated water withdrawals at 1,819 MGD and consumption for thermoelectric cooling at 168 MGD for 2015 (Davis, 2016). The key difference in the estimates was an updated population projection from the state showing slower growth.

As part of our modeling exercise, we generated an estimate of water consumption for Georgia's power sector. The methods we used are described in later sections. Based upon water consumption coefficients derived from the literature and the way that electricity is generated in the state, we calculated 2015 water consumption for thermoelectric cooling to be 153 MGD.

An Example Comparing Thermoelectric and Municipal Water Consumption

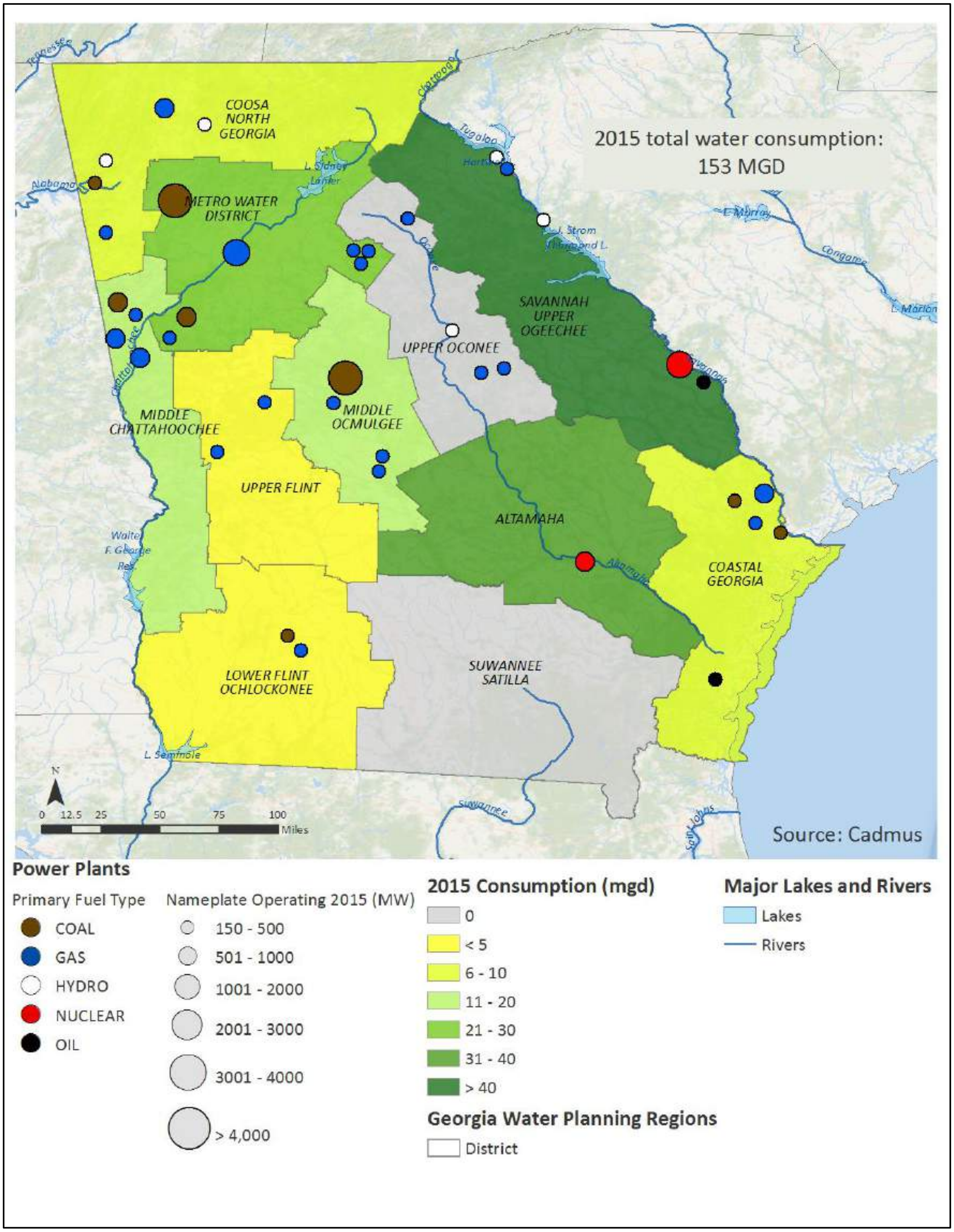
To put thermoelectric water consumption in context, the municipal water system for Gwinnett County, northeast of Atlanta, serves 795,000 people and consumes about 20 MGD on average. Rockdale County is east of Atlanta. Its municipal water system serves 72,600 people and consumes about 6 MGD on average (Georgia Environmental Protection Division, 2017, n.d.). This means that reducing total water consumption for thermoelectric cooling in Georgia by around 17% would save about as much water as is used consumptively by these two systems that serve more than 860,000 Georgians. It is worth noting that this equivalence does not necessarily translate into additional municipal water supply capacity. There are numerous factors that affect levels of available water supply within each basin.

Table 2 shows our estimated values for thermoelectric water consumption by planning region. Figure 5 provides a map of Georgia's power generating capacity and water consumption by water planning region. The map and table show that the regions with nuclear generation (Altamaha and Savannah-Upper Ogeechee) have the highest daily rates of water consumption, followed by the Metro Water District, which has both coal and natural gas generation. These three regions account for two-thirds of the total water consumption for power generation in the state. The map also shows 2015 generating capacity by planning region. In a later section, we will provide estimates of water consumption through 2050 for various load projections and alternate future scenarios.

Table 2. Water consumption for thermoelectric power generation cooling by Water Planning Region in millions of gallons per day.

Water Planning Regions	2015 Water Consumption (MGD)
Altamaha	31
Coastal Georgia	9
Coosa North Georgia	6
Lower Flint Ochlockonee	0.8
Metro Water District	28
Middle Chattahoochee	17
Middle Ocmulgee	18
Savannah Upper Ogeechee	42
Suwannee Satilla	0
Upper Flint	0.2
Upper Oconee	0
TOTAL	153

Figure 5. Electricity generating capacity and water consumption in 2015 by water planning region.



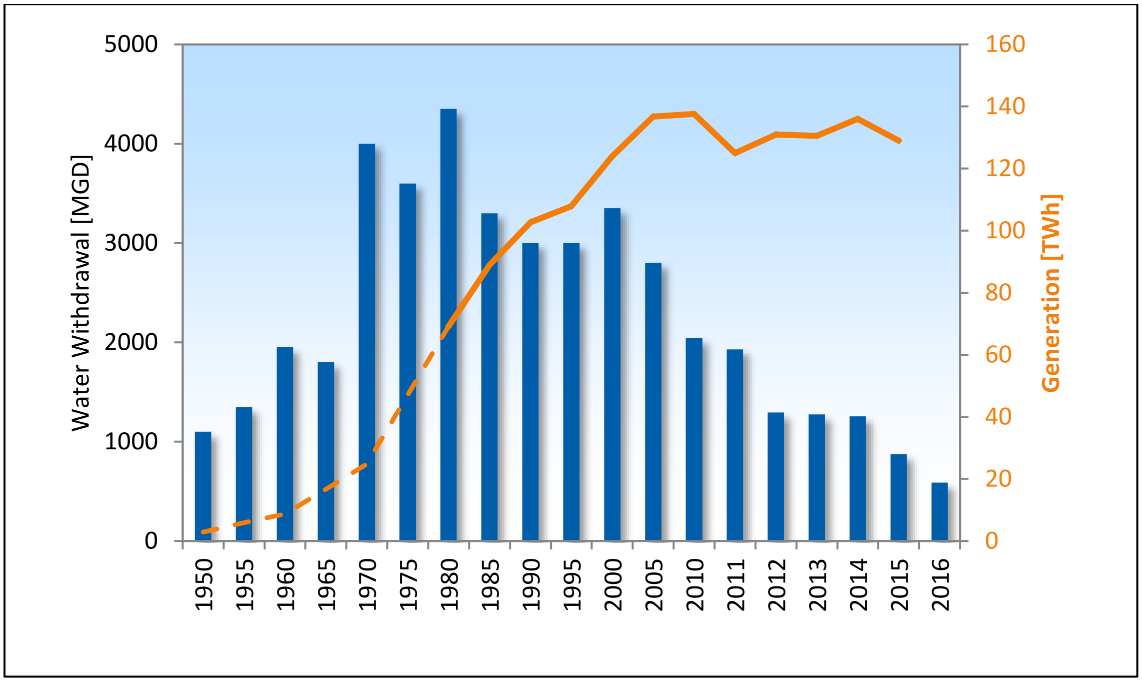
Note: Some natural gas plants are air-cooled and do not require cooling water.

IV. Water Use for Georgia’s Power Plants

Water withdrawals for thermoelectric cooling have changed considerably over time. Figure 6 shows changes in water withdrawals by Georgia’s thermoelectric power sector from 1950 to 2016, based on data from Georgia EPD (Fanning, Doonan, Trent, & McFarlane, 1991), USGS (Lawrence, 2016), and Georgia Power (Georgia Power, 2003-2017) with changes in generation and population shown for context. The reasons for the changes in water withdrawals are likely tied to both the rate of electricity demand growth, as well as the fuel types and cooling technologies used. From 1950 through 1980, water withdrawals increased significantly as population and electric generation increased (Fanning et al., 1991). Additionally, most new generation capacity relied on once-through cooling systems.

From a peak of 4,350 MGD in 1980 to the present, water withdrawals have fallen significantly (Lawrence, 2016) even as total electric generation has increased. Three major declines in water withdrawals have occurred: the first in the 1980s, the second starting in about the year 2000, and a third from 2014 to 2016, resulting in 2016 water withdrawals of 587 MGD. The decline in the 1980s was likely due to an increase in generation from recirculating cooling coal and nuclear plants, and a corresponding decrease in generation from once-through cooling coal plants. After 2000, Georgia’s natural gas capacity rapidly increased, leading to a decline in generation from once-through cooling coal plants. More recently, several large once-through cooling power plants have been decommissioned. Figure 6 shows these changes in the state’s power sector.

Figure 6. Water withdrawal for thermoelectric power generation in Georgia and generation in terawatt hours, 1950-2016.



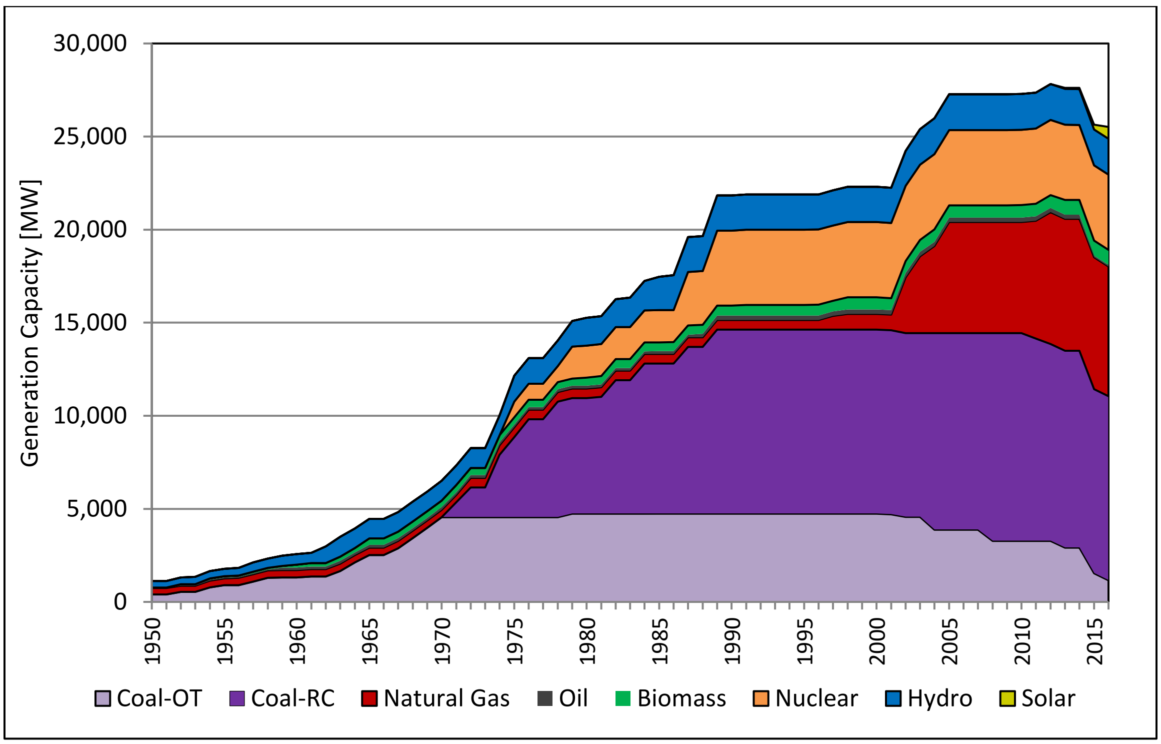
Sources: Derived from Fanning et al. (1991); Lawrence et al., 2016; EIA, and Georgia Power (withdrawal numbers after 2010).

Note: Dashed line is estimated generation based on capacity and typical capacity factors (a ratio of a power plant's actual output compared to its potential output) by fuel type.

Water withdrawal, though, is only one piece of the thermoelectric water use picture. Water withdrawals by plants with once-through cooling can be massive, typically on the order of 30,000 gallons per megawatt-hour (gal/MWh) of generation, and potentially in excess of 100,000 gal/MWh (Macknick et al., 2011; Peer & Sanders, 2016). As a result, plants using once-through cooling have an outsized influence on the water withdrawal numbers. As once-through plants are replaced by plants with recirculating cooling (or retrofitted with cooling towers) (Cheek, 2008), the water withdrawals decrease, but the amount of water consumed and not returned to water bodies may increase substantially. Unfortunately, there are no complete data on water consumption across the thermoelectric power sector over the same period going back to 1950. Nevertheless, changes in the composition of the power sector can provide insight into the direction of the expected changes.

Figure 7 shows the composition of generating capacity by fuel type for Georgia's electric power sector, based on generator year online and plant retirement data available in 2014 from the Environmental Protection Agency's (EPA) Emissions & Generation Resource Integrated Database (eGRID) (EPA, 2017) and EIA Form 860 (Energy Information Administration, 2017a). These totals include thermoelectric (nuclear, fossil fuel, and biomass plants with cooling) and renewable generation sources.[3] The generating capacity chart shows several major changes in the composition of the power sector; each change is marked by a new source type being added to the state's mix. From the 1950s through about 1970, most of the capacity additions were coal plants with once-through (OT) cooling. Then, from about 1970 through the late 1980s, the major capacity additions included coal plants with recirculating cooling (RC) and nuclear plants. After 2000, new natural gas plants added significantly to power capacity. Finally, in the past five years, coal plants with once-through cooling have been retired, while solar capacity has begun to come online.

Figure 7. Electric generating capacity in Megawatts (MW) for Georgia's power sector, 1950 – 2016.



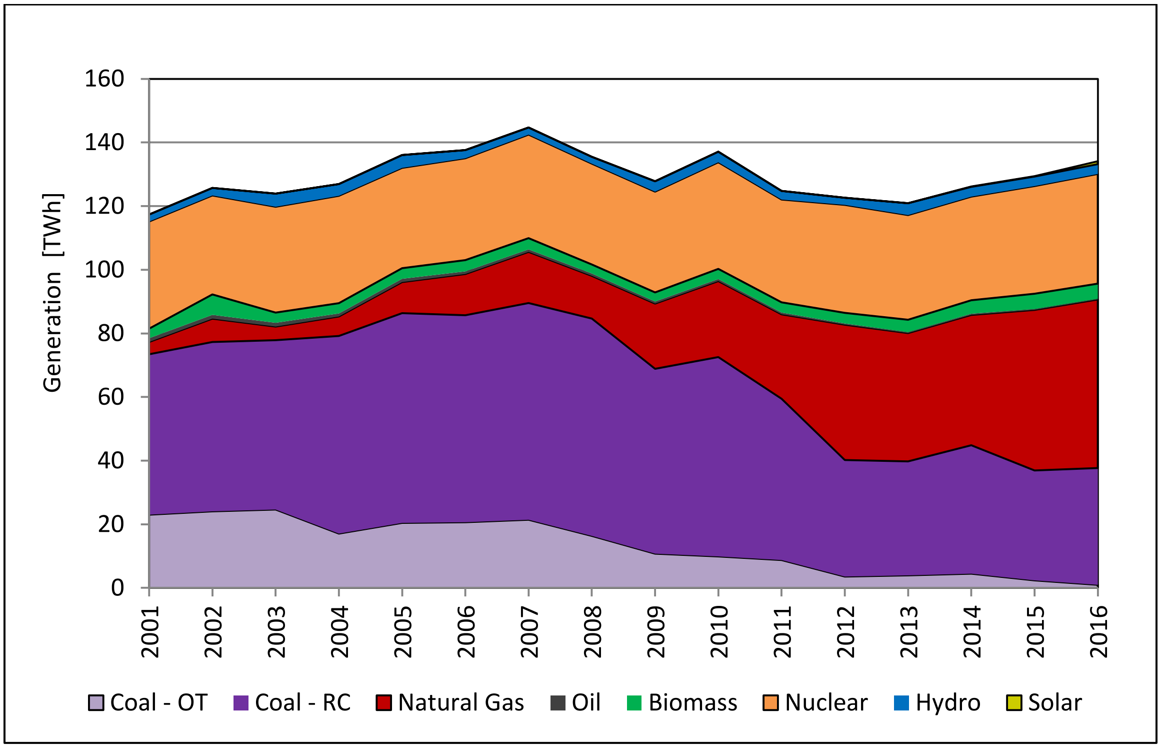
OT – once through cooling; RC – recirculating cooling.
Source: Derived from EIA, EPA, and eGRID data.

Figure 8 shows the annual generation totals by fuel type since 2001, based on EIA generation data (U.S. Energy Information Administration, 2016b). Generation from coal plants with once-through cooling is nearly phased out, coal with recirculating cooling is decreasing, and natural gas is

[3] The figure does not include capacities for oil and gas combustion generators that are only used sporadically or in emergencies (capacity factors generally under 5 percent) and do not require water cooling.

increasing as a portion of the generation mix. Nuclear, hydroelectric and biomass generation are relatively stable.

Figure 8. Annual electric generation in terawatt-hours (TWh) for Georgia's power sector, 2001-2016.



OT – once through cooling; RC – recirculating cooling; NGCC – natural gas combined cycle.
Source: Derived from EIA Form 923 data.

The very detailed generation data used to create Figure 8 offer a path toward estimating water consumption changes. It is possible to estimate water consumption—and model future water consumption—by developing Georgia-specific water consumptive use rates for the most common power plant types as classified by their fuel type and cooling technology. The following section explains how these consumptive water use rates were developed based on available data for power plant water use in Georgia. We present a reconstruction of historical water use based on the consumptive use rates and previously reported data on annual generation by fuel type later in this chapter.

Data Sources for Estimating Consumptive Water Use by Georgia's Power Plants

There are several data sources that can be used for estimating consumptive water use rates at thermoelectric power plants in Georgia. Table 3 shows the literature and data sources used in this analysis. The goal is to use these data sources to estimate consumptive water use rates by fuel type and cooling technology for power plants in Georgia. Table 3 presents information on the data

available, including the data years available, whether individual plant data are available, whether data are presented as rates or volumetric use, and whether the data can be used to determine rates specific to Georgia (versus a national average).

Table 3. Relevant literature and data sources for estimating consumptive water use by Georgia's thermoelectric power plants.

Source	Data Years	Primary Water Use Source	Individual Plant Data	Rate, Use, or Both	Specific to Georgia
Fanning et al., 1991	1980-1987	Reports submitted to Georgia EPD	Use	Use	Yes
CDM (Davis & Horrie, 2010)	2003-2007	Reports submitted to Georgia EPD	No	Rate	Yes
Macknick et al., 2011	~1995-2010	Various studies	No	Rate	No
UCS (Averyt et al., 2011)	2008	Macknick et al., 2011, and EIA- 923	Yes	Both	Use – Yes Rate – No
USGS (Diehl and Harris), 2014)	2010	Modeled, and based on EIA-923	Yes	Use	Yes
EIA Form 923 (U.S. Energy Information Administration, 2016b)	2013-2015	EIA-923 Sec. 8D	Yes	Use	Yes
Peer and Sanders, 2016	2014	EIA-923 Sec. 8D	Yes	Rate	Yes
Georgia Power, 2016	2010-2016	Reports submitted to Georgia EPD	Yes	Use	Yes

Since the consumptive water use rate is a rate statistic expressed as a ratio in gallons per MWh, it requires data on both water consumption and electric generation, ideally at specific generators. We used EIA Form 923 Generation data as the source of electric generation in all cases (U.S. Energy Information Administration, 2016b).

To compute average consumptive use rates by fuel and technology type classes we used three approaches:

- For data sources with volumetric use by plant, we divided total use by generation with each fuel and technology type class to obtain the rate;
- For data sources with rate data by plant, we used the generation data by plant as a weighting factor to compute the average; and
- For data sources with only rate data and not available by plant, we used the rates directly.

Appendix A contains more information on the data available from each source, and the methods used to compute consumptive water use rates. One important note is that water use data is based on reported values for all of the listed references except one: the USGS study (Diehl, 2014) developed thermodynamic models of each plant, and generated modeled estimates of usage. All the other consumptive use data sources utilized primary reporting data submitted either to EIA in Form 923 Section 8D or in water use reports submitted to Georgia EPD directly by Georgia Power.[4]

Estimates of Consumptive Water Use Rates by Fuel, Technology Type

This section summarizes estimates of consumptive water use for thermoelectric power plants in Georgia. This study provides water use coefficients in units of gallons per megawatt hour for each of the following plant types:

- Coal with once-through cooling;
- Coal with recirculating cooling (cooling towers);
- Natural gas combined cycle;
- Nuclear with recirculating cooling; and
- Biomass with recirculating cooling.

These estimates are specific to Georgia and, in nearly all cases, were computed based on reported or estimated water use for plants in Georgia. We calculated statewide averages based on water consumption data available at the plant level (in various appendices provided with the cited studies); as a result, they may not reflect the national averages reported in the studies. Furthermore, while many national studies (e.g., Macknick et al. 2011) report water use rates using the median statistic to reduce the bias of outliers, we use a generation-weighted average to ensure that the number is reflective of the entire Georgia fleet performance for each power plant type.

[4] In practice, these sources are identical, as it appears Georgia Power submits the same information to both Georgia EPD and EIA.

Table 4. Consumptive water use rates in gallons per megawatt hour
from various sources and the coefficients we used for modeling thermoelectric power plants in Georgia.

Source	Data years	Coal-OT	Coal-RC	NGCC	Nuclear	Biomass
CDM (Davis & Horrie, 2010)	2003-2007	-	567	198	880	-
UCS (Averyt et al., 2011)	2008	250	687	198	672	553
USGS (Diehl, 2014)	2010	354	462	199	610	-
Peer & Sanders (2016)	2014	204	569	215	884	-
EIA Form 923 8D (U.S. Energy Information Administration, 2016b)	2013-2015	-	600	182	874	362
Value used in modeling		366	495	199	794	495[5]

OT – once through cooling; RC – recirculating cooling; NGCC – natural gas combined cycle.

Appendix A explains the differences between the estimates, and our rationale for selecting the values used for our modeling. In brief, the methods for selecting the final values are described below:

- **Coal with once-through cooling (Coal-OT)** – We used the USGS (Diehl, 2014) estimates for the two Georgia Power plants with this cooling method that remain active in 2016, weighted by generation.[6]
- **Coal with recirculating cooling (Coal-RC)** – We used the USGS (Diehl, 2014) estimates for Georgia's other coal power plants, weighted by generation in 2015. We also applied a correction factor of +7% to account for the fact that 2010 – the year of the USGS (Diehl, 2014) estimates – was anomalously low compared to other years' data submitted to EIA and Georgia EPD.
- **Natural gas combined cycle (NGCC)** – All the values were in close agreement. We adopted the USGS (2014) value for Georgia's NGCC power plants because it had the most consistent estimates and a larger sample size.
- **Nuclear**[7] – The USGS (Diehl, 2014) study presents a range of estimates of water consumption based on the operating conditions of nuclear plants in 2010. The values in the

[5] The environmental and water use factors for biomass and coal are similar, so we lumped them together.

[6] The value used in modeling is higher than the average rate for the Diehl and Harris (2016) analysis because that analysis averaged data from more plants, some of which are now offline.

[7] All nuclear power plants in Georgia use recirculating cooling with cooling towers.

reports submitted to EIA and Georgia EPD exceed the USGS (Diehl, 2014) "High" estimate by over 130 gal/MWh. Since exceeding the "High" estimate to such a degree is unlikely, we adopted the USGS (Diehl, 2014) "High" estimate of 743 gal/MWh as the baseline, and applied the same +7% correction factor as for Coal-RC.

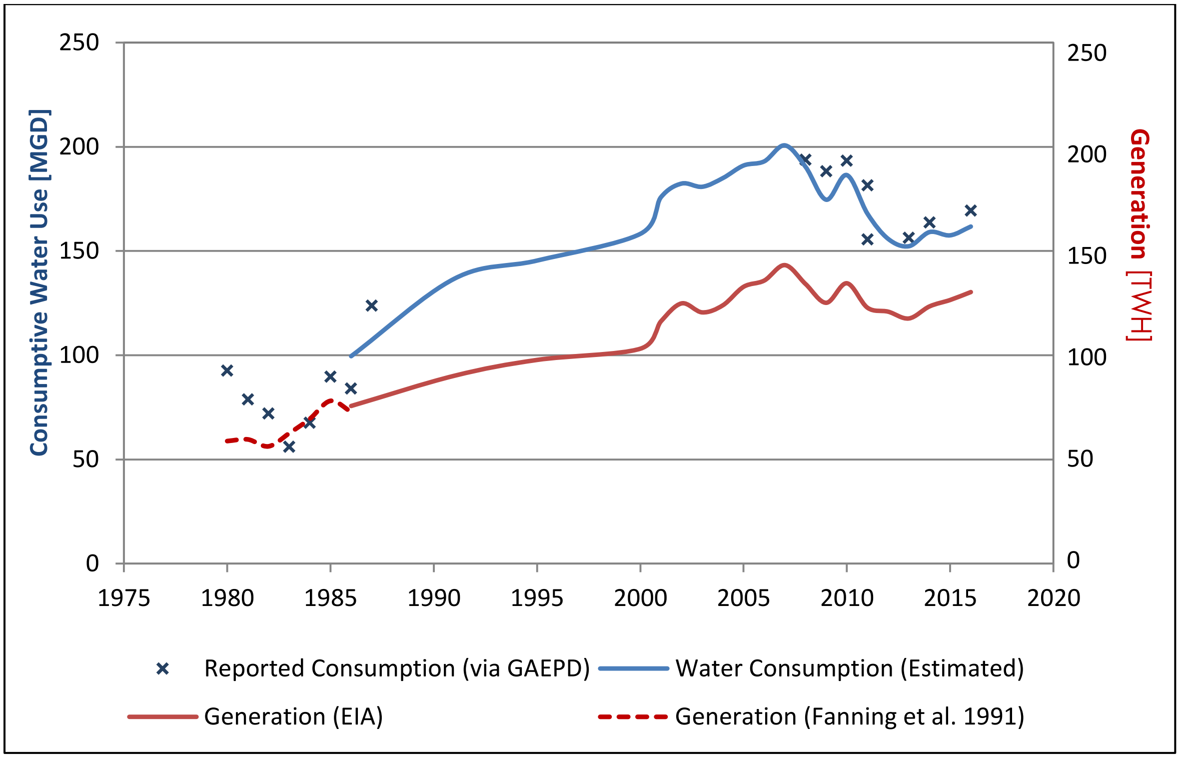
- **Biomass** – There were limited data on water consumption for Georgia's power plants using biomass. Only one plant reported data, and it did not use biomass exclusively. Most of the biomass generation occurs at relatively small non-utility generators with water consumption rates that are similar to coal (Macknick et al., 2011). Given the data limitations, and for simplicity, we assumed the water consumption rate for biomass generators matches the rate for Coal-RC generators. In the modeling, we lumped biomass generating capacity together with coal with recirculating cooling.

Reconstructing a History of Consumptive Water Use in Georgia

Understanding consumptive use by the power sector is important to decision- and policy-makers. More than withdrawal, consumption affects the amount of water left in streams for other uses. Data limitations have made it difficult to generate credible statewide estimates of total water consumption by the thermoelectric power sector in Georgia. The most recent USGS estimates of water use in Georgia report only withdrawals and return flows, the difference of which does not equal consumption (Lawrence, 2016). Georgia EPD, Georgia Power, and the EIA track reported water consumption, but the data are subject to methodological errors, and there are omissions as not all plants report data.

Our calculated consumptive water use rates (see Table 4) offer another option for estimating statewide water consumption for the entire power sector (Lawrence, 2016). Very simply, multiplying the consumptive water use rates in gallons per MWh by total annual electric generation for each class of plant (in MWh) yields total water consumption. Figure 9 displays the historical reported values and the estimated values for this study for total water usage for the thermoelectric power sector in Georgia.

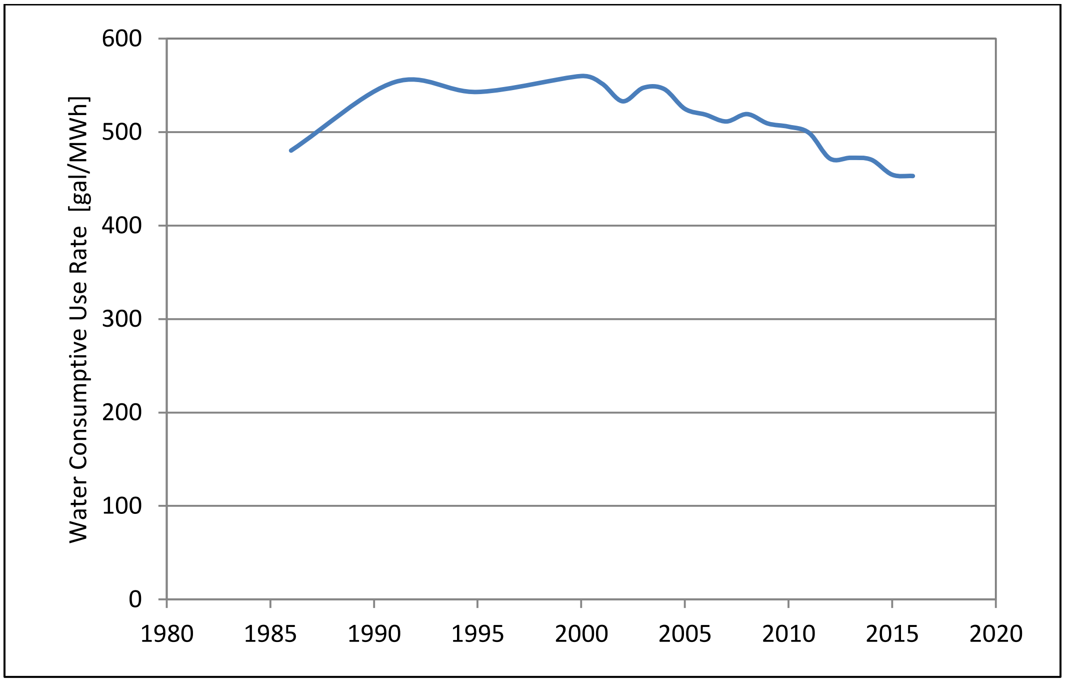
Figure 9. Estimated thermoelectric power sector water consumption and electric generation in Georgia, 1986-2015



Consumptive water use in Georgia reached its peak in 2008 at 200 MGD. We compared the estimated water consumption with available data on reported total consumption submitted to the Georgia EPD by Georgia Power (including generation by Southern Company) for 2009 and later (Georgia Power, 2016), and data in Fanning et al. (Fanning et al., 1991) for 1980-1987. While these reports do not include all electric generation in the state, they likely cover more than 90 percent of it. Further, our estimated water consumption does include all generation from the thermoelectric power sector. The agreement between the estimated and reported data is good, replicating both the scale and trends. Thus, we feel confident that the water use coefficients are accurate and useful for modeling the power sector's water consumption.

Finally, we can plot the overall fleet-wide average water consumption rate over time for the thermoelectric power sector in Georgia. Figure 10 shows that although generation and water usage are closely linked, there have been changes in the consumptive use rate over time. The rate climbed in the late 1980s, likely as a result of nuclear generators coming online. Then, starting in about 2000, the rate began a slow decline, which corresponded with the increasing share of natural gas generation, and decreasing share of coal-fired generation. Overall, the rate has fallen from a peak of 560 gal/MWh in 2000 to 453 gal/MWh in 2016, a 20 percent decrease. The future direction of the consumptive water use rate will depend on the total power demand and changes in the generation mix in Georgia's power fleet going forward.

Figure 10. Fleet-wide consumptive water use rate for Georgia's thermoelectric power sector in gallons per megawatt-hour.



Water Savings from Energy Efficiency

Energy efficiency avoids the need for electricity generation, and so does not have any associated need for water use. The amount of water saved from reducing energy demand depends on the type of electricity generation that energy efficiency displaces. In the short-term, reduced demand displaces the marginal unit of generation, that is, the type of capacity that already exists and is called upon last to provide supply. This is often natural gas, as those units can be turned on and off quickly. In the medium- and long-term, however, reduced demand could displace whatever type of extant capacity is least economical, or new capacity that would have been built next. In Georgia's case, these could be coal in the first instance, or nuclear, natural gas, or even solar PV power in the latter. The factors influencing this displacement are complicated and depend upon the scale of reduced demand, economics, and decisions made by the Public Service Commission. While a weighted average of consumptive use for the generating fleet is less precise, it is easier to calculate. Figure 9 reflects that the average volume of water consumed for every MWh in 2016 was 453 gallons per MWh.

V. Modeling the Baselines

We undertook analysis of water use in Georgia for electricity generation using a power sector model developed by CNA (Faeth, 2014; Faeth et al., 2014). The model is set up to meet projected load growth in the most economical way possible given the available generation options. The options for electricity generation in the model include six types of primary energy sources: coal, hydroelectric, natural gas, nuclear, solar radiation, and wind.

For coal and natural gas generation, there are different combustion technologies that can be employed which have different implications for water use. Steam from coal can be generated under sub-critical or super-critical conditions, the latter being more efficient. Similarly, natural gas can be used in conventional or combined cycle technologies. While combined cycle generation is more efficient, conventional generation is often air-cooled. Given the primary fuel types and cooling technologies, it is possible to represent a wide variety of combinations in the model. In Georgia, however, just seven combinations are used to generate almost all electricity, as shown in Table 5. Coal, nuclear, and natural gas generation accounted for 93 percent of all electricity generation in the state in 2015.

Table 5. Share of electricity generation in Georgia by energy source and cooling technology in 2015.

Primary Energy Source or Fuel Type	Cooling Technology	Share
Natural gas combined-cycle	Recirculating	36%
Conventional coal	Recirculating	27%
Nuclear	Recirculating	26%
Biomass	Recirculating	4%
Conventional gas	Air-cooled	2%
Conventional coal	Once-through	2%
Oil	All types	<1%
Solar photovoltaic	None required	<1%

Source: EIA.

CNA's Electricity-Water Nexus model is a mixed-integer linear programming model that seeks to find the optimal solution to meet electric power demand at least cost. Mixed-integer linear programming means that part of the model solution can only be in whole numbers—in this case, the number of power plants. The model simulates both new plant construction and existing plant retirement due to aging.

The model is set up to meet power demand for each year of the simulation by choosing from a set of representative power plants that reflect the energy source, combustion, and cooling technologies shown in Table 5, with the exception that we lumped biomass with conventional coal and dropped oil.

In **Appendix B**, we provide a list of the electricity generating units addressed in this study along with information about their characteristics and water use. Information about these units was used to create the profiles of the representative generating units in the model.

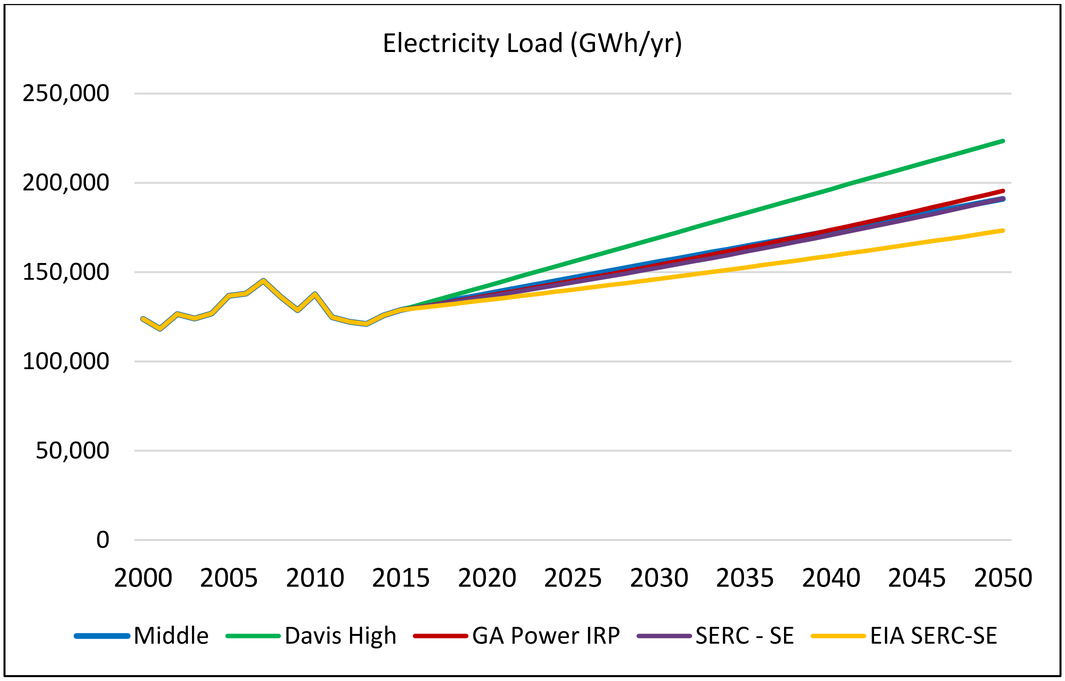
Load Growth Projections

We assembled available load growth projections to create a baseline for the model from which to evaluate alternate future scenarios. The sources for these load growth projections include:

- **Davis Expected; Davis High** – A study for Georgia EPD's Ad Hoc Energy Group by CDM (Davis, 2016). This study developed "Expected" and "High" scenarios for load growth out to 2050 based upon population projections. The growth rate for the Expected scenario was 1.13 percent per year, and the High scenario growth rate was 1.6 percent per year.
- **Georgia Power IRP** – Georgia Power's 2016 Integrated Resource Plan (IRP), which projects 1.2 percent annual growth on average from 2016-2025 (Georgia Power Company, 2016).
- **SERC-SE** – Southeast Reliability Corporation's (SERC's) 2016 regional supply and demand projections for its southeastern region for 2015-2025, which shows an average growth rate of 1.13 percent per year (SERC Reliability Corporation, 2016).
- **EIA SERC-SE** –EIA's load growth projection for SERC's southeastern region "reference case without the Clean Power Plan," which projects an annual growth rate out to 2050, averaging 1.095 percent (U.S. Energy Information Administration, 2017a).

We used these growth rates, starting from 2015, and made linear projections extending to 2050. The results are shown in Figure 11.

Figure 11. Load growth projections in GWh per year for Georgia, 2016-2050, and actual.



Sources: Derived from Davis (Davis, 2016), Georgia Power (Georgia Power Company, 2016), SERC (SERC Reliability Corporation, 2016) and EIA (U.S. Energy Information Administration, 2017b).

Cost Data

The model chooses from the set of electricity generating options to meet each year's electricity demand, based on the cost of each option and constraints we place on the model's ability to add new generating capacity. For example, new nuclear generating capacity and solar PV are limited in some scenarios to align with Georgia Power's implementation plans.

For each representative power plant, we defined a set of characteristics for cost, generation, and environmental performance that were based upon the actual fleet (Appendix B). These characteristics include fixed and variable costs; water withdrawal and consumption; and emissions of nitrogen oxides (NO_x), mercury, sulfur dioxide (SO_2), particulate matter (PM), and carbon dioxide (CO_2). Fixed costs include amortized capital costs and fixed operating costs. Variable costs include variable operation and maintenance costs, including fuel and transmission costs. Together these represent total system costs.

Capital, fixed operating and maintenance, and variable operating and maintenance costs were taken from a recent study by EIA entitled *Capital Cost Estimates for Utility Scale Electricity Generating Plants* (U.S. Energy Information Administration, 2016a).

Long-term fuel costs for coal and natural gas were derived from EIA's online reference source for the *2017 Annual Energy Outlook* (U.S. Energy Information Administration, 2017a). We took the 2016 and 2050 prices for each and used them to make a straight-line fuel cost projection. EIA's analysis gives a price change of $2.28 to $2.39 per million British Thermal Units (BTU) for coal delivered for electric power over the period, and $3.40 to $6.35 for natural gas for electric power generation. These prices are for the SERC-SE region under the reference case ***without*** the Clean Power Plan (CPP), a policy put forward by the Obama Administration to control carbon dioxide emissions from electric generating units.

Baseline Scenario Results

We used the model to explore three of the load growth projections presented in Figure 11 under baseline assumptions. The three baselines included the Davis Expected ("Middle Baseline") and Davis High ("High Baseline"), and EIA SERC-SE ("Low Baseline") load projections. We chose not to model the Georgia Power IRP and SERC-SE projections because they are substantially similar to the Davis Expected or "Middle Baseline" load projection. For the chosen three baseline scenarios, we made the following assumptions:

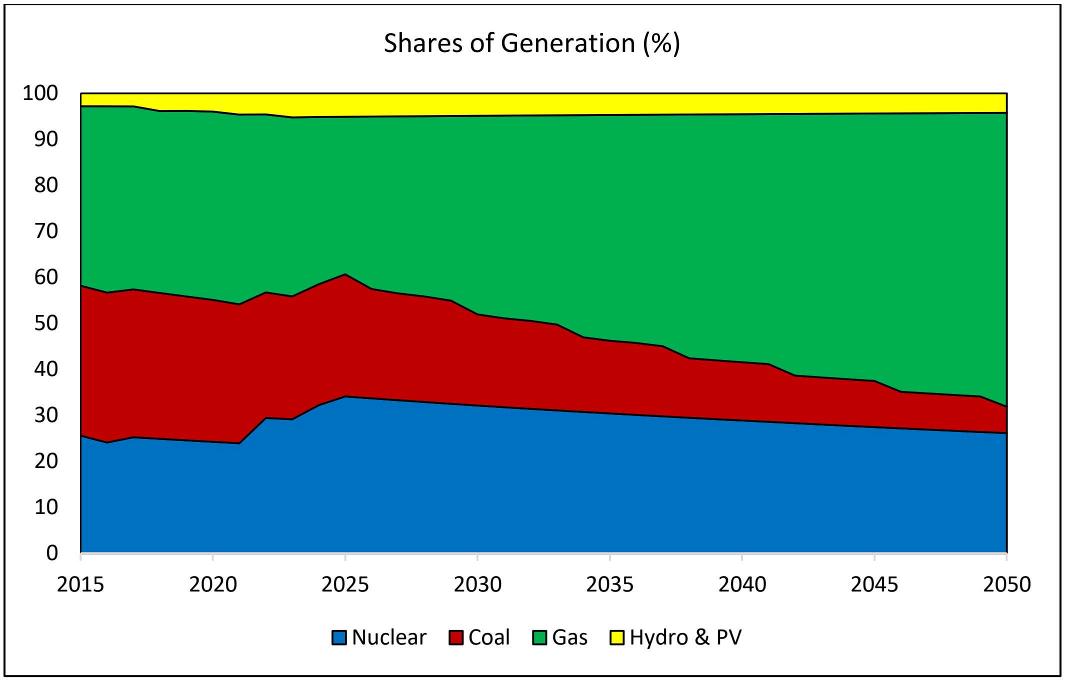
- Existing coal units retire after 65 years of operation. This useful life assumption is a conservative estimate based on the average age of recently retired coal units in Georgia, which is 55 years. Retirements that fall close together are spread out to avoid disruption.
- No additions or retirement of hydroelectric capacity.
- Two new nuclear generating units, Vogtle 3 and 4, come online in 2021 and 2022, respectively, and all four of the existing nuclear units (Vogtle units 1 and 2 as well as the two units at Plant Hatch) continue operating through 2050.
- Solar PV additions include only those currently planned under Georgia Power's Renewable Energy Development Initiative (REDI).
- Any needed capacity will be made up by additions of natural gas.

Figure 12 shows the modeling results for the percent, or share, of electricity generation by type under the Davis Expected or "Middle Baseline" load projection. Under the Middle Baseline:

- Coal production contracts substantially;
- Nuclear increases when the two new Vogtle units are added;
- Renewables, which include hydro and solar PV, increase incrementally; and
- Power generation from natural gas increases dramatically, continuing a shift that began 10 years ago with the drop in natural gas prices.

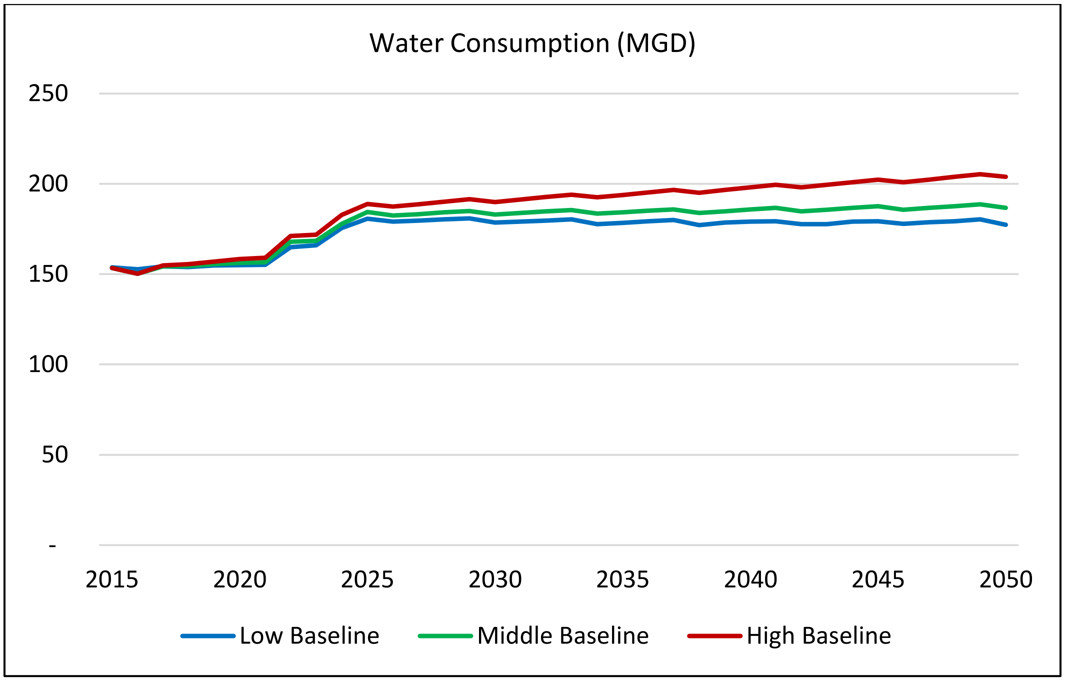
The addition of the two nuclear units can be seen in the jumps in that category in 2021 and 2022. In addition, the ratcheting down in coal generation reflects the retirement of aging coal units. For the High Baseline and Low Baseline load projections, the main difference compared to Figure 12 is more or less natural gas generation as needed to meet the differing levels of demand.

Figure 12. Electric power generation shares under Middle Baseline load growth projection.



The increase in electricity demand shown across all baseline load demand projections and the way that demand is met have significant implications for water consumption by the power sector in Georgia. Figure 13 shows the amount of water consumed for thermoelectric cooling under each of the baseline scenarios. The most striking feature is the jump in water consumption that occurs with the addition of the two nuclear generating units. This occurrence accounts for most of the growth in water consumption over the entire period. In contrast, there is no increase in water use after the addition of the nuclear units in the Low Baseline and a relatively small increase under the Middle Baseline, even though demand grows by one-third and almost half, respectively, in those scenarios. The reason is the continued shift from coal to natural gas. While coal consumes almost about 500 gallons of water for cooling to generate one MWh of electricity, natural gas uses only 199 gal/MWh. In contrast, nuclear uses nearly 800 gal/MWh, in part because there is no smokestack to help release heat (see Table 4).

Figure 13. Water consumption under the Middle, Low, and High Baseline scenarios.



We estimate that 2015 water consumption for thermoelectric cooling in Georgia was 153 MGD. Under the Low, Middle, and High Baseline scenarios, water consumption would grow by 2050 to 177 MGD, 187 MGD, and 204 MGD, respectively, which equates to increases of 16, 22, and 33% compared to 2015. However, even with the addition of two nuclear units in Vogtle 3 and 4, the increases in water consumption are much less than the increases in electricity demand over the period because of the transition from coal to natural gas generation.

Figure 14 maps generating capacity and water consumption for the Middle Baseline in 2050. A few things stand out. First, nuclear power generating capacity increases in the Savannah Upper Ogeechee, as does water consumption. Second, by 2050, the only coal generating capacity that remains is in the Middle Ocmulgee. And third, natural gas generation increases in various locations across the state. Figure 15 shows the change in water consumption between 2015 and 2050 for the Middle Baseline. Water consumption declines in those regions where coal generating capacity retires, but goes up substantially in those regions where nuclear capacity is added. Small increases are seen where natural gas capacity is added.

Table 6 provides the water consumption values by water planning region for 2015 and for each of the baseline scenarios in 2050. The largest absolute changes occur in the Savannah Upper Ogeechee region due to the addition of two nuclear generating units (Vogtle 3 and 4).

Methodological Note

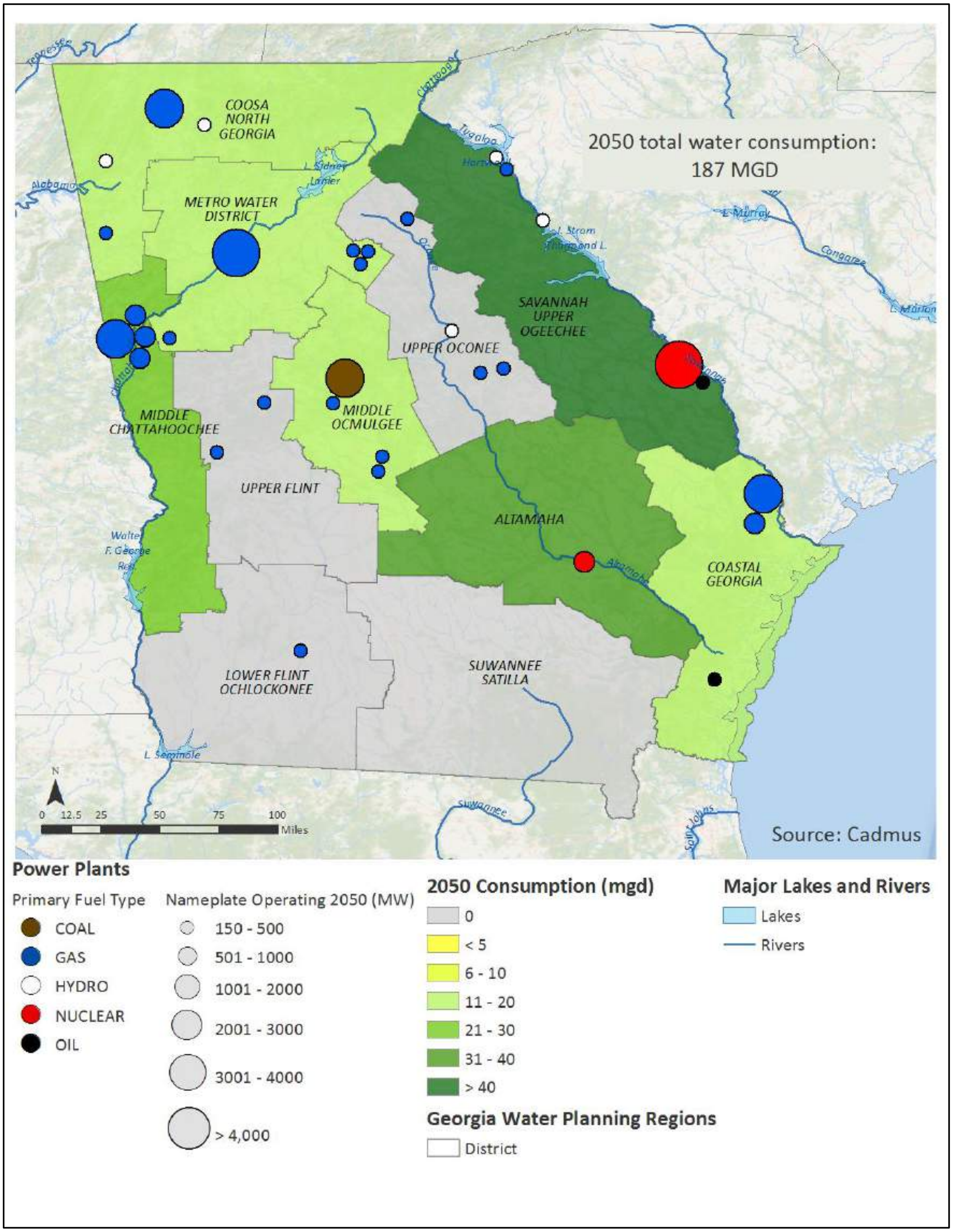
The model we used for this analysis is not disaggregated by water planning region. To determine water consumption by planning region in 2015, we used the latitude and longitude of existing power plants to correlate them with the water planning regions. We then calculated the generation from each generating type by region, multiplied that generation by the appropriate water use coefficient, summed the total by water planning region, and confirmed that it matched the statewide result from the model.

For the 2050 values, we used the locations of coal and nuclear plants in the same way. For coal electric generating units (EGUs), by 2050, only a single existing plant would still be operating, using our assumption of a retirement age of 65 years and no new coal plant additions. For the new nuclear scenario, we also know the planned locations of those units and so could identify the affected planning region for the projected changes in water consumption. The location of the under-construction Vogtle units is known. For the high nuclear scenario, we assumed the two additional units would go in Stewart County, the location for which Georgia Power received regulatory approval for early permitting work.

Natural gas generation presented more of a challenge because the variance across scenarios in natural gas generation is so large, and the potential locations of any new EGUs are not known. We do know that any new natural gas EGU must go where there is a large gas transmission pipeline and a cooling water source. New natural gas units are also more likely in close proximity to electricity transmission infrastructure. As new plants are often located next to or near existing capacity for these reasons, we decided to allocate changes between 2015 and 2050 natural gas generation for each scenario in proportion to the current pattern of natural gas generation. For example, if an existing plant was responsible for 10 percent of natural gas combined cycle generation, that location was assigned 10 percent of the change predicted in the statewide modeling results. Using these new natural gas generation numbers, we calculated water consumption by planning region.

We ignored water consumption for solar PV because it is so small, much less than 1 MGD.

Figure 14. Electricity generating capacity and water consumption in 2050
for the Middle Baseline by water planning region



Note: Some natural gas plants are air-cooled and do not require cooling water.

Figure 15. Changes in water consumption for thermoelectric cooling
for the Middle Baseline between 2015 and 2050 by water planning region.

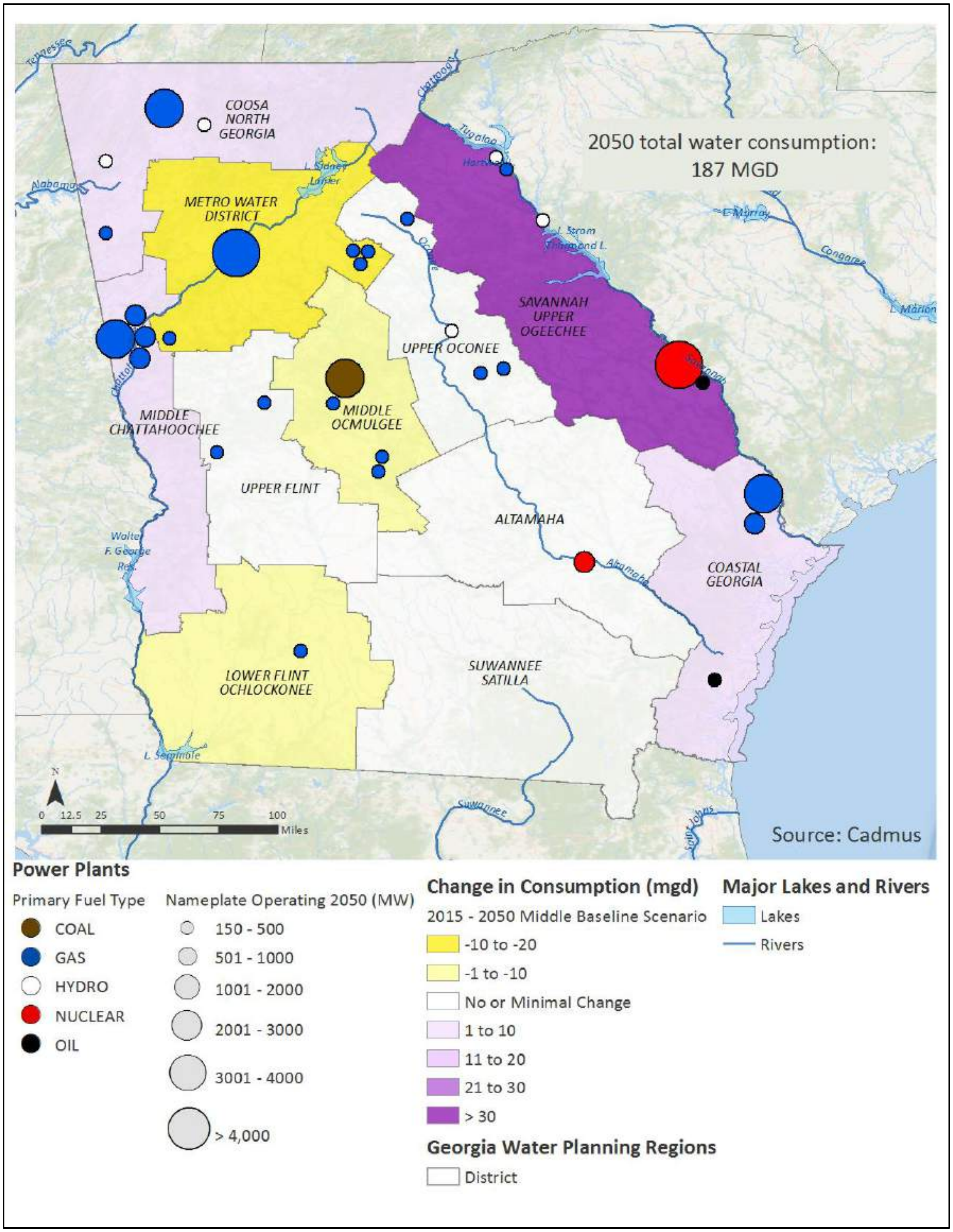
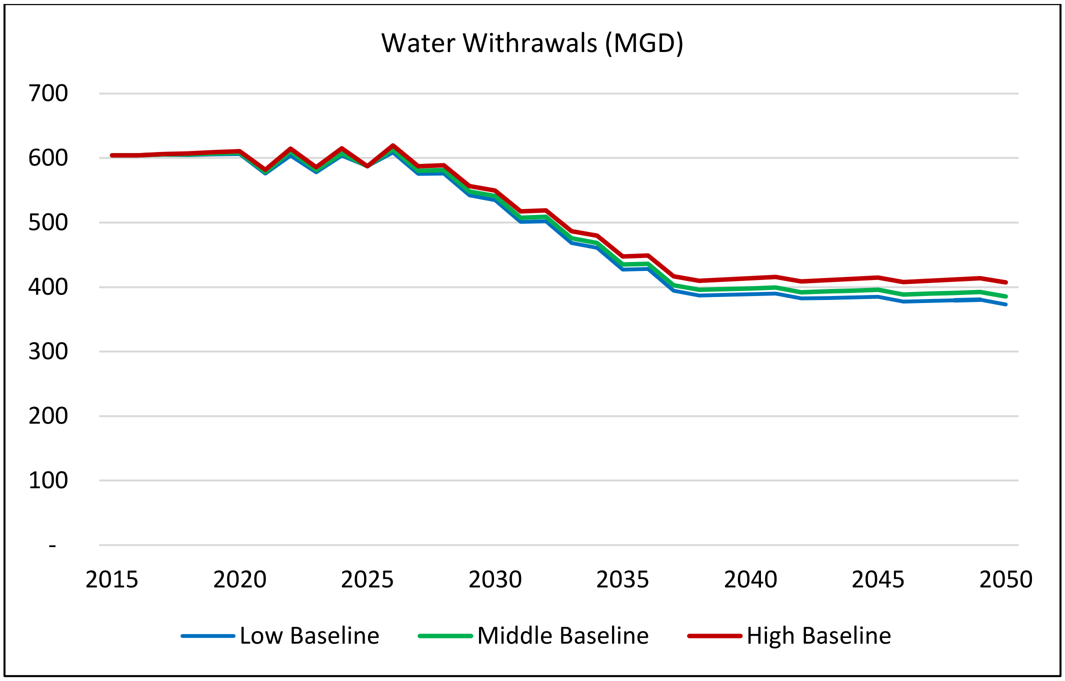


Table 6. Water consumption values by water planning region for 2015 and each baseline in 2050.

	2015	2050		
Water Planning Region	All Scenarios	Low Baseline	Middle Baseline	High Baseline
	(MGD)			
Altamaha	31.4	31.2	31.2	31.2
Coastal Georgia	9.1	15.4	18.2	23.0
Coosa North Georgia	6.0	9.3	10.9	13.9
Lower Flint Ochlockonee	0.8	0.0	0.0	0.0
Metro Water District	27.7	8.8	10.4	13.1
Middle Chattahoochee	17.3	18.3	21.6	27.5
Middle Ocmulgee	18.2	17.2	17.8	18.5
Savannah Upper Ogeechee	42.4	76.4	76.4	76.4
Suwannee Satilla	0.0	0.0	0.0	0.0
Upper Flint	0.2	0.0	0.0	0.0
Upper Oconee	0.0	0.0	0.0	0.0
TOTAL	153	177	187	204

Figure 16 shows water withdrawals from the power sector. We estimate that the 2015 level was 604 MGD. The scenarios show less impact from nuclear generation on water withdrawals because cooling towers, the technology used by these nuclear plants, consume most of what they withdraw.

Figure 16. Water withdrawals under the Middle, Low, and High Baseline scenarios.



In addition to water consumption, there are other important environmental implications associated with each of the baseline scenarios, in particular, for air emissions. Most of these are tied to the replacement of coal generation, which emits sulfur dioxide (SO_2), nitrogen oxides (NO_x), particulates, mercury, and carbon dioxide (CO_2). In comparison, nuclear power has no air emissions, while natural gas emits no SO_2, mercury or particulates, only about 5-10 percent of the NO_x, and half or less of the CO_2. Figure 17 shows our projection for coal generation from 2015 to 2050, which is based on scheduled retirements. Across all baseline scenarios, air emissions for SO_2, particulates, mercury, and NO_x follow this same pattern of decline as they are all a function of coal generation.

CO_2 emissions do not follow this pattern (see Figure 18). While natural gas generation has much lower CO_2 emissions than coal, the emissions are not negligible. The addition of two nuclear generating units and the shift from coal to natural gas produces a drop in emissions that is maintained for the Low and Middle Baseline scenarios but still results in a CO_2 increase for the High Baseline scenario. We calibrated the model to match 2015 emissions as reported by EIA, which were 59 million metric tons (MMT) (U.S. Energy Information Administration, 2016c). By 2050, CO_2 emissions for the Low, Middle, and High Baseline scenarios are 52, 59, and 71 MMT, representing changes of -14, 0 and 19 percent respectively. As with water consumption, these changes are not in lockstep with the significant increases in electricity demand.

Figure 17. Coal generation for all baseline scenarios follows a retirement schedule based upon age.

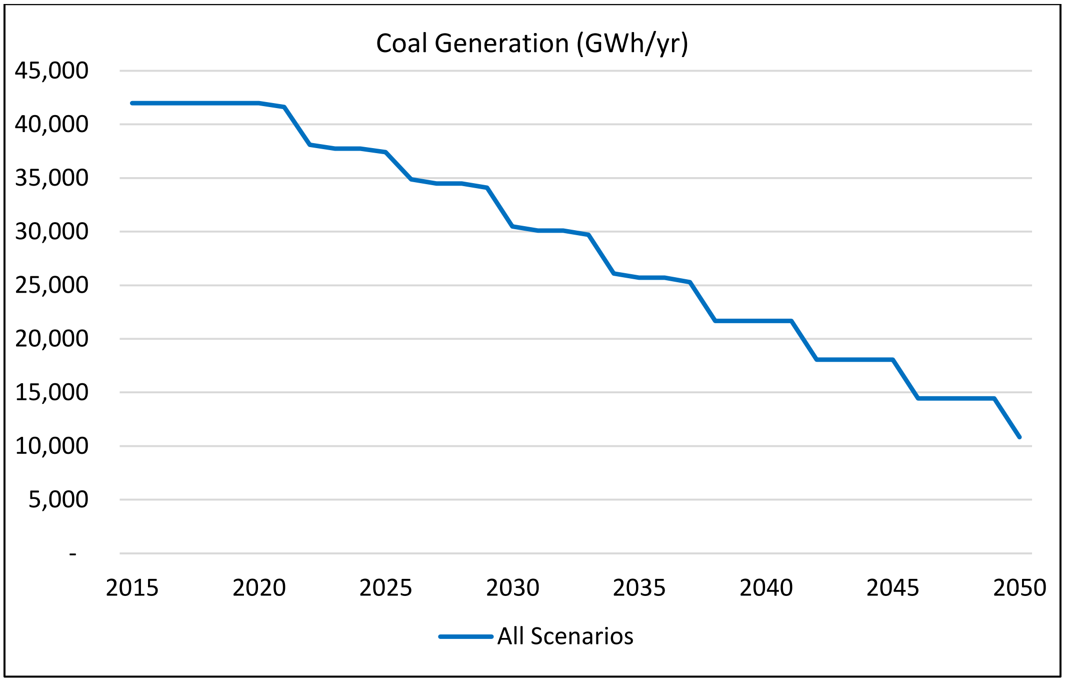


Figure 18. Carbon dioxide emissions for the three baseline scenarios.

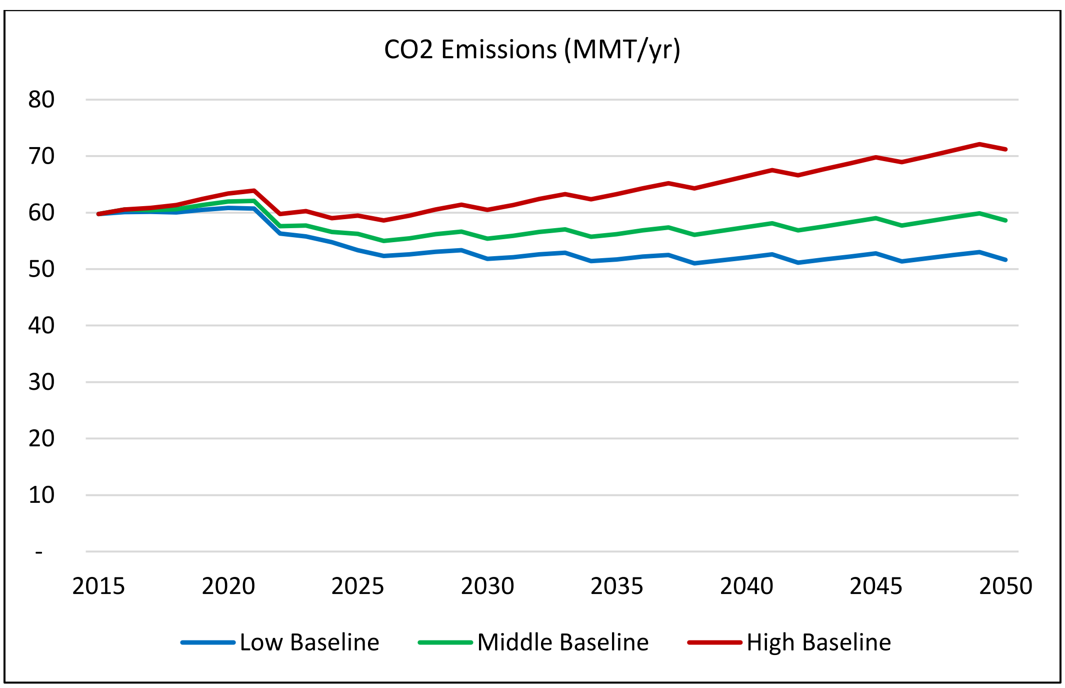


Table 7. Modeling results for key indicators for 2015 and baseline scenarios in 2050.

	2015	2050		
	All Scenarios	Low Baseline	Middle Baseline	High Baseline
Load projection (GWh/yr)	128,818	171,774	189,251	220,825
Coal generation (GWh/yr)	41,972	10,844	10,844	10,844
Nuclear generation (GWh/yr)	32,946	49,418	49,418	49,418
Gas generation (GWh/yr)	50,260	103,453	120,930	152,452
Hydro & PV generation (GWh/yr)	3,640	8,059	8,059	8,111
Water withdrawals (MGD)	604	373	385	407
Water consumption (MGD)	153	177	187	204
Carbon dioxide (MMT/yr)	60	52	59	71
Sulfur dioxide (tons/yr)	68,000	17,000	17,000	17,000
Nitrogen oxide (tons/yr)	52,000	21,000	23,000	26,000
Total system cost ($b/yr)	8.9	11.6	12.9	14.9
Total fixed costs ($b/yr)	5.9	6.1	6.4	7.0
Total variable costs ($b/yr)	3.0	5.6	6.5	7.9

VI. Results for Alternate Future Scenarios

In order to explore the implications of different future pathways for Georgia's electric power sector, we created six alternate scenarios built from the Middle Baseline scenario. These scenarios include:

1. **High energy efficiency (*EE at 0.8%/yr*[8])** – This scenario posits an increase in energy efficiency starting in 2020 that results in 0.8% annual load reduction from the Middle Baseline load projection. From 2013 to 2015 Georgia achieved a 0.29 percent annual load growth reduction (Energy Information Administration, 2013-2015). The target chosen for this scenario is a very achievable level of efficiency improvement, particularly considering that other states have far exceeded this value (Executive Office of Energy and Environmental Affairs, 2017). All generation capacity assumptions are the same as for the Middle Baseline.
2. **More renewable energy (*Status Quo RE*)** – In this scenario, we assume a continued expansion of solar PV at the current average annual installation rate (based on the timespan of Georgia Power's Advanced Solar Initiative (ASI) and Renewable Energy Development Initiative (REDI) programs). We assume that this rate of solar capacity additions, which is 300 MW per year, continues until 2050.
3. **Additional nuclear power (*Additional Nuclear*)** – We assume development of two additional nuclear units in 2034 and 2036, in addition to the two added in 2021 and 2022 (Vogtle 3 and 4). This scenario mimics Georgia Power's proposal to study the feasibility of building two new units in Stewart County, as set out in its 2016 IRP. Any additional needed capacity will come from natural gas.
4. **No new nuclear (*No New Nuclear*)** – Here we assume that the two new nuclear units (Vogtle 3 and 4) scheduled for 2021 and 2022 never come on line. Instead, we assume that solar PV contributes at the level of the Status Quo RE (scenario 2) with natural gas making up any gap in generation.
5. **High energy efficiency and more renewable energy (*Hi EE & Status Quo RE*)** – In this scenario we combine the EE at 0.8%/year and Status Quo RE scenarios outlined above (scenarios 1 & 2).
6. **High energy efficiency and 35 percent renewable energy (*Hi EE & RE at 35%*)** – Various studies of the potential for renewable energy in the U.S. project much higher rates of penetration than that achieved by the Status Quo RE scenario. Two recent studies provide estimates out to 2050 for renewable energy's share of generation. One provides a range from 33 to 59% with a 44% mid-range (Cole, 2016) and another estimates at least 35% (U.S. Department of Energy, 2015). For this scenario, we started with the EE at 0.8%/year scenario and added enough renewable energy each year to hit 35 percent of generation by 2050. That rate of additional solar PV came to 825 MW a year.

[8] These titles in italics will be the name referred to in future use in both text and figures.

Load Demand and Electric Power Generation

To understand the results for water consumption, air emissions and costs, we must first see how electricity load demand changes and is met under each scenario. Figure 19 provides the Middle Baseline and EE at 0.8%/year load projections. While the Middle Baseline yields an increase in load demand of 47 percent between 2015 and 2050, the energy efficiency additions assumed under alternate future scenario 1 reduce that increase to just 11 percent, the difference being about 46,000 GWh per year in 2050.

Figure 19. Load projections for the Middle Baseline and EE at 0.8%/year scenarios.

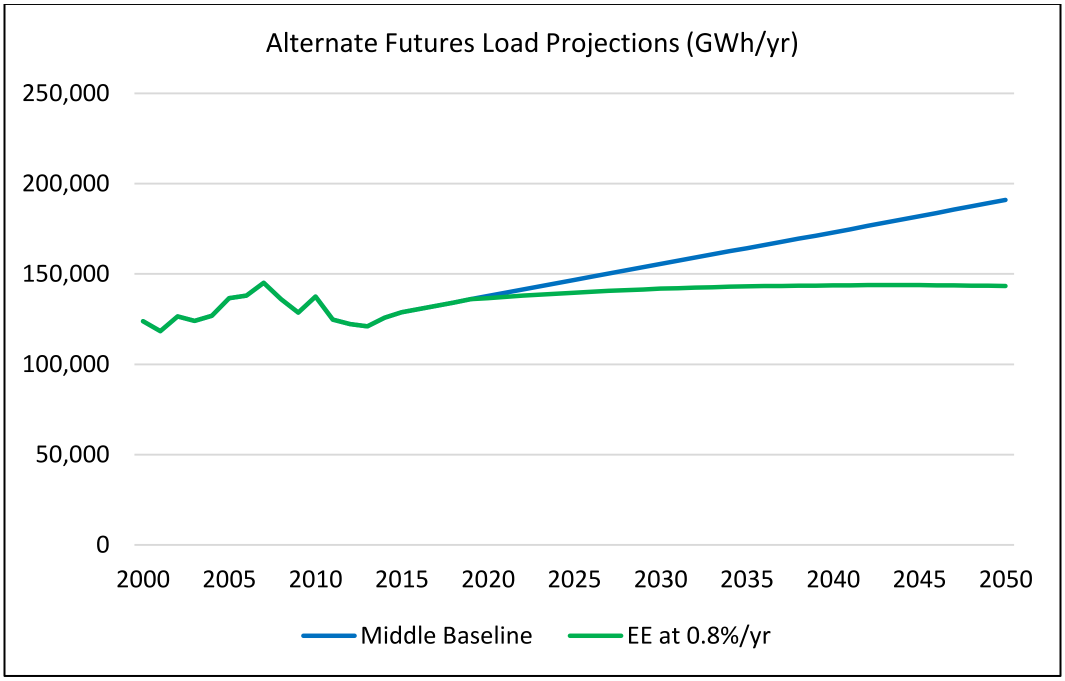
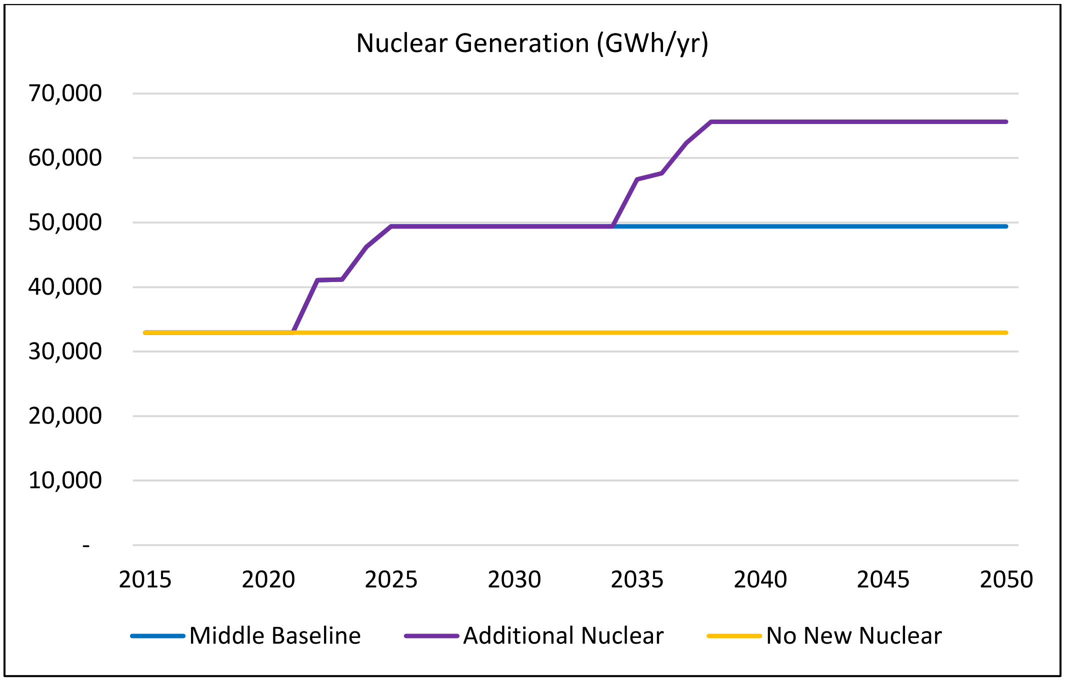


Figure 20 shows nuclear power generation under the three scenarios in which it differs. We use the Middle Baseline assumption for the energy efficiency and renewable energy scenarios (EE at 0.8%, Status Quo RE, Hi EE & Status Quo RE and Hi EE & RE at 35%). In these scenarios, nuclear generation increases by 50 percent with the addition of Vogtle 3 and 4 in 2021 and 2022. For the Additional Nuclear scenario, another two units are added and generation again increases by the same amount, doubling the generation from nuclear power at the start of the scenario. The capacity factor for nuclear power varies only slightly because, due to low operating costs, nuclear units almost always run at or near maximum capacity. For the No New Nuclear scenario, nuclear power stays flat throughout the modeling run.

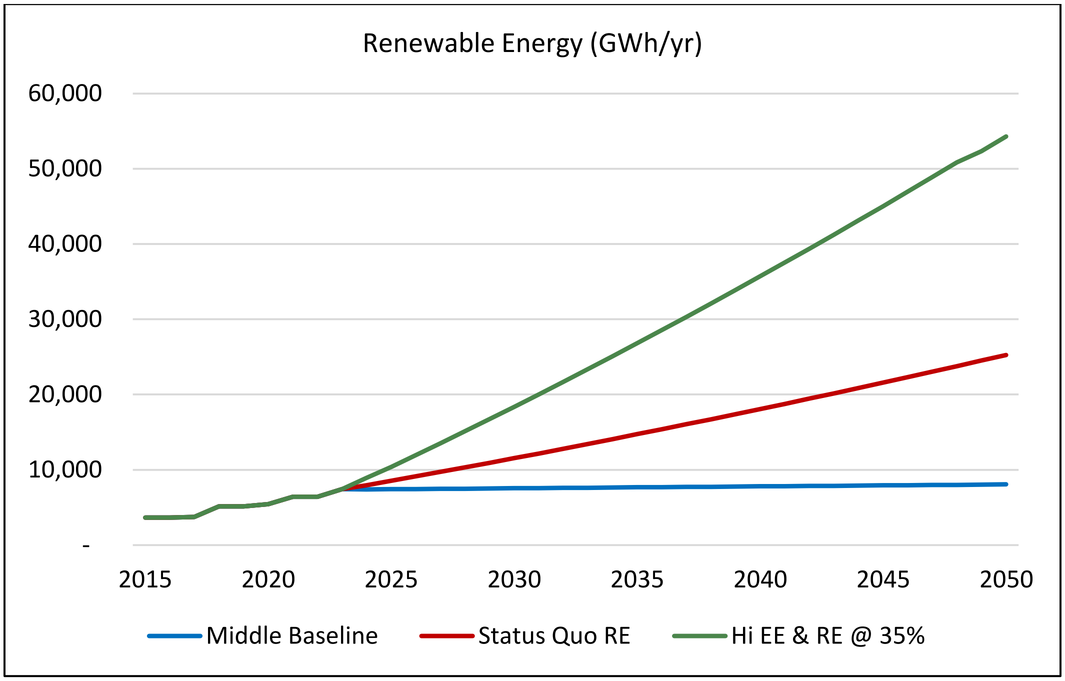
Figure 20. Nuclear power generation for the Middle Baseline and alternate future scenarios.



For three of the scenarios we adjust the amount of renewable energy generation, assumed to be solar PV. The source could include wind because the environmental attributes are the same (i.e. little or no water consumption, no air emissions, no CO_2 emissions) and the financial attributes are also similar (no fuel costs). In Figure 21 we provide the amounts of renewable generation for the Middle Baseline (also used for the nuclear scenarios), Status Quo RE (also used for EE at 0.8%/year, Status Quo RE and No New Nuclear scenarios), and High EE & RE at 35% scenarios. The numbers include hydroelectricity, which we assume to be constant for each scenario and which comprises most of the starting value. For the Middle Baseline, the share of renewable energy is about 3 percent in 2015 and grows slightly, to 4 percent, by 2050.

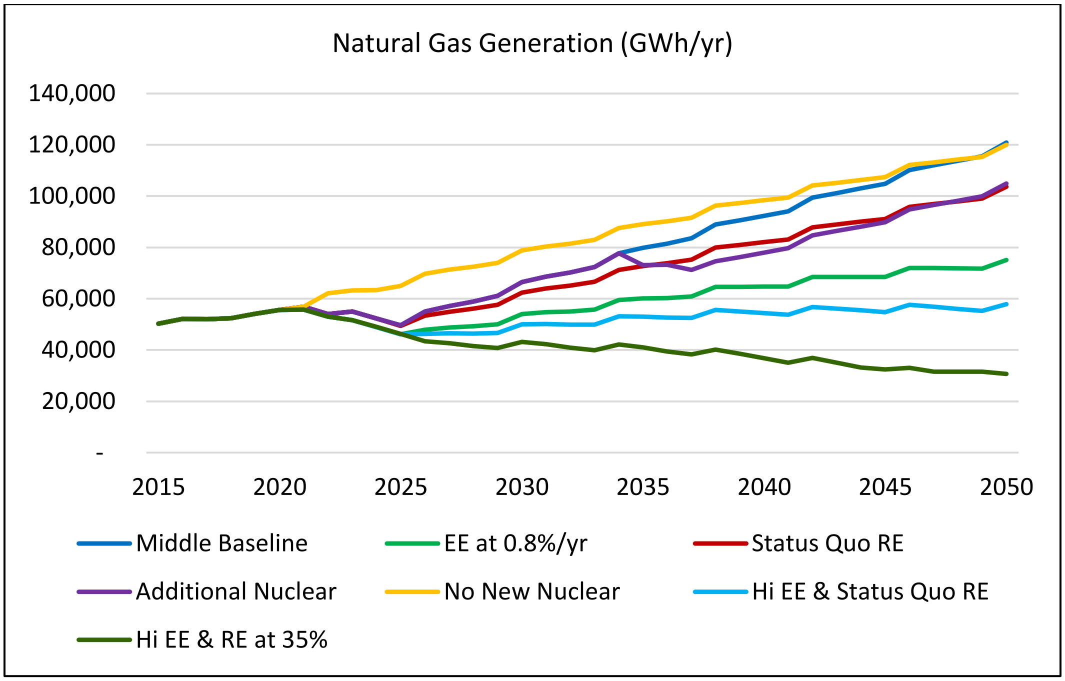
In the Status Quo RE scenario, renewable energy comprises 13 percent of generation by 2050. When coupled with energy efficiency, which results in lower demand, the amount is 18 percent. As indicated by its name, in 2050 the Hi EE & RE at 35% alternate future scenario yields a 35 percent share of generation for renewable power in 2050.

Figure 21. Renewable energy generation including hydroelectric and solar PV by scenario.



Natural gas generation shows the greatest variance across the scenarios because we assume that it increases or decreases in response to changes in load and supply as needed to meet demand. As a result, the alternate future scenarios produce a wide range of results for natural gas generation, from significant increases to large drops (see Figure 22). Coal generation is the same in each scenario, but as we have seen, nuclear and solar PV generation change appreciably, as does electricity demand. How these assumptions are combined yields differing outcomes for natural gas generation, as well as for water consumption, CO_2 and other air emissions, and costs.

Figure 22. Electric power generation by natural gas.



For all but the No New Nuclear scenario, natural gas generation drops after 2020 as two new nuclear units (Vogtle 3 and 4) come online. After about 2025, growth in natural gas generation picks up again for all of the scenarios except for Hi EE & RE at 35%. In the Middle Baseline scenario, natural gas generation grows steadily after 2025 and eventually has the highest amount of natural gas generation of all the scenarios, topping out at 120,000 gigawatt hours (GWh) per year, or 64% of total electricity generation. For the scenario with no nuclear additions (No New Nuclear), final natural gas generation is only slightly smaller as solar PV makes up the gap left by the absence of two new nuclear generating units. For the Additional Nuclear scenario, the addition of those units suppresses natural gas generation, so that it ultimately has a 55 percent share of electricity generation in 2050.

Energy efficiency, by reducing electricity demand, has a large impact on natural gas generation. By itself, our assumed level of energy efficiency cuts natural gas generation by 46,000 GWh per year, or 38 percent of the Middle Baseline's generation. Under the EE at 0.8%/year scenario, natural gas generation is just over 52% of total electricity generation at the end of the simulation. With the addition of Status Quo RE, natural gas generation is reduced to 40 percent of power production in 2050, and with Hi EE & RE at 35%, it accounts for just 21 percent.

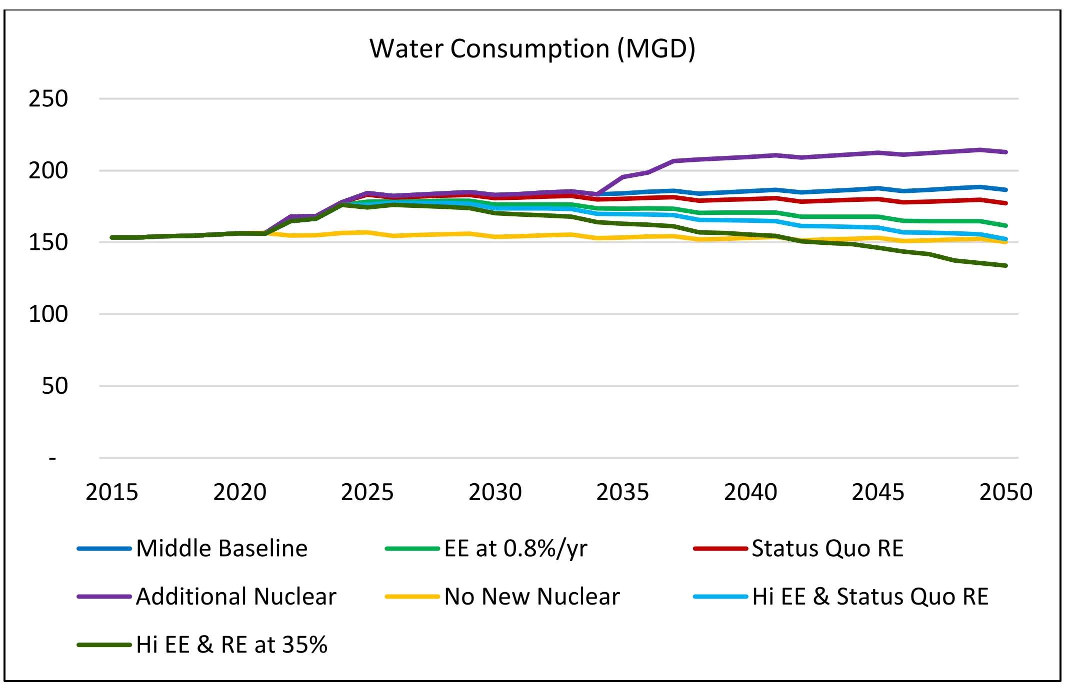
Water Use, Carbon Dioxide, and Air Emissions

A comparative view of the results for water consumption from each of the alternate future scenarios is shown in Figure 23.

The addition of Vogtle units 3 and 4 in 2021 and 2022 will have a significant impact on water consumption for thermoelectric cooling, increasing it by as much as 20%. Under the Additional Nuclear scenario, if two additional nuclear units are added in Stewart County, water consumption would go up by 43% compared to 2015 by the end of the simulation period. In the Middle Baseline, after the addition of the nuclear units in 2021 and 2022, water consumption goes up by only another 3 percent, as natural gas replaces coal. The impact of nuclear generation on consumptive water use can be seen most clearly in the No New Nuclear scenario, where solar PV replaces nuclear power. In that option, water consumption remains flat from 2015 to 2050.

For all of the alternate future scenarios that have energy efficiency and solar PV, water consumption declines after the addition of the two nuclear units in 2021 and 2022. The degree of drop is dependent upon the amount of generation replaced either by energy conservation or renewable energy, neither of which require water. While nuclear power drives an increase in consumptive water use, energy efficiency and solar PV reduce it.

Figure 23. Water consumption for alternate future scenarios.



An Example Comparing Municipal Water Use with Water Savings from Energy Efficiency and Renewable Energy

All else being equal, an increase in the state's energy efficiency performance to a modest 0.8%/year results in a reduction by 2050 of 28 MGD of water consumption. That is the equivalent of the consumptive use of the Gwinnett County and Rockdale County municipal water systems combined, two systems that collectively serve more than 860,000 Georgians.

Adding the water consumption savings from "status quo" renewable energy development to the gains from energy efficiency, produces a savings of 38 MGD by 2050 -- nearly twice the current consumption of Gwinnett County. This is a population equivalent of approximately 1.6 million people.

It is worth noting that this equivalence does not necessarily translate into additional municipal water supply capacity. There are numerous factors that affect levels of available water supply within each basin.

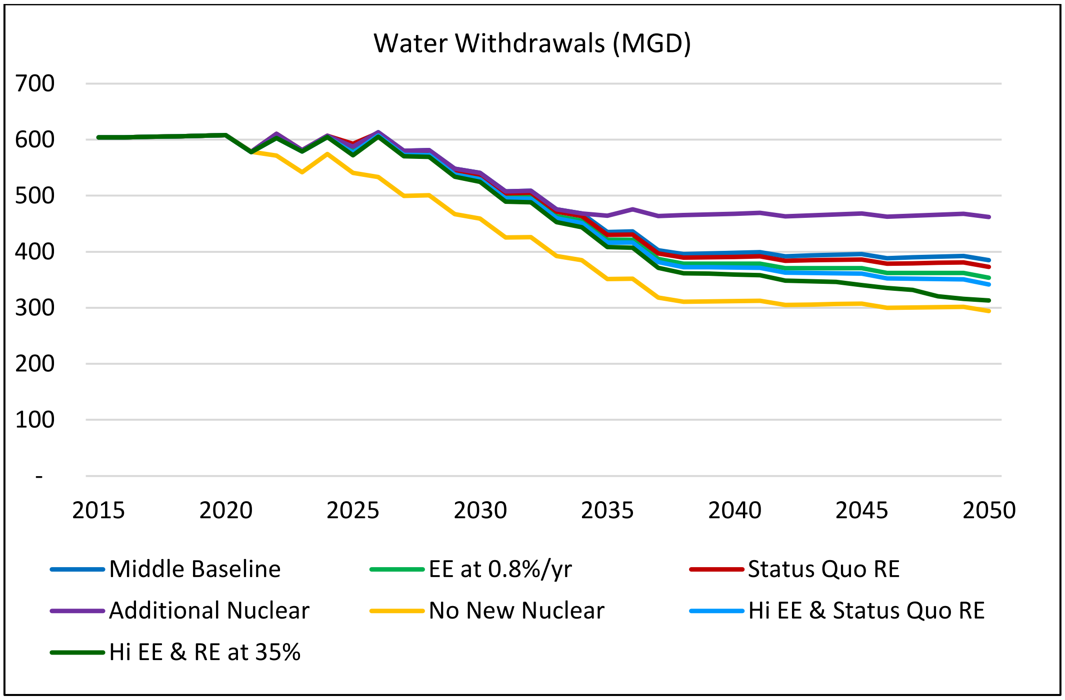
Table 8 provides the water consumption values in 2015 and for each alternate future scenario in 2050 by water planning region. The largest absolute differences are seen for the Savannah Upper Ogeechee planning region because of the differences in nuclear generation under the different scenarios. The Altamaha, Coastal Georgia, Metro Water District and Middle Chattahoochee planning regions show large relative changes under the various scenarios. The Metro Water District always shows declines due to the closure of coal generating units.

Table 8. Water consumption values in 2015 and for each alternate future scenario in 2050 by water planning region.

	2015	2050					
Water Planning Region	All Scenarios	EE at 0.8%/yr	Status Quo RE	Additional Nuclear	No New Nuclear	Hi EE & Status Quo RE	Hi EE & RE at 35%
		(MGD)					
Altamaha	31.4	31.4	31.2	41.4	20.8	31.2	31.2
Coastal Georgia	9.1	11.0	15.4	15.6	18.0	8.4	3.3
Coosa North Georgia	6.0	6.8	9.3	9.4	10.8	5.1	2.0
Lower Flint Ochlockonee	0.8	0.0	0.0	0.0	0.0	0.0	0.0
Metro Water District	27.7	6.3	8.8	8.9	10.2	4.8	1.9
Middle Chattahoochee	17.3	13.1	18.4	43.6	21.4	10.0	4.0
Middle Ocmulgee	18.2	16.5	17.2	17.3	17.6	16.1	15.3
Savannah Upper Ogeechee	42.4	76.4	76.4	76.4	50.9	76.4	76.4
Suwannee Satilla	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Upper Flint	0.2	0.0	0.0	0.0	0.0	0.0	0.0
Upper Oconee	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	153	162	177	213	150	152	134

In contrast to water consumption, the results for water withdrawals show declines for all of the alternate future scenarios as once-through and recirculating cooling coal electricity generation retires (see Figure 24). The Additional Nuclear and No New Nuclear scenarios bound the upper and lower results, with the remaining scenarios grouped in the middle. The 2015 value for water withdrawals is about 600 MGD, and drops to 462 MGD under the Additional Nuclear scenario and to 294 MGD under the No Additional Nuclear scenario.

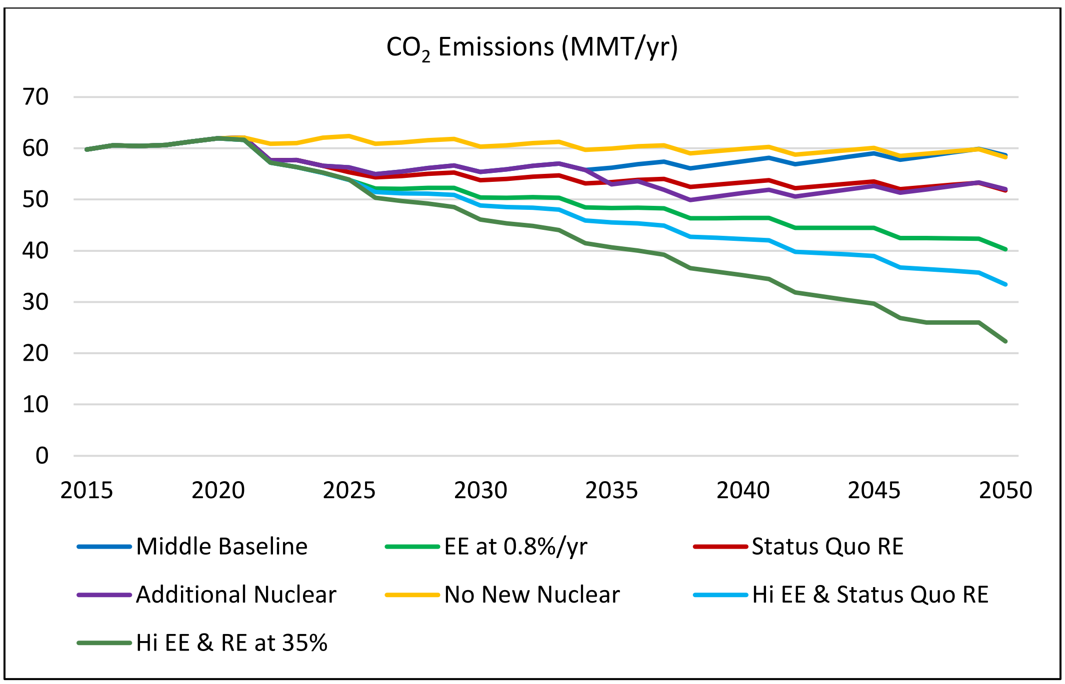
Figure 24. Water withdrawals for alternate future scenarios.



Though nuclear power increases water consumption, it decreases CO_2 emissions, as do energy efficiency and solar PV. Figure 25 shows that the scenarios with the highest CO_2 emissions also have the highest use of natural gas generation. The Middle Baseline and No New Nuclear scenarios have just about the same starting as ending emissions – 59 million metric tons (MMT) per year in 2015 versus 58 MMT in 2050. All of the other scenarios show significant reductions in CO_2 emissions, and those with the biggest declines also have the greatest water consumption savings.

The Status Quo RE and Additional Nuclear scenarios generate the same CO_2 emissions by 2050 – 52 MMT per year—a 10% reduction from the Middle Baseline. The scenarios that combine energy efficiency and solar PV provide the greatest decreases. The EE at 0.8%/year, Hi EE & Status Quo RE, and Hi EE & RE at 35% alternate future scenarios cut emissions by 18, 25, and 36 MMT per year respectively, or 31, 42, and 62% lower than the 2050 Middle Baseline.

Figure 25. Carbon dioxide emissions for alternate future scenarios.

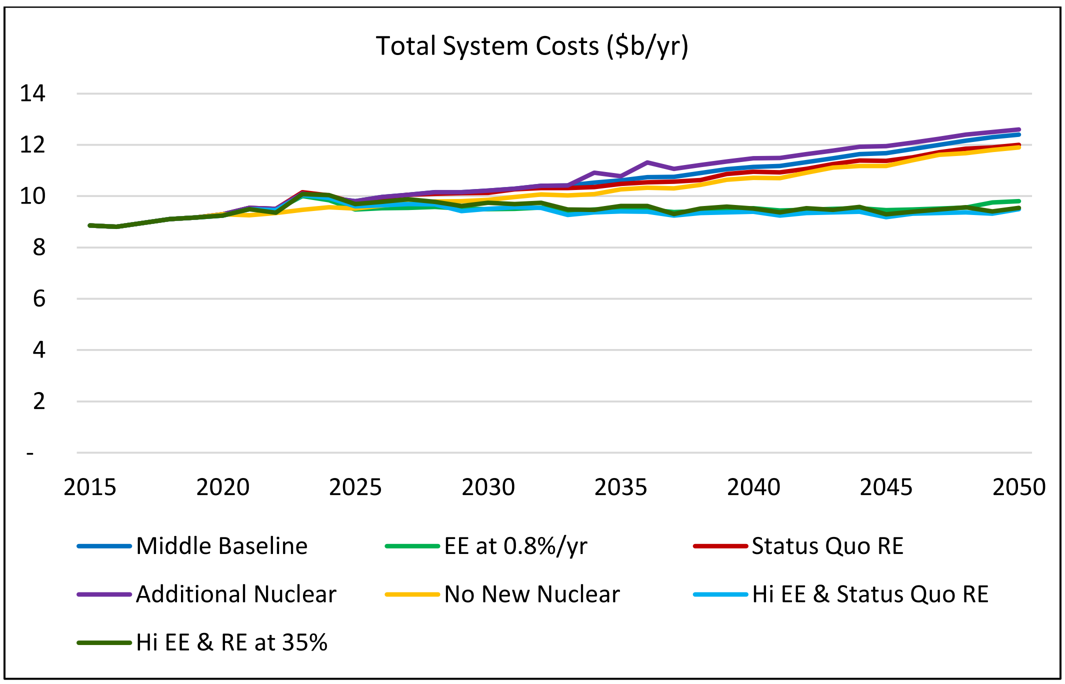


Total System, Fixed and Variable Costs

In addition to generation and related environmental impacts, we also simulated total system costs, which are the sum of fixed and variable costs. Fixed costs include capital and fixed operation and maintenance costs, while variable costs are those tied to the amount of generation, including fuel. For this analysis, we included a variable cost of $30 for each MWh of generation avoided through efficiency measures. Recent analysis shows a range of energy efficiency costs ranging from $0/MWh to $50/MWh (Lazard, 2014). Our value falls in the middle of the range.

Figure 26 shows total system costs for each alternate future scenario. It is obvious that there are two groupings of scenarios – those that include energy efficiency and those that do not, with the gap at about $3 billion per year.

Figure 26. Total system costs for alternate future scenarios.



The reasons for the outcomes are not the same for each scenario, however. Figure 27 presents fixed costs for each alternate future scenario. It shows that scenarios that depend more on natural gas generation have lower fixed costs. This is because natural gas has low capital and fixed operating costs, while nuclear has higher initial capital costs and fixed operating costs. Solar PV has higher initial capital costs and fixed operating costs than natural gas generation but lower capital and operating costs than nuclear energy. In contrast, natural gas has higher variable costs, largely because of fuel costs, whereas nuclear has very low fuel costs and energy efficiency and solar PV have none (see Figure 28). The scenarios with the most natural gas generation (see Figure 22) have the highest variable costs. Table 9 summarizes the modeling results for key indicators for all alternative future scenarios.

Figure 27. Total fixed costs for alternate future scenarios.

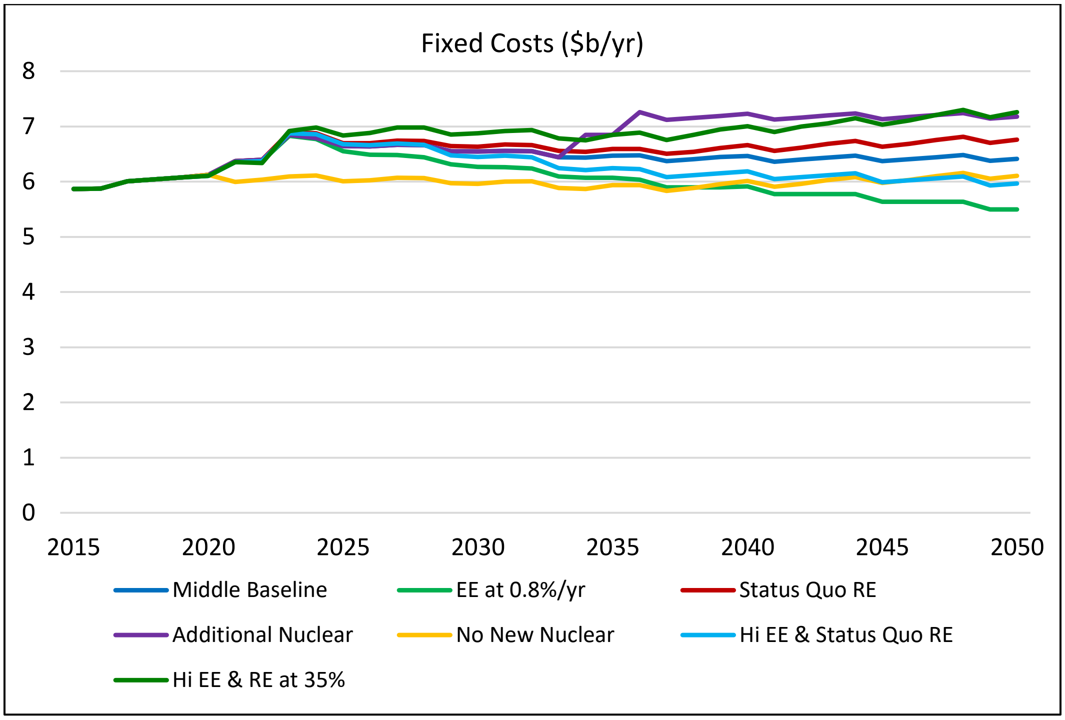


Figure 28. Total variable costs for alternate future scenarios.

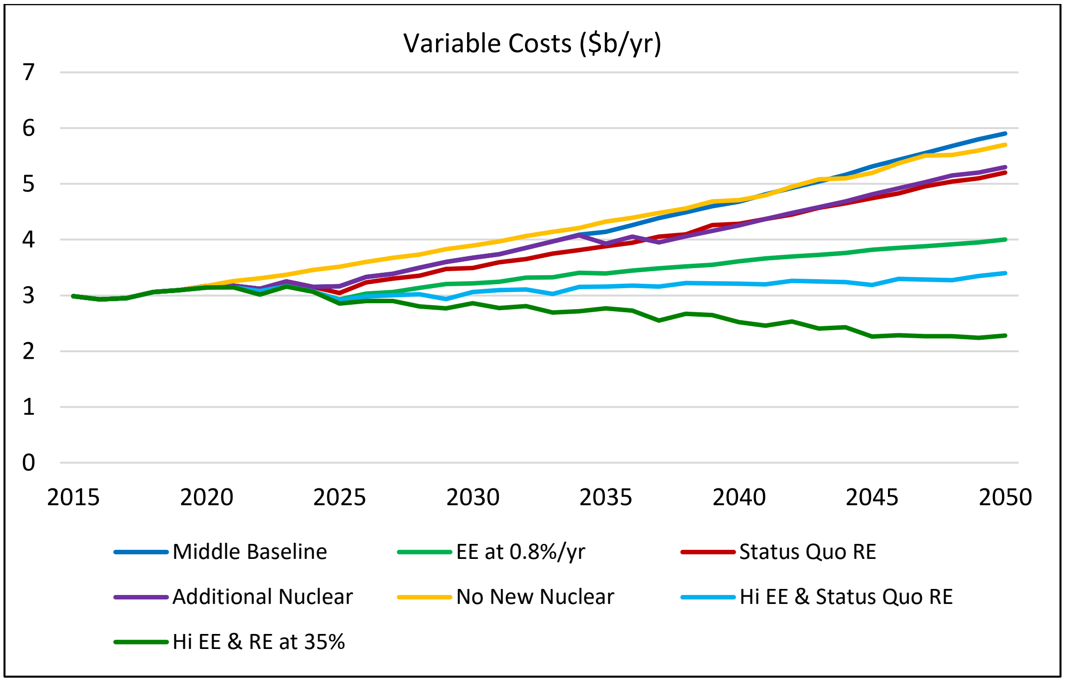


Table 9. Modeling results for key indicators in 2015 and alternate future scenarios in 2050.

	2015	2050					
	All Scenarios	EE at 0.8%/yr	Status Quo RE	Additional Nuclear	No New Nuclear	Hi EE & Status Quo RE	Hi EE & RE at 35%
Load projection (GWh/yr)	128,818	143,465	189,251	189,251	189,251	143,465	143,465
Coal generation (GWh/yr)	41,972	10,844	10,844	10,608	10,844	10,844	10,608
Nuclear generation (GWh/yr)	32,946	49,418	49,418	65,619	32,946	49,418	49,418
Gas generation (GWh/yr)	50,260	75,143	103,959	104,965	119,967	57,937	30,279
Hydro & PV generation (GWh/yr)	3,640	8,059	25,266	8,059	25,495	25,266	54,299
Water withdrawals (MGD)	604	353	373	462	294	341	313
Water consumption (MGD)	153	162	177	213	150	152	134
Carbon dioxide (MMT/yr)	60	40	52	52	58	33	22
Sulfur dioxide (tons/yr)	68,000	17,000	17,000	17,000	17,000	17,000	17,000
Nitrogen oxide (tons/yr)	52,000	19,000	21,000	21,000	23,000	17,000	15,000
Total system cost ($b/yr)	8.9	9.8	12.4	13.0	12.3	9.5	9.5
Total fixed costs ($b/yr)	5.9	5.5	6.8	7.2	6.1	6.0	7.3
Total variable costs ($b/yr)	3.0	4.3	5.6	5.8	6.2	3.5	2.3

VII. Conclusions

Our analysis demonstrates that the amount of water used to meet Georgia's power demands is not simply a function of increased demand for electricity. It will depend to a significant degree on the choices that Georgia's public officials and power providers make regarding how best to meet that demand. It will also depend on the choices that consumers make regarding the energy efficiency of the products they buy and how they use them. Several key conclusions follow from our results:

1. A wide range of outcomes for water withdrawals and consumption are possible depending on electricity demand and how it is met. While higher demand certainly means a greater need for power generation, the resulting water use profile depends heavily on the combination of fuel types (nuclear, coal, natural gas, or solar energy) and cooling technologies (once-through, recirculating, dry, or none) used to meet the capacity need.
2. By avoiding the need for new generation, energy efficiency reduces water use, carbon dioxide emissions, air emissions, and total system cost. Reductions in demand through various efficiency and conservation programs have the benefit of permanently reducing demand and avoiding the need for new generation investments and their associated water use, CO_2, and other air emissions. Energy efficiency investments can save money for the user and, even at the upper end, are less expensive than new generation.
3. Cost-effective generation options are available to meet demand while reducing water use, CO_2, and air emissions. The costs of solar energy, wind energy, and batteries are coming down rapidly (Cole, 2016). These technologies, though currently used in miniscule amounts in Georgia, have lower capital and operating costs than nuclear energy and are not far from natural gas or coal generation costs (U.S. Energy Information Administration, 2016a). Solar PV and wind are financially viable now, and the cost of storage is coming down. In the timeframe we considered in this report (2015 to 2050), these options are expected to become even more cost competitive, bringing with them with significant health and environmental benefits.
4. While it appears that Georgia is currently on a pathway toward greater water consumption because of the pending completion of two new nuclear generating units, this impact can be mitigated. Greater deployment of energy efficiency and renewable energy could help to counterbalance those increases in water use.
5. Despite its increased water use, nuclear power does have the benefit of reducing the emissions of CO_2, SO_2, NO_x, particulates, and mercury when compared to coal, and CO_2 and NO_x when compared to natural gas generation. However, it also requires greater water consumption than other, more cost-effective currently available technologies for electricity conservation and generation.

Appendix A: Water Consumptive Use Factors by Fuel Type in Georgia

Data Sources

We used several data sources for estimating consumptive water use at thermoelectric power plants in Georgia. Table A-1 shows the literature and data sources used in this analysis. While some data sources present the consumptive water use rates directly (either for individual plants or averages across fuel types or cooling technologies), others present only the volumetric data on water consumption which requires further dividing by generation. Based on the data types available, there are basically three ways to estimate consumptive water use rates for plants in Georgia:

- Computation based on reported water use data;
- Averaging consumptive use rate values from other studies; and
- Modeling based on a heat budget model of the power plant.

Table A-1. Relevant literature and data sources for estimating consumptive water use by Georgia's thermoelectric power plants.

Source	Data Years	Primary Water Use Source	Individual Plant Data	Rate, Use, or Both	Specific to Georgia
Fanning et al., 1991	1980-1987	Reports submitted to Georgia EPD	Use	Use	Yes
CDM (Davis & Horrie, 2010)	2003-2007	Reports submitted to Georgia EPD	No	Rate	Yes
Macknick et al., 2011	~1995-2010	Various studies	No	Rate	No
UCS (Averyt et al., 2011)	2008	Macknick et al., 2011, and EIA- 923	Yes	Both	Use – Yes Rate – No
USGS (Diehl and Harris), 2014)	2010	Modeled, and based on EIA-923	Yes	Use	Yes
EIA Form 923 (U.S. Energy Information Administration, 2016b)	2013-2015	EIA-923 Sec. 8D	Yes	Use	Yes
Peer and Sanders, 2016	2014	EIA-923 Sec. 8D	Yes	Rate	Yes
Georgia Power, 2016	2010-2016	Reports submitted to Georgia EPD	Yes	Use	Yes

Computation based on reported water use

In this method, the data sources provide the actual water consumption for individual plants, and we computed the rates by dividing use by electric generation. There are two primary sources of data for reported water consumption on a plant by plant basis: reports submitted to the Georgia EPD, and data submitted to the EIA on Form 923, section 8D. Both include plant or generator level estimates of the monthly consumptive water use in addition to measured monthly withdrawals. The data source for plant level electric generation (in MWh) is Energy Information Administration (EIA) Form 923 (U.S. Energy Information Administration, 2016b).

We used original source data from Georgia Power (2016), and EIA Form 923 Section 8D for data after 2010. Georgia Power's reported consumptive use values include engineering estimates, including the values for several of the company's largest plants. We also used secondary sources that reported data from one of the two data sources listed previously to acquire additional years of historical water consumption data for individual plants. Sources with additional reported consumption data include Fanning et al., 1991, the appendices of the Union of Concerned Scientists report (Averyt et al., 2011) and the USGS (Diehl, 2014) studies. The additional data years available are shown in Table A-1.

Averaging values from other studies

The second method is to summarize consumptive water use coefficients from other studies and literature on power plant operations. Macknick et al. took this approach to develop national consumptive water use rate estimates based on averaging values found in prior studies (Macknick et al., 2011). The UCS study (Averyt et al., 2011) adopted the Macknick et al. coefficients, but performed the additional step of classifying the power plants by fuel and cooling type. Their rates are not specific to Georgia, although they do provide actual water use data reported to EIA for individual plants.

The CDM (2010) memorandum used original source data to compute consumptive water use rates for Georgia's power sector for various classes of fuel and cooling technology types, but doesn't present the original source data (Davis & Horrie, 2010).

The Peer and Sanders (2016) study does present the consumptive water use rates calculated for individual plants based on EIA data, and we were able to isolate the plants in Georgia from their appendices. To compute average consumptive use rates for fuel and cooling technology type classes from these data, we had to weight the reported rates based on the generation of individual plants in each class (e.g. NGCC generators).

Modeling based on a heat budget model of the power plant

The previous two methods use direct estimation of water use rates based on recorded water consumption and generation. The USGS study by Diehl and Harris (2014) instead used thermodynamic modeling to construct reasonably detailed heat budgets for 1,290 thermoelectric power plants in the United States, and estimate water consumption for each plant. The methodology, detailed in a companion USGS publication by Diehl and others (2013), explains how each plant type and cooling type is modeled, as well as how the water sources were determined.

The heat-budget model of each plant allows for calculation of the water usage based on monthly operational and climate data for 2010. While there are some simplifying assumptions, the benefit of this method is that it is methodologically consistent across plants, and it ensures that the specified water usage is plausible from a thermodynamic perspective. When computing average use rates with these data, we simply treated the model-estimated water consumption as reported water use, and computed the use rate by dividing by generation.

Data Agreement and Uncertainty

EIA Form 923 is considered the most complete and authoritative data source for reported water consumption at power plants in the United States, but there are many recognized limitations in the quality of the data (Averyt et al., 2013). Foremost among these is the completeness of the dataset. Reporting rates have improved in recent years, but data gaps in earlier years make historical comparisons difficult (Peer & Sanders, 2016).

Given that there are two primary sources reporting data on water usage (consumptive use reports submitted to Georgia EPD and EIA Form 923), we elected to compare them for Georgia's power plants. We compared reported water consumption from each of these two data sources from 2013 to 2015.[9] We found them to be nearly identical, and within a rounding error. This is unsurprising given that Georgia Power likely reports the same data to EIA and Georgia EPD (Georgia Power Company, 2016). A notable distinction is that the EIA data do give slightly more detail about the methods for estimating water consumption. A variety of methods are used to report water consumption, including estimation based on design specification, estimation based on pump capacities and run times, and measured discharges.

This level of detail in the EIA Form 923 data allows comparison with the estimates in USGS (2014), which use an internally consistent methodology, to identify uncertainty in the EIA estimation methods. Table A-2 compares the estimates using percent bias (PBIAS)[10] between the EIA Form 923 and USGS values by plant for thermoelectric fossil fuel plants. The closest values are obtained when the data are reported in Form 923 as "estimated based on stated pump capacity and pump running time." Many of the other methods can have bias values above 50 percent.

[9] Prior to 2013 there appear to be major discrepancies in the raw EIA Form 923 data. In many cases the data from 2011 and 2012 are three orders of magnitude different from those in 2013. We discarded the 2011 and 2012 EIA Form 923 data as they were unusable for analysis.

[10] We calculated PBIAS as (EIA Form 923 value – USGS value)/(USGS value).

Table A-2. Percent bias of EIA Form 923 data
compared to USGS (2014) computed values by method.

EIA Form 923, Section 8D Reporting Method	n	Median of Absolute Value PBIAS	PBIAS Values
Estimated based on stated pump capacity and pump running time	2	12%	11, 13
Measured using a cumulative or continuous flow meter	4	52%	323, 50, 7, -54
Consumption estimated from withdrawal amount and a loss coefficient	2	30%	5, 55
Consumption calculated as the difference of withdrawal and discharge flows	1	87%	87
Unknown	1	38%	38

Discussion – Estimated Water Use Coefficients by Fuel, Cooling Type

Coal with Once-Through Cooling – 366 gal/MWh

In principle, these plants can return nearly all of the water they consume back to their water source by condensing the steam generated during combustion and rejecting it along with the large amount of water used to cool the steam. These plants have very high water withdrawals, often more than 40,000 gallons per MWh. The body of water used can have a significant impact on cooling performance. Some plants located on the coast use ocean water, a basically infinite source of constant temperature cooling water. In Georgia, however, only the Kraft Plant uses saline water for cooling. The remaining once-through coal plants are cooled by river water or lake water (e.g., Crisp plant) or a more complex cooling set-up (e.g., Harllee Branch[11]). When discharging back to a fresh water body, the returned water is at a much higher temperature than when it was withdrawn, typically between 90 and 110 degrees Fahrenheit, though in some cases even higher (Averyt et al., 2011). Though this temperature is far below the boiling point of water, the increased heat content does increase the available energy for evaporation once the water is returned to a surface water body. The result is increased evaporative loss from the water body, which is a de-facto consumptive use of once-through power plants (Diehl et al., 2013). In some cases, once-through plants also release a small amount of steam into the atmosphere, which can result in additional consumptive use.

There are a limited number of data sources for the water consumption of coal steam plants using once-through cooling. In some cases, plants reporting the data to EIA do compute consumptive use, though none of the plants in Georgia currently do so. Prior to 2004, Plant Yates was a once-through plant, and did report consumption to Georgia EPD. Based on data from 1980 to 1987 in Georgia Information Circular 87, Plant Yates averaged 422 gal/MWh of consumptive use (Fanning et al.,

[11] Harllee Branch plant is now retired, so there are no remaining plants with complex once-through cooling.

1991). Peer and Sanders (2016) reported a national average water consumption for once-through coal plants of 204 gal/MWh, based on 42 plants with data. The Union of Concerned Scientists used data from Macknick et al. (2011) to develop an estimate of 250 gal/MWh based on data from fewer than 10 plants nationwide. In both cases, it is probable that the plants reporting consumptive use are accounting primarily for water discharged as steam or wastewater (Averyt et al., 2011). By contrast, the USGS study by Diehl and Harris (2014) accounts for “forced” open-water evaporation of the receiving water body. The method uses a heat balance to quantify the additional increment of open-water evaporation based on the amount of heat rejected to the body in the returned cooling water, the area of the water body, and the ambient temperature of the water body prior to the return of the cooling water (Diehl, 2013).

The USGS (2014) study computed the consumptive use at four plants: Harllee Branch, Hammond, Mitchell, and McIntosh (Diehl, 2014).[12] Table A-3 shows the estimated consumptive water use rate for the once-through coal plants in the USGS (2014) study. In total, the generation-weighted average water consumption for the once-through coal plants is 354 gal/MWh, which is slightly more than the 330 gal/MWh national median in the study (Diehl, 2014). It appears that the plants with a river water source (Hammond, Mitchell, and McIntosh) have a slightly higher average consumption, at roughly 360 to 450 gal/MWh, than the Harllee Branch plant, which has a more complex cooling system and has an average consumption of roughly 345 gal/MWh.

Table A-3. Consumptive Water Use (CU) rate for coal plants with once-through cooling in Georgia.

Plant ID	Name	CU* Rate 2010 [gal/MWh]	Generation 2010 [GWh]	OOS in 2016**	Source Type - Water Source
708	Hammond	359.0	2959		River – Coosa River
709	Harllee Branch	345.3	5707	x	Complex – Lake Sinclair
727	Mitchell	457.4	104	x	River – Flint River
6124	McIntosh	455.0	241		River – Savannah River
715	McManus		3	x	Saline – Turtle River
733	Kraft		938	x	Saline – Savannah River
753	Crisp Plant		0.8		Lake – Lake Blackshear

*CU – Consumptive Use
**OOS – Out of Service
Source: USGS (Diehl & Harris, 2014)

For modeling purposes, the consumptive use rates are based on plants that will still be in operation over the modeling period. Thus, basing the consumptive use figure on the rates for the Hammond

[12] The study omitted the Kraft and McManus plants, which use saline water for cooling, and the Crisp plant, which had virtually no generation.

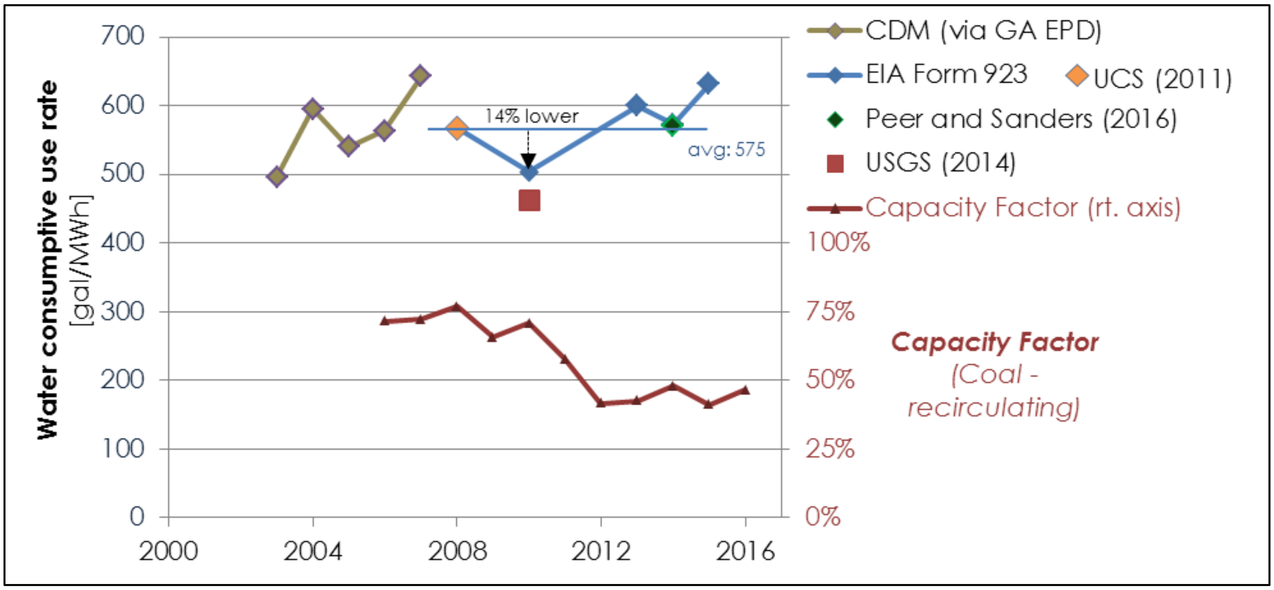
and McIntosh plants weighted by 2015 generation, the value is **366 gal/MWh for coal once-through plants**.

Coal with Recirculating Cooling – 495 gal/MWh

Coal plants with recirculating cooling use combustion to generate steam and drive the turbines. Then, heat exchange with cooling water is used to recondense the steam to water and return the condensed steam back to the boiler. In plants with recirculating tower cooling, the cooling water itself is cooled after condensing the steam in a wet cooling tower, which transfers heat to the atmosphere through the latent heat of vaporization (evaporation) and, to a lesser extent, sensible heat exchange. The vaporized water is released up the tower, and represents the large majority of the consumptive water use (Diehl, 2013).

There are several data sources with plant-specific water consumption data for Georgia, or fleet average data for coal plants with recirculating cooling (RC). Several of these data sources are based on data reported by plant operators to the EIA, or to the Georgia EPD as part of the water withdrawal permit, and they are largely consistent with each other. A CDM memo reported the average rate for all coal-RC plants from 2003 to 2007 based on Georgia EPD data (CDM, 2010). Several studies also reported individual plant water use rates from data submitted to the EIA, including the UCS study for 2008, the USGS study for 2010, and the Peer and Sanders study for 2014. These values are in addition to the original source EIA Form 923 data for 2013-2015 (US EIA, "Form 923"). All of these data sources are reasonably consistent on an average basis, though individual plants have larger variability due to operational differences, and changes in reporting methods. Figure A-1 shows the year-to-year variation in the generation-weighted average consumptive water use rate for these data sources.

Figure A-1. Coal recirculating consumptive use rate over time by data source.
Year 2010 is 14 percent below average for EIA data, and is the start of a decline in capacity factor for coal plants in GA.



Sources: Data from Peer & Sanders, 2016; CDM, 2010; Averyt et al., 2011; USGS, 2014; EIA Form 923; EIA Form 860.

Figure A-1, the USGS study ended up with a lower value for consumptive use than most other studies that rely on reported water use data (Diehl & Harris, 2014). The several studies that use Georgia-specific plant reported data have a remarkable consistency in the overall generation-weighted average consumption rate over many years of EIA or Georgia EPD data (US EIA, "Form 923"). At the individual plant level, however, there is significant year-to-year variability in water consumption rates, as well as changing methodologies for reporting consumption. Based on methodology alone, the USGS (2014) study appears to develop the most consistent and rigorous estimates of consumptive use. We do note, however, that 2010 appears to have had lower-than-average consumptive use for coal plants with cooling towers. The difference between the 2010 rate from reported EIA data and the 2008-2015 average is roughly 14 percent. It also marks the start in a downward trend in capacity factor. Recognizing that some of the variability in consumptive water use rates may be attributable to anomalous reported data (outliers), we adjusted the USGS estimate (462 gal/MWh) upwards by half of this amount, or 7 percent. This leads to a value of **495 gal/MWh for coal plants with recirculating cooling**.

Natural Gas Combined Cycle – 199 gal/MWh

Natural gas combined cycle (NGCC) plants use a two-phase generating cycle that combines a gas combustion turbine with a steam turbine that is driven in part by the hot exhaust from the combustion turbine. Both components generate electricity, but only the steam turbine results in water consumption. It is important to analyze NGCC data at the plant level to ensure that both the generation and capacity of both generator types are included. In general, estimates for the consumptive water use of natural gas combined cycle plants are remarkably consistent at roughly 200 gal/MWh. Macknick et al. (2011), found an average of 198 gal/MWh based on a sample of five plants, and the UCS study used this value for plants in Georgia. The CDM memo (2010) also found a rate of 198 gal/MWh for Georgia plants, based on a five-year average (2003-2007) (Davis & Horrie, 2010). When weighted by generation, the USGS study found an average rate for Georgia plants of 199 gal/MWh, based on 2010 data (Diehl & Harris, 2014). Peer and Sanders (2016) found slightly different rates for plants in 2014, based on EIA Form 923 data. They found an average of 215 gal/MWh for Georgia, albeit only for four plants, whereas most other sources had six or seven plants. Peer and Sanders' study also distinguished standard NGCC from NGCC with cogeneration, and found standard plants consume on average 218 gal/MWh, while plants with cogeneration use 183 gal/MWh. A similar relationship was found in the USGS study, with consumptive use for standard and cogeneration NGCC of 211 and 189 gal/MWh, respectively (Diehl & Harris, 2014). Diehl et al. (2013) explained this difference by showing that the useful heat output from cogeneration plants results in less heat that has to be removed through the condenser, resulting in less evaporation.

Water consumption does not vary significantly over time for NGCC plants, and multiple independent estimates have found nearly identical estimates of water consumption. If desired, future modeling could use different rates for plants with and without cogeneration if the relative proportion is expected to change. For the fleet average, we used the generation-weighted average values from the USGS study (2014). Thus, the value for **natural gas combined cycle plants is 199 gal/MWh**. We did find notable trends or anomalies from year to year in the reported data, and did not use a correction factor as we have done for coal with recirculating cooling.

Nuclear with Recirculating Cooling – 794 gal/MWh

Nuclear power plants are different from fossil fuel-fired thermoelectric plants in that they don't use combustion to heat water to generate steam, but rather use the heat given off by the decay of the radioactive fuel. This means that there is no exhaust from combustion, so energy can only leave the plant as electricity or through the cooling system (Diehl et al., 2013). Nuclear plants have a somewhat lower thermal efficiency and higher water consumption than fossil fuel thermoelectric plants. In Georgia, only two nuclear generation plants—Edwin Hatch and Vogtle—have been built, and both use recirculating cooling with cooling towers. Each plant has two nuclear generation units.

Water use rates calculated for Georgia's nuclear plants do not differ widely by type of data source. All of the estimates based on reported plant data are closely in line, whether the original data source was EIA Form 923 data or water consumption reports filed with Georgia EPD. In fact, the reported values were consistent within a rounding error for the comparable period of 2013-2015 (US EIA, "Form 923"; Georgia Power, 2016). These estimates all fall within a range of roughly 825–915 gal/MWh, and are consistent for both plants. The 2013-2015 generation weighted average for these plants is 874 gal/MWh, based on the original source EIA Form 923 data (US EIA, "Form 923").

By contrast, the USGS study that used heat budget modeling estimates an average of roughly 610 gal/MWh (Diehl & Harris, 2014). This aligns reasonably well with the Macknick et al. study's median estimates for nuclear power plant water consumption of 672 gal/MWh for nuclear plants nationwide (Macknick et al., 2011). The methodology proposed by Diehl et al. (2013) for nuclear plants makes several simplifying assumptions about efficiency and reactor power output. Generally, peak efficiency and generation for nuclear plants occurs in winter months, and output declines in the summer. This assumption may not hold for the Georgia nuclear plants, as there is a secondary peak in power output during the summer (July and August), during which generation nearly matches winter output.

Reconciling the two estimates of water usage for nuclear plants in Georgia is challenging. Unfortunately, there do not appear to be records of reported consumption in 2010 to allow for direct comparisons between the USGS (2014) estimated and reported values. The reported values for water consumption are very consistent, perhaps too consistent. While the monthly reported values differ from year to year, the annual average water usage at both plants remained constant when rounded to the nearest 1 MGD between 2008 and 2016 (Georgia Power, 2016). The EIA Form 923 data documentation states the flow values reported are based on the "Estimated based on stated pump capacity and pump running time" method. This was the reporting method with the least bias for fossil fuel plants (see Table A-2). Additionally, the maximum of the range of values from several studies is near the 874 gal/MWh computed form the EIA Form 923 data (Macknick et al., 2011; Peer & Sanders, 2016). It appears that the two Georgia nuclear plants may simply be near the high end of the range for consumptive water use by nuclear plants. In fact, the Hatch plant establishes the high end of the range for the Peer and Sanders study. The USGS study (2014) also estimated a plausible range of consumption values for every plant in the study which would take into account variations between plant designs, but is bounded by thermodynamically plausible values for the plant (Diehl & Harris, 2014). The high-end of the range in the USGS study is 743 gal/MWh based on operational data from 2010. So, while it appears the Georgia plants may use more water than other nuclear plants, they are unlikely to exceed the USGS estimated maximum to such an extent. Thus, the high end of the USGS estimated range is a more reasonable starting point for a water use rate, but it is worth noting that 2010 appears to be a year with below normal water consumption. Since the cooling method is largely the same, we apply the same correction factor as for the coal plants with recirculating cooling and adjust this estimate upwards by 7 percent.

The value we use for the consumptive water use rate for nuclear is **794 gal/MWh for nuclear plants** (with recirculating cooling) in Georgia. This strikes a reasonable balance between the very consistent reported data that indicate Georgia's nuclear plants use more water than similar plants in other states, and the thermodynamic modeling of the USGS study (2014) by Diehl and Harris that indicates the reported values are likely too high.

Other Fuel Types

We did not investigate the water use rates for most other fuel types and cooling technologies, because they either make up a very small portion of Georgia's electricity generation or do not require water for cooling. Generation from oil (and similar petroleum products) makes up a negligible portion of generation in Georgia. Georgia does not have any appreciable thermoelectric generation from other combinations of fuel types and cooling technologies. That is, there are no once-through natural gas or nuclear plants, and no thermoelectric plants with dry-cooling. Renewable technologies that do not require cooling, including wind and solar, were not within the scope of this analysis. Wind requires no water for operation, and solar uses a very small amount for occasional washing of panels.

Finally, estimating consumptive water use for hydroelectric power was not within the scope of this study. Doing so would require knowing the additional evaporation associated with the surface area of reservoirs impounded by the dams with hydroelectric generators. We did not identify any sources of data on consumptive use (i.e. induced evaporation) from Georgia hydroelectric generators. Readers interested in the total quantity of water used for hydroelectric generation can find information in Fanning et al. (1991), but only total water use and not consumptive use is reported.

Consumptive Water Use Rates

In summary, we have investigated the available literature and data pertaining to consumptive water use by the thermoelectric power sector in Georgia. Table A-4 summarizes the values we used for each generation type and compares them with the values reported in five of the primary data sources.

Table A-4. Consumptive water use rates in gallons per megawatt hour (gal/MWh) from various sources and the coefficients we used for modeling thermoelectric power plants in Georgia.

Source	Data Years	Coal-OT	Coal-RC	NGCC	Nuclear	Biomass
CDM (Davis & Horrie, 2010)	2003-2007	-	567	198	880	-
UCS (Averyt et al., 2011)	2008	250	687	198	672	553
USGS (Diehl, 2014)	2010	354	462	199	610	-
Peer & Sanders (2016)	2014	204	569	215	884	-
EIA Form 923 8D (U.S. Energy Information Administration, 2016b)	2013-2015	-	600	182	874	362
Value used in modeling		366	495	199	794	495

The values used in our modeling reflect the best current estimates for the fleet of operational thermoelectric plants in Georgia. Year-to-year variations in water temperatures, rapid changes in capacity factors, changes in plant technology, and construction of new plants in different locations may contribute to some uncertainty in these values in the future. This level of uncertainty should be small relative to the magnitude of changes in water consumption due to changes in composition of the power sector, and amount of generation from each fuel, and cooling technology type.

Finally, these values represent a fleet-wide average of water consumptive use rates, so any modeling of hydrologic changes (e.g., flow downstream of individual plants) should consider whether to instead use plant-specific consumptive use rates.

Appendix B: Comparison of Thermoelectric Consumptive Use Values

The purpose of this appendix is three-fold:

1. Identify the plants and electrical generating units (EGUs) that are reflected in the Georgia Water-Energy Nexus Study[13];
2. Compare the existing state record of thermoelectric consumptive use, by power plant, to the values that the study model computes for the period of 2002-2016, highlighting important similarities and variances in the values; and
3. Consolidate plant-specific background energy and water use data to help the reader develop a clearer understanding of thermoelectric water use in Georgia.

A predictive model is a computational tool that relies on a series of data inputs and algorithms to make predictions about the future. To increase our confidence in a model's results, we calibrate it by ensuring the algorithms produce results that match or come close to matching the actual historic record. In the case of this study, the model is designed to make predictions about electrical generation, plant dispatch and the resulting changes in thermoelectric withdrawals and thermoelectric consumptive use of water in Georgia.

While the water-energy nexus model is calibrated to match electrical generation by power plant/power plant type, it has not been calibrated to a historical record of thermoelectric consumptive water use because there is not a definitive historical record. The closest thing we have to a historical record of thermoelectric consumptive use is the water use data reported by Georgia Power to Georgia EPD. Georgia EPD tracks this data in a file titled the Consumptive Use Database (CUD). This appendix examines how closely this study comports with the data set in the CUD.

In making this comparison, it is important to keep in mind several aspects of the study modeling. The water use factors used in this study reflect averages by fuel and cooling type across all plants in the state. The factors aren't plant specific and they don't account for minor differences within a given category (e.g. natural draft vs induced draft cooling technology). Additionally, the water use factors represent annual averages. Finally, the study is forward-focused. It relies on the most recent literature and studies to identify appropriate water use factors. A historical water use factor might be different for certain technologies.

[13] The water-energy nexus model used for this study relies on "model" plants that are designed to match the existing fleet of plants being analyzed. For example, while the model does not have an entity called "Plant Bowen," it does have 3,500 MW of coal-fired capacity with recirculating cooling located in the Etowah River basin.

Conversely, there are several important aspects of the state's thermoelectric consumptive use record to keep mind that help explain the degree to which this study comports with the historical record in the CUD.

Historical Record Includes Estimation: The consumptive use reflected in the state's CUD is not necessarily "measured" data. Due to cooling system configurations that do not lend themselves to a straightforward measurement of consumptive use (i.e. total measured withdrawals minus total measured discharges), Georgia Power makes engineering-based estimates of consumptive use for several of its plants (Hobson, 2002). The GA WEN study approach to estimating consumptive use for these plants (based on our literature review) may differ from the approach used by Georgia Power.

Zero Consumptive Use for Once-Through Plants: The state's historic thermoelectric consumptive use record assumes zero consumptive use for most of the coal-fired facilities with once-through cooling. Based on our review of the relevant literature, this study does assume consumptive water use at these facilities.

It is important to note that the relevance of the study's assumption of consumptive water use for once-through units diminishes greatly for all future forecasts. In both the baseline and alternative future scenarios, generation from once-through units decreases quickly and is close to zero within a number of years.

Zero Consumptive Use for Plants without Withdrawal Permits: There are three NGCC power plants in Georgia that take water service from a municipal water provider and, consequently, do not have individual water withdrawal permits. As a result, these plants do not report water use to the state and the state's CUD does not reflect any consumptive use at these plants. Our study does assume consumptive use at these plants.

It is important to note that this consumptive use is reflected in the state's overall record of consumptive use, but is recorded as municipal consumptive use associated with the particular municipal water utility that serves these power plants.

Complex and Changing Plant Configurations: The state's thermoelectric consumptive use record includes a single monthly data record for consumptive water use by water withdrawal permit number at each power plant. In several cases, the consumptive use associated with a single withdrawal permit reflects a complex and changing power plant configuration behind the water intake. For instance:

Plant McDonough was, for many years, a coal plant with once-through cooling. Shortly before all the coal units were retired, the plant installed cooling towers, and the plant operated briefly as a coal plant with recirculating cooling. Around the time the coal units retired, Georgia Power built several natural gas combined cycle plants on the property, and it now operates as a NGCC plant with recirculating cooling.

Plant Wansley hosts four separate power plants (as defined and tracked by the U.S. Energy Information Administration): Plant Wansley (coal with recirculating cooling); Plant Wansley Combined Cycle (NGCC with recirculating cooling); Wansley Unit 9 (NGCC with recirculating cooling) and the Chattahoochee Energy Facility (NGCC with recirculating cooling). The plants/units came online, respectively, in the late 1970s, 2002, 2004, and 2003. Since 2003 the state's consumptive water use record has reflected the water use of two coal units with recirculating cooling and four NGCC units with recirculating cooling.

Effect of Using Net Generation: The study's estimates of consumptive use have an inherent conservative tendency because they are calculated by multiplying a consumptive use factor by the reported net generation for each plant (by fuel type, if multiple fuel types are in use). Net generation is computed by subtracting the electricity used to operate a power plant from the gross generation of the plant. This difference is sometimes referred to as parasitic load. In some cases, parasitic load can be quite high, especially in plants that have a lot of ancillary equipment. For instance, Plant Bowen operates selective catalytic reduction units to remove nitrogen oxides, powers large fans to push the flue gas through the wet flue gas scrubbers, crushes limestone for the scrubbers, uses a pneumatic system to move coal ash, and processes gypsum produced by the scrubbers. All this non-power related equipment can account for many megawatts of parasitic load.

This appendix has two sections:

Table B-1 lists the power plants and EGUs reflected in this study; and

The plant-by-plant detail includes the abovementioned comparison of the state's consumptive use record and the consumptive use estimates applied in this study.

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Table B-1. Plants and electric generating units (EGUs) reflected in the study modeling.

Red font indicates retired unit.

EPA Plant ID	Plant	Utility	Water Source	County	Plant NP Capacity (MW)[14]	Cooling Technology	WW Permit #
703	Bowen	Georgia Power	Etowah River	Bartow	3,499	Recirculating with Natural Draft Cooling Tower; four towers in service in 1971, 1972, 1974 and 1975	008-1491-01
7917	Chattahoochee Energy Facility	Oglethorpe Power Co.	Chattahoochee River	Heard	540	Recirculating with Induced Draft Cooling Tower; one tower in operation in 2003	Part of Wansley Permit
6051	Edwin Hatch	Georgia Power, et al.	Altamaha River	Appling	1,722	Recirculating with Induced Draft Cooling Tower; two towers in service in 1975	001-0690-01
55406	Effingham County Power Project	SEPG Operating Services, LLC	Municipality	Effingham	597	Recirculating with Induced Draft Cooling Tower; one tower in service in 2003	N/A
708	Hammond	Georgia Power	Coosa River	Floyd	953	Once through without cooling pond(s)	057-1490-02
709	Harllee Branch	Georgia Power	Lake Sinclair	Putnam	1,746	Once through without cooling pond(s)	117-0390-01
710	Jack McDonough	Georgia Power	Chattahoochee River	Cobb	2,520	Recirculating with Induced Draft Cooling Tower; three towers in service in 2011 and 2012 (two towers installed in 2008 already retired)	033-1291-03
733	Kraft	Georgia Power	Savannah River	Chatham	334	Once through without cooling pond(s)	025-0192-02

[14] Plant Nameplate Capacity does not include the capacity of any of the retired units at that plant that appear in the table

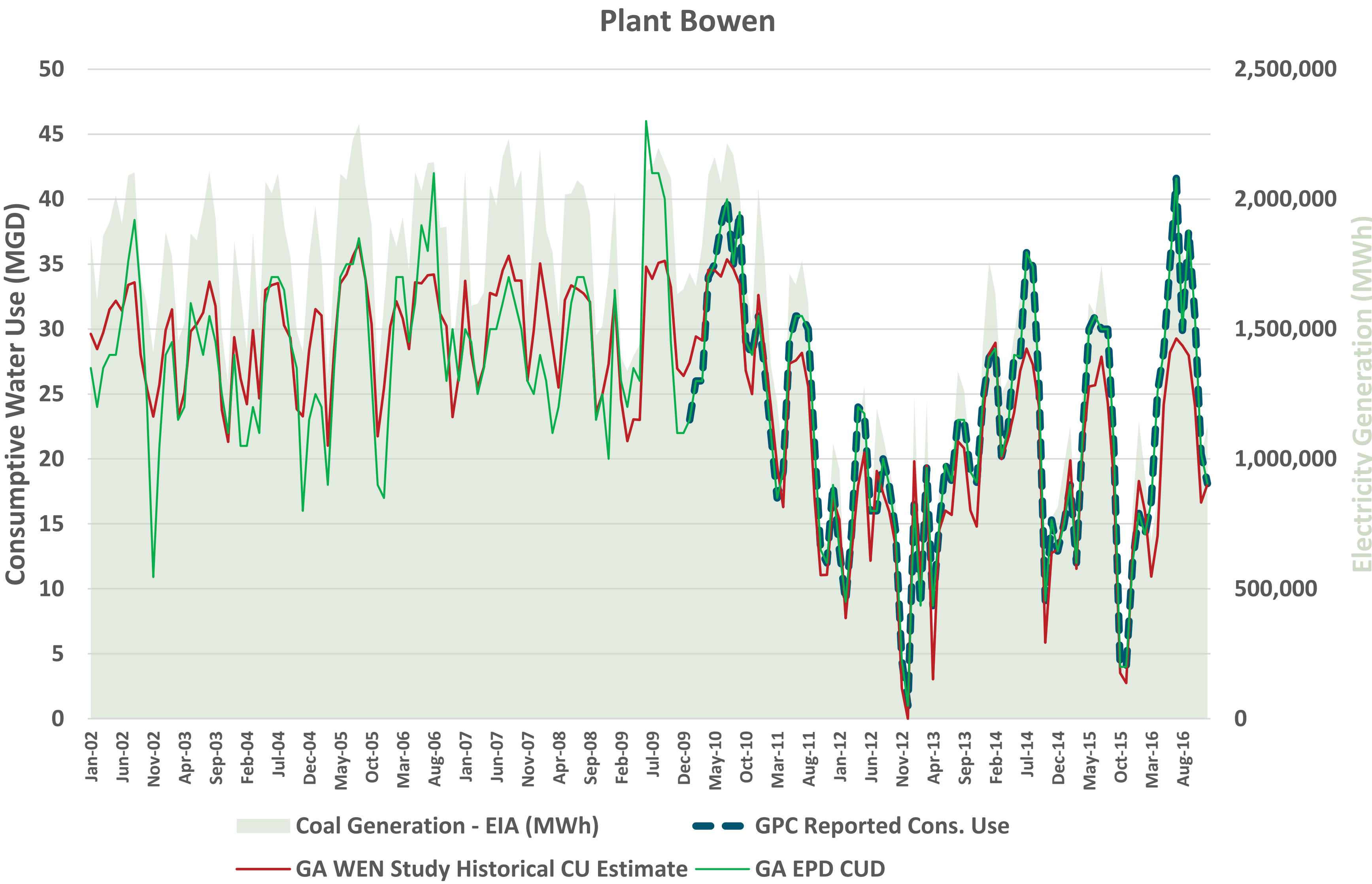
Units	Technology	Date of Operation	Date of Retirement	Unit NP Cap. (MW)	Prime Mover	Ener Srce.
Bowen 1	Conventional Steam Coal	Oct-71		805.8	ST	BIT
Bowen 2	Conventional Steam Coal	Sep-72		788.8	ST	BIT
Bowen 3	Conventional Steam Coal	Dec-74		952.0	ST	BIT
Bowen 4	Conventional Steam Coal	Nov-75		952.0	ST	BIT
Chattahoochee EF 1	Natural Gas Fired Combined Cycle	Feb-03		176.0	CT	NG
Chattahoochee EF 2	Natural Gas Fired Combined Cycle	Feb-03		176.0	CT	NG
Chattahoochee EF 3	Natural Gas Fired Combined Cycle	Feb-03		187.7	CA	NG
Hatch 1	Nuclear	Dec-75		857.1	ST	NUC
Hatch 2	Nuclear	Sep-79		864.7	ST	NUC
Effingham Co. PP UNT1	Natural Gas Fired Combined Cycle	Aug-03		199.4	CT	NG
Effingham Co. PP UNT2	Natural Gas Fired Combined Cycle	Aug-03		199.4	CT	NG
Effingham Co. PP STG	Natural Gas Fired Combined Cycle	Aug-03		197.8	CA	NG
Hammond 1	Conventional Steam Coal	Jun-54		125.0	ST	BIT
Hammond 2	Conventional Steam Coal	Sep-54		125.0	ST	BIT
Hammond 3	Conventional Steam Coal	Jun-55		125.0	ST	BIT
Hammond 4	Conventional Steam Coal	Dec-70		578.0	ST	BIT
Branch 1	Conventional Steam Coal	Jun-65	Apr-17	299.2	ST	BIT
Branch 2	Conventional Steam Coal	Jun-67	Sep-17	359.0	ST	BIT
Branch 3	Conventional Steam Coal	Jul-68	Apr-17	544.0	ST	BIT
Branch 4	Conventional Steam Coal	Jun-69	Apr-17	544.0	ST	BIT
McDonough 1	Conventional Steam Coal	Aug-63	Feb-12	299.2	ST	BIT
McDonough 2	Conventional Steam Coal	Jun-64	Sep-11	299.2	ST	BIT
McDonough 4	Natural Gas Fired Combined Cycle	Dec-11		375.0	CA	NG
McDonough CT4A	Natural Gas Fired Combined Cycle	Dec-11		232.5	CT	NG
McDonough CT4B	Natural Gas Fired Combined Cycle	Dec-11		232.5	CT	NG
McDonough 5	Natural Gas Fired Combined Cycle	Apr-12		375.0	CA	NG
McDonough 5ACT	Natural Gas Fired Combined Cycle	Apr-12		232.5	CT	NG
McDonough 5BCT	Natural Gas Fired Combined Cycle	Apr-12		232.5	CT	NG
McDonough 6	Natural Gas Fired Combined Cycle	Oct-12		375.0	CA	NG
McDonough 6ACT	Natural Gas Fired Combined Cycle	Oct-12		232.5	CT	NG
McDonough 6BCT	Natural Gas Fired Combined Cycle	Oct-12		232.5	CT	NG
Kraft ST1	Conventional Steam Coal	Jul-58	Oct-15	50.0	ST	BIT
Kraft 2	Conventional Steam Coal	May-61	Oct-15	54.4	ST	BIT
Kraft 3	Conventional Steam Coal	May-65	Oct-15	103.5	ST	BIT
Kraft 4	Natural Gas Steam Turbine	Mar-72	Oct-15	126.0	ST	NG

EPA Plant ID	Plant	Utility	Water Source	County	Plant NP Capacity (MW)	Cooling Technology	WW Permit #
6124	McIntosh	Georgia Power	Savannah River	Effingham	178	Once through without cooling pond(s)	051-0192-01
56150	McIntosh Combined Cycle Facility	Georgia Power	Savannah River	Effingham	1,377	Recirculating with Induced Draft Cooling Tower; two towers in service in 2005	Under McIntosh permit
715	McManus	Georgia Power	Turtle River	Glynn	144	Once through without cooling pond(s)	063-0712-01
55040	Mid-Georgia Cogeneration Facility	SEPG Operating Services, LLC	Municipality	Houston	323	Recirculating with Induced Draft Cooling Tower; one tower in service 1998	N/A
727	Mitchell	Georgia Power	Flint River	Dougherty	163	Once through without cooling pond(s)	047-1192-01
6257	Scherer	Georgia Power, et al.	Lake Juliette	Monroe	3,564	Recirculating with Natural Draft Cooling Tower; four towers in service in 1982, 1984, 1987, 1989	102-0590-03 & 102-0590-05
55382	Thomas A Smith Energy Facility	Oglethorpe Power Co.	Municipality	Murray	1,192	Recirculating with Induced Draft Cooling Tower; two cooling towers in service in 2002	N/A
649	Vogtle	Georgia Power, et al.	Savannah River	Burke	2,320	Recirculating with Natural Draft Cooling Tower; two towers in service in 1987 and 1989, two towers under construction	017-0191-05 & 017-0191-11
6052	Wansley	Georgia Power, et al.	Chattahoochee River	Heard	1,904	Recirculating with Induced Draft Cooling Tower; two towers in operation in 1976 and 1978	074-1291-06 & 074-1291-07
55965	Wansley Combined Cycle	Southern Power	Chattahoochee River	Heard	1,239	Recirculating with Induced Draft Cooling Tower; two towers in service in 2002	Part of Wansley Permit?
7946	Wansley Unit 9	MEAG	Chattahoochee River	Heard	568	Recirculating with Induced Draft Cooling Tower; one tower in service in 2003	Part of Wansley Permit
728	Yates	Georgia Power	Chattahoochee River	Coweta	807	Recirculating with Induced Draft Cooling Tower; two towers in service in 1974, five towers in service 2004	038-1291-02

Units	Technology	Date of Operation	Date of Retirement	Unit NP Cap. (MW)	Prime Mover	Ener Srce.
McIntosh 1	Conventional Steam Coal	Feb-79		177.6	ST	BIT
McIntosh CCF 10ST	Natural Gas Fired Combined Cycle	Jun-05		281.9	CA	NG
McIntosh CCF 11ST	Natural Gas Fired Combined Cycle	Jun-05		281.9	CA	NG
McIntosh CCF C10A	Natural Gas Fired Combined Cycle	Jun-05		203.2	CT	NG
McIntosh CCF C10B	Natural Gas Fired Combined Cycle	Jun-05		203.2	CT	NG
McIntosh CCF C11A	Natural Gas Fired Combined Cycle	Jun-05		203.2	CT	NG
McIntosh CCF C11B	Natural Gas Fired Combined Cycle	Jun-05		203.2	CT	NG
McManus 1	Petroleum Liquids	Nov-52	Apr-15	50.0	ST	RFO
McManus 2	Petroleum Liquids	Jun-59	Apr-15	93.7	ST	RFO
Mid-GA Cogen CT1	Natural Gas Fired Combined Cycle	Oct-97		106.5	CT	NG
Mid-GA Cogen CT2	Natural Gas Fired Combined Cycle	Feb-98		106.5	CT	NG
Mid-GA Cogen ST1	Natural Gas Fired Combined Cycle	Dec-97		110.0	CA	NG
Mitchell 3	Conventional Steam Coal	Jun-64	Jul-16	163.2	ST	BIT
Scherer 1	Conventional Steam Coal	Mar-82		891.0	ST	SUB
Scherer 2	Conventional Steam Coal	Feb-84		891.0	ST	SUB
Scherer 3	Conventional Steam Coal	Jan-87		891.0	ST	SUB
Scherer 4	Conventional Steam Coal	Feb-89		891.0	ST	SUB
T.A. Smith EF 1GT1	Natural Gas Fired Combined Cycle	Jun-02		147.0	CT	NG
T.A. Smith EF 1GT2	Natural Gas Fired Combined Cycle	Jun-02		147.0	CT	NG
T.A. Smith EF 1STG	Natural Gas Fired Combined Cycle	Jun-02		302.0	CA	NG
T.A. Smith EF 2GT1	Natural Gas Fired Combined Cycle	Jun-02		147.0	CT	NG
T.A. Smith EF 2GT2	Natural Gas Fired Combined Cycle	Jun-02		147.0	CT	NG
T.A. Smith EF 2STG	Natural Gas Fired Combined Cycle	Jul-02		302.0	CA	NG
Vogtle 1	Nuclear	May-87		1160.0	ST	NUC
Vogtle 2	Nuclear	May-89		1160.0	ST	NUC
Wansley 1	Conventional Steam Coal	Dec-76		952.0	ST	BIT
Wansley 2	Conventional Steam Coal	Apr-78		952.0	ST	BIT
Wansley CC CT6A	Natural Gas Fired Combined Cycle	Jun-02		203.1	CT	NG
Wansley CC CT6B	Natural Gas Fired Combined Cycle	Jun-02		203.1	CT	NG
Wansley CC CT7A	Natural Gas Fired Combined Cycle	Jun-02		203.1	CT	NG
Wansley CC CT7B	Natural Gas Fired Combined Cycle	Jun-02		203.1	CT	NG
Wansley CC ST6	Natural Gas Fired Combined Cycle	Jun-02		213.3	CA	NG
Wansley CC ST7	Natural Gas Fired Combined Cycle	Jun-02		213.3	CA	NG
Wansley Unit 9 - CT1	Natural Gas Fired Combined Cycle	Jun-04		171.0	CT	NG
Wansley Unit 9 - CT2	Natural Gas Fired Combined Cycle	Jun-04		171.0	CT	NG
Wansley Unit 9 - ST1	Natural Gas Fired Combined Cycle	Jun-04		226.0	CA	NG
Yates 1	Conventional Steam Coal	Sep-50	Apr-15	122.5	ST	BIT
Yates 2	Conventional Steam Coal	Nov-50	Apr-15	122.5	ST	BIT
Yates 3	Conventional Steam Coal	Aug-52	Apr-15	122.5	ST	BIT
Yates 4	Conventional Steam Coal	Jun-57	Apr-15	156.2	ST	BIT
Yates 5	Conventional Steam Coal	May-58	Apr-15	156.2	ST	BIT
Yates 6	Natural Gas Steam Turbine	Jul-74	May-15 (Conv)	403.7	ST	BIT
Yates 7	Natural Gas Steam Turbine	Apr-74	May-15 (Conv)	403.7	ST	BIT

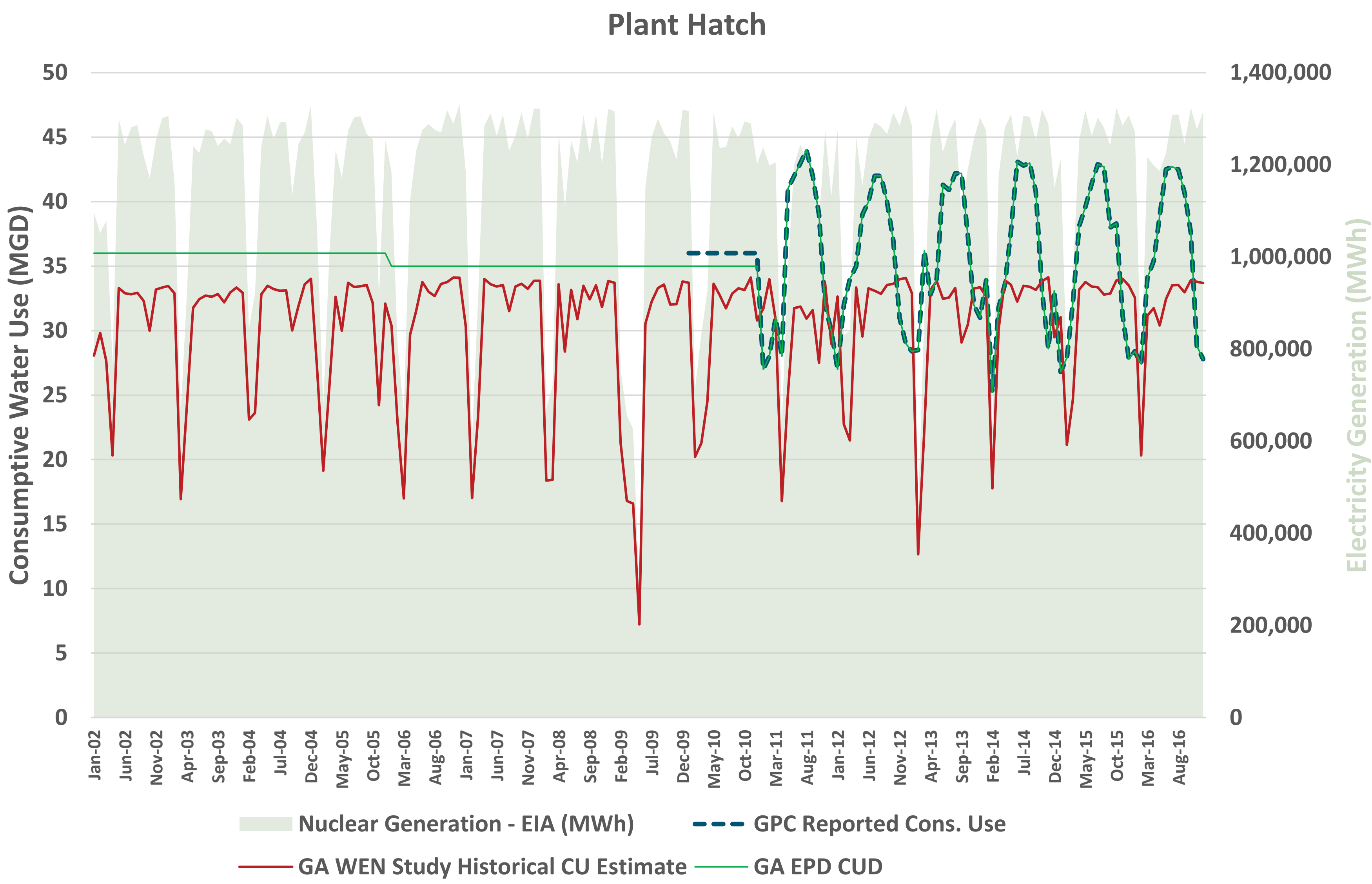
Plant Bowen

Location:	Cartersville, GA (Bartow Co.)
Nameplate Capacity (EIA):	3,499 MW
Plant Type:	Four conventional coal boilers, burning bituminous coal, with steam turbines
Date of Operation:	1971 - 1975
Owner:	Georgia Power
Cooling Water Source:	Etowah River
Cooling Technology:	Recirculating with Natural Draft Cooling Tower; four towers in service in 1971, 1972, 1974 and 1975
Water Withdrawal Permit(s):	008-1491-01
Permitted Monthly Average:	85 MGD
GA WEN Study Baseline Modeling Notes:	Coal with RC Cooling - 495 gallons consumptive use per MWh of generation


Plant Bowen
Consumptive Water Use (MGD)
Electricity Generation (MWh)
0
5
10
15
20
25
30
35
40
45
50
0
500,000
1,000,000
1,500,000
2,000,000
2,500,000
Jan-02
Jun-02
Nov-02
Apr-03
Sep-03
Feb-04
Jul-04
Dec-04
May-05
Oct-05
Mar-06
Aug-06
Jan-07
Jun-07
Nov-07
Apr-08
Sep-08
Feb-09
Jul-09
Dec-09
May-10
Oct-10
Mar-11
Aug-11
Jan-12
Jun-12
Nov-12
Apr-13
Sep-13
Feb-14
Jul-14
Dec-14
May-15
Oct-15
Mar-16
Aug-16
Coal Generation - EIA (MWh)
GPC Reported Cons. Use
GA WEN Study Historical CU Estimate
GA EPD CUD

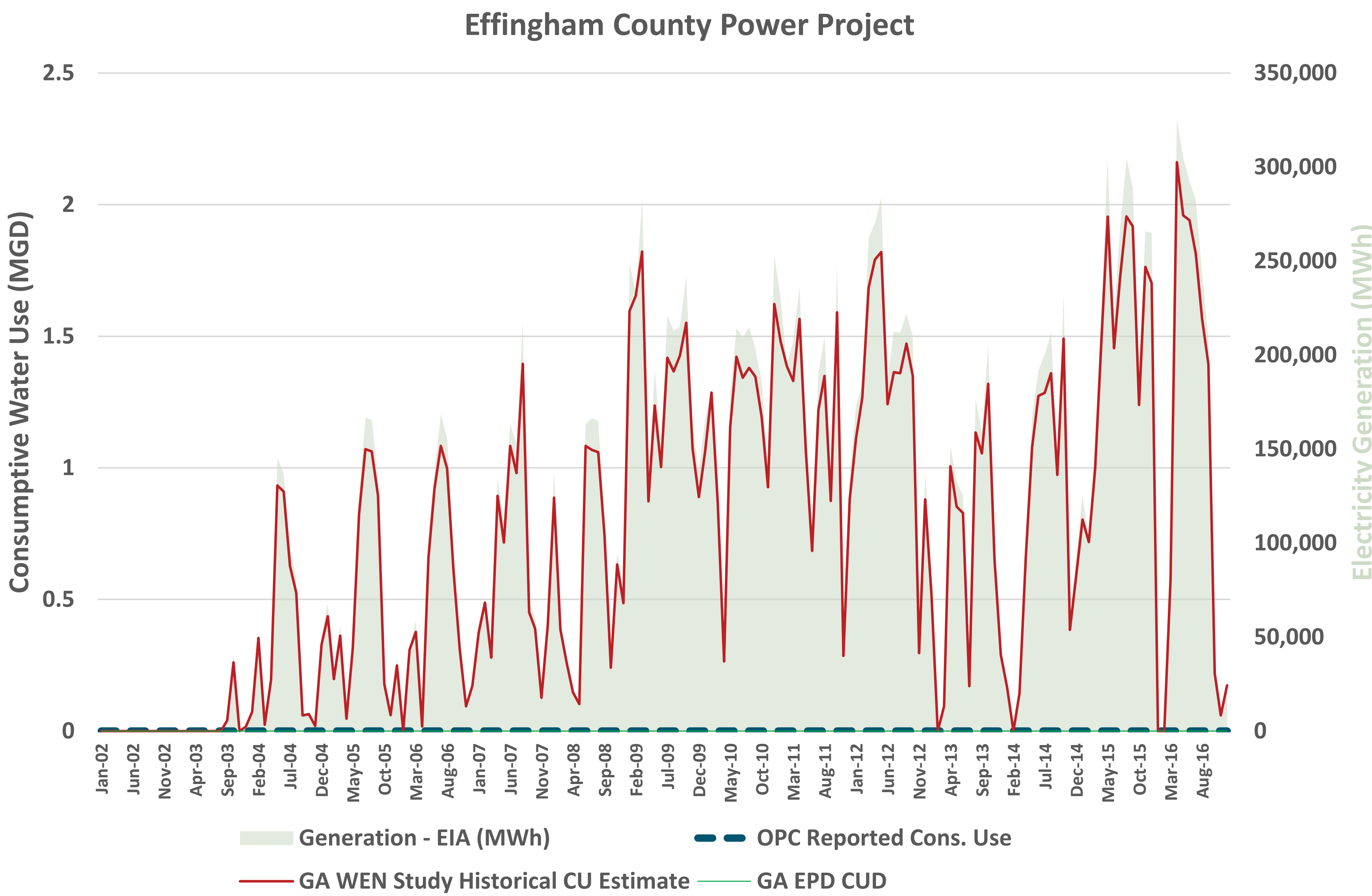
Plant Hatch

Location:	Baxley, GA (Appling Co.)
Nameplate Capacity (EIA):	1,722 MW
Plant Type:	Two boiling water reactors with steam turbines
Date of Operation:	Dec. 1975 and Sept. 1979
Owner:	Georgia Power (50.1%); Oglethorpe Power (30%); MEAG (17.7%); Dalton Utilities (2.2%)
Cooling Water Source:	Altamaha River
Cooling Technology:	Recirculating with Induced Draft Cooling Tower; two towers in service in 1975
Water Withdrawal Permit(s):	001-0690-01 and 001-0001
Permitted Monthly Average:	85 MGD and 1.1 MGD (respectively)
GA WEN Study Baseline Modeling Notes:	Nuclear - 794 gallons consumptive use per MWh of generation


Plant Hatch
Consumptive Water Use (MGD)
Electricity Generation (MWh)
50
45
40
35
30
25
20
15
10
5
0
1,400,000
1,200,000
1,000,000
800,000
600,000
400,000
200,000
0
Jan-02
Jun-02
Nov-02
Apr-03
Sep-03
Feb-04
Jul-04
Dec-04
May-05
Oct-05
Mar-06
Aug-06
Jan-07
Jun-07
Nov-07
Apr-08
Sep-08
Feb-09
Jul-09
Dec-09
May-10
Oct-10
Mar-11
Aug-11
Jan-12
Jun-12
Nov-12
Apr-13
Sep-13
Feb-14
Jul-14
Dec-14
May-15
Oct-15
Mar-16
Aug-16
Nuclear Generation - EIA (MWh)
GPC Reported Cons. Use
GA WEN Study Historical CU Estimate
GA EPD CUD

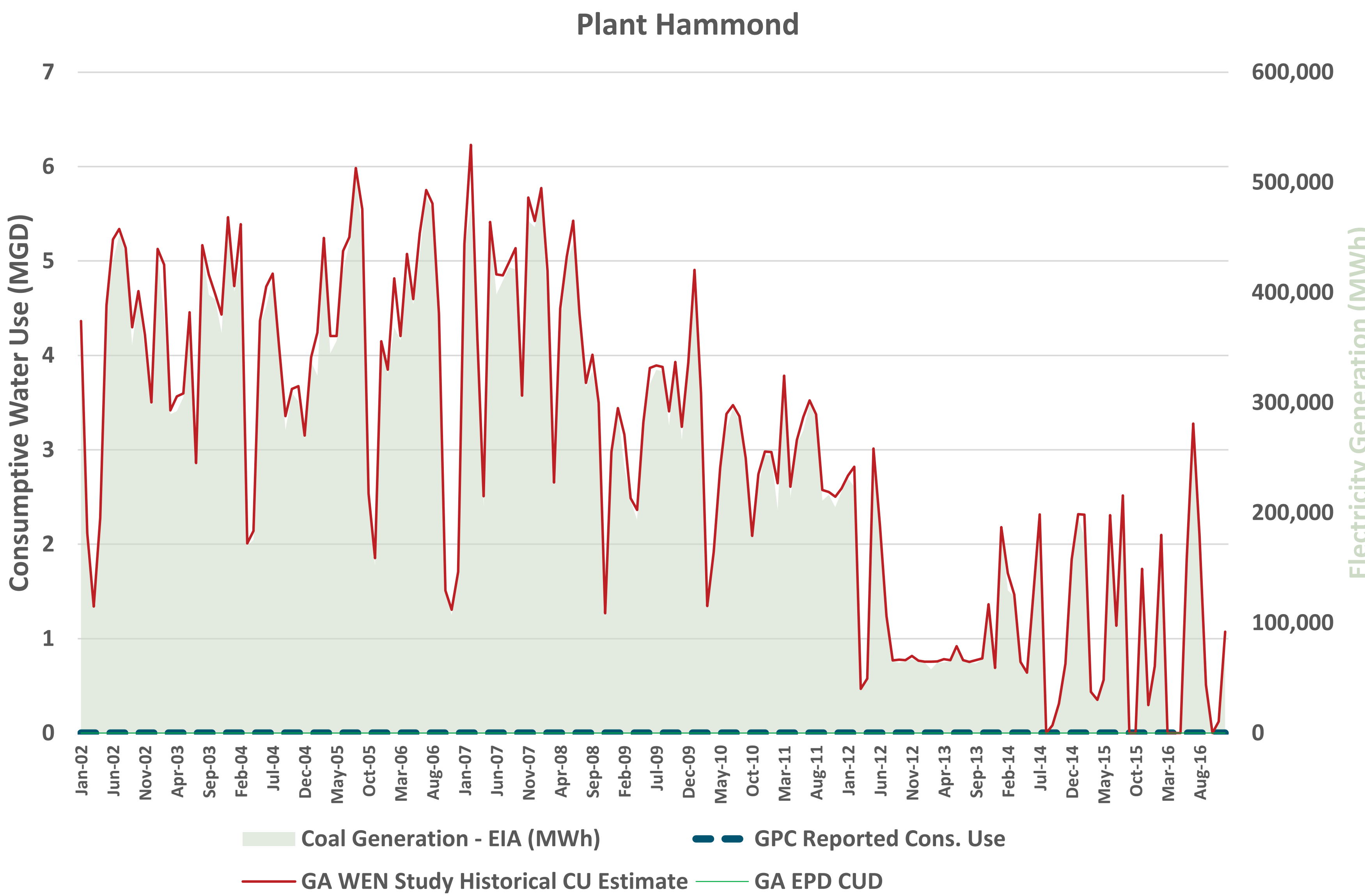
Effingham County Power Project

Location:	Rincon, GA (Effingham Co.)
Nameplate Capacity (EIA):	597 MW
Plant Type:	One combined cycle natural-gas fired unit
Date of Operation:	Aug. 2003
Owner:	Southeast PowerGen, LLC
Cooling Water Source:	Municipality
Cooling Technology:	Recirculating with Induced Draft Cooling Tower; one tower in service in 2003
Water Withdrawal Permit(s):	N/A
Permitted Monthly Average:	N/A
GA WEN Study Baseline Modeling Notes:	NGCC - 199 gallons consumptive use per MWh of generation


Effingham County Power Project
Consumptive Water Use (MGD)
Electricity Generation (MWh)
2.5
2
1.5
1
0.5
0
350,000
300,000
250,000
200,000
150,000
100,000
50,000
0
Jan-02
Jun-02
Nov-02
Apr-03
Sep-03
Feb-04
Jul-04
Dec-04
May-05
Oct-05
Mar-06
Aug-06
Jan-07
Jun-07
Nov-07
Apr-08
Sep-08
Feb-09
Jul-09
Dec-09
May-10
Oct-10
Mar-11
Aug-11
Jan-12
Jun-12
Nov-12
Apr-13
Sep-13
Feb-14
Jul-14
Dec-14
May-15
Oct-15
Mar-16
Aug-16
Generation - EIA (MWh)
OPC Reported Cons. Use
GA WEN Study Historical CU Estimate
GA EPD CUD

Plant Hammond

Location:	Rome, GA (Floyd Co.)
Nameplate Capacity (EIA):	953 MW
Plant Type:	Four conventional coal boilers with steam turbines, burning bituminous coal
Date of Operation:	Units 1-3: 1954 and 1955; unit 4 came online in 1970
Owner:	Georgia Power
Cooling Water Source:	Coosa River
Cooling Technology:	Once through without cooling pond(s)
Water Withdrawal Permit(s):	057-1490-02
Permitted Monthly Average:	655 MGD
GA WEN Study Baseline Modeling Notes:	Coal with once-through cooling - 366 gallons consumptive use per MWh of generation


Plant Hammond
Consumptive Water Use (MGD)
Electricity Generation (MWh)
0
1
2
3
4
5
6
7
0
100,000
200,000
300,000
400,000
500,000
600,000
Jan-02
Jun-02
Nov-02
Apr-03
Sep-03
Feb-04
Jul-04
Dec-04
May-05
Oct-05
Mar-06
Aug-06
Jan-07
Jun-07
Nov-07
Apr-08
Sep-08
Feb-09
Jul-09
Dec-09
May-10
Oct-10
Mar-11
Aug-11
Jan-12
Jun-12
Nov-12
Apr-13
Sep-13
Feb-14
Jul-14
Dec-14
May-15
Oct-15
Mar-16
Aug-16
Coal Generation - EIA (MWh)
GPC Reported Cons. Use
GA WEN Study Historical CU Estimate
GA EPD CUD

Plant Harllee Branch

Location:	Milledgeville, GA (Putnam Co.)
Nameplate Capacity (EIA):	1,746 MW (all retired as of 2017)
Plant Type:	Four conventional coal boilers, burning bituminous coal, with steam turbines
Date of Operation:	1965 - 1969
Owner:	Georgia Power
Cooling Water Source:	Lake Sinclair
Cooling Technology:	Once through without cooling pond(s)
Water Withdrawal Permit(s):	033-1291-03
Permitted Monthly Average:	1,245 MGD
GA WEN Study Baseline Modeling Notes:	Coal with once-through cooling - 366 gallons consumptive use per MWh of generation (for this historical comparison only - units now retired)

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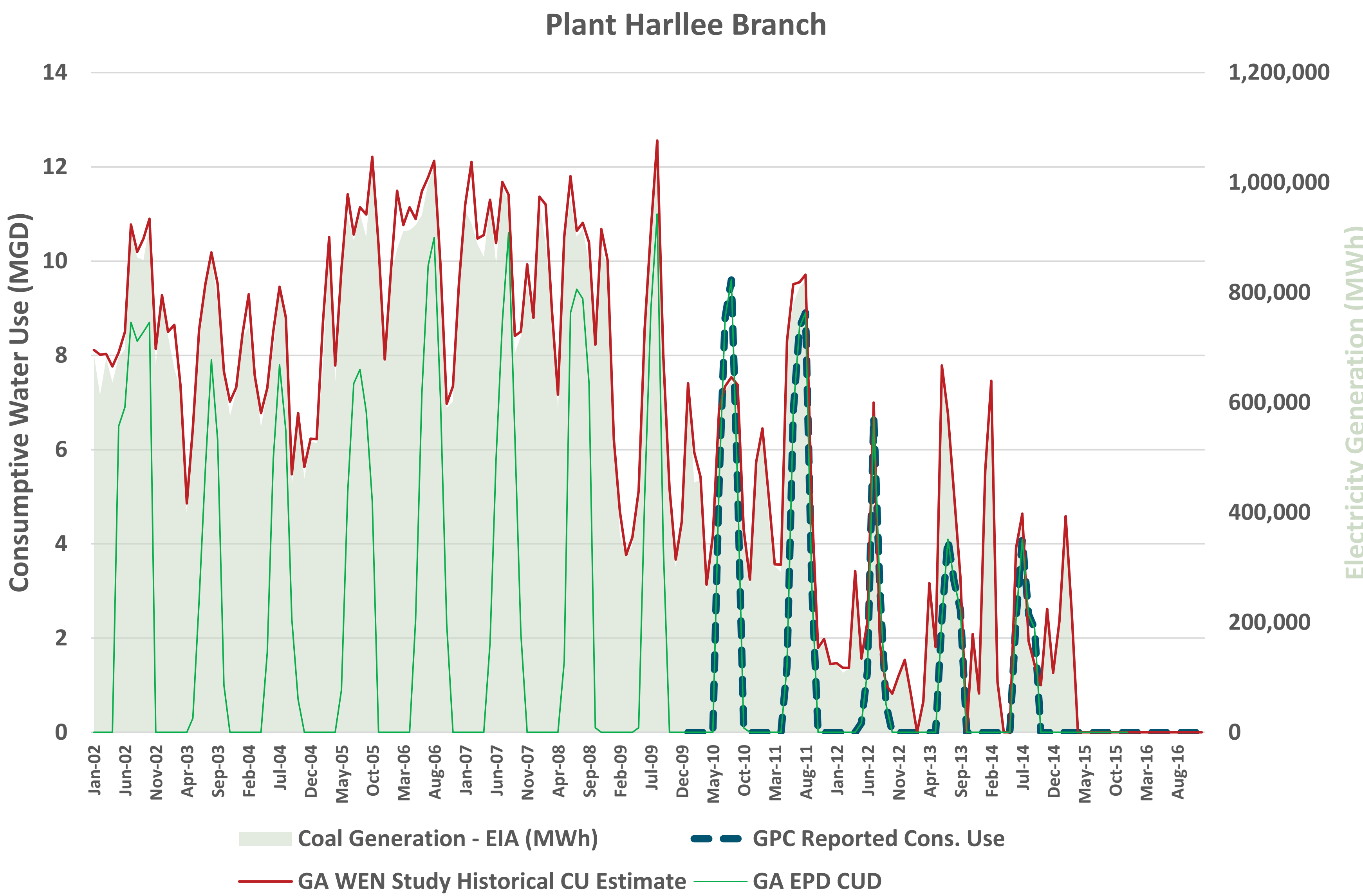
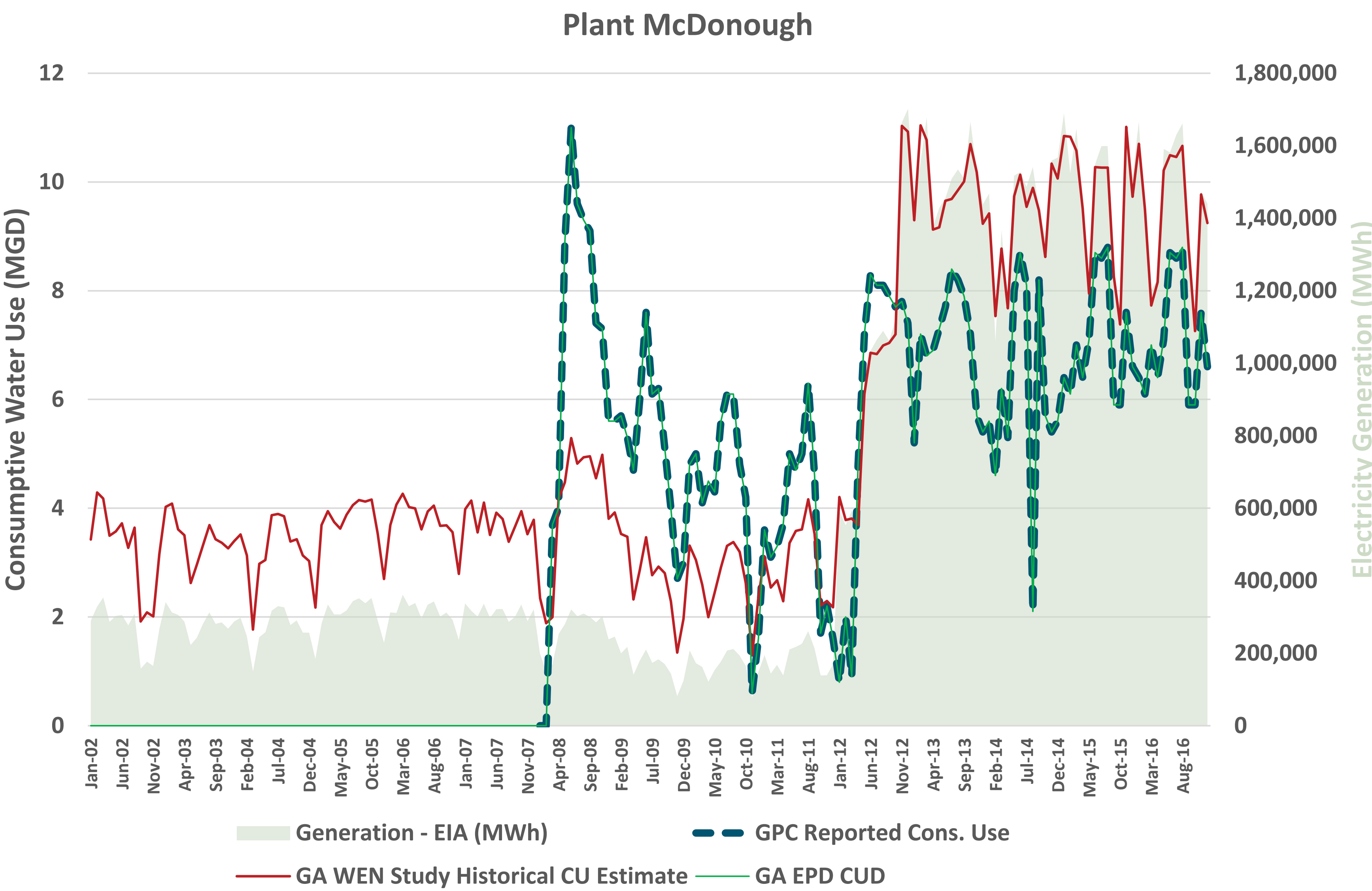


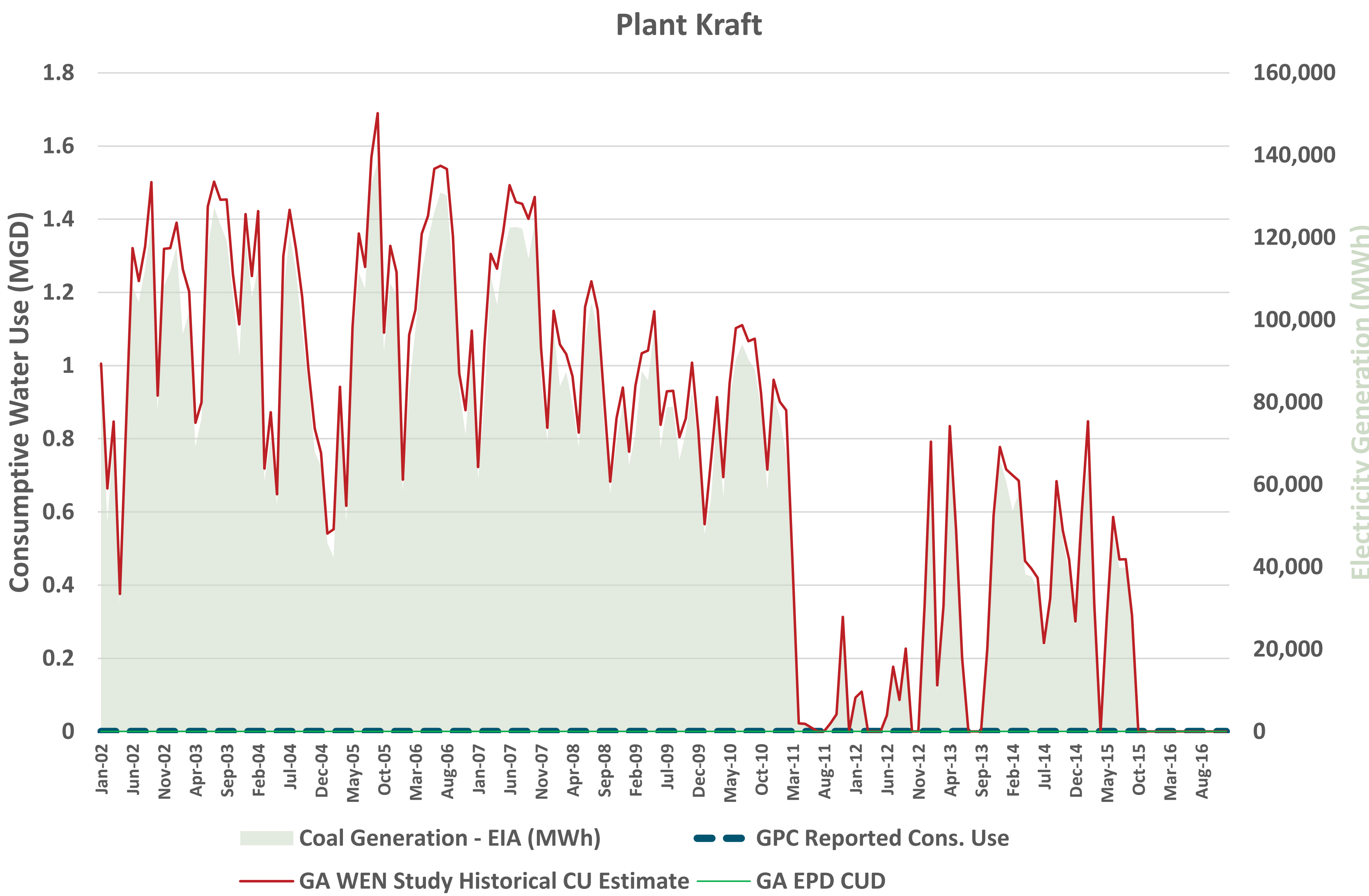
Plant McDonough

Location:	Smyrna, GA (Cobb Co.)
Nameplate Capacity (EIA):	2,520 MW
Plant Type:	Three natural gas-fired combined cycle units (prior to 2011 also had two conventional coal units with steam turbines)
Date of Operation:	2011 and 2012
Owner:	Georgia Power
Cooling Water Source:	Chattahoochee River
Cooling Technology:	Recirculating with Induced Draft Cooling Tower; three towers in service in 2011 and 2012 (two towers installed in 2008 already retired)
Water Withdrawal Permit(s):	033-1291-03
Permitted Monthly Average:	30 MGD
GA WEN Study Baseline Modeling Notes:	Coal units operate with once-through cooling from Jan. 2002 - April 2008 (366 gallons consumptive use per MWh of generation); coal units operate with recirculating cooling from April 2008 - February 2012 (495 gallons consumptive use per MWh of generation). This only pertains to this historical comparison, since the units are now retired. Consumptive use related to natural gas generation is not calculated prior December 2011 because the generation is de minimis and associated with combustion turbines that requires no cooling water. Natural gas generation after December 2011 (start date of first NGCC unit) is NGCC with recirculating cooling (199 gallons of consumptive use per MWh of generation).


Plant McDonough
Consumptive Water Use (MGD)
Electricity Generation (MWh)
0
2
4
6
8
10
12
0
200,000
400,000
600,000
800,000
1,000,000
1,200,000
1,400,000
1,600,000
1,800,000
Jan-02
Jun-02
Nov-02
Apr-03
Sep-03
Feb-04
Jul-04
Dec-04
May-05
Oct-05
Mar-06
Aug-06
Jan-07
Jun-07
Nov-07
Apr-08
Sep-08
Feb-09
Jul-09
Dec-09
May-10
Oct-10
Mar-11
Aug-11
Jan-12
Jun-12
Nov-12
Apr-13
Sep-13
Feb-14
Jul-14
Dec-14
May-15
Oct-15
Mar-16
Aug-16
Generation - EIA (MWh)
GPC Reported Cons. Use
GA WEN Study Historical CU Estimate
GA EPD CUD

Plant Kraft

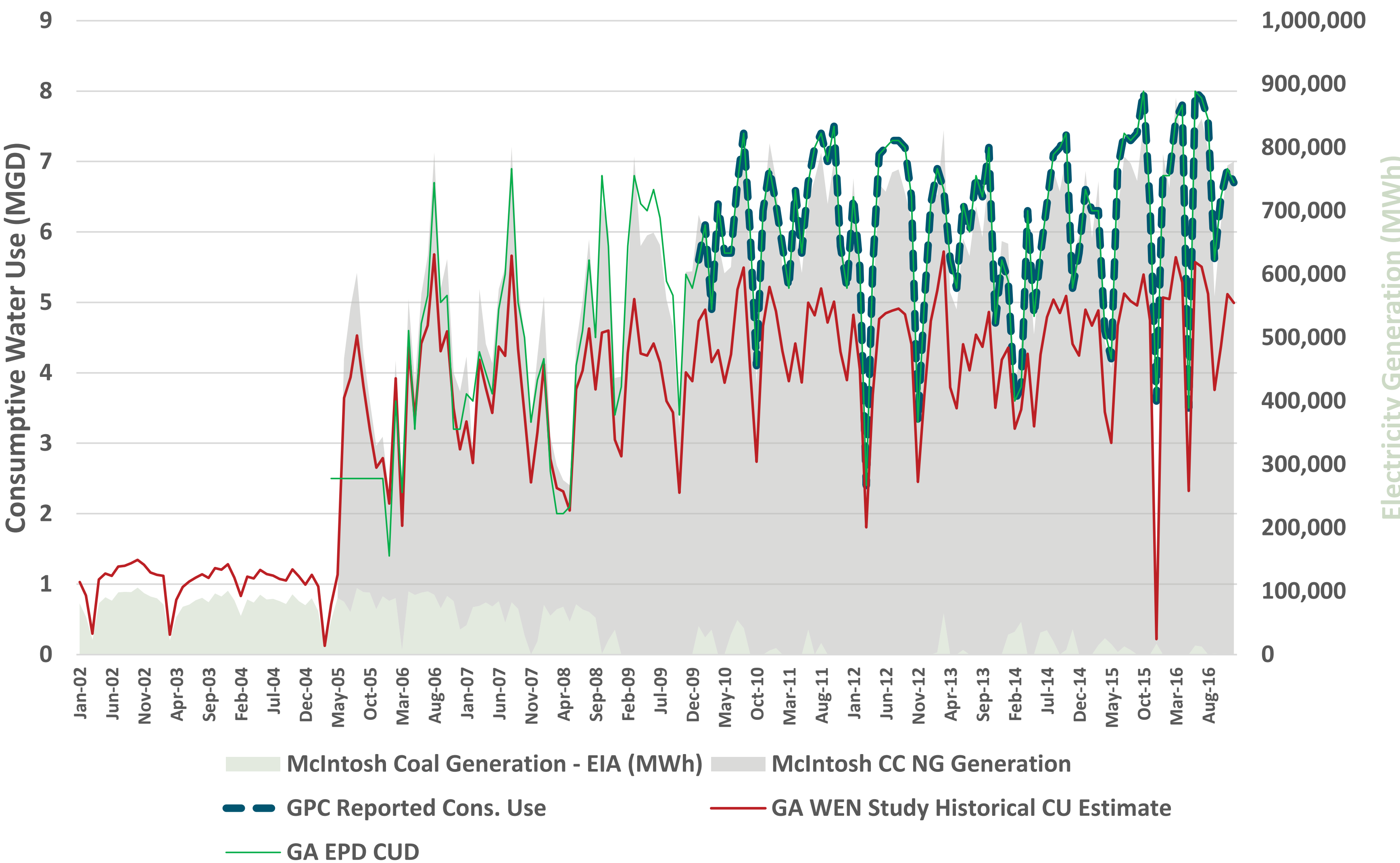
Location:	Port Wentworth, GA (Chatham Co.)
Nameplate Capacity (EIA):	344 MW (all retired as of 2015)
Plant Type:	Three conventional coal boilers with steam turbines, burning bituminous coal and one natural-gas boiler with steam turbine
Date of Operation:	Plant Kraft's three coal units started operation in the 1958 - 1965 timeframe; the gas unit came online in 1972
Owner:	Georgia Power/Savannah Electric (prior to 2006)
Cooling Water Source:	Savannah River
Cooling Technology:	Once through without cooling pond(s)
Water Withdrawal Permit(s):	025-0192-02
Permitted Monthly Average:	267 MGD
GA WEN Study Baseline Modeling Notes:	Coal with once-through cooling - 366 gallons consumptive use per MWh of generation (for this historical comparison only - units now retired)


Plant Kraft
Consumptive Water Use (MGD)
Electricity Generation (MWh)
1.8
1.6
1.4
1.2
1
0.8
0.6
0.4
0.2
0
160,000
140,000
120,000
100,000
80,000
60,000
40,000
20,000
0
Jan-02
Jun-02
Nov-02
Apr-03
Sep-03
Feb-04
Jul-04
Dec-04
May-05
Oct-05
Mar-06
Aug-06
Jan-07
Jun-07
Nov-07
Apr-08
Sep-08
Feb-09
Jul-09
Dec-09
May-10
Oct-10
Mar-11
Aug-11
Jan-12
Jun-12
Nov-12
Apr-13
Sep-13
Feb-14
Jul-14
Dec-14
May-15
Oct-15
Mar-16
Aug-16
Coal Generation - EIA (MWh)
GPC Reported Cons. Use
GA WEN Study Historical CU Estimate
GA EPD CUD

Plant McIntosh & McIntosh Combined Cycle

Location:	Rincon, GA (Effingham Co.)
Nameplate Capacity (EIA):	1,554
Plant Type:	One conventional coal boiler with steam turbine (178 MW); two natural gas combined cycle units (1,377 MW)
Date of Operation:	1979 and 2005, respectively
Owner:	Georgia Power
Cooling Water Source:	Savannah River
Cooling Technology:	Once-through cooling for coal unit; Recirculating with Induced Draft Cooling Tower; two towers in service in 2005 for NGCC units
Water Withdrawal Permit(s):	051-0192-01 (surface water) and 051-0004 (groundwater)
Permitted Monthly Average:	130 MGD / 0.45 MGD, respectively
GA WEN Study Baseline Modeling Notes:	Coal generation treated as coal with once-through cooling (366 gallons of consumptive use per MWh of generation) and natural gas generation treated as NGCC with recirculating cooling (199 gallons of consumptive use per MWh of generation).

Plant McIntosh and McIntosh Combined Cycle Facility



Plant McManus

Location:	Brunswick, GA (Glynn Co.)
Nameplate Capacity (EIA):	144 MW (all retired as of 2015)
Plant Type:	Two fuel-oil fired boilers with steam turbines
Date of Operation:	Plant McManus units began operation in 1952 and 1959
Owner:	Georgia Power
Cooling Water Source:	Turtle River
Cooling Technology:	Once through without cooling pond(s)
Water Withdrawal Permit(s):	063-0712-01 and 063-0006
Permitted Monthly Average:	155 MGD and 0.15 MGD (respectively)
GA WEN Study Baseline Modeling Notes:	This plant is not reflected in the GA WEN study because it was retired in 2015. Additionally, we have not compared Georgia EPD data for this plant to the results of the GA WEN methodology because (1) our research did not focus on oil-fired boilers with once-through cooling due to the fact that, on a going-forward basis, none are operating in the state and (2) because Plant McManus used brackish water for cooling, which does not impact Georgia's water management planning in the way the use of fresh surface water does.

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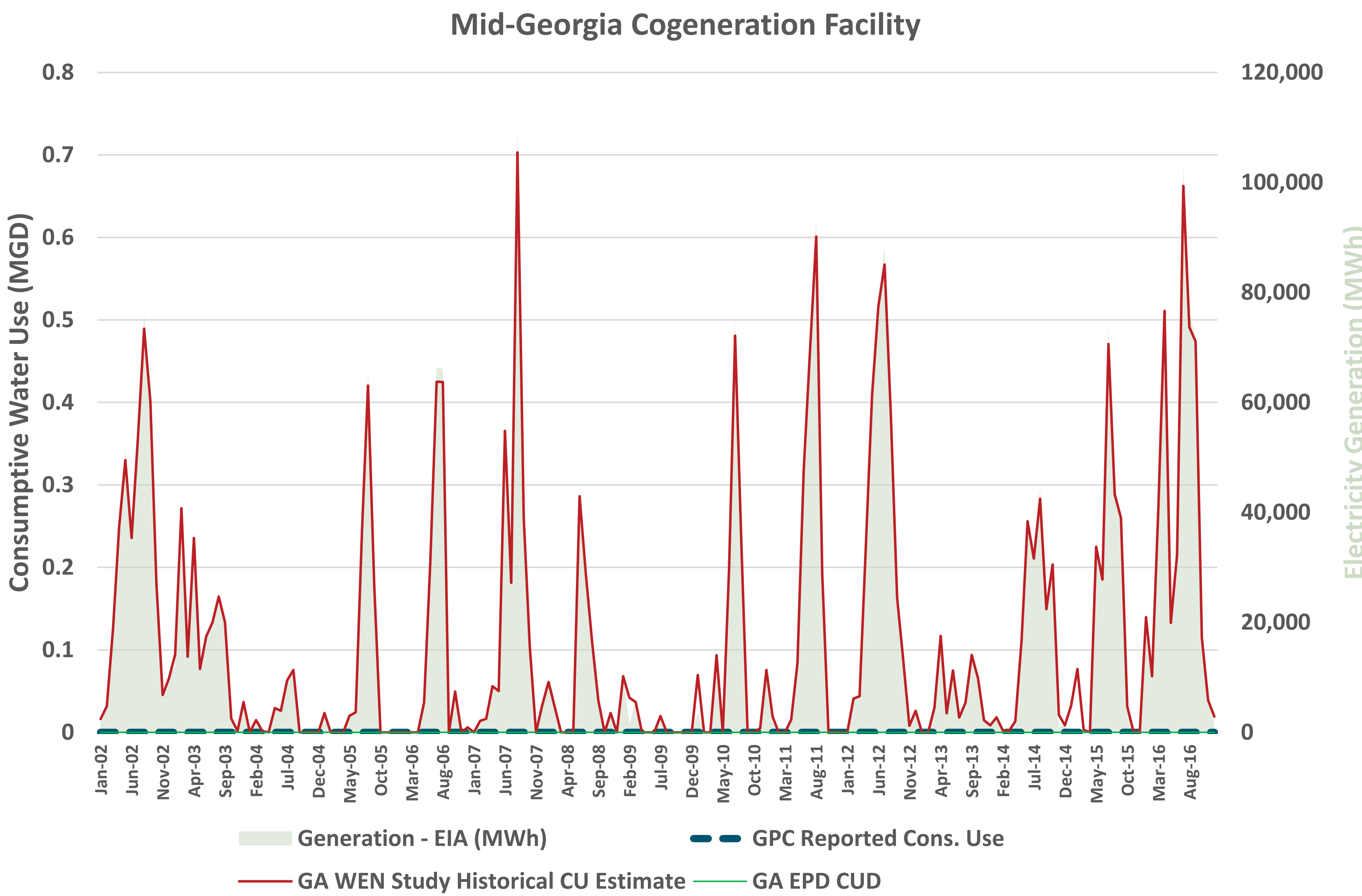
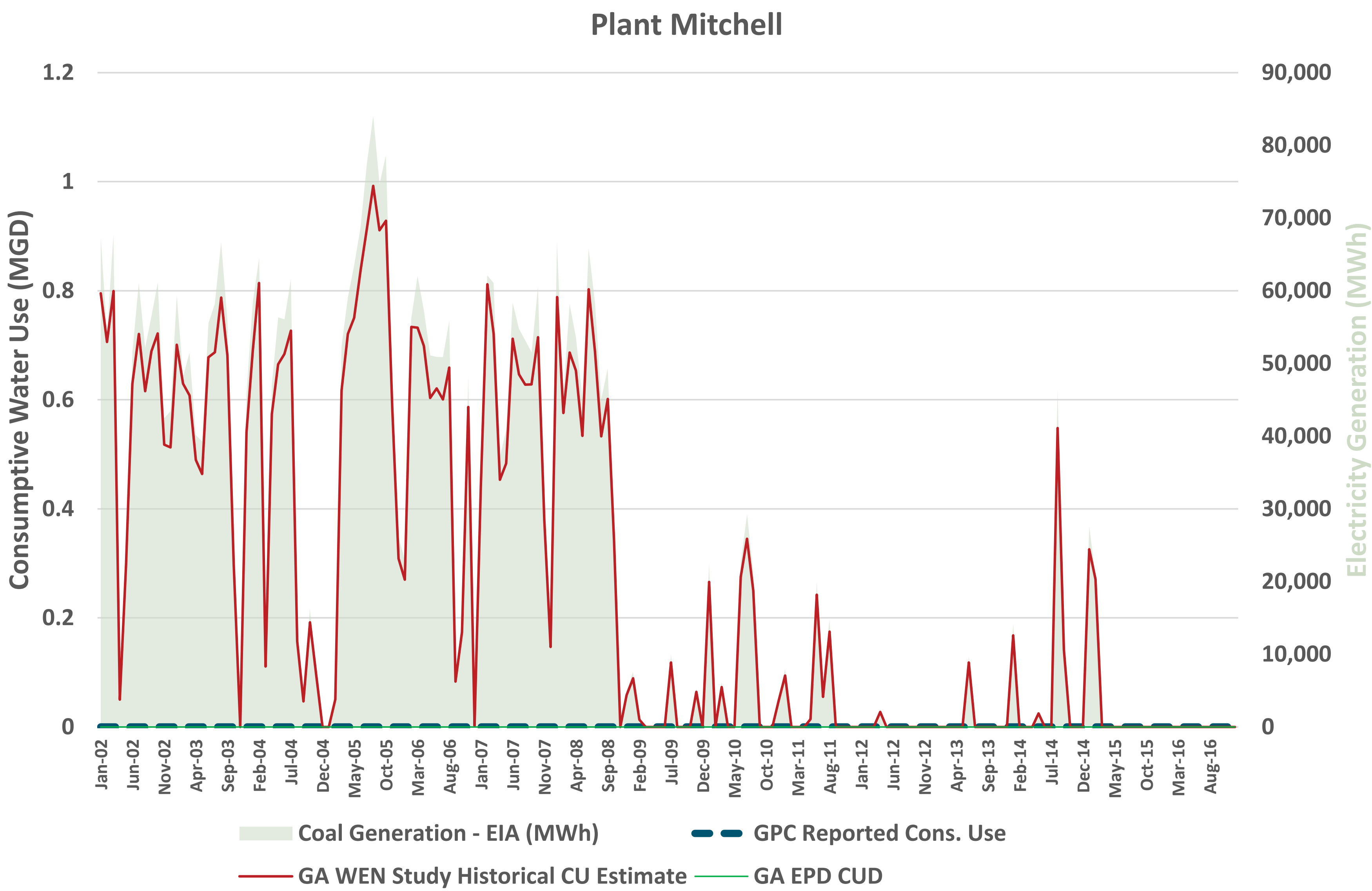
Mid-Georgia Cogeneration Facility

Location:	Kathleen, GA (Houston Co.)
Nameplate Capacity (EIA):	323 MW
Plant Type:	One natural gas-fired combined cycle unit
Date of Operation:	1997-1998
Owner:	Southeast PowerGen, LLC
Cooling Water Source:	Municipality
Cooling Technology:	Recirculating with Induced Draft Cooling Tower; one tower in service 1998
Water Withdrawal Permit(s):	N/A
Permitted Monthly Average:	N/A
GA WEN Study Baseline Modeling Notes:	NGCC - 199 gallons consumptive use per MWh of generation


Mid-Georgia Cogeneration Facility
Consumptive Water Use (MGD)
Electricity Generation (MWh)
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0
20,000
40,000
60,000
80,000
100,000
120,000
Jan-02
Jun-02
Nov-02
Apr-03
Sep-03
Feb-04
Jul-04
Dec-04
May-05
Oct-05
Mar-06
Aug-06
Jan-07
Jun-07
Nov-07
Apr-08
Sep-08
Feb-09
Jul-09
Dec-09
May-10
Oct-10
Mar-11
Aug-11
Jan-12
Jun-12
Nov-12
Apr-13
Sep-13
Feb-14
Jul-14
Dec-14
May-15
Oct-15
Mar-16
Aug-16
Generation - EIA (MWh)
GPC Reported Cons. Use
GA WEN Study Historical CU Estimate
GA EPD CUD

Plant Mitchell

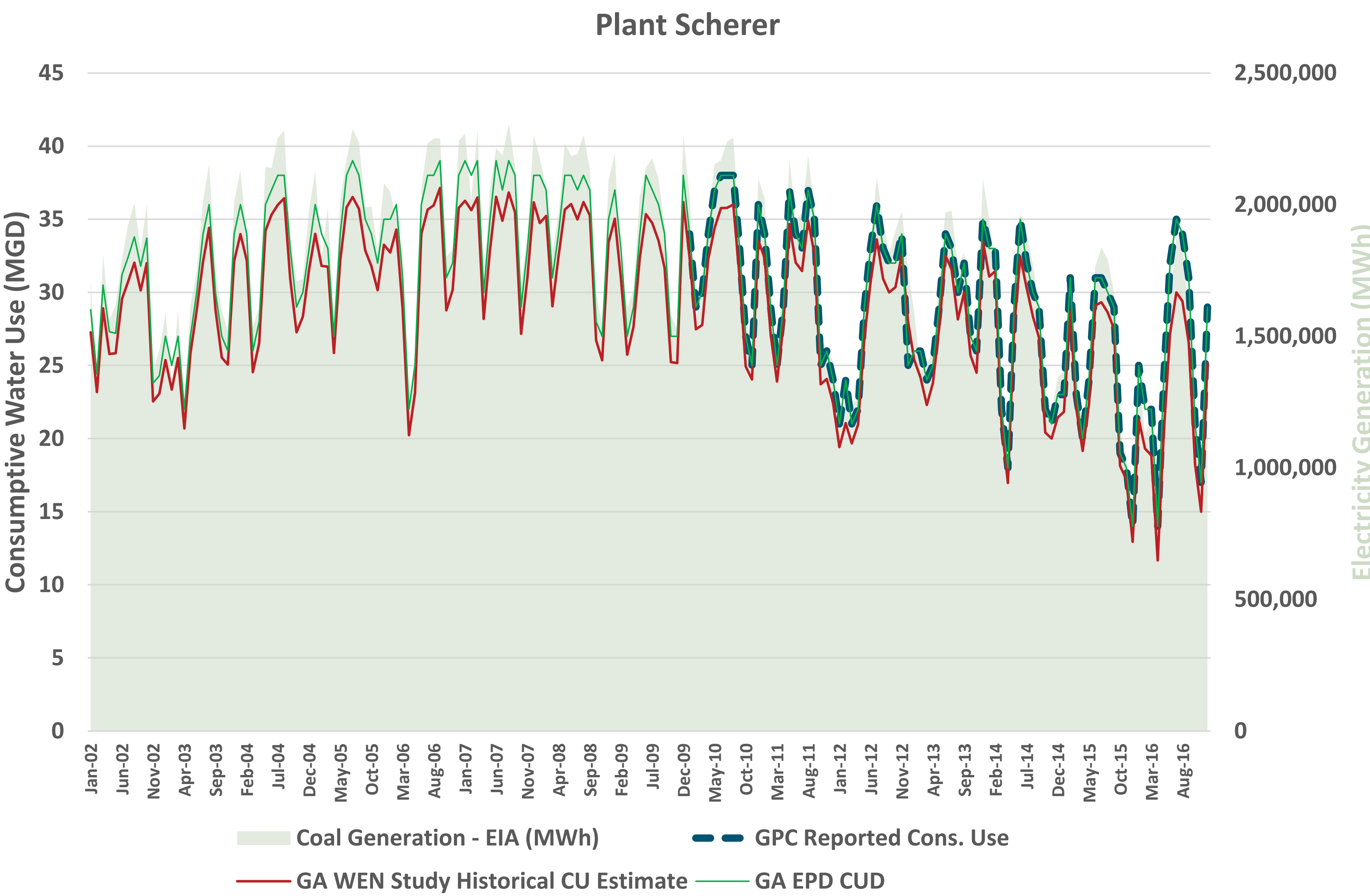
Location:	Albany, GA (Dougherty Co.)
Nameplate Capacity (EIA):	163 MW
Plant Type:	One conventional coal boiler with steam turbine
Date of Operation:	June 1964 (retired as of July 2016)
Owner:	Georgia Power
Cooling Water Source:	Flint River
Cooling Technology:	Once through without cooling pond(s)
Water Withdrawal Permit(s):	047-1192-01 and 047-0012
Permitted Monthly Average:	232 MGD and 0.25 MGD (respectively)
GA WEN Study Baseline Modeling Notes:	Coal with once-through cooling - 366 gallons consumptive use per MWh of generation (for this historical comparison only - units now retired)



Plant Mitchell
Consumptive Water Use (MGD)
Electricity Generation (MWh)
1.2
1
0.8
0.6
0.4
0.2
0
90,000
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
Jan-02
Jun-02
Nov-02
Apr-03
Sep-03
Feb-04
Jul-04
Dec-04
May-05
Oct-05
Mar-06
Aug-06
Jan-07
Jun-07
Nov-07
Apr-08
Sep-08
Feb-09
Jul-09
Dec-09
May-10
Oct-10
Mar-11
Aug-11
Jan-12
Jun-12
Nov-12
Apr-13
Sep-13
Feb-14
Jul-14
Dec-14
May-15
Oct-15
Mar-16
Aug-16
Coal Generation - EIA (MWh)
GPC Reported Cons. Use
GA WEN Study Historical CU Estimate
GA EPD CUD

Plant Scherer

Location:	Juliette, GA (Monroe Co.)
Nameplate Capacity (EIA):	3,564 MW
Plant Type:	Four conventional coal boilers, burning bituminous coal, with steam turbines
Date of Operation:	1982 - 1989
Owner:	Ownership of Units 1, 2 and 4 is divided among Georgia Power, Oglethorpe Power, MEAG, Dalton Utilities and Gulf Power
Cooling Water Source:	Ocmulgee River and Lake Juliette (respectively)
Cooling Technology:	Recirculating with Natural Draft Cooling Tower; four towers in service in 1982, 1984, 1987, 1989
Water Withdrawal Permit(s):	102-0590-03 and 102-0590-05
Permitted Monthly Average:	213 MGD and 115 MGD (respectively)
GA WEN Study Baseline Modeling Notes:	Coal with RC Cooling - 495 gallons consumptive use per MWh of generation

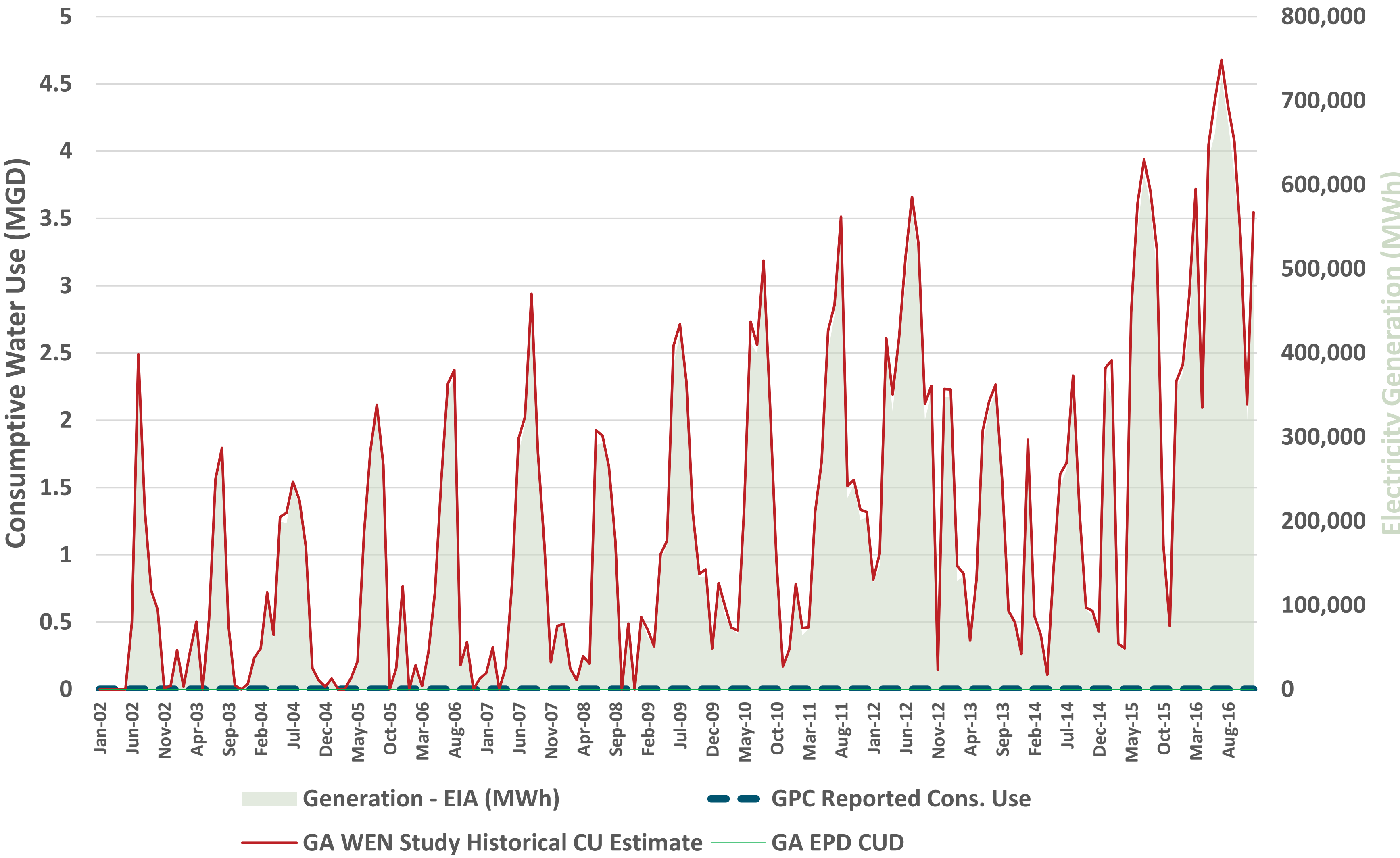


Plant Scherer
Consumptive Water Use (MGD)
Electricity Generation (MWh)
45
40
35
30
25
20
15
10
5
0
2,500,000
2,000,000
1,500,000
1,000,000
500,000
0
Jan-02
Jun-02
Nov-02
Apr-03
Sep-03
Feb-04
Jul-04
Dec-04
May-05
Oct-05
Mar-06
Aug-06
Jan-07
Jun-07
Nov-07
Apr-08
Sep-08
Feb-09
Jul-09
Dec-09
May-10
Oct-10
Mar-11
Aug-11
Jan-12
Jun-12
Nov-12
Apr-13
Sep-13
Feb-14
Jul-14
Dec-14
May-15
Oct-15
Mar-16
Aug-16
Coal Generation - EIA (MWh)
GPC Reported Cons. Use
GA WEN Study Historical CU Estimate
GA EPD CUD

Thomas A. Smith Energy Facility

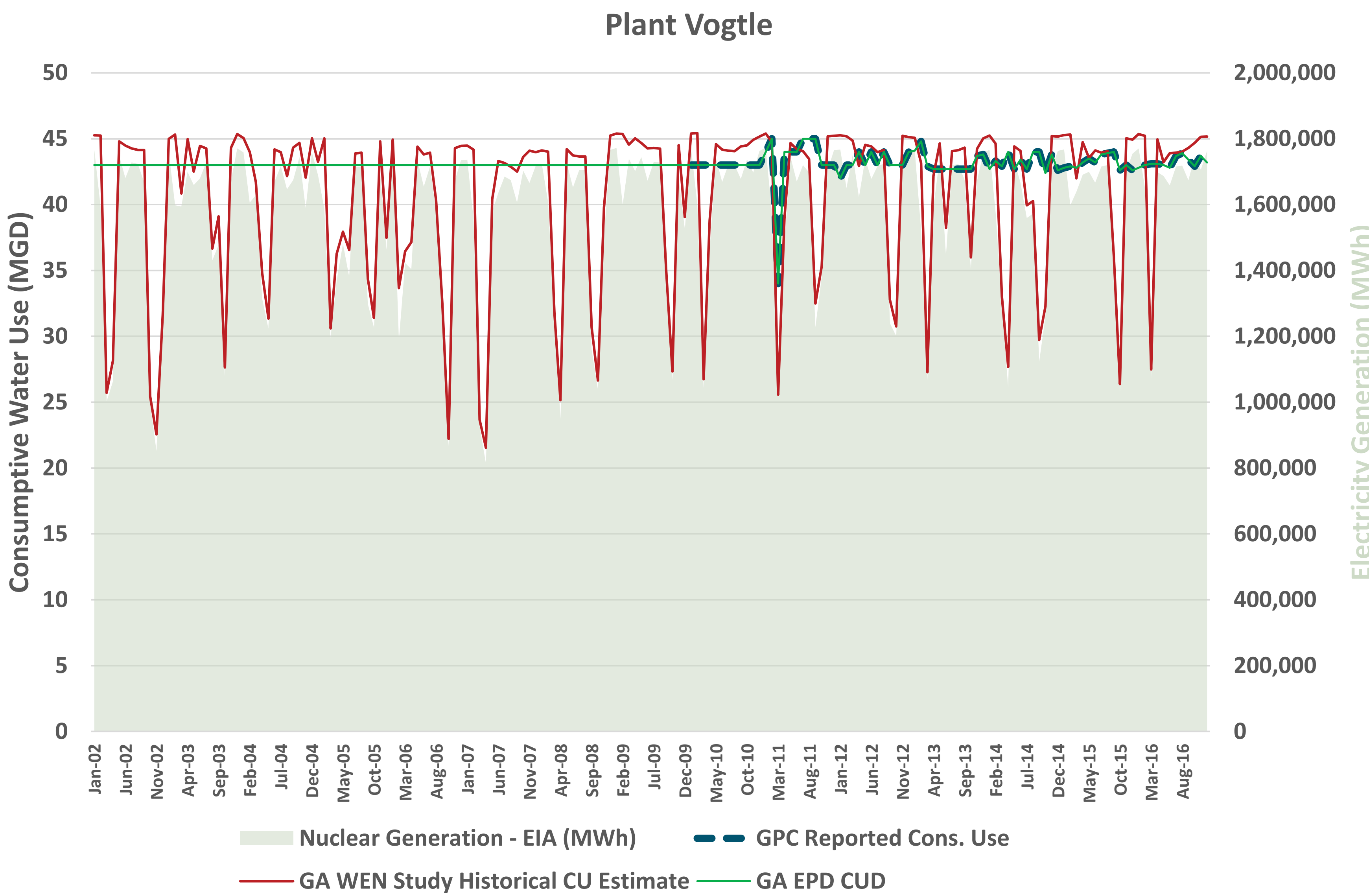
Location:	Dalton, GA (Murray Co.)
Nameplate Capacity (EIA):	1,192 MW
Plant Type:	Two natural gas combined cycle units
Date of Operation:	June 2002
Owner:	Oglethorpe Power Company
Cooling Water Source:	Municipality
Cooling Technology:	Recirculating with Induced Draft Cooling Tower; two cooling towers in service in 2002
Water Withdrawal Permit(s):	N/A
Permitted Monthly Average:	N/A
GA WEN Study Baseline Modeling Notes:	NGCC - 199 gallons consumptive use per MWh of generation

Thomas A. Smith Energy Facility



Plant Vogtle

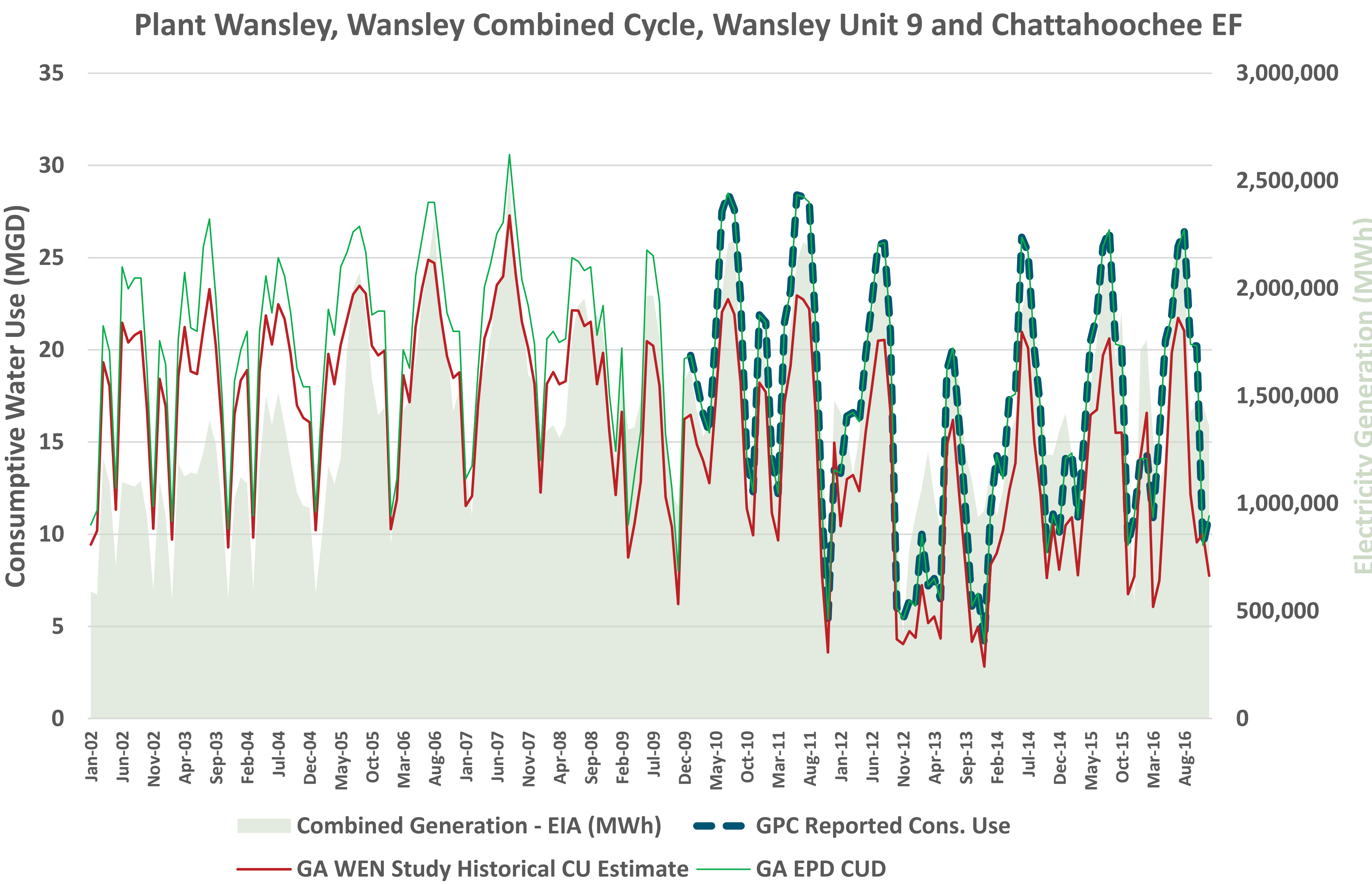
Location:	Waynesboro, GA (Burke Co.)
Nameplate Capacity (EIA):	2,320 MW
Plant Type:	Two pressurized water nuclear reactors with steam turbines
Date of Operation:	Vogtle’s units 1 and 2 began operation in 1987 and 1989
Owner:	Georgia Power (45.7%); Oglethorpe Power (30%); MEAG (22.7%); Dalton Utilities (1.6%)
Cooling Water Source:	Savannah River; Savannah River; Cretaceous Sand, Gordon; and Surficial (respective to permit numbers)
Cooling Technology:	Recirculating with Natural Draft Cooling Tower; two towers in service in 1987 and 1989, two towers under construction
Water Withdrawal Permit(s):	017-0191-05; 017-0191-11; 017-0003; and 017-0006
Permitted Monthly Average:	85.00 MGD; 62.00 MGD; 6.0 MGD; and 2.9 MGD (respectively)
GA WEN Study Baseline Modeling Notes:	Nuclear - 794 gallons consumptive use per MWh of generation



Plant Vogtle
Consumptive Water Use (MGD)
Electricity Generation (MWh)
50
45
40
35
30
25
20
15
10
5
0
2,000,000
1,800,000
1,600,000
1,400,000
1,200,000
1,000,000
800,000
600,000
400,000
200,000
0
Jan-02
Jun-02
Nov-02
Apr-03
Sep-03
Feb-04
Jul-04
Dec-04
May-05
Oct-05
Mar-06
Aug-06
Jan-07
Jun-07
Nov-07
Apr-08
Sep-08
Feb-09
Jul-09
Dec-09
May-10
Oct-10
Mar-11
Aug-11
Jan-12
Jun-12
Nov-12
Apr-13
Sep-13
Feb-14
Jul-14
Dec-14
May-15
Oct-15
Mar-16
Aug-16
Nuclear Generation - EIA (MWh)
GPC Reported Cons. Use
GA WEN Study Historical CU Estimate
GA EPD CUD

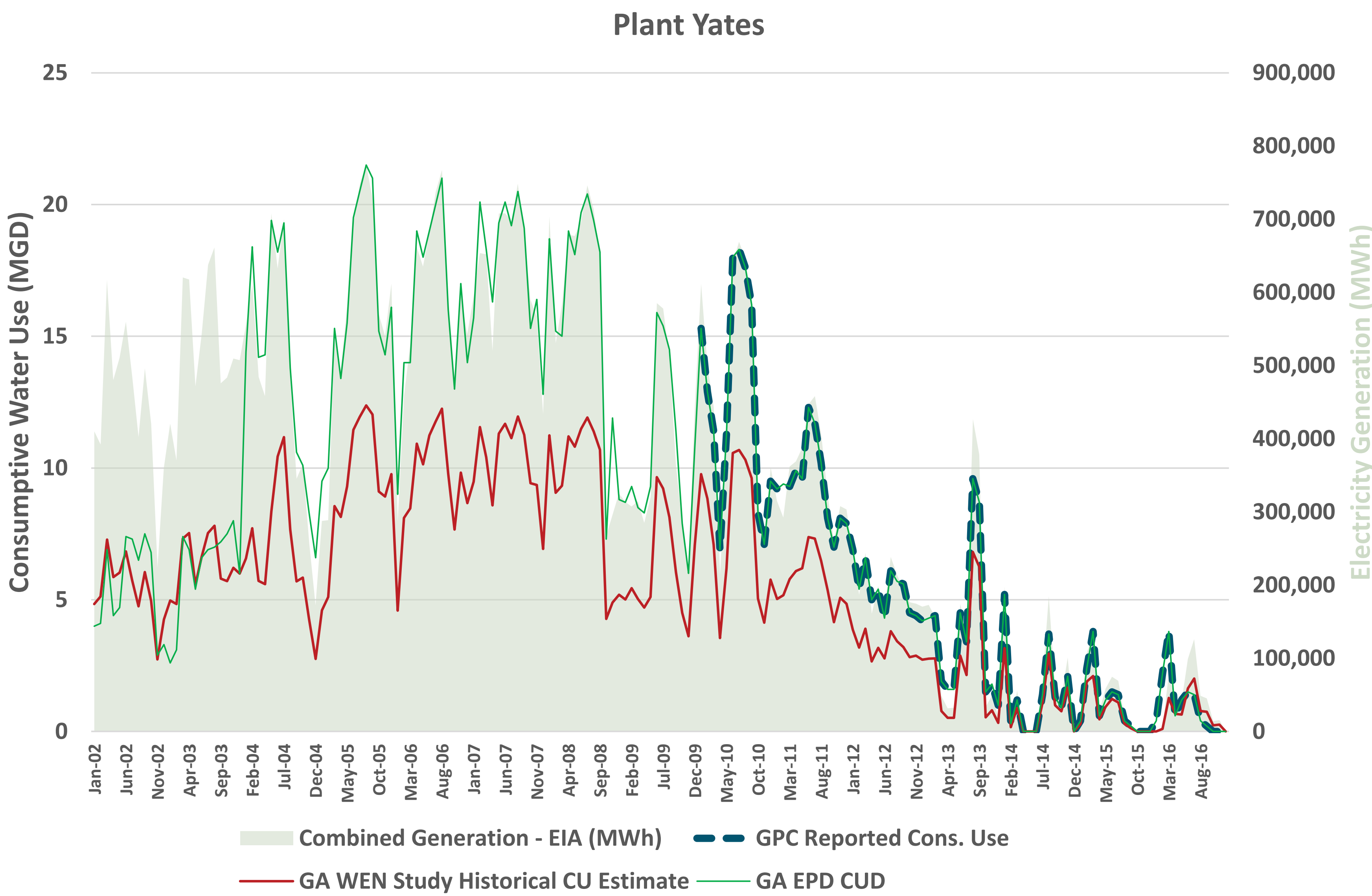
Plant Wansley, Wansley Combined Cycle, Wansley Unit 9 and Chattahoochee Energy Facility (co-located plants)

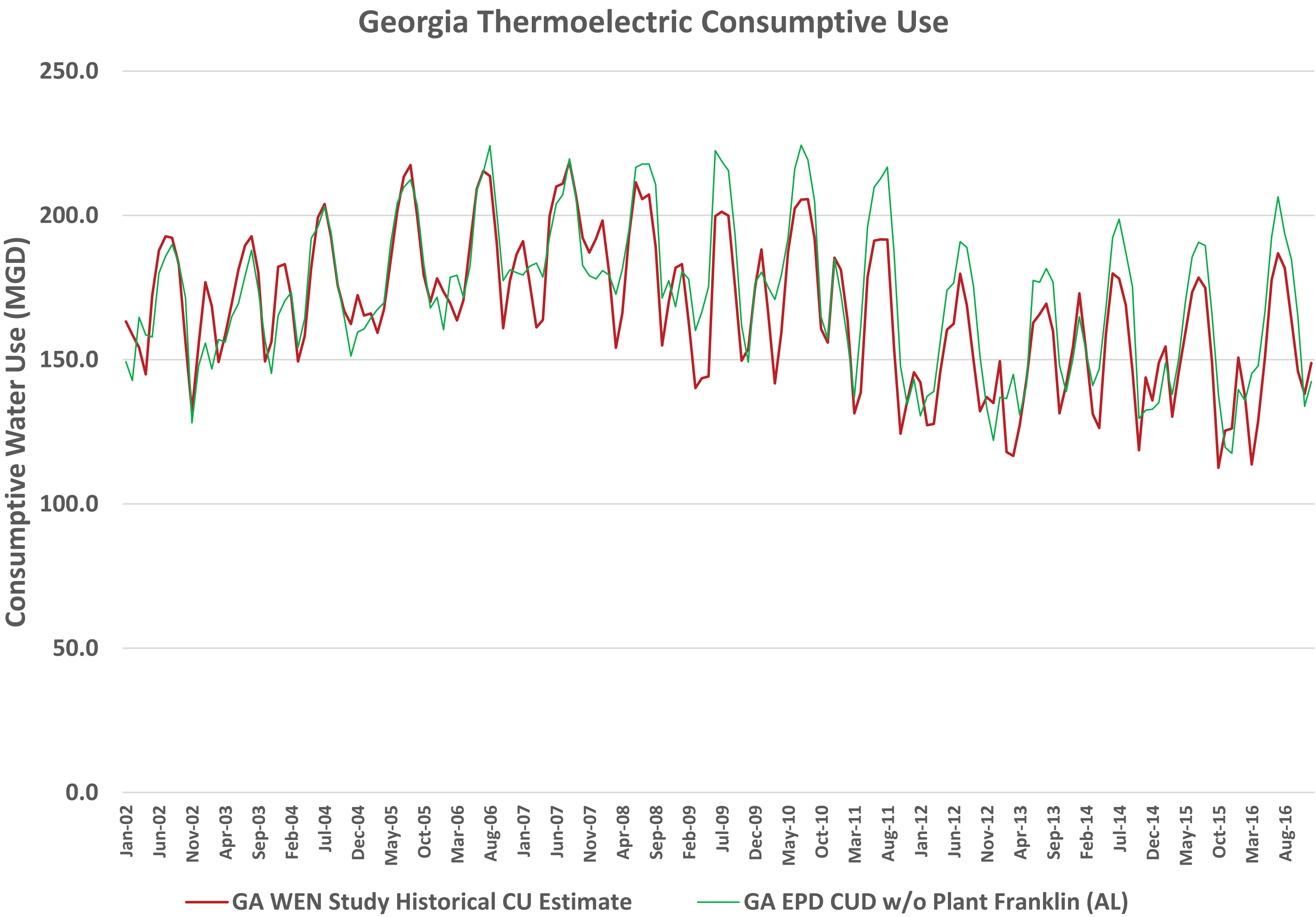
Location:	Roopville, GA (Heard Co.)
Nameplate Capacity (EIA):	Wansley: 1,904 MW; Wansley CC: 1,239 MW; Wansley Unit 9: 568 MW; Chattahoochee EF: 540 MW
Plant Type:	Two conventional coal-fired boilers with steam turbines and three combined cycle natural gas units
Date of Operation:	1976-1978; 2002; 2004 and 2003, respectively
Owner:	Plant Wansley: Georgia Power (53.5%), Oglethorpe Power (30%), MEAG (15.1%) and Dalton Utilities (1.4%); Plant Wansley CC: Georgia Power; Wansley Unit 9: MEAG; and Chattahoochee EF: Oglethorpe Power
Cooling Water Source:	Chattahoochee River and Service Water Reservoir (respectively)
Cooling Technology:	Recirculating with Induced Draft Cooling Tower; six towers in operation between 1976 and 2003
Water Withdrawal Permit(s):	074-1291-06 & 074-1291-07
Permitted Monthly Average:	116 MGD and 110 MGD (respectively)
GA WEN Study Baseline Modeling Notes:	Coal generation treated as coal with recirculating cooling (495 gallons of consumptive use per MWh of generation) and natural gas generation treated as NGCC with recirculating cooling (199 gallons of consumptive use per MWh of generation). Generation from fuel oil was not included because the generation from the fuel oil was de minimis and likely not water consumptive.


Plant Wansley, Wansley Combined Cycle, Wansley Unit 9 and Chattahoochee EF
Consumptive Water Use (MGD)
Electricity Generation (MWh)
0
5
10
15
20
25
30
35
0
500,000
1,000,000
1,500,000
2,000,000
2,500,000
3,000,000
Jan-02
Jun-02
Nov-02
Apr-03
Sep-03
Feb-04
Jul-04
Dec-04
May-05
Oct-05
Mar-06
Aug-06
Jan-07
Jun-07
Nov-07
Apr-08
Sep-08
Feb-09
Jul-09
Dec-09
May-10
Oct-10
Mar-11
Aug-11
Jan-12
Jun-12
Nov-12
Apr-13
Sep-13
Feb-14
Jul-14
Dec-14
May-15
Oct-15
Mar-16
Aug-16
Combined Generation - EIA (MWh)
GPC Reported Cons. Use
GA WEN Study Historical CU Estimate
GA EPD CUD

Plant Yates

Location:	Newnan, GA (Coweta Co.)
Nameplate Capacity (EIA):	807 MW
Plant Type:	Two natural gas boilers with steam turbines (Yates formerly had seven coal boilers with steam turbines - five were retired and two were converted to natural gas)
Date of Operation:	The first five Scherer units began operation in the 1950s and units six and seven began operation in 1974
Owner:	Georgia Power
Cooling Water Source:	Chattahoochee River
Cooling Technology:	Recirculating with Induced Draft Cooling Tower; two towers in service in 1974, five towers in service 2004
Water Withdrawal Permit(s):	038-1291-02
Permitted Monthly Average:	104 MGD
GA WEN Study Baseline Modeling Notes:	With respect to coal generation, we calculated that that all seven units operated as once-through cooling units until June 2004 (366 gallons of consumptive use per MWh of generation) and as recirculating systems thereafter (496 gallons per MWh). This makes our estimate slightly conservative in terms of total consumptive use. This pertains only to this historical comparison, because the units are now retired. For 2016, we used the same water use factor for the natural gas generation since, following conversion of units 6 and 7, natural gas was burned in the same configuration. We ignored the historic generation associated with fuel oil because it was de minimis (less than 1%).


Plant Yates
Consumptive Water Use (MGD)
Electricity Generation (MWh)
25
20
15
10
5
0
900,000
800,000
700,000
600,000
500,000
400,000
300,000
200,000
100,000
0
Jan-02
Jun-02
Nov-02
Apr-03
Sep-03
Feb-04
Jul-04
Dec-04
May-05
Oct-05
Mar-06
Aug-06
Jan-07
Jun-07
Nov-07
Apr-08
Sep-08
Feb-09
Jul-09
Dec-09
May-10
Oct-10
Mar-11
Aug-11
Jan-12
Jun-12
Nov-12
Apr-13
Sep-13
Feb-14
Jul-14
Dec-14
May-15
Oct-15
Mar-16
Aug-16
Combined Generation - EIA (MWh)
GPC Reported Cons. Use
GA WEN Study Historical CU Estimate
GA EPD CUD



Georgia Thermoelectric Consumptive Use
Consumptive Water Use (MGD)
250.0
200.0
150.0
100.0
50.0
0.0
Jan-02
Jun-02
Nov-02
Apr-03
Sep-03
Feb-04
Jul-04
Dec-04
May-05
Oct-05
Mar-06
Aug-06
Jan-07
Jun-07
Nov-07
Apr-08
Sep-08
Feb-09
Jul-09
Dec-09
May-10
Oct-10
Mar-11
Aug-11
Jan-12
Jun-12
Nov-12
Apr-13
Sep-13
Feb-14
Jul-14
Dec-14
May-15
Oct-15
Mar-16
Aug-16
GA WEN Study Historical CU Estimate
GA EPD CUD w/o Plant Franklin (AL)

Methodology Notes

The graphs above reflect four data series:

- Electricity generation data by plant.
- Georgia Water-Energy Nexus Study Historical Estimate.
- Georgia Power Reported Consumptive Use.
- Georgia Environmental Protection Division (EPD) Consumptive Use Database (CUD).

The sections below explain the methodology used to acquire and/or calculate each data series.

Electricity Generation Data

- Data Source is Energy Information Administration (EIA) Form 923.
- Extracted annual generation data by fuel type – Page 1 Generator and Fuel Data.
- Consolidated and summed data by month, by plant.
- Used coefficient factors to generation study consumptive use estimate by fuel type.
- For purposes of graphing – zeroed out any negative monthly generation numbers because it does not bear on/accurately reflect related water use.

Georgia Water-Energy Nexus Study Historical Estimate

- This value was calculated by multiplying the appropriate consumptive use factor from the study by the monthly generation.
- *Very Simple Plants* – For the following plants, EIA only reports generation by one fuel source. This monthly generation data was multiplied by the appropriate water use factor from Appendix A.
    - ***Vogtle*** (649)
    - ***Hatch*** (6051)
    - ***Thomas A. Smith*** (55382)
    - ***Effingham County PP*** (55406)
- Simple Plants
    - Coal and Fuel Oil Generation: For the following plants, EIA reports generation from coal and fuel oil. For the purposes of calculating the study consumptive use estimate, we multiplied the appropriate water use factor by the coal generation only. We ignored the generation associated with the fuel oil for two reasons. First, the generation from the fuel oil was de minimis (less than 1%). Second, we assume the fuel oil was burned in a start-up combustion turbine and did not consume cooling water.
        - ***Bowen*** (703)
        - ***Hammond*** (708)
        - ***Branch*** (709)
        - ***Mitchell*** (727)
        - ***Scherer*** (6257)

- ◦ ***Kraft*** (733) - For this plant, EIA reports generation by coal, by fuel oil and by natural gas. For the purposes of calculating the study consumptive use estimate, we multiplied the appropriate water use factor by the coal generation only.
  - ▪ We ignored the generation associated with the fuel for two reasons. First, the generation from the fuel oil was de minimis (less than 1%). Second, we assume the fuel oil was burned in a start-up combustion turbine and did not consume cooling water.
  - ▪ We ignored the generation from natural gas because this was generation from Unit 4 – a natural gas combustion turbine. We assume there is no cooling water use associated with this generation.
- ◦ ***Mid-Georgia Cogen*** (55040) – For this plant, EIA reported generation by natural gas and fuel oil. For the purposes of calculating the study consumptive use estimate, we multiplied the appropriate water use factor by the natural gas generation only. We ignored the generation associated with the fuel because it is de minimis (less than 1.5% over 15 years).

- Complex plants
  - ◦ ***McDonough*** (710) - The complexity of this plant arises from the fact that it installed cooling towers on existing coal units during the time horizon and it began operating natural gas combined cycle (NGCC) plants in late 2011 after many years of just using natural gas (NG) onsite for two small NG combustion turbines. EIA reports generation from coal, fuel oil and natural gas across the time horizon. The notes below explain how we calculated the study consumptive use estimate by generation type. The total study consumptive use estimate is the sum of the respective consumptive use estimates described below.
    - ▪ Coal Generation
      - Coal generation is reported from January 2002 to February 2012 (last month of operation of coal units).
      - Cooling towers for coal begin operation February (unit 1) and April (unit 2) 2008 (from Georgia Power report to EPD).
      - For purposes of calculating the study consumptive use estimate, we assume:
        - ◦ Coal units operate as once-through cooling from Jan. 2002 - April 2008.
        - ◦ Coal units operate as recirculating cooling from April 2008 - February 2012.
    - ▪ Natural Gas Generation
      - NG generation is reported across the entire time horizon.
      - It is de minimis prior to December 2011 - associated with units 3A and 3B (two 42 MW combustion turbines).

- The generation from NG increases dramatically in December 2011, reflecting the start of operation of the first NGCC unit.
- For purposes of calculating the study consumptive use estimate, we:
  - Ignore NG generation prior to December 2011 because it is de minimis and is associated with combustion turbine that requires no cooling water.
  - For NG generation after December 2011, we multiplied the generation by the NGCC rate.

- Fuel oil
  - We ignored the generation associated with fuel oil because it is de minimis and does not require cooling water.

- ***McIntosh*** (7140) ***& McIntosh CC*** (56150): the complexity of these plants arises because EIA reports generation from multiple fuels for both plants and both plants are behind one water withdrawal permit. The resolution of the first issue is described in the bullets below. The resolution of second issue is simply addressed by summing the respective consumptive uses of each plant to determine the total study consumptive use estimate for this permitted withdrawal.
  - Plant McIntosh
    - This plant includes one coal unit and eight natural gas combustion turbines.
    - EIA reports generation from coal, natural gas and fuel oil across the time horizon.
    - For the purposes of calculating the study consumptive use estimate, we multiplied the appropriate water use factor by the coal generation only.
    - We ignored the generation from the natural gas and fuel oil because we assumed these fuels were used in the combustion turbines, which require no cooling water.
  - Plant McIntosh Combined Cycle (CC)
    - For this CC unit, EIA only reports generation from natural gas. For the purposes of calculating the study consumptive use estimate, we multiplied this generation by the appropriate water use factor from the CNA memo.
- ***Wansley*** (6052), ***Wansley CC*** (55965), ***MEAG Unit 9*** (7946) and ***Chattahoochee Energy Facility*** (7917): the complexity of these plants arises because EIA reports generation from multiple fuels for one of the plants and all four plants are behind one water withdrawal permit. The resolution of the first issue is described in the bullets below. The resolution of second issue is simply addressed by summing the respective consumptive uses of each plant to determine the total study consumptive use estimate for this permitted withdrawal.
  - Wansley - For this plant, EIA reports generation by coal and fuel oil. For the purposes of calculating the study consumptive use estimate, we multiplied the

appropriate water use factor by the coal generation only. We ignored the generation associated with the fuel oil for two reasons. First, the generation from the fuel oil was de minimis (less than 1%). Second, we assume the fuel oil was burned in a start-up combustion turbine and did not consume cooling water.

    - Wansley CC - For this CC unit, EIA only reports generation from natural gas. For the purposes of calculating the study consumptive use estimate, we multiplied this generation by the appropriate water use factor from the CNA memo.
    - MEAG Unit 9 - For this CC unit, EIA only reports generation from natural gas. For the purposes of calculating the study consumptive use estimate, we multiplied this generation by the appropriate water use factor from the CNA memo.
    - Chattahoochee Energy Facility - For this CC unit, EIA only reports generation from natural gas. For the purposes of calculating the study consumptive use estimate, we multiplied this generation by the appropriate water use factor from the CNA memo.
- ***Yates*** (728): the complexity of this plant arises from (1) the fact that two of the seven units have had cooling towers since 1974, while the other five units were retrofitted with cooling towers in 2004; (2) EIA reports generation from coal, fuel oil and natural gas; and (3) five of the units were retired in 2015, while the remaining two were converted to natural gas boilers with steam turbines in that year. The bullet points below describe how we addressed these issues.
    - Background
        - Across the time horizon, up to March 2015, Plant Yates operated seven conventional coal boilers with steam turbines.
            - Five of these units (1-5) were built in the 1950s (680 MW nameplate capacity).
            - Two of these units (6 & 7) were built in 1974 (807 MW nameplate capacity).
        - The first five units operated as once-through units from inception until 2004, when Georgia Power installed induced draft cooling towers for these units.
        - Units 6 & 7 operated with induced draft cooling towers since they were built in 1974.
        - In 2015, Georgia Power retired units 15 and converted units 6 & 7 to natural gas boilers.
    - Cooling Technology Change
        - For the purposes of calculating the study consumptive use estimate related to the coal generation, we assume that all seven units operated as once-through cooling units until June 2004 and as recirculating systems

thereafter. This makes our estimate slightly conservative in terms of total consumptive use.

- Multiple fuels and fuel conversion
    - For the purposes of calculating the study consumptive use estimate, we multiplied the time-appropriate water use factor (see note above) by the natural gas and coal generation. To the extent natural gas was used in the units before 2015 or after the conversion of units 6 & 7 in 2015, it was burned in the same configuration (simple boiler with or without recirculating cooling) as the coal and has a similar water use factor. We ignored the generation associated with fuel oil because it was de minimis (less than 1%).

Georgia Power Reported Consumptive Use

- In response to a request to share any relevant thermoelectric water use data, Georgia EPD provided Cadmus with a series of reports submitted by Georgia Power and Southern Company that represent the companies' reporting of water withdrawals and consumptive water use at the plants they operate.
- We extracted this data and graphed the consumptive use by plant.
- While the current graphs only reflect seven years of this data (2010-2016 inclusive), the graphing so far demonstrates that these data are the same the data contained in the state's Consumptive Use Database.

Georgia EPD Consumptive Use Database (CUD)

- This data set contains monthly consumptive use values by plant/permit number.
- In some instances, the dataset contains more than one record (row) for a single permit. For instance, the dataset has four records for Plant Scherer. But, in each case where that is true, only one record has associated data. We have assumed this is aggregate data for the plant.
- We used this data directly for graphing purposes, without manipulation.

Appendix C: Georgia Power Water Research Center at Plant Bowen

Water Research Center at Plant Bowen

Georgia Power

Georgia Power opened its Water Research Center (WRC) in 2012 in partnership with the Electric Power Research Institute (EPRI), Southern Research Institute (SRI) and 14 other companies aligned with the power generation industry. It is the first U.S. research facility of its kind and its purpose is to explore and research water-dependent technologies associated with power generation. The center is dedicated to finding new ways to reduce water consumption and increase efficiency across the energy industry. The outcome of this pioneering research is analyzed to determine what works and what doesn't work to conserve water in very specific ways when generating electricity.

Research at the center focuses on seven distinct areas of study:

- **[Moisture Recovery:]** Researching innovative technologies and methods to recover moisture that would otherwise be consumed or lost through emissions "scrubbing," cooling tower plumes and flue gas.
- **[Cooling Tower and Advanced Cooling Systems:]** Examining new ideas for reducing cooling water use such as increasing cooling tower cycles of concentration, diverting or reducing cooling tower heat loads, assessing the feasibility and applicability of hybrid wet/dry cooling systems and more.
- **[FGD and Process Wastewater Treatment:]** Focusing on technologies to treat and reuse water from various waste sources throughout the plant – including flue gas desulfurization (FGD) discharges, cooling tower blowdown, floor drains and storm water runoff.
- **[Zero-Liquid Discharge:]** Exploring technologies that separate pollutant-bearing waters into a solid material that can be used or landfilled and a high-quality distillate that can be reused.
- **[Solid Landfill Water Management:]** Exploring water issues related to managing on-site landfills with the addition of new solids such as zero-liquid discharge salts and sludges.
- **[Carbon Technology Water Issues:]** Developing models to determine the impacts of various post-combustion, carbon-capture technologies on the use of water at the plant site to reduce the impact of carbon dioxide capture on plant water use.
- **[Water Modeling, Monitoring & Best Management Practices:]** Using results from each of the focus areas to model strategies for managing water use/reuse and to explore tools for evaluating overall water use (baseline and real time).

1

Water Research Center at Plant Bowen

The research conducted thus far at the WRC has enabled technological advancements in multiple areas. Presently, the primary focus is process wastewater treatment for compliance with the Steam Electric Effluent Limitations Guidelines (ELG) rule. In November 2015, the U.S. Environmental Protection Agency (EPA) released the final ELG rule establishing new "best available technology" (BAT) limits for several wastewater streams associated with coal-fired generating plants, including those facilities that have scrubbers. In the ELG rule, EPA set stringent scrubber wastewater discharge limits for arsenic, mercury, nitrate-nitrite and selenium and identified chemical precipitation followed by biological treatment as the BAT to meet these new limits.

Extensive studies began in 2014 at the WRC to evaluate several physical-chemical-biological treatment systems for their applicability to a large-scale coal-fired power plant. Research at the WRC showed that some systems were unable to consistently and reliably meet the new limits while others held more promise. Southern Company (parent company of Georgia Power) is testing pilot scale systems now with encouraging results.

In addition to informing technological strategies for achieving cost-effective environmental compliance, research at the WRC has also directly led to technology advancements for power plant operation. In 2014, EPRI conducted a study on ultraviolet (UV) water treatment technology at the WRC. UV treatment can be applied as a chemical-free alternative to traditional dechlorination of feedwater for the boiler. Feedwater must be dechlorinated to protect plant equipment from fouling and oxidation associated with chlorine naturally present in the water.

During its test period at the WRC, this technology effectively dechlorinated and disinfected the feedwater to purity levels within specifications for boiler feedwater. As a result, Plant Bowen implemented a full-scale demonstration of the UV technology to be used during normal plant operations, which has proven to be an advanced method for dechlorination, while also generating cost savings by eliminating the use of dechlorination chemicals.

About Georgia Power

Georgia Power is the largest electric subsidiary of Southern Company (NYSE: SO), America's premier energy company. Value, Reliability, Customer Service and Stewardship are the cornerstones of the company's promise to 2.5 million customers in all but four of Georgia's 159 counties. Committed to delivering clean, safe, reliable and affordable energy at rates below the national average, Georgia Power maintains a diverse, innovative generation mix that includes nuclear, coal and natural gas, as well as renewables such as solar, hydroelectric and wind. Georgia Power focuses on delivering world-class service to its customers every day and the company is consistently recognized by J.D. Power and Associates as an industry leader in customer satisfaction. For more information, visit www.GeorgiaPower.com and connect with the company on Facebook (Facebook.com/GeorgiaPower), Twitter (Twitter.com/GeorgiaPower) and Instagram (Instagram.com/ga_power).

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