Memphis and Tennessee Valley Authority

Risk Analysis of Future TVA Rates for Memphis

Prepared for Friends of the Earth

December 11, 2019

AUTHORS

David White, PhD
Kenji Takahashi
Melissa Whited
Shelley Kwok
Divita Bhandari

Synapse Energy Economics, Inc.

485 Massachusetts Avenue, Suite 2
Cambridge, Massachusetts 02139

617.661.3248 | www.synapse-energy.com

CONTENTS

EXECUTIVE SUMMARY

Memphis Light, Gas, and Water (MLGW) has historically obtained its electricity through a wholesale power contract with the Tennessee Valley Authority (TVA). Currently MLGW is engaged in an Integrated Resource Plan (IRP) process to determine whether to continue taking wholesale power from TVA or to procure electricity from elsewhere. During the IRP process, MLGW is comparing various alternative supply options against the cost of continuing to purchase power from TVA. This report contributes to the discussion by providing additional information regarding factors that could cause TVA's costs and wholesale electricity rates to increase well beyond historical levels.

TVA's rates have increased substantially over the last decade. From 2006 to 2018, TVA's electricity prices for MLGW increased by 30 percent.[1] This increase was, in part, driven by a 2013 decision by the TVA Board to increase rates by 1.5 percent per year to improve its operating margin, build new power plants, and reduce its debt burden.[2] Those rate increases have passed significant costs on to the Local Power Companies (LPC)—such as MLGW—and have resulted in concerns about further rate increases in the future. The rate increases have also encouraged LPCs to consider alternative electricity procurement options.

Recently, TVA indicated its intent to keep rates stable for 10 years, with contract terms that would cap rate increases.[3] Despite this stated intent, TVA could still increase rates at any time, particularly if costs rise. TVA has not made any firm guarantees that it will keep rates stable, and it is mandated by congressional charter to set rates sufficient to cover its costs. Furthermore, fuel costs are automatically passed through to customers in the monthly fuel cost adjustments, which are not included in any rate stability provisions. Thus, any cost increases will be passed on to its customers sooner or later. In fact, for the recently completed TVA fiscal year 2019, operating revenues increased by 1 percent despite lower sales,[4] resulting in the average energy cost for all TVA customers increasing from $70.05 to $71.43 per megawatt hour (an increase of 1.82 percent).[5]

This report investigates various risk factors that could have an adverse effect on TVA's costs and, thus, rates in the next 10 years. The purpose of this report is not to forecast future rates, as the probabilities of many uncertainties are unknown, but rather to examine the extent to which some factors could increase costs and rates above expectations. Synapse has reviewed extensive historical materials as well

---

[1] MLGW Annual Reports for 2008 to 2018.

[2] See, for example, page 13 of the TVA Budget Proposal and Management Agenda for FY 2017 and the rate schedule analysis in Appendix C of this report.

[3] For example, see Flessner, K, 2019c in report References.

[4] TVA Press Release of November 15, 2019. See: https://www.tva.gov/Newsroom/Press-Releases/TVA-Delivers-Strong-Financial-Results-and-Strengthens-Partnerships-in-FY-2019

[5] *Ibid*. 2018 sales were 160,339 million kWh and revenues were $11,233 million. 2019 sales were 158,443 million kWh and revenues were $11,318 million.

as forward-looking public materials and statements about expectations and plans in order to quantify the potential impact from several cost categories. We caution that we have not conducted an exhaustive review of all of the possible cost changes that TVA could experience but have instead focused on a relatively small number of potentially impactful cost categories.

We have identified five key risk factors that could have a substantial impact on TVA's rates. We did not assess the impacts of inflation except for the fossil fuel and carbon price cost categories. We note that the impacts of future inflation could be quite large for some cost categories such as operation and maintenance (which includes labor costs) and new plant additions. Synapse analyzed the five risk factors and roughly quantified the potential rate increases over the next 10 years in terms of a percentage of the current rates, as summarized below.

Figure E-1. Potential rate impacts due to risk factors for the next 10 years

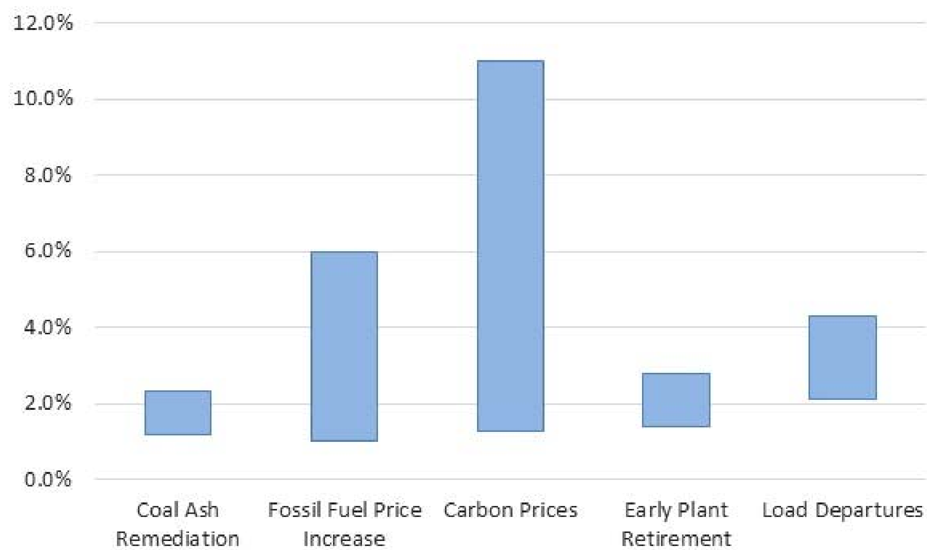


Table E-1. Potential rate impacts due to risk factors for the next 10 years

Risk Factor	Possible Cost /Rate Impact	Comment
Coal Ash Remediation	Roughly 1.2%–2.3%	Depends on to CCR treatment methodologies
Fossil Fuel Price Increase	1%–6%	Depends on many factors
Carbon Prices	1.25%–11%	Depends on carbon price and TVA generation mix
Early Plant Retirement	Roughly 1.4%–2.8%	For 2,000 to 4,000 megawatts of early coal retirement
Load Departures	Roughly 2.1%–4.3%	Depends on the magnitude of EE and DER adoption, as well as load departures and TVA's ability to reduce fixed costs

The likelihood of any individual risk factor is uncertain, but each represents a plausible circumstance that would increase TVA's costs and, consequently, its revenue requirements and rates. Based on our analysis of potential changes in this limited number of cost factors, we developed an overall estimate of the potential combined impacts for 2026 and 2031 for MLGW that represent a reasonable range of possible futures, taking into account the potential impacts for the five risk factors listed above over the next 10 years. Table E-2 shows the range of potential cumulative rate increases in 2026 and 2031 in percentage terms, while Table E-3 shows the range of potential annual power purchase cost increases for Memphis for those two years, based on Memphis' annual power procurements from TVA over the past several years at approximately $1 billion per year. We selected these two years because 2026 is the first year in which MLGW could be supplied with an alternative power supply and 2031 would be five years into a new power supply. Our analysis concludes that there are potential rate increase risks for MLGW customers ranging from 9 percent to 34 percent per year by 2031, for a total increase of approximately $90 million to about $340 million by 2031.

Table E-2. Memphis TVA potential rate increases (% relative to 2018 Rate)

Case / Year	2026	2031
High Scenario	21%	34%
Low Scenario	6%	9%

Table E-3. Memphis TVA potential power purchase cost increases ($ million)

Case / Year	2026	2031
High Scenario	$211	$343
Low Scenario	$56	$90

The probability of all five risk factors occurring at the same time is extremely low. However, the results of our risk analysis capture a plausible range of future price impacts for TVA power purchases for Memphis. We believe that this range is plausible in part because our analysis does not quantify many other risk factors that could also occur. Notably, a possible extreme situation not included here could be a nuclear accident that causes closure of some or all of TVA's nuclear plants. Another extreme situation would be total decarbonization of the power supply. In fact, one TVA IRP scenario assessed the latter possibility and it greatly increased costs and prices. Below we briefly describe some additional risk factors that we have identified but not quantified. Additional risk factors from TVA's 10-K report are listed in Appendix D.

- **TVA's retirement fund obligations:** TVA reports that as of September 2018, its pension plan had assets of $8.0 billion compared with liabilities of $11.7 billion. TVA states that while it made a contribution to the plan in 2018 of $300 million, it expects to pay more than $700 million in 2019.[6] The need to increase contributions to the pension plan could increase costs to LPCs.

- **Costs of nuclear waste and decommissioning costs:** Decommissioning costs could be in excess of funds previously collected, particularly if regulations governing closure and remediation become more stringent. Permanent storage of nuclear waste could also increase costs for TVA substantially. Although TVA has been storing spent fuel in anticipation that a final storage site for nuclear waste will be opened by the U.S. government, there is a very real possibility that no such site will be opened. In that case, TVA could be required to arrange for permanent storage itself, at great expense.[7]

- **Costs of and feasibility of modular nuclear reactors:** TVA has offered to be a test site for such reactors but not to finance them. Taking on financial responsibility for any type of new nuclear reactor could be a big risk.

- **Impact of TVA's debt cost increase:** TVA is currently enjoying historically low interest rates on its $21 billion debt. Higher interest rates could cause rate increases.

- **Impact of cost increases due to potential wage increases:** TVA employs nearly 10,000 individuals. Wage and salary increases would increase TVA's costs.

- **Impact of rising temperature on power plant operation:** This could reduce nuclear and coal plant operating efficiencies during summer periods, resulting in higher operating costs or even forcing these plants offline during heat waves.

- **Unplanned major capital expenses:** Some plants, especially nuclear plants, may require large capital expenditures to replace major equipment. In general, we expect that these costs are included in the TVA financial plans. Unexpected costs would however need to be covered with increased revenues.

[6] TVA 2019 10-K, p. 69.

[7] TVA 2019 10-K, p. 33.

1. BACKGROUND

1.1. Current Rates

In 2017, MLGW had approximately 433,000 electric retail customers and purchased 14,300 gigawatt hours (GWh) of electricity from TVA.[8] MLGW currently purchases all of its electricity and transmission services under a wholesale rate contract from TVA. In 2018 MLGW's electric purchases from TVA totaled $1,036 million.[9] MLGW is the single largest TVA customer and accounts for about 11 percent of TVA power sold to LPCs.[10]

TVA's charges to LPCs are specified in its *Wholesale Power Rate – Schedule WS*, which details charges for delivery points, demand, grid access, energy, time of use consumption, and fuel price adjustments. This schedule applies to all LPCs served by TVA, but depending on the specific services, the effective rate will vary somewhat by specific customer. Based on our analysis of TVA's 10-K filings, the average LPC aggregate rate in 2018 was $73.00 per megawatt hour (MWh).[11] Recent studies present similar TVA rates.[12] Based on our review of MLGW's annual reports, we estimate Memphis paid TVA roughly $1 billion or an average of $72.58 per MWh in 2018.[13]

In recent years, TVA has increased its rates to LPCs to improve its operating margin and to reduce its debt load. At the same time, it has reduced rates to its direct-serve industrial customers, allegedly to better align those rates with actual costs per TVA's 2015 cost of service study.[14] Since 2013, LPC rates have been increasing at 1.5 percent per year. At the same time, there has been a roughly equivalent decline in the fuel adjustment charges.[15]

---

[8] ICF. 2018. ICF Resources. 2018. Assessment of Wholesale Power Options for Memphis Light, Gas and Water - Preliminary Draft. p. 3.

[9] MLGW 2018 Annual Report.

[10] *Ibid.*

[11] TVA 10-K Sales and Revenue data presented in Appendix A of this report.

[12] For example, a 2018 study by ICF identified that the rate for MLGW was $74.00 per MWh in 2017, while the MLGW 2018 Annual Report shows that the cost was $74.00 per MWh, which probably includes some distribution losses. Note though that this does not fully reflect the TVA rate increase of 1.5 percent that occurred in October of 2018. *See:* ICF 2018, p. 3, and MLGW. *2018 Annual Report*, pp. M-13 and M-3. Purchased power costs: $1,035,989,000. Total kWh sales: 13,993,089 kWh.

[13] See Appendix F of this report.

[14] TVA. 2015. The 2013 Cost of Service is summarized in Appendix C of that document.

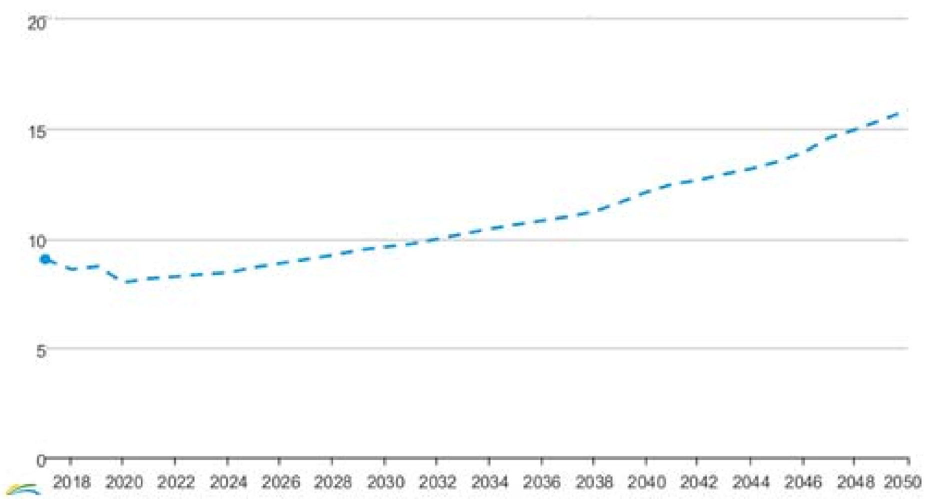
[15] See the Fuel expense line of the TVA Income Statement in Appendix A of our report.

1.2. Potential for Future Rate Increases

Several recent studies have reviewed MLGW's supply alternatives and projected TVA rates. For example, a 2018 study by ICF projected TVA rates rising to $95 per MWh in 2038, while a 2019 study by ACES projected TVA rates will increase to $100 per MWh in 2038.[16] The general consensus from these studies is that TVA's rates will increase by approximately 25 percent over 20 years. This translates into a rate increase of roughly 1.5 percent per year—a little below recent inflation rates of 2 percent. Neither study predicts a rate decline.

Although not directly related to TVA customers, the 2019 Annual Energy Outlook (AEO) produced by the U.S. Energy Information Administration (EIA) for this region predicts that end-use electricity prices will decline slightly through 2020, and then increase at about 2 percent per year roughly equivalent to the expected inflation rate. It is worth noting that the regional end-use prices are only a little above the expected TVA wholesale prices in the near term. This projection is shown in Figure 1-1.

Figure 1-1. 2019 AEO Reference Case SERC end-use electricity prices, all-sectors average



Source: U.S. Energy Information Administration Annual Energy Outlook 2019 data, available at https://www.eia.gov/outlooks/aeo/data/browser.

TVA is currently offering LPCs 20-year contracts that provide a rate discount of 3.1 percent.[17] However, it is not a rate freeze; rather, the agreement states "TVA is committed to provide Distributor power at rates as low as feasible under the Valley Public Power Model." There is, however, a rate adjustment protection clause which states that "[i]n the event the TVA implements rate adjustments that increase wholesale base rates by more than 5% within the next five years (ending FY2024) or 10% over any 5-year period within the initial 20 year term, the Parties will endeavor to negotiate new terms for 180 days

[16] ACES. 2019, p. 6.

[17] TVA. 2019c. Long-Term Partnership Proposal Term Sheet, TVA Discussion Draft 07-31-19. See Appendix E of this report.

after which the Distributor may reduce WPC notice provision to 10 years, which will immediately terminate this Amendment."

As such, rates may increase, but if they increase over the specified limits the LPC may reduce the contract term to 10 years. In this case, the LPC would lose the 3.1 percent discount. Thus, TVA's obligations are limited and rates could change in the future due to numerous risk factors that we discuss later.

We note that the contract terms also do not address changes in the monthly fuel cost adjustment charge, which is applied on top of the base rates and can be a significant portion of an LPC's charges. Further, it is not clear whether the structure of the rates themselves could be modified. Recently TVA added a "wires access charge" to the rate schedule while reducing the energy charges. Although this was presented as a revenue neutral change at the system level, it likely increased bills for some customers while reducing bills for others. Other similar changes in the future could be interpreted as keeping rates stable, although there might be disproportionate impacts on some customers, namely higher rates for Memphis and other LPCs and lower rates for TVA's industrial customers.

2. Risk Analysis of TVA's Costs and Rates

TVA is a very large electricity supplier operating more than 33,000 megawatts (MW) of generating facilities, including hydroelectric, coal, nuclear, and natural gas. These facilities represent significant financial investments, which TVA is recovering over time through rates charged to its customers. Changes in the operating costs of these facilities (including waste disposal and decommissioning) or changes in TVA's customer load could impact TVA's financial stability and cause it to raise its rates.[18]

Synapse conducted a risk analysis of factors that could substantially impact the rates that TVA charges its customers, including MLGW. We focused on five specific risk factors and attempted to quantify the range of impacts that each could have on TVA's rates. The five risk factors that we quantified are:

1. Coal Ash Remediation
2. Fossil Fuel Price Increase
3. Carbon Prices
4. Early Plant Retirement
5. Load Departures

There are other possible risk factors that we have not quantified, some of which we have listed at the end of this chapter. A fairly extensive list of possible risk factors is given in TVA's 2018 10-K SEC filing and is reproduced in Appendix D.

The starting point for our analysis is TVA's most recent data from the 2018 fiscal year. In FY 2018, TVA sales to LPCs were 140,873 million kilowatt hours (kWh) and the revenues were $10,262 million.[19] That corresponds to an average rate of $72.80 per MWh. To illustrate potential rate impacts, if an additional $100 million in costs were passed on to the LPCs, their effective rates would be increased by $0.71 per MWh, or 1.0 percent.[20]

We then assessed the above risk factors to calculate what the rate impacts would be if the additional costs were directly passed through to the LPC customers in rates. In general, we reviewed what the impacts could be approximately 10 years in the future. Our objective is not to predict what *will* happen, but rather to identify what could reasonably happen.[21] We conducted our assessment in comparison with a "Reference" case from the recent TVA IRP, which is the combination of the "Base Case" strategy

---

[18] The TVA Act requires TVA to charge rates for power that will cover its costs. Therefore, any increase in costs or reduction in load will eventually require TVA to increase its rates.

[19] TVA Sales and Revenue in Appendix A.

[20] $100 million / $10, 262 million = ~ 1.0 percent. To the extent that total revenues increase in the future the percentage impact of a given fixed cost will decline. But the estimated costs themselves may also increase.

[21] For example, a nuclear accident at a TVA plant could significantly increase the cost of nuclear operations. But we do not attempt to either assess the probability or cost impacts of such an event.

with the "Current Outlook" scenario.[22] While actual TVA strategy may differ from the IRP Base Case in the future, using this case provides a well-defined reference point for the cost impact calculations.

In addition to the specific risk factors discussed below, there are also general inflationary pressures on TVA's costs. This is especially true for operating and maintenance, which represented 28 percent of TVA's operating expenses in 2018.[23] Recent inflation has been roughly 2 percent per year. In the absence of cost reductions, TVA's overall cost increases because of inflation would be close to 1 percent per year.

2.1. Detailed Risk Analysis

1. Coal Ash Remediation (Coal Combustion Residuals)

The remediation of Coal Combustion Residuals (CCR) represents a large potential cost for TVA. CCR is contained in a number of TVA coal facilities, some of which have been closed, while some are intended to remain open during the life of the associated generation unit. Many of these facilities do not contain liners because they were constructed prior to the requirement that such facilities be built with liners.

Coal Combustion Residual Facilities

TVA has committed to a programmatic approach to the elimination of wet storage of CCRs within the TVA service area. Under the CCR Conversion Program, TVA has committed to (1) convert all operational coal-fired plants to dry CCR storage, (2) close all wet storage facilities, and (3) meet all applicable state and federal regulations.

The CCR Conversion Program is scheduled to be completed by 2023 with the exception of the impoundments at Gallatin. As of September 30, 2018, TVA had spent approximately $1.5 billion on the CCR Program. TVA is planning to spend an additional $1.2 billion on the CCR Program through 2023. This excludes new requirements related to the Gallatin CCR facilities lawsuits.[24] These estimates may change depending on the final closure method selected for each facility.

Further, coal ash residuals from Gallatin could impose significant additional environmental clean-up costs. TVA has been involved in litigation with regard to certain of these facilities and has been ordered to move all CCR material from unlined facilities at Gallatin Fossil Plant to a lined facility that will have to

---

[22] The TVA 2019 IRP results are summarized in Appendix B of this report. Note also that the IRP provides specific results for the years 2028 and 2038. In this analysis we will be focusing on 2028. Our Reference case is also labeled "A1" in the TVA materials.

[23] See TVA Income Statement in Appendix A. TVA 2018 O&M expenses were $2,527 million of total operating expenses of $8,921 million.

[24] TVA 2018 10-K, p. 66.

be constructed for that purpose. (Although a panel of the Sixth Circuit reversed this decision, the plaintiffs have petitioned for a rehearing.)[25]

TVA's own risk and financial analysis discloses the following background and potential financial costs associated with Gallatin CCR:

> At September 30, 2018, TVA has estimated these [Gallatin CCR facilities] costs to be approximately $900 million. The TVA Board approved regulatory accounting treatment for certain costs associated with compliance with orders or settlements related to lawsuits involving CCR facilities.[26]
>
> Offsite relocation for this or any other reason would materially increase TVA's project cost estimate. If TVA is required to use a facility offsite, then the costs could be approximately $2.0 billion, plus an amount of additional costs reflecting the expected impacts of inflation given the extended duration of an offsite relocation project.[27]

These factors indicate that the Gallatin facility CCR cleanup will be approximately $1.1 billion more than the estimated cost of $900 million. It is also possible that the $1.2 billion that TVA plans to spend on CCR conversion for other coal plants through 2023 is too low.

In order to assess the reasonableness of TVA's own CCR cost estimates, we have investigated estimated CCR costs from Duke Energy Carolinas and Dominion Virginia. Table 2-1 presents such estimates in terms of (a) average unit costs per cubic yard of coal ash by three different CCR clean-up methods and (b) potential total CCR costs for TVA. We estimated the potential total costs based on the CCR unit costs and TVA's own estimated coal ash amounts of 92.3 million cubic yards from its coal power plants.[28]

Unit costs differ widely by CCR treatment methods. The closure-by-removal approach is about twice as expensive as the closure-in-place approach. The cost estimates for beneficial use of CCR are even higher than these costs. Assuming Duke Energy's average costs of closure-by-removal method, the total costs for TVA would be about $3.6 billion. Assuming Dominion's beneficial use approaches, the total CCR costs for TVA could be much larger, ranging from $9.5 to $20 billion.

---

[25] TVA 2018 10-K, p. 33.

[26] TVA 2018 10-K, p. 71.

[27] TVA 2018 10-K, p. 66.

[28] Estimated coal ash amounts for TVA's each existing power plant are available at https://www.tva.gov/Environment/Environmental-Stewardship/Coal-Combustion-Residuals.

Table 2-1. Unit cost of CCR and potential total CCR costs for TVA

CCR Treatment Methods	Unit Cost ($/cubic yard)	Potential Total Cost for TVA ($ billion)	Source
Closure-in-place	$18	$1.7	Duke Energy
Closure-by-removal	$39	$3.6	Duke Energy
Beneficial Use - Low End	$103	$9.5	Dominion Virginia
Beneficial Use - High End	$224	$20.6	Dominion Virginia

Source: Duke Energy's CCR cost estimates available at https://deq.nc.gov/news/hot-topics/coal-ash-nc/coal-ash-closure-options-january-2019: Dominion Virginia. 2018. High Level Summary Coal Combustion Residuals Recycling/Beneficial Use Assessment Business Plan. Available at https://www.dominionenergy.com/library/domcom/media/about-us/electric-projects/coal-ash/ccr-recycling-beneficial-use-assessment-summary.pdf?la=en

TVA's own CCR estimates total about $4.7 billion ($1.5 billion spent to date on CCR Conversion Program + $1.2 billion for additional expected costs on the CCR program + $2.0 billion for potential CCR costs for Gallatin plant). While this total estimate is larger than the total cost using the average unit cost for Duke Energy's closure-by-removal method, it is important to note that many of CCR closure activities under review by TVA (which most likely influenced the TVA's own cost estimates) are closure-in-place.[29] Thus, there is a possibility that TVA's cost estimates are underestimated if it were required to use either the closure-by-removal method or the beneficial-use method for more of its coal power plants.

For the purpose of our risk analysis, we assume that the potential high-end total cost for TVA is $6.5 billion, a mid-point between Duke's closure-by-removal approach and Dominion's low-end beneficial-use estimate. This results in approximately $2.9 billion of additional costs beyond the cost ($3.6 billion) TVA has spent ($1.5 billion on CCR program) and is currently budgeting ($1.2 billion on CCR program + $0.9 billion for Gallatin) based on its 10-K financial filing.

Amortizing the total cost of $2.9 billion over 20 years would result in an additional annual cost of over $230 million, which would increase LPC rates by 2.3 percent.[30] For the potential low-end cost, we assumed the impact is half of the high-end impact or approximately $1.5 billion, slightly over what TVA estimated for potential additional CCR costs from Gallatin. This results in a potential rate impact of about 1.2 percent over the next 10 years.

We note that TVA continues to generate approximately 19 percent of its electricity from coal.[31] TVA expects to continue generating additional tons of coal ash that could materially impact future TVA power prices.

[29] This information is available at https://www.tva.gov/Environment/Environmental-Stewardship/Coal-Combustion-Residuals.

[30] The cost is amortized over 20 years using the current blended TVA interest rate of 4.81 percent (page 57 of TVA's 2018 10-K) resulting in an annual amortization rate of 7.9 percent.

[31] See Appendix A of this report.

2. Fossil Fuel Price Increases

TVA's generation mix as of 2018 is shown in Table 2-2. TVA generation approximately 39 percent of its supply by nuclear, 20 percent from natural gas or oil, and 19 percent from coal. In addition, TVA purchased 13 percent of its power, the majority from gas and coal generation.

Table 2-2. TVA 2018 power supply by generation source

	Energy (TWh)	Percent
Coal-fired	30.5	19%
Nuclear	62.5	39%
Hydroelectric	14.4	9%
Natural Gas and/or oil fired	32.1	20%
Combustion turbine and diesel generators	0.0	0%
Renewable resources (non-hydro)	0.0	0%
Total TVA Operated Generation Facilities	**139.5**	**87%**
Purchased power (non-renewable)	14.4	9%
Purchased power (renewable)	6.4	4%
Total Power Supply	**160.3**	**100%**

Source: Derived from the TVA 2018 10-K filing.

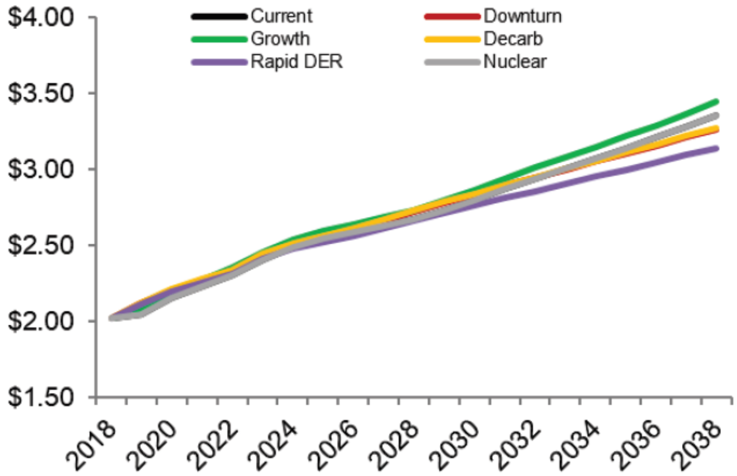
The reference case for TVA's IRP indicates that the expected generation mix in 2038 will be quite similar to the 2018 generation mix shown above, with a significant quantity of fossil generation.[32] Specifically, the TVA IRP reference case for 2038 includes 9.2 gigawatts (GW) of gas combustion turbine generation, 7.3 GW of gas combined cycle generation, and 5.0 GW of coal generation.[33] This quantity of fossil generation represents a substantial exposure to increases in fossil fuel prices.

Fossil fuel prices are expected to rise significantly over the next two decades. The TVA IRP projects that coal prices will increase by over 50 percent and natural gas prices will double by 2038 (as shown in Figure 2-1 and Figure 2-2). Increased fuel costs would be passed through to customers through the fuel adjustment charges, raising the total electricity costs for customers.

[32] The reference case is the Base Case Strategy, Scenario 1: Current Outlook.

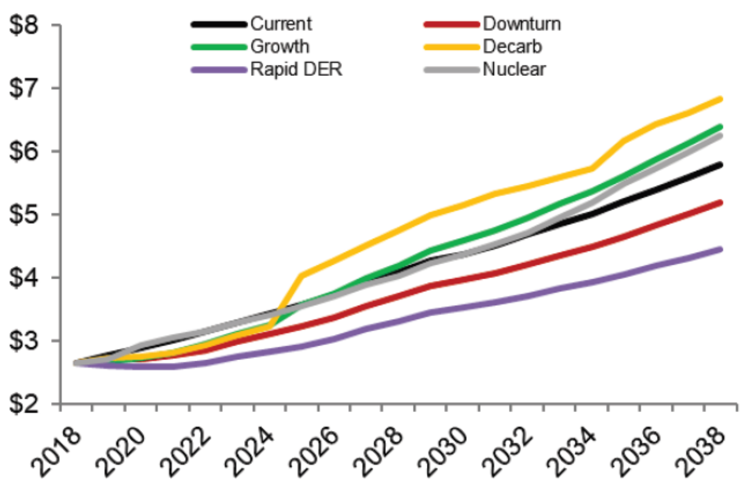
[33] TVA. 2019a., Figure G-1. Tabulated in table B-1 in report Appendix B.

Figure 2-1. TVA IRP coal price forecasts ($ nominal/MMBtu)



Source: TVA. 2019a. Figure 6-4.

Figure 2-2. TVA IRP gas price forecasts ($ nominal/MMBtu)



Source: TVA. 2019a. Figure 6-3.

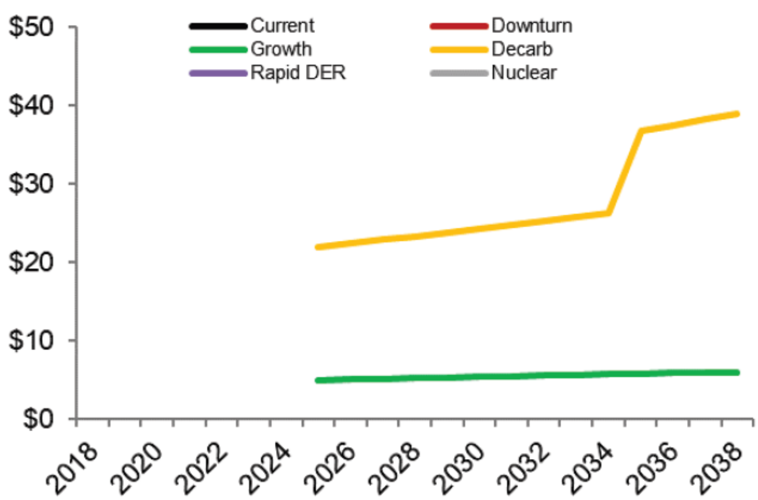
The mid-point price increases in 2028 are about 30 percent for coal and 25 percent for natural gas relative to 2018. If one takes the 2018 generation levels and applies the 2028 and 2038 mid-point fuel prices from the IRP, TVA would expect to incur increases in annual costs of $253 million and $821 million respectively—roughly 2.5 percent in 2028 and to 8 percent in 2038. If one looks at the 2028 price ranges in these TVA forecasts, the potential rate impacts in that year could range from 1 to 6 percent. There may be some offsetting savings, but these increased costs are substantial and indicate that customer prices could increase significantly. As noted above, because fuel cost adjustments are automatically passed on to the customer bills, any such increases require no changes in the rate schedule itself.

3. Carbon Price

As efforts increase to counteract global climate change, there is the likelihood that a price will be assigned to carbon emissions. In 2018 TVA produced 55,500 thousand tons of carbon dioxide (CO_2) emissions from its fossil generation.[34] This quantity will likely decrease over time with coal plant closures.[35] If some form of carbon pricing appears imminent, TVA could take further actions to reduce those emissions. Because uncertainty abounds about TVA's future CO_2 emissions and potential carbon prices, we have investigated a wide range of possible impacts.

The TVA 2019 IRP assumes no carbon prices for most of the scenarios including the reference case. One scenario uses a price of about $4 per ton starting in 2025 and increasing gradually over time. Another scenario assumes a price of about $21 per ton in 2025 increasing to about $40 per ton in 2040.[36] However some analyses indicate that prices of $100 per ton are needed to make a real difference in combating global warming.[37]

Figure 2-3. TVA CO_2 cost forecasts ($ nominal/ton)



Source: TVA. 2019a. Figure 6-6.

[34] As per the TVA IRP analysis CO_2 emissions will decline in most scenarios. For our Reference case, which is the Base Case strategy with the Current Outlook scenario (1A), CO_2 emissions decline from about 48,000 thousand tons in 2019 to 38,000 thousand tons in 2038. TVA IRP, Appendix I, CO_2 Metric Results, page I-2.

[35] We note though that the TVA IRP reference case still has 5 GW of coal in 2038. See figure B-5.

[36] TVA 2019 IRP, page 6-6.

[37] For example, in its February 2018 decision on requirements for Integrated Resource Plans, the California Public Utilities Commission (CPUC) found that a marginal abatement cost would of $150 per metric ton of avoided CO_2 would be required to meet the state's emissions reduction target. The CPUC therefore proposed a greenhouse gas price for planning purposes, rising to $150 per ton by 2030. *See:* California PUC, "Decision setting requirements for load serving entities filing Integrated Resource Plans," Rulemaking 16-02-007, issued February 13, 2018, at 105 and following.

We chose a range from \$5 to \$22 per ton of CO_2 in 2028 to represent the range of possible effects beyond the TVA reference scenario which assumes zero. The following table shows possible costs ranging from \$100 million to \$600 million per year (roughly a 1 to 6 percent cost increase). While the actual impacts are very uncertain at this time, it is likely that there will be some future cost impacts that will be passed on to the TVA customers. Even shifting away from fossil generation will result in costs for new zero-carbon resources.

We estimate that TVA's total CO_2 emission rate in 2018 is approximately 55 million tons based on TVA's CO_2 emissions rate of 346 tons per GWh and the total power supply in that year.[38] TVA plans to reduce the emission rate to 310 tons per GWh in 2020.[39] The TVA IRP reports future emissions for the Reference case of 43.2 million tons per year.[40] For other scenarios in the IRP, the average emissions range from 22.8 to 53.3 million tons per year. For our impact analysis we used a range of 25 million to 50 million tons of CO_2 as shown in Table 2-3. It is important to note that these estimates do not take into account any impacts from methane leaks from natural gas production and delivery.[41]

Table 2-3. TVA carbon cost impact estimates in 2028 (Million \$)

Emission	Million tons of CO_2	CO_2 Price (\$/ton) \$5	\$22	
High	50	250	1,100	\$ Million
Low	25	125	550	\$ Million

Note: Using 2031 CO_2 prices of \$24 per ton would produce slightly higher costs ranging from \$125 to \$1,200 million, roughly from 2.5 to 12 percent.

The possible impacts range from \$125 to \$1,100 million in 2028. Impacts of these magnitudes could increase costs and customer rates from 1.25 to 11 percent, and it is quite likely that such costs would increase further in the future.

4. Accelerated Depreciation of Coal and Nuclear Plant Retirements

Over the past several years, utilities have made substantial capital investments in coal plants to meet environmental regulations by the U.S. Environmental Protection Agency (EPA), the costs of which will continue to be recovered from customers over the coming years. Future CO_2 regulations may force additional coal plants to retire earlier than expected in the TVA IRP because there will be no cost-

[38] TVA. 2019d. FY 2020 Budget Proposal & management Agenda and FY 2018 Performance Report, page 38.

[39] *Ibid*.

[40] TVA. 2019a, page 7-22.

[41] A recent study published in the journal *Science* in 2018 found that the methane leakage rate from domestic oil and gas operations is about 2.3 percent of total production per year, which is 60 percent higher than the U.S. Environmental Protection Agency's estimate. This study is available at https://science.sciencemag.org/content/361/6398/186.

effective ways to reduce or remove CO_2 emissions from coal plants. Further, increasing levels of cost-competitive renewable energy generation could also lead coal plants to retire.

While retiring coal and nuclear plants is often the most economical option for utilities, these assets frequently have large undepreciated balances which can lead to near-term rate impacts. Specifically, early retirement of coal or nuclear plants could result in accelerated write-offs of the remaining asset values. In the TVA IRP reference case, there are no nuclear retirements as of 2038, and coal capacity is only reduced from 7.8 to 5 GW over the same period. Accelerated depreciation of any additional retirements would increase rates in the near term for TVA's customers.

In 2018 TVA carried $31.8 billion of net completed plant assets on its books, as shown in the following table by asset class.[42] Nuclear represented the largest category at $13.9 billion. The next largest category was for coal-fired plants at $5.4 billion, which actually increased by $0.3 billion from the previous fiscal year representing additional capital investments. The 2018 net asset value in terms of capacity comes to $700 per kilowatt (kW) for coal, $343 per kW for natural gas, and $1,740 per kW for nuclear.

Table 2-4. TVA 2018 completed plant asset value, as of September 30

	2018			2017		
	Cost	Accumulated Depreciation	Net	Cost	Accumulated Depreciation	Net
Coal-fired	$ 16,482	$ 11,033	$ 5,449	$ 15,937	$ 10,791	$ 5,146
Gas and oil-fired	5,990	1,459	4,531	4,995	1,359	3,636
Nuclear	25,227	11,310	13,917	25,010	10,834	14,176
Transmission	7,515	3,038	4,477	7,264	3,039	4,225
Hydroelectric	3,087	1,012	2,075	3,015	967	2,048
Other electrical plant	1,881	1,107	774	1,756	1,008	748
Intangible software	3	—	3	—	—	—
Multipurpose dams	900	367	533	928	387	541
Other stewardship	29	9	20	42	19	23
Total	$ 61,114	$ 29,335	$ 31,779	$ 58,947	$ 28,404	$ 30,543

Source: TVA 2018 10-K, p. 94.

As mentioned previously, the TVA reference case keeps 5 GW of coal and 8.3 GW of nuclear operational in 2038. In 2018 those resources represented $19.4 billion in assets. If any of those resources were to be retired earlier, TVA would likely take accelerated depreciation on those assets before the closing of the resources.[43] To illustrate, if 2,000 MW of coal is retired early, it would result in a net plant write-off (based on 2018 values) of approximately $1,400 million. Taking that write-off over 10 years represents

[42] TVA 2018 10-K, Balance Sheet.

[43] Per TVA 2014 10-K filing on page 91, TVA adjusts depreciation rates so that any retiring generating "units will be fully depreciated by the applicable idle dates."

an expense of $140 million per year. In terms of costs and rate impacts, this translates to roughly a 1.4 percent rate increase.

For the purpose of our risk analysis, we adopt this 1.4 percent rate increase as the potential low-end annual rate impact from early retirements of existing coal power plants. For the potential high-end rate impact, we assume twice the level of early retirements (approximately 4,000 MW) depreciated over 10 years, which results in a potential rate impact of 2.8 percent.

These specific calculations are purely hypothetical, but coal plants are under various pressures and additional retirement of TVA coal plants in the next 10 years is a possibility. The same could hold true for nuclear plants as well.[44]

5. Load Reductions or Departures Due to Distributed Energy Resources and Other Factors

At a basic level, electricity rates are determined by dividing total costs by electricity sales. TVA's current outlook in its latest IRP Current Outlook scenario projects that its electricity load will remain almost flat over the next 20 years.[45] However, sales could decline or even increase, depending on a variety of factors, which would then impact electricity rates. If costs remain the same but sales decline, rates will necessarily rise in order to collect the necessary revenue to cover costs. Common reasons that sales decline are industries departing the region, customer adoption of energy efficiency technologies, and customer adoption of distributed energy resources (DERs) such as behind-the-meter solar and combined heat and power.

TVA has opened the door for its LPC customers to install DERs. The 2019 TVA Long-Term Partnership term sheet states that "TVA will commit to providing enhanced flexibility for distribution solutions between 3-5% of load by October 1, 2021." Future increases in that DER limit are also possible.

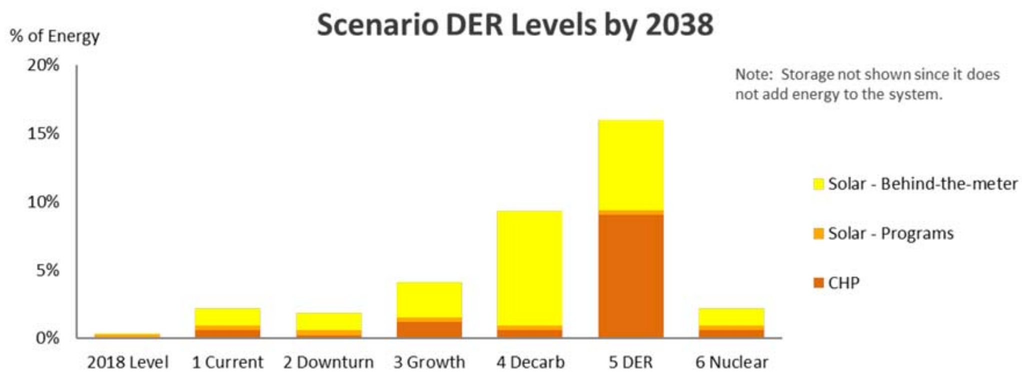
TVA's 2019 IRP projects that the penetrations of DERs under TVA territory would reach a level of approximately 2 percent under the current trend. The TVA IRP also presents other scenarios including "Growth" and "DER" in which DERs reach 4 and 15 percent of energy respectively by 2038, as shown in Figure 2-4.[46]

[44] However, these potential cost increases could be offset with lower cost resources such as renewable resources

[45] Figure B-5 in Appendix B of this report.

[46] TVA. 2019a. Figure C-2.

Figure 2-4. Projections of DER in TVA's territory under various IRP scenarios



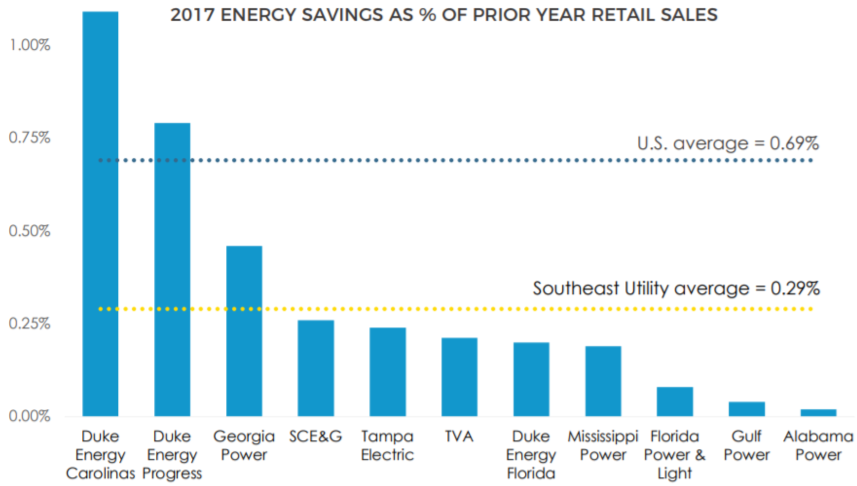
Source: TVA. 2019a. 2019 Integrated Resource Plan, Volume 1 – Final Resource Plan.

Furthermore, there are likely to be load reductions due to the effects of energy efficiency programs. The current level of load reductions under TVA's territory is about 330 GWh per year or about 0.2 percent of sales.[47] If the level of energy efficiency activities remains the same over the next 10 years, the cumulative impact on TVA's energy sales would reach about 2.5 percent. However, this level of savings is one of the lowest levels in the nation. Leading states have been saving energy at 2 to 3 percent per year.[48] In the Southeast, Duke Energy Carolinas has been expanding its energy efficiency programs over the past several years and now reached a level over 1 percent per year. If we assume that energy efficiency activities by LPCs in TVA's territory collectively achieve 1 percent per year annual savings over the next 10 years, the cumulative impact would reach about 6 percent during this time frame.

[47] SACE. 2018. *Energy Efficiency in the Southeast - 2018 Annual Report.* Available at https://cleanenergy.org/wp-content/uploads/2018-Energy-Efficiency-in-the-Southeast-SACE.pdf.

[48] See ACEEE's the State Energy Efficiency Scorecard reports. Available at https://aceee.org/state-policy/scorecard.

Figure 2-5. Efficiency program performance of major southeastern utilities in 2017



Source: SACE. 2018. Energy Efficiency in the Southeast - 2018 Annual Report.

Some industries or other LPCs may decide to leave TVA altogether, like Memphis is now considering. This is more likely for the larger customers on TVA's borders with access to other systems, such as Bowling Green, Kentucky or Bessemer in Alabama. Excluding the potential impact of departures of any LPCs, the total load impact from energy efficiency and DERs could range from 4 percent to 8 percent over the next 10 years and 5 percent to about 13 percent by 2031 based on the assumptions we discussed above on energy efficiency and DER. Table 2-5 presents our estimates of potential load impacts for 2026, 2028, and 2031. The impacts of DER are based on TVA IRP's scenario analysis for the Growth scenario and the DER scenario.

Table 2-5. Potential load reduction impacts due to energy efficiency and DER

	2026	2028	2031
High	6%	8%	13%
Low	3%	4%	5%

If TVA loses sales, rates for the remaining customers could increase because of the need to continue to recover operational and fixed costs. The extent to which this might happen is uncertain, and TVA can to some extent reduce costs as load declines. A full TVA financial and operational model would be needed to do a complete analysis. However, TVA's recent operating expenses can provide a rough estimation.

Table 2-6 shows TVA's FY 2018 operating expenses. The first two categories (fuel and purchased power) are fairly responsive to changes in load and represent 34 percent of the operating expenses. Expenses in the third category (operating and maintenance) can be reduced as generation is reduced, but also represent substantial fixed costs for operating and maintaining the plants. The last two categories represent fixed costs given current sales.

Table 2-6. TVA FY 2018 operating expenses

	Million $	Percent
Fuel	$ 2,049	23%
Purchased power	$ 973	11%
Operating and maintenance	$ 2,854	32%
Depreciation and amortization	$ 2,527	28%
Tax equivalents	$ 518	6%
Total operating expenses	$ 8,921	100%

Source: TVA 10-K; also see Sales and Revenue and Income statements in Appendix A of this report.

About half of TVA's operating expenses (operating and maintenance, depreciation and amortization, and tax equivalents) are somewhat inflexible to short-term changes in loads. In the longer term, operations and maintenance (O&M) expenses specifically could be reduced by closing facilities but might require a capital write-off. Based on the somewhat inflexible nature of some of the TVA expense categories, we estimate rate impacts from the potential load reductions as presented in Table 2-5 above. The magnitudes of the load losses and cost impacts will likely increase over time.[49] Looking at 2028, an 8 percent load reduction in the high case as given in Table 2-5 could reduce revenue by about 4 percent and increase rates by 4.3 percent, and a 4 percent load reduction under the low case could reduce revenue by about 2 percent and increase rates by 2.1 percent.

To the extent that load reductions occur over a number of years, TVA could retire plants and make other cost reductions to reduce the rate impacts. But the general issue is how rapidly TVA could reduce expenses if sales were to decline. There is likely to be some lag in doing so, and therefore a cost increase for the remaining load.

[49] A 13 percent load reduction under the high case as given in Table 3 could reduce revenue by about 6.4 percent and increase rates by 7.4 percent, and a 5 percent load reduction under the low case could reduce revenue by about 2.5 percent and increase rates by 2.6 percent.

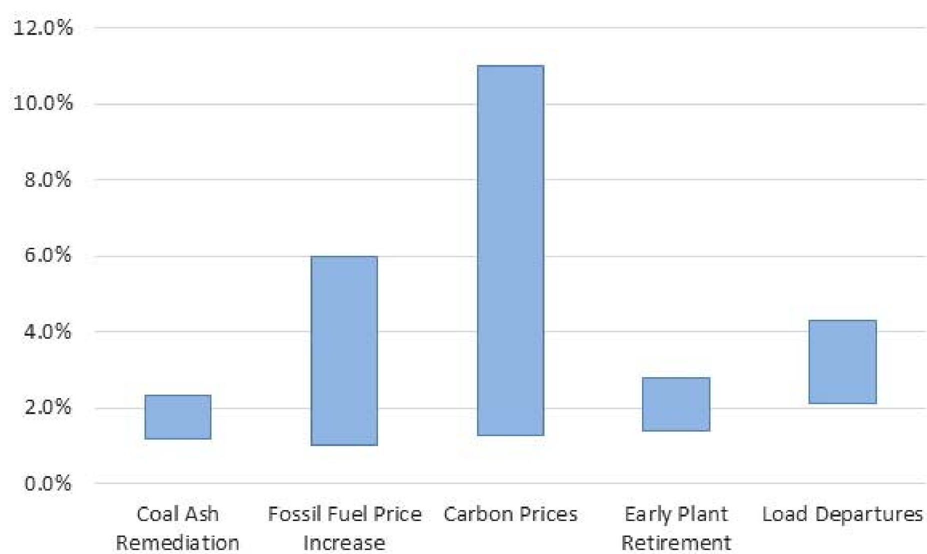
2.2. Summary of Potential Rate Impacts due to Risk Factors

We have only quantified a few of the possible risk factors that could increase TVA's costs, and thus rates, which we summarize in Table 2 7 and Figure 2 6. The time scale of these factors varies by risk factor.

Table 2-7. Summary of potential rate increase risks for the next 10 years

Risk Factor	Possible Cost /Rate Impact	Comment
Coal Ash Remediation	Roughly 1.2%–2.3%	Depends on CCR treatment methodologies
Fossil Fuel Price Increase	1%–6%	Depends on many factors
Carbon Prices	1.25% - 11%	Depends on carbon price and TVA generation mix
Early Plant Retirement	Roughly 1.4% - 2.8%	For 2,000 - 4,000 MW of early coal retirement.
Load Departures	Roughly 2.1% - 4.3%	Depends on magnitude of EE and DER adoption, as well as load departures and TVA's ability to reduce fixed costs.

Figure 2-6. Potential rate impacts due to risk factors for the next 10 years



In addition to these five factors, there are many other potential circumstances which could affect TVA's rates. We discuss several of these factors qualitatively in the next section.

2.3. Other Risk Factors

There are numerous other risk factors that could result in higher costs for TVA, and therefore higher rates for TVA's customers. Below we briefly describe some of these risk factors, although we have not quantified the potential impact of these factors on TVA's rates. Nevertheless, they should be taken into account when evaluating power supply options. Additional risk factors from the TVA 10-K report are listed in Appendix D.

- **TVA's retirement fund obligations:** TVA reports that as of September 2018, its pension plan had assets of $8.0 billion compared with liabilities of $11.7 billion. TVA states that while it made a contribution to the plan in 2018 of $300 million, it expects to pay more than $700 million in 2019.[50] The need to increase contributions to the pension plan could increase costs to LPCs.

- **Costs of nuclear waste and decommissioning costs:** Decommissioning costs could be in excess of funds previously collected, particularly if regulations governing closure and remediation become more stringent. Permanent storage of nuclear waste could also increase costs for TVA substantially. Although TVA has been storing spent fuel in anticipation that a final storage site for nuclear waste will be opened by the U.S. government, there is a very real possibility that no such site will be opened. In that case, TVA could be required to arrange for permanent storage itself, at great expense.[51]

- **Costs of and feasibility of modular nuclear reactors:** TVA has offered to be a test site for such reactors but not to finance them. Taking on financial responsibility for any type of new nuclear reactor could be a big risk.

- **Impact of TVA's debt cost increase:** TVA is currently enjoying historically low interest rates on its $21 billion debt.[52] Higher interest rates could cause rate increases.

- **Impact of cost increases due to potential wage increases:** TVA employs nearly 10,000 individuals. Wage and salary increases would increase TVA's costs.

- **Impact of rising temperature on power plant operation:** This could reduce nuclear and coal plant operating efficiencies during summer periods, resulting in higher operating costs or even forcing these plants offline during heat waves.

- **Unplanned major capital expenses:** Some plants, especially nuclear plants, may require large capital expenditures to replace major equipment. In general, we expect that these costs are included in the TVA financial plans. Unexpected costs would however need to be covered with increased revenues.

---

[50] TVA 2019 10-K, p. 69.

[51] TVA 2019 10-K, p. 33.

[52] See Appendix A.5 of this report for details.

3. TVA RATES FOR MEMPHIS

Memphis currently purchases its electric power from TVA under a wholesale power contract. What might those prices look like in the future?

We analyzed five possible risk factors that could increase TVA's costs. While the likelihood of any one scenario is uncertain, each represents a plausible circumstance that would increase TVA's costs and rates. We also qualitatively discussed seven additional cost factors in the previous section. Additional risk factors from the most recent TVA 10-K filing are listed in Appendix D.

Two key considerations need to be kept in mind: (1) TVA has the option of deferring costs when setting rates so that costs may not immediately impact rates but have to be added later, and (2) we have only roughly quantified five out of many more possible risk factors.

Although the probability of each risk factor is unknown and many other factors could impact rates, we have developed an overall estimate of the potential combined impacts for 2026 and 2031 below in Table 3-1 and Table 3-2. These tables show the range of potential impacts in terms of rate increases as a percentage of the 2018 rate and in terms of potential annual power purchase cost increases for Memphis. We derived these estimates based on our estimates of the five risk factors over the next 10 years. We selected these two years because 2026 is the first year in which MLGW could be supplied with an alternative power supply and 2031 would therefore be five years into a new power supply. Our analysis concludes that there are potential risks of rate increases for MLGW customers ranging from 9 percent to 34 percent per year by 2031, which are translated into $90 million to about $340 million by 2031.

Table 3-1. Memphis TVA potential rate increases (% relative to 2018 Rate)

Case / Year	2026	2031
High Scenario	21%	34%
Low Scenario	6%	9%

Table 3-2. Memphis TVA potential power purchase cost increases ($ million)

Case / Year	2026	2031
High Scenario	$211	$343
Low Scenario	$56	$90

While the chance of all five factors occurring at the same time is very small, the results of this risk analysis represents a plausible range of future price impacts for TVA power purchases for Memphis. This is partly because our analysis excludes many other risk factors we identified in this report. Notably a possible extreme situation, not included here, could be a nuclear accident that causes closure of some or all of TVA's nuclear plants. Another extreme situation would be total decarbonization of the power supply. In fact, one TVA IRP scenario assessed the latter possibility and it greatly increased costs and prices.

4. SUMMARY AND CONCLUSIONS

TVA has made recent assertions, but no guarantees, of stable rates for up to 10 years. We investigated a number of possible factors that could have an adverse effect of TVA's costs and, thus, rates. We found the following expected range of rate increases for each risk factor:

1. **Coal Ash Remediation:** Roughly 1.2%–2.3%
2. **Fossil Fuel Price Increase:** 1%–6%
3. **Carbon Prices:** 1.25%–11%
4. **Early Plant Retirement:** Roughly 1.4%–2.8%
5. **Load Departures:** Roughly 2.1%–4.3%

All of these factors would detrimentally affect TVA prices to Memphis. In the unlikely event that all of these factors were combined, we would expect rates could be increased by approximately 6 percent to 21 percent in 2026 and approximately 9 percent to 34 percent in 2031 relative to the rates TVA's IRP base case would suggest.

References

ACES. 2019. *Memphis Light, Gas and Water Long-Term Portfolio Considerations*, prepared for Memphis Light, Gas and Water (MLGW).

Brattle Group. 2019. *Power to Memphis – Options for a Reliable, Affordable and Greener Future*, prepared for Friends of the Earth.

Flessner, K. 2019a. "TVA completes upgrades at its oldest and biggest nuclear power plant, boosting output," *Times Free Press*, August 5, 2019.

Flessner, K. 2019b. "TVA's new power plan for the future focuses on technology, not more generation," *Times Free Press*, August 22, 2019.

Flessner, K. 2019c. "TVA offers rebates to local power companies that sign long-term contracts with TVA," *Times Free Press*, August 22, 2019.

Flessner, K. 2019d. "Study says solar cheaper than TVA," *Times Free Press*, September 11, 2019.

Flessner, K. 2019e. "TVA coal ash cleanup to cost billions of dollars and decades to complete, officials say," *Times Free Press*, September 14, 2019.

Flessner, K. 2019f. "Most TVA distributor get rebates for extending purchase agreements," *Times Free Press*, September 30, 2019.

Gaines, J. 2019. "TVA says power rates will freeze to current rate for 10 years," *Knoxville News Sentinel*, August 23, 2019.

GDS Associates. 2019. *Evaluation of Long-Term Power Supply Alternatives*, prepared for Memphis Light, Gas and Water (MLGW).

ICF Resources. 2018. *Assessment of Wholesale Power Options for Memphis Light, Gas and Water - Preliminary Draft*, prepared for FHL Company.

Memphis Light, Gas and Water. 2008-2018. *Annual Report*. Available at http://www.mlgw.com/about/annualreport.

SACE. 2018. Energy Efficiency in the Southeast - 2018 Annual Report.

Siemens. 2019a. *Integrated Resource Plan and Transmission Analysis PSAT Meeting*, August 2019 for MLGW.

Siemens. 2019b. *Integrated Resource Plan and Transmission Analysis PSAT Meeting*, September 2019 for MLGW.

Tennessee Valley Authority. 2008-2018. *10-K Annual Report*, submitted to the U.S. Securities and Exchange Commission.

Tennessee Valley Authority. 2015. *Refining the Wholesale Pricing Structure, Products, Incentives and Adjustments for Providing Electricity to TVA Customers – Final Environmental Assessment*, July 2015.

Tennessee Valley Authority. 2019a, *2019 Integrated Resource Plan, Volume 1 – Final Resource Plan*, August 2019.

Tennessee Valley Authority. 2019b, *2019 Integrated Resource Plan, Volume 2 – Final Environmental Impact Statement*, August 2019.

Tennessee Valley Authority. 2019c. Long-Term Partnership Proposal Term Sheet, TVA Discussion Draft 07-31-19

Tennessee Valley Authority. 2019d. *FY 2020 Budget Proposal & Management Agenda and FY 2018 Performance Report*, submitted to the U.S. Congress.

Whited, M., T. Woolf. 2018. *Electricity Prices in the Tennessee Valley*, Synapse Energy Economics for the Southern Alliance for Clean Energy.

Memphis power supply related documents can be found at http://www.mlgw.com/about/powersupply.

The TVA IRP materials can be found at https://www.tva.gov/Environment/Environmental-Stewardship/Integrated-Resource-Plan.

Appendix A. TVA Financial Statements

A.1 TVA Sales and Revenues

A.2 TVA's Power Supply

A.3 TVA Operating Income and Expenses

A.4 TVA Cash Flow

A.5 TVA Balance Sheet

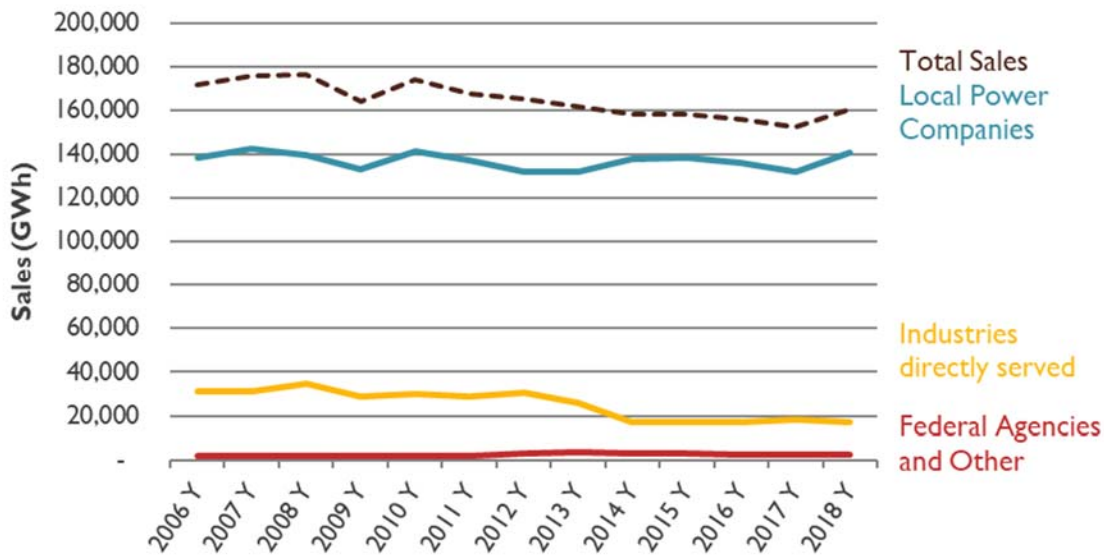
All TVA data is for the TVA Fiscal Year that ends on September 30.

A.1. TVA Sales and Revenues

The Tennessee Valley Authority (TVA) is a public entity established in the 1930s to foster economic development of the region. TVA's initial efforts focused on hydroelectric power and infrastructure development. Now it is primarily a wholesale provider of electric power to local (public) power companies. TVA also serves some direct industrial and federal governmental loads. Most of the current electric generation is from nuclear and coal power, with a recent move into natural gas.[53]

The following table shows 20 years of sales by TVA. Over this period, there has been a general decline in total and direct industry sales. The LPC sales have been relatively flat with the variations from year to year primarily weather-related. Currently LPCs represent about 88 percent of TVA's sales.[54]

Figure A-1. TVA historical sales



Source: TVA Form 10-K filings.

Most of the LPC customers have full requirements long-term contracts, so TVA is not very exposed to short-term market conditions. Those contracts also have fuel adjustment clauses, so the customers, rather than TVA, are exposed to fuel price risks. The full requirements service includes energy, transmission, ancillary services, and capacity, but not distribution.

[53] See TVA Power Supply table in Appendix A.

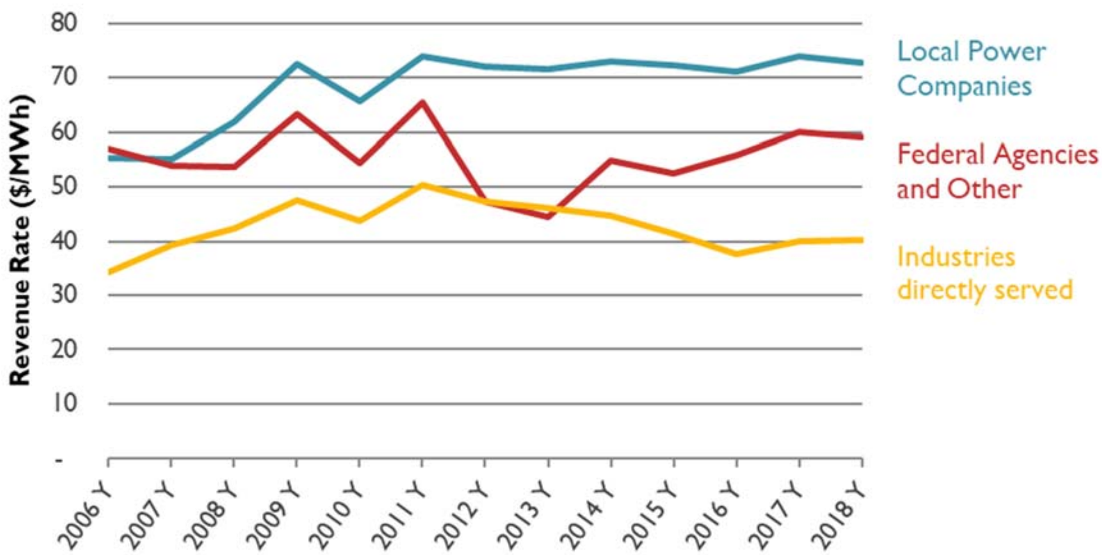
[54] Unless otherwise indicated, TVA financial information is for the TVA Fiscal Year ending September 30.

TVA as a public entity does not issue equity but finances its operations with revenue from the sale of power and through the issuance of debt (bonds).

TVA is essentially self-regulated and has great flexibility in its operations, investments, and rates. However, it is required by its charter to set rates adequate to cover its costs.

Figure A-2 shows effective revenue rates[55] (revenue divided by sales) for TVA's major customer classes since 2006. These rates for both LPCs and directly served industries increased substantially from 2006 to 2011, with average LPC charges increasing from $55.30 per MWh in 2006 to $72.80 per MWh in 2018, an increase of 32 percent over 12 years.

Figure A-2. Effective revenue rates by customer class



Source: TVA Form 10-K filings

[55] Rather than delve into the details of the rate schedules and fuel adjustment charges, our analysis focuses on the bottom line revenue and sales values as reported in TVA's 10-K filings.

Table A-1. TVA sales and revenue

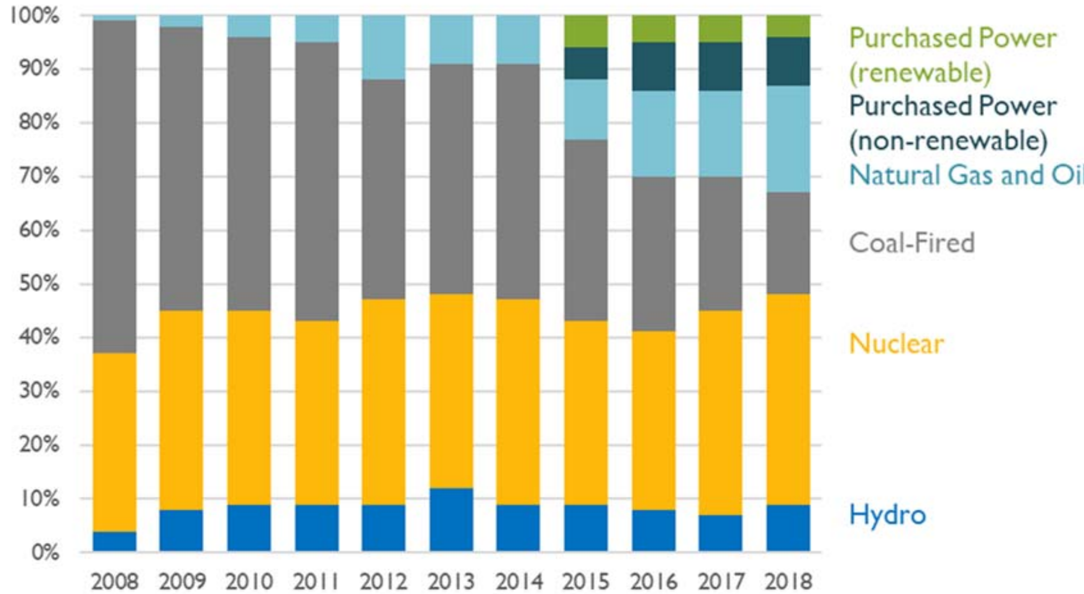
	2014 Y	2015 Y	2016 Y	2017 Y	2018 Y
Sales (millions of kWh)	158,057	158,163	155,855	152,362	160,338
Local power companies	137,772	138,394	136,213	131,849	140,873
Industries directly served	17,417	16,955	17,240	18,317	17,278
Federal agencies and other	2,868	2,814	2,402	2,196	2,187
Revenue from sales of electricity (million $)	10,999	10,847	10,461	10,586	11,075
Local power companies	10,062	9,998	9,696	9,741	10,262
Industries directly served	780	701	649	735	695
Federal agencies and other	157	148	134	132	129
Revenue from sales of electricity ($/MWh)	69.6	68.6	67.1	69.5	69.1
Local power companies	73.0	72.2	71.2	73.9	72.8
Industries directly served	44.8	41.3	37.6	40.1	40.2
Federal agencies and other	54.7	52.6	55.8	60.1	59.0

Source: TVA 10-K filings.

A.2. TVA's Power Supply

Figure A-3 shows how TVA's power supply has changed substantially over the last 10 years. The most significant change has been in coal-fired generation, which has declined from 62 to 19 percent over the past decade. There has been a modest increase in nuclear generation associated with the opening of a new nuclear plant. Natural gas generation has increased from zero to 20 percent. There have been significant increases in purchased power in the last four years up to about 13 percent. The non-renewable purchases represent 9 percent of the supply and represent a mix of natural gas and coal generation. TVA's renewable energy of 13 percent consists of 9 percent from its own hydro and 4 percent from purchases (which are a mix of wind, hydro, and solar).[56]

Figure A-3. TVA power supply – 2008 through 2018



Source: TVA 10-K, 2008-2018.

[56] TVA 2018 10-K, Power Purchase Contracts, p. 16.

TVA's peak load in 2018 was 32,509 megawatts (MW). This was above the peaks of 2016 and 2017, but below those of 2014 and 2015.[57] TVA is a dual-peaking utility with similar peaks in both the winter and summer. Its generating capacity in 2018 was 37,514 MW, as shown in Table A-2. This shows TVA has a fairly typical reserve margin of about 15 percent. TVA resources represent 89 percent of the total capacity, and the contract resources account for 11 percent. Combustion turbines represent a large portion of the capacity but are only used rarely. Comparing this with the above supply figure, one can see that proportionally more generation comes from nuclear and natural gas than from coal.

Table A-2. Summer Net Capability - September 30, 2018

	Capability (MW)
TVA Resources	
Nuclear	7,723
Coal-Fired	7,886
Natural Gas & Oil	
Combustion Turbines	5,713
Combined Cycle	6,778
Hydroelectric	5,398
Other	10
Total TVA	33,526
Contract Renewables	314
Power Purchase Agreements	3,674
Total Summer Net Capability	**37,514**

Source: Derived from the TVA 2018 10-K filing, page 43.

[57] TVA 2018 10-K, Selected Financial Data, p. 46.

Table A-3. TVA power supply by generation source

Power Supply by Generation Source	Percent									
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Coal-fired	62%	53%	51%	52%	41%	43%	44%	34%	29%	25%	19%
Nuclear	33%	37%	36%	34%	38%	36%	38%	34%	33%	38%	39%
Hydroelectric	4%	8%	9%	9%	9%	12%	9%	9%	8%	7%	9%
Natural Gas and/or oil fired	0%	0%	4%	5%	12%	9%	9%	11%	16%	16%	20%
Combustion turbine and diesel	1%	2%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Renewable resources (non-hyd	< 0.01	< 0.01	< 0.01	< 0.01	< 0.01	< 0.01	< 0.01	0%	0%	0%	0%
Total TVA Operated Generatio	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**88%**	**86%**	**86%**	**87%**
Purchased power (non-renewa	0%	0%	0%	0%	0%	0%	0%	6%	9%	9%	9%
Purchased power (renewable)	0%	0%	0%	0%	0%	0%	0%	6%	5%	5%	4%
Total Power Supply	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Power Supply by Generation Source	GWh										
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Coal-fired	109,308	86,816	88,568	87,220	67,755	69,628	69,545	53,775	45,198	38,091	30,464
Nuclear	58,180	60,607	62,518	57,028	62,797	58,293	60,062	53,775	51,432	57,898	62,532
Hydroelectric	7,052	13,104	15,630	15,096	14,873	19,431	14,225	14,235	12,468	10,665	14,430
Natural Gas and/or oil fired	0	0	6,946	8,387	19,831	14,573	14,225	17,398	24,937	24,378	32,068
Combustion turbine and diesel	1,763	3,276	0	0	0	0	0	0	0	0	0
Renewable resources (non-hyd	0	0	0	0	0	0	0	0	0	0	0
Total TVA Operated Generatio	**176,304**	**163,804**	**173,662**	**167,730**	**165,255**	**161,925**	**158,057**	**139,183**	**134,035**	**131,031**	**139,494**
Purchased power (non-renewa	0	0	0	0	0	0	0	9,490	14,027	13,713	14,430
Purchased power (renewable)	0	0	0	0	0	0	0	9,490	7,793	7,618	6,414
Total Power Supply	**176,304**	**163,804**	**173,662**	**167,730**	**165,255**	**161,925**	**158,057**	**158,163**	**155,855**	**152,362**	**160,338**

Source: TVA 10-K filings.

Table A-4. TVA summer net capability at September 30, 2018

Source of Capability	Location	Number of Units	Summer Net Capability (MW)	Date First Unit Placed in Service (CY)	Date Last Unit Placed in Service (CY)
TVA-Operated Generating Facilities					
Nuclear					
Browns Ferry[2]	Alabama	3	3,309	1974	1977
Sequoyah	Tennessee	2	2,292	1981	1982
Watts Bar	Tennessee	2	2,122	1996	2016
Total Nuclear		7	7,723		
Coal-Fired					
Bull Run	Tennessee	1	865	1967	1967
Cumberland	Tennessee	2	2,470	1973	1973
Gallatin	Tennessee	4	976	1956	1959
Kingston	Tennessee	9	1,398	1954	1955
Paradise	Kentucky	1	971	1963	1970
Shawnee	Kentucky	9	1,206	1953	1955
Total Coal-Fired		26	7,886		
Natural Gas and/or Oil-Fired[3][4]					
Simple-Cycle Combustion Turbine					
Allen	Tennessee	20	456	1971	1972
Brownsville	Tennessee	4	468	1999	1999
Colbert	Alabama	8	392	1972	1972
Gallatin	Tennessee	8	642	1975	2000
Gleason	Tennessee	3	500	2000	2000
Johnsonville	Tennessee	20	1,269	1975	2000
Kemper	Mississippi	4	348	2002	2002
Lagoon Creek	Tennessee	12	1,048	2001	2002
Marshall County	Kentucky	8	608	2002	2002
Subtotal Simple-Cycle Combustion Turbine		87	5,731		
Combined-Cycle Combustion Turbine					
Ackerman[5]	Mississippi	1	713	2007	2007
Allen[6]	Tennessee	1	1,106	2018	2018
Caledonia[7]	Mississippi	3	765	2003	2003
John Sevier[8]	Tennessee	1	871	2012	2012
Lagoon Creek[9]	Tennessee	1	525	2010	2010
Magnolia	Mississippi	3	918	2003	2003
Paradise[10]	Kentucky	1	1,100	2017	2017
Southaven	Mississippi	3	780	2003	2003
Subtotal Combined-Cycle Combustion Turbine		14	6,778		
Total Natural Gas and/or Oil-Fired		101	12,509		
Hydroelectric					
Conventional Plants	Alabama	36	1,176	1925	1962
	Georgia	2	35	1931	1956
	Kentucky	5	223	1944	1948
	North Carolina	6	492	1940	1956
	Tennessee	60	1,856	1912	1972
Pumped-Storage[11]	Tennessee	4	1,616	1978	1979
Total Hydroelectric		113	5,398		
Diesel Generator					
Meridian	Mississippi	5	9	1998	1998
TVA Non-hydro Renewable Resources[12]			1		
Total TVA-Operated Generating Facilities			33,526		
Contract Renewable Resources[13]			314		
Power Purchase and Other Agreements[14]			3,674		
Total Summer Net Capability			37,514		

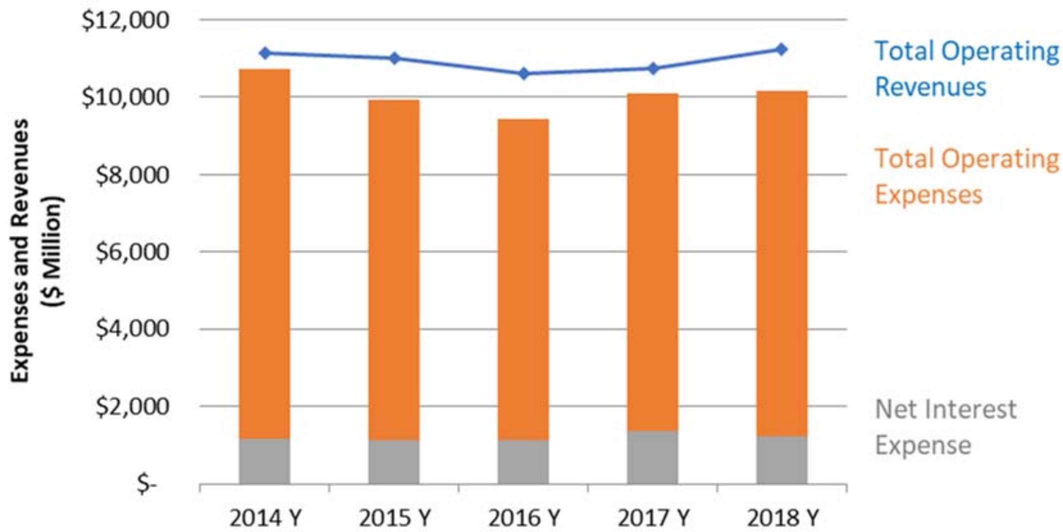
Source: TVA 2018 10-K filing.

A.3. TVA Operating Income and Expenses

TVA's financial situation has improved over the last 10 years as TVA has reduced its debt burden by $2.1 billion, from $23.4 billion in 2010 to $21.3 billion in 2018. During this time period, TVA retired many uneconomic coal plants and replaced them with new natural gas generation and purchased power.

As shown in Figure A-4, TVA's operating revenues have been comfortably above its operating expenses for the past several years. Interest expenses[58] have declined as TVA's long-term debt has been reduced and interest rates are at historically low levels.

Figure A-4. TVA operating income and expenses



Source: TVA 10-K filings; TVA Income Statement.

[58] Direct interest expenses have declined from $1.344 to $1,243 million over this five-year period. This does not show so clearly in the Net Interest Expense, which includes offsetting allowance for funds used during construction amounts in the first three years.

Table A-5. TVA's income statements from 2014 to 2018

Income Statement (As-reported)	2014 Y	2015 Y	2016 Y	2017 Y	2018 Y
As Of Date	9/30/2014	9/30/2015	9/30/2016	9/30/2017	9/30/2018
Source Document	9/30/2016 10-K	9/30/2016 10-K	9/30/2018 10-K	9/30/2018 10-K	9/30/2018 10-K
Currency Code	USD	USD	USD	USD	USD
(in millions)					
Operating revenues					
Revenue from sales of electricity	$ 10,999	$ 10,847	$ 10,461	$ 10,586	$ 11,075
Other revenue	$ 138	$ 156	$ 155	$ 153	$ 158
Total operating revenues	$ 11,137	$ 11,003	$ 10,616	$ 10,739	$ 11,233
Operating expenses					
Fuel	$ 2,730	$ 2,444	$ 2,126	$ 2,169	$ 2,049
Purchased power	$ 1,094	$ 950	$ 964	$ 991	$ 973
Operating and maintenance	$ 3,341	$ 2,838	$ 2,842	$ 3,362	$ 2,854
Depreciation and amortization	$ 1,843	$ 2,031	$ 1,836	$ 1,717	$ 2,527
Tax equivalents	$ 540	$ 525	$ 522	$ 525	$ 518
Total operating expenses	$ 9,548	$ 8,788	$ 8,290	$ 8,764	$ 8,921
Operating income	$ 1,589	$ 2,215	$ 2,326	$ 1,975	$ 2,312
Other income (expense), net	$ 49	$ 29	$ 43	$ 56	$ 50
Interest expense					
Interest expense	$ 1,344	$ 1,347	$ 1,371	$ 1,346	$ 1,243
Allowance for funds used during construction	$ (175)	$ (214)	$ (235)	$ -	$ -
Net interest expense	$ 1,169	$ 1,133	$ 1,136	$ 1,346	$ 1,243
Net income (loss)	$ 469	$ 1,111	$ 1,233	$ 685	$ 1,119
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)					
Net income (loss)	$ 469	$ 1,111	$ 1,233	$ 685	$ 1,119
Other comprehensive income (loss)					
Net unrealized gain (loss) on cash flow hedges	$ 4	$ (72)	$ (139)	$ 59	$ 10
Reclassification to earnings from cash flow hedges	$ (2)	$ 65	$ 129	$ (26)	$ 26
Total other comprehensive income (loss)	$ 2	$ (7)	$ (10)	$ 33	$ 36
Total comprehensive income (loss)	$ 471	$ 1,104	$ 1,223	$ 718	$ 1,155

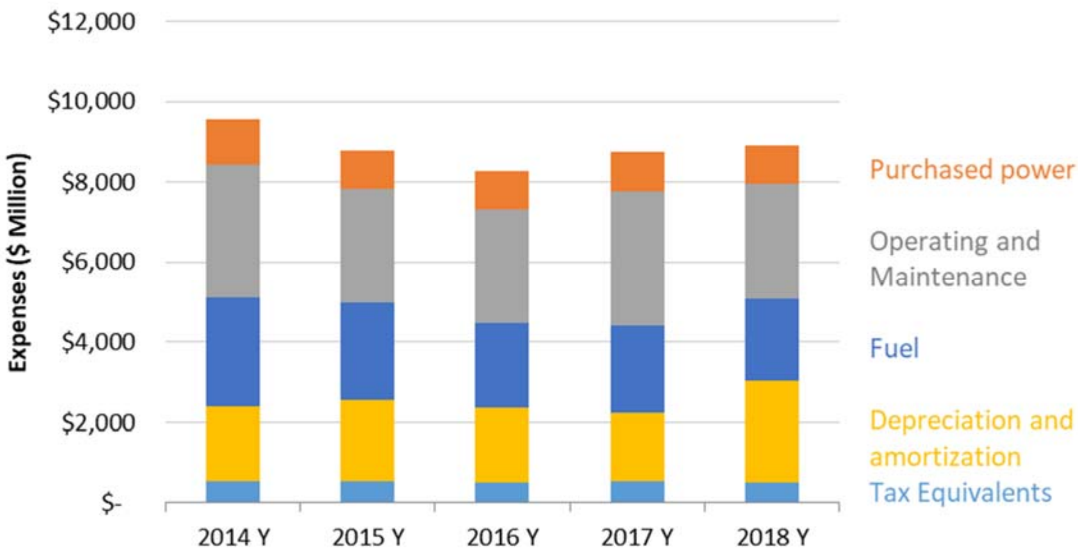
Source: TVA 10-K filings.

A.4. TVA Cash Flow

More details about the operating expenses are shown in Figure A-5. The largest portion of TVA's operating expenses in 2018 (32 percent) are identified as Operating and Maintenance (approximately $2.8 billion), which represents labor and contract services. While a detailed breakout of this expense is not provided, it is likely that much of the expense is for nuclear plant operations and TVA employees' wages and benefits.[59]

Fuel costs have been declining as coal-fired generation has diminished. Purchased power costs are about 10 percent. Depreciation and amortization expenses were 28 percent in 2018, but these have varied from year to year as plants have been closed and assets written off.

Figure A-5. TVA operating expenses



Source: TVA 10-K filings.

The net income for operating activities is carried over to the cash flow statement where it is used for construction expenditures, pension contributions, bond redemptions, and other expenses. The consolidated cash flow statements for 2014 through 2018 are provided in Table A-7 below.

Some items of note are:

1. Construction expenditures have averaged $2,370 million per year over this period.
2. Redemptions and repurchases of power bonds have averaged $982 million per year.
3. Pension contributions have averaged $386 million per year.

---

[59] TVA has around 10,000 employees who receive fairly high wages for the region. Assuming approximate wage and benefit costs at roughly $100,000 per person, we estimate $1 billion for this expense category.

Table A-6. TVA cash flow statement

Cash Flow (As-reported)	**2014 Y**	**2015 Y**	**2016 Y**	**2017 Y**	**2018 Y**	**2014-2018**
As Of Date	9/30/2014	9/30/2015	9/30/2016	9/30/2017	9/30/2018	**Average**
Source Document	9/30/2016 10-K	9/30/2016 10-K	9/30/2018 10-K	9/30/2018 10-K	9/30/2018 10-K	
Currency Code	USD	USD	USD	USD	USD	
(in millions)						
Cash flows from operating activities						
Net income (loss)	$ 469	$ 1,111	$ 1,233	$ 685	$ 1,119	$ 923
Adjustments to reconcile net income (loss) to net cash provided by operating activities						
Depreciation and amortization (including amortization of debt i	$ 1,888	$ 2,077	$ 1,882	$ 1,763	$ 2,554	$ 2,033
Amortization of nuclear fuel cost	$ 279	$ 277	$ 287	$ 341	$ 382	$ 313
Non-cash retirement benefit expense	$ 572	$ 332	$ 327	$ 837	$ 324	$ 478
Prepayment credits applied to revenue	$ (100)	$ (100)	$ (100)	$ (100)	$ (100)	$ (100)
Fuel cost adjustment deferral	$ (38)	$ (6)	$ (83)	$ 98	$ (30)	$ (12)
Fuel cost tax equivalents	$ 6	$ (18)	$ (16)	$ 5	$ (7)	$ (6)
Changes in current assets and liabilities						
Accounts receivable, net	$ (79)	$ 93	$ (83)	$ 230	$ (68)	$ 19
Inventories and other current assets, net	$ 34	$ (12)	$ 50	$ 1	$ 65	$ 28
Accounts payable and accrued liabilities	$ 147	$ (121)	$ (4)	$ (119)	$ 134	$ 7
Accrued interest	$ 2	$ (13)	$ (3)	$ (17)	$ (36)	$ (13)
Regulatory asset costs	$ (56)	$ (23)	$ (31)	$ (50)	$ (13)	$ (35)
Pension contributions	$ (256)	$ (282)	$ (281)	$ (805)	$ (304)	$ (386)
Insurance recoveries	$ 175	$ 63				$ 119
Settlements of asset retirement obligations	$ (14)	$ (58)	$ (139)	$ (123)	$ (106)	$ (88)
Other, net 1	$ (49)	$ (5)	$ 3	$ (10)	$ 41	$ (4)
Net cash provided by operating activities	$ 2,980	$ 3,315	$ 3,042	$ 2,736	$ 3,955	$ 3,206
Cash flows from investing activities						
Construction expenditures	$ (2,384)	$ (2,850)	$ (2,710)	$ (2,153)	$ (1,759)	$ (2,371)
Combustion turbine asset acquisition	$ -	$ (342)				$ (171)
Nuclear fuel expenditures	$ (326)	$ (350)	$ (300)	$ (305)	$ (457)	$ (348)
Purchases of investments	$ (48)	$ (52)	$ (50)	$ (49)	$ (49)	$ (50)
Loans and other receivables	$ -	$ -	$ -	$ -	$ -	$ -
Advances	$ (6)	$ (17)	$ (10)	$ (11)	$ (12)	$ (11)
Repayments	$ 6	$ 8	$ 7	$ 8	$ 4	$ 7
Other, net 2	$ 2	$ 18	$ (50)	$ (26)	$ 4	$ (10)
Net cash used in investing activities	$ (2,756)	$ (3,585)	$ (3,113)	$ (2,536)	$ (2,269)	$ (2,852)
Cash flows from financing activities						
Long-term debt						
Issues of power bonds	$ 989	$ 973	$ -	$ 999	$ 998	$ 792
Redemptions and repurchases of power bonds	$ (365)	$ (1,180)	$ (76)	$ (1,558)	$ (1,731)	$ (982)
Payments on debt of variable interest entities	$ (30)	$ (32)	$ (33)	$ (35)	$ (36)	$ (33)
Redemptions of notes payable			$ -	$ (27)	$ (53)	$ (27)
Short-term debt issues (redemptions), net	$ (1,837)	$ 437	$ 370	$ 583	$ (811)	$ (252)
Payments on leases and leasebacks	$ (73)	$ (80)	$ (159)	$ (136)	$ (42)	$ (98)
Financing costs, net	$ (4)	$ (7)	$ -	$ (4)	$ (3)	$ (4)
Payments to U.S. Treasury	$ (14)	$ (5)	$ (6)	$ (5)	$ (5)	$ (7)
Other, net 3	$ 8	$ (36)	$ (25)	$ (17)	$ (4)	$ (15)
Net cash (used in) provided by financing activities	$ (1,326)	$ 70	$ 71	$ (200)	$ (1,687)	$ (614)
Net change in cash and cash equivalents	$ (1,102)	$ (200)	$ -	$ -	$ (1)	$ (261)
Cash and cash equivalents at beginning of period	$ 1,602	$ 500	$ 599	$ 300	$ 300	$ 660
Cash and cash equivalents at end of period	$ 500	$ 300	$ 300	$ 300	$ 299	$ 340

Source: TVA 10-K filings.

A.5. TVA BALANCE SHEET

The consolidated TVA Balance Sheets for the last five years are provided in the table on the following page.[60]

Some items of note are:

1. The completed plant asset has increased by about $13,000 million.
2. Construction in progress has decreased from $5,951 million to $1,999 million.
3. Post-retirement and post-employment benefit obligations have decreased from $5,839 million to $4,476 million, reflecting the pension contributions mentioned above.
4. Total long-term debt has decreased from $23,227 million to $21,307 million.
5. For 2018 the income statement gives $1,243 million as Net Interest Expense. Paired with the above debt number, that gives an average debt rate of 5.83 percent.

[60] TVA 10-K filings.

Balance Sheet (As-reported)	2014 Y	2015 Y	2016 Y	2017 Y	2018 Y
As Of Date	9/30/2014	9/30/2015	9/30/2016	9/30/2017	9/30/2018
Source Document	9/30/2014 10-K	9/30/2016 10-K	9/30/2016 10-K	9/30/2018 10-K	9/30/2018 10-K
Currency Code	USD	USD	USD	USD	USD
(in millions)					
ASSETS					
Current assets					
Cash and cash equivalents	$ 500	$ 300	$ 300	$ 300	$ 299
Restricted cash and cash equivalents				$ -	$ 13
Restricted cash and investments	$ 19	$ 15	$ -		
Accounts receivable, net	$ 1,676	$ 1,600	$ 1,747	$ 1,569	$ 1,657
Inventories, net	$ 1,056	$ 1,031	$ 993	$ 1,065	$ 961
Regulatory assets 1	$ 481	$ 506	$ 536	$ 447	$ 414
Other current assets	$ 56	$ 54	$ 68	$ 65	$ 86
Total current assets	$ 3,788	$ 3,506	$ 3,644	$ 3,446	$ 3,430
Property, plant, and equipment		$ -			
Completed plant	$ 47,564	$ 50,069	$ 51,564	$ 58,947	$ 61,114
Less accumulated depreciation	$ (24,589)	$ (26,318)	$ (27,592)	$ (28,404)	$ (29,335)
Net completed plant	$ 22,975	$ 23,751	$ 23,972	$ 30,543	$ 31,779
Construction in progress	$ 5,951	$ 7,147	$ 8,458	$ 2,842	$ 1,999
Nuclear fuel	$ 1,322	$ 1,415	$ 1,450	$ 1,401	$ 1,487
Capital leases	$ 102	$ 94	$ 163	$ 161	$ 149
Total property, plant, and equipment, net	$ 30,350	$ 32,407	$ 34,043	$ 34,947	$ 35,414
Investment funds	$ 1,981	$ 2,011	$ 2,257	$ 2,603	$ 2,862
Regulatory and other long-term assets		$ -			
Regulatory assets 2	$ 8,994	$ 10,418	$ 10,164	$ 8,698	$ 6,612
Other long-term assets	$ 483	$ 403	$ 386	$ 323	$ 349
Total regulatory and other long-term assets	$ 9,477	$ 10,821	$ 10,550	$ 9,021	$ 6,961
Total assets	**$ 45,596**	**$ 48,745**	**$ 50,494**	**$ 50,017**	**$ 48,667**
LIABILITIES AND PROPRIETARY CAPITAL					
Current liabilities					
Accounts payable and accrued liabilities	$ 2,029	$ 2,127	$ 2,163	$ 1,940	$ 1,982
Environmental cleanup costs - Kingston ash spill 1	$ 21				
Accrued interest	$ 380	$ 366	$ 363	$ 346	$ 305
Current portion of leaseback obligations	$ 75	$ 79	$ 58	$ 37	$ 38
Current portion of energy prepayment obligations	$ 100	$ 100	$ 100	$ 100	$ 10
Regulatory liabilities 1	$ 184	$ 164	$ 154	$ 163	$ 187
Short-term debt, net	$ 596	$ 1,034	$ 1,407	$ 1,998	$ 1,216
Current maturities of power bonds	$ 1,032	$ 32	$ 1,555	$ 1,728	$ 1,032
Current maturities of long-term debt of variable interest ent	$ 32	$ 33	$ 35	$ 36	$ 38
Current maturities of notes payable		$ -	$ 27	$ 53	$ 46
Total current liabilities	$ 4,449	$ 3,935	$ 5,862	$ 6,401	$ 4,854
Other liabilities					
Post-retirement and post-employment benefit obligations	$ 5,839	$ 7,107	$ 6,929	$ 5,477	$ 4,476
Asset retirement obligations	$ 3,089	$ 3,682	$ 3,840	$ 4,176	$ 4,665
Other long-term liabilities	$ 1,962	$ 2,221	$ 2,776	$ 3,055	$ 2,715
Leaseback obligations	$ 616	$ 537	$ 409	$ 302	$ 263
Energy prepayment obligations	$ 310	$ 210	$ 110	$ 10	$ -
Environmental cleanup costs - Kingston ash spill 2	$ -				
Regulatory liabilities 2	$ -			$ 25	$ 104
Total other liabilities	$ 11,816	$ 13,757	$ 14,064	$ 13,045	$ 12,223
Long-term debt, net					
Long-term power bonds, net	$ 21,948	$ 22,617	$ 20,901	$ 20,205	$ 20,157
Long-term debt of variable interest entities, net	$ 1,279	$ 1,233	$ 1,199	$ 1,164	$ 1,127
Long-term notes payable		$ -	$ 48	$ 69	$ 23
Total long-term debt, net	$ 23,227	$ 23,850	$ 22,148	$ 21,438	$ 21,307
Total liabilities	$ 39,492	$ 41,542	$ 42,074	$ 40,884	$ 38,384
Proprietary capital					
Power program appropriation investment	$ 258	$ 258	$ 258	$ 258	$ 258
Power program retained earnings	$ 5,240	$ 6,357	$ 7,594	$ 8,282	$ 9,404
Total power program proprietary capital	$ 5,498	$ 6,615	$ 7,852	$ 8,540	$ 9,662
Nonpower programs appropriation investment, net	$ 601	$ 590	$ 580	$ 572	$ 564
Accumulated other comprehensive income (loss)	$ 5	$ (2)	$ (12)	$ 21	$ 57
Total proprietary capital	$ 6,104	$ 7,203	$ 8,420	$ 9,133	$ 10,283
Total liabilities and proprietary capital	**$ 45,596**	**$ 48,745**	**$ 50,494**	**$ 50,017**	**$ 48,667**

Appendix B. TVA 2019 IRP OVERVIEW

TVA periodically goes through an Integrated Resource Planning process. The latest 2019 IRP was completed in August of this year.[61]

The first step in this process was to identify the key uncertainties facing TVA which are listed below:

Figure B-1. TVA IRP uncertainties

Uncertainty	Description
Electricity Demand	The customer energy requirements (in gigawatt hours) for the TVA service territory (including losses), representing the load to be served by TVA
Market Power Price	The hourly price of energy ($/megawatt hour) at the TVA boundary, used as a proxy for market price of power
Natural Gas Prices	The price ($/million BTUs) of natural gas, including transportation
Coal Prices	The price ($/million BTUs) of coal, including transportation
Solar Prices	The price ($/megawatt hour) of solar power purchase agreements delivered to TVA
Storage Prices	The price ($/kW) of storage new builds
Regulations	All regulatory and legislative actions, including applicable codes and standards, that impact the operation of electric utilities, excluding CO_2 regulations
CO_2 Regulation/Price	The cost of compliance with possible CO_2 related regulation and/or the price of cap-and-trade legislation, represented as a $/ton value
Distributed Generation Penetration	National trending of distributed generation resources and potential regional activity by customers or third-party developers (not TVA)
National Energy Efficiency (EE) Adoption	An estimate of EE measure adoption by customers nationally, recognizing the impacts of technology affordability, electricity price, and consumer interest on the willingness to adopt efficiency measures
Electrification	An estimate of electric end-use technology adoption displacing other commercial energy forms and providing new services
Economic Outlook (National/Regional)	All aspects of the regional and national economy, including general inflation, financing considerations, population growth, GDP and other factors that drive the overall economy

Source: TVA. 2019a, Table 6-1, page 6-2.

The TVA 2019 IRP then created six Scenarios as presented below:

[61] TVA. 2019a, 2019 Integrated Resource Plan, Volume 1 – Final Resource Plan, August 2019. Available athttps://www.tva.gov/Environment/Environmental-Stewardship/Integrated-Resource-Plan.

Figure B-2. TVA IRP scenarios

	SCENARIOS
1	**CURRENT OUTLOOK** which represents TVA's current forecast for these key uncertainties and reflects modest economic growth offset by increasing efficiencies;
2	**ECONOMIC DOWNTURN** which represents a prolonged stagnation in the economy, resulting in declining loads (customers using less power) and delayed expansion of new generation;
3	**VALLEY LOAD GROWTH** which represents economic growth driven by migration into the Valley and a technology-driven boost to productivity, underscored by increased electrification of industry and transportation;
4	**DECARBONIZATION** which is driven by a strong push to curb greenhouse gas emissions due to concern over climate change, resulting in high CO_2 emission penalties and incentives for non-emitting technologies;
5	**RAPID DER ADOPTION** which is driven by growing consumer awareness and preference for energy choice, coupled with rapid advances in technologies, resulting in high penetration of distributed generation, storage and energy management;
6	**NO NUCLEAR EXTENSIONS** which is driven by a regulatory challenge to relicense existing nuclear plants and construct new, large-scale nuclear. This scenario also assumes subsidies to drive small modular reactor (SMR) technology advancements and improved economics.

Source: TVA. 2019a, ES-7.

In this context TVA then developed five strategies:

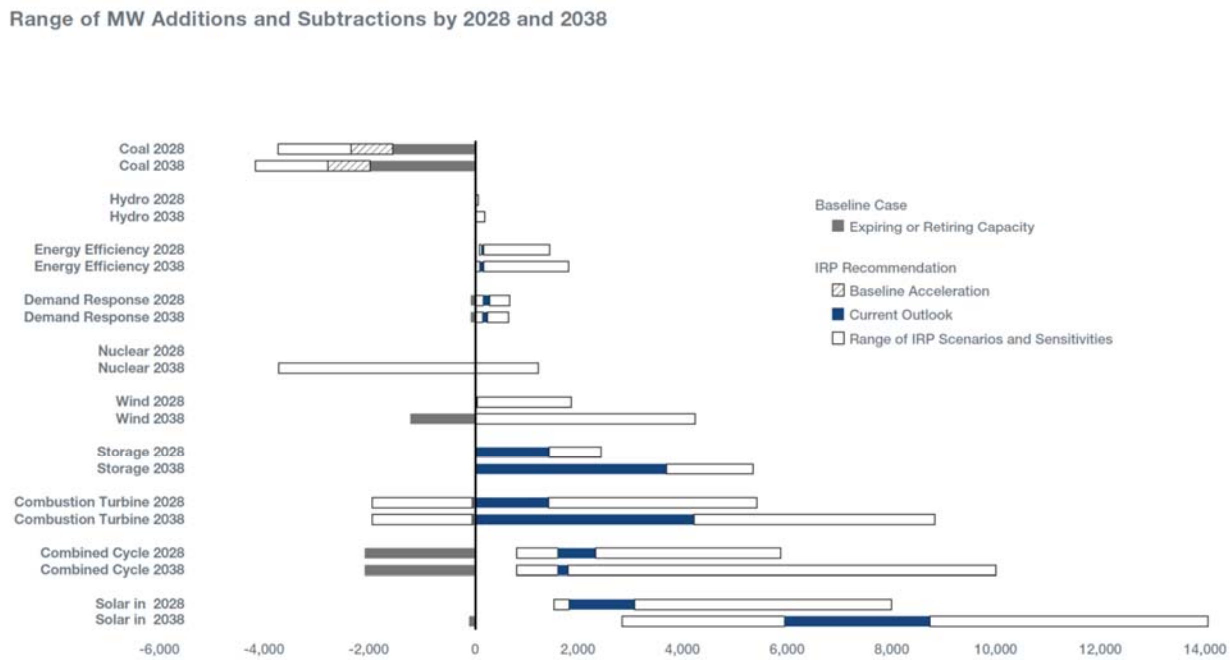
Figure B-3. TVA IRP strategies

	STRATEGIES
A	**BASE CASE** which represents TVA's current assumptions for resource costs and applies a planning reserve margin constraint. This constraint applies in every strategy and represents the minimum amount of capacity required to ensure reliable power;
B	**PROMOTE DISTRIBUTED ENERGY RESOURCES** which incents DER to achieve higher, long-term penetration levels. The DER options include energy efficiency, demand response, combined heat and power, distributed solar and storage;
C	**PROMOTE RESILIENCY** which incents small, agile capacity to maximize operational flexibility and the ability to respond to short-term disruptions on the power system;
D	**PROMOTE EFFICIENT LOAD SHAPE** which incents targeted electrification (by incentivizing customers to increase electricity usage in off-peak hours) and demand response (by incentivizing customers to reduce electricity usage during peak hours). This strategy promotes efficient energy usage for all customers, including those with low income;
E	**PROMOTE RENEWABLES** which incents renewables at all scales (from utility size to residential) to meet growing or existing consumer demand for renewable energy.

Source: TVA. 2019a, ES-7.

The six scenarios combined with five strategies create 30 cases that TVA analyzed in its IRP. The resource retirements and additions associated with all those cases are summarized in the following chart. All of the cases incorporate both coal retirements and addition of storage and solar.

Figure B-4. TVA resource additions and subtractions



Source: TVA. 2019a, Figure 9-1.

The following figure shows the resource capacity changes in the base case. Note the addition of significant renewable capacity, but only a slight reduction in coal capacity from 7.8 to 5.0 GW. All nuclear plants remain in operation in 2038.

Table B-1. TVA base case resource capacity

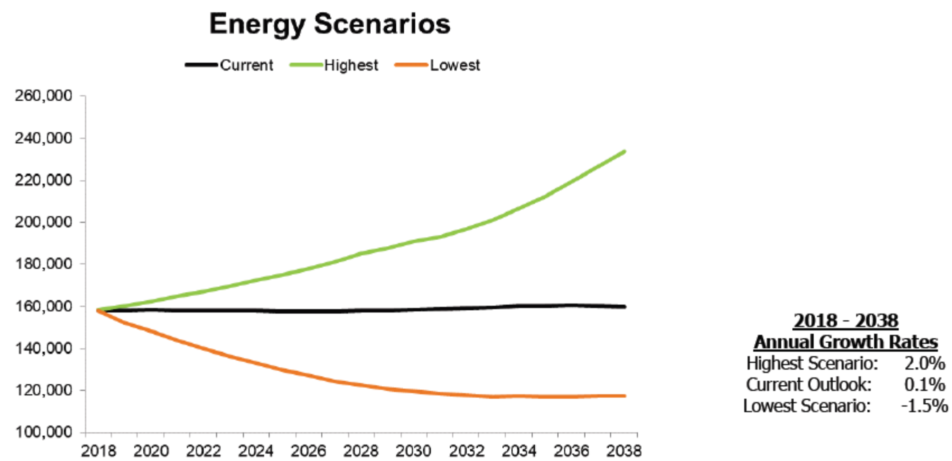
Base Case Capacity (GW) - Current Outlook

Resource	2018	2023	2028	2033	2038	Change
DR	1.8	1.8	1.7	1.7	1.6	-0.2
EE	0.0	0.1	0.1	0.1	0.0	0.0
Storage	1.6	1.7	1.7	1.7	1.7	0.1
Renewables	0.3	0.6	1.9	3.4	4.3	4.0
Gas CT	5.3	5.5	6.2	7.2	9.2	3.9
Gas CC	7.9	7.2	7.9	7.9	7.3	-0.6
Coal	7.8	7.1	6.2	5.8	5.0	-2.8
Hydro	2.4	2.5	2.5	2.5	2.5	0.1
Nuclear	8.0	8.3	8.3	8.3	8.3	0.3
Total	35.1	34.8	36.5	38.6	39.9	4.8

Source: TVA. 2019a, Figure G-1.

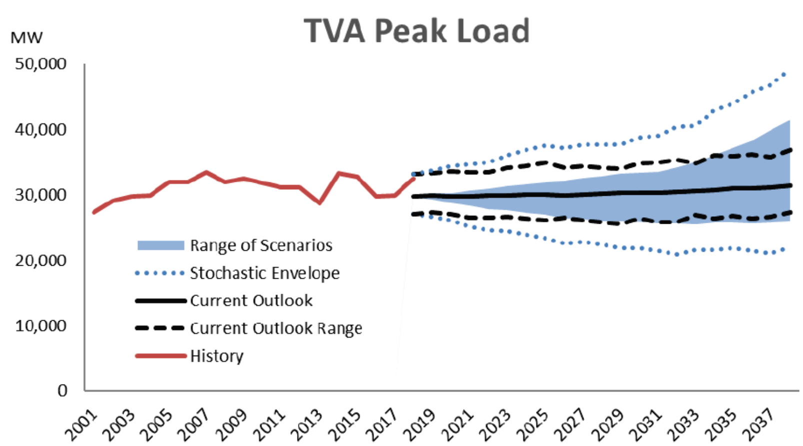
Also of interest in the current study is how loads might change in various cases. The following two figures summarize the findings of the IRP. A wide range of possible loads was considered with energy requirements possibly decreasing by 25 percent or increasing by 50 percent by 2038.

Figure B-5. TVA IRP energy loads



Source: TVA. 2019a, Figure 4-5.

Figure B-6. TVA IRP peak loads



Source: TVA. 2019a, Figure 6-10.

The IRP has very little to say about customer rates. The IRP uses some metrics for evaluating the effects of electric rates. These calculations are discussed in Chapter 5 of Volume 2 and in Appendix J to the IRP. For all of the various cases the economic impacts in terms of real per capita income and employment differed very little from the base case. For real per capita income, the range was from -0.04 to 0.00 percent (i.e., for all of the cases the effect was the same as the base case or slightly worse). For employment, the range was from 0.00 to +0.11 percent (i.e., for all of the cases the employment effects were the same as or better than the base case).[62]

Although rate information is not available in the IRP, our conclusion from this economic analysis is that the TVA IRP does not predict a very wide variation in customer rates for any of the scenario and strategy combinations that they considered.

[62] TVA. 2019b, Tables 5-5 and 5-6.

Appendix C. Recent TVA Rate Schedules

The Local Power Companies are served by TVA under rate schedule WS. Two historical years of Schedule WS are presented and compared below. The comparison shows a substantial increase over this period.

However, in addition to these rates there are monthly fuel cost adjustments that determine the actual LPC payments. Our analysis of the aggregate revenue rate based on the TVA 10-K forms shows that the net effective rate has remained fairly level over the most recent five years. The most likely explanation for level effective rates is that the base rates increases have been offset by reductions in the fuel cost adjustments. This is also consistent with the overall reduction in TVA fuel costs which declined from $2.73 to $2.05 billion from 2014 to 2018.[63]

Schedule WS						
		2015	**2018**	**Change**		
STANDARD SERVICE		Schedule	Schedule	Absolute	Percent	
Onpeak Demand Charge:	Summer Period	$7.13	$8.07	$0.94	13%	per kW of Onpeak Billing Demand per month
	Winter Period	$6.27	$7.14	$0.87	14%	per kW of Onpeak Billing Demand per month
	Transition Period	$6.27	$7.14	$0.87	14%	per kW of Onpeak Billing Demand per month
Maximum Demand Charge:	Summer Period	$2.61	$2.97	$0.36	14%	per kW of Maximum Billing Demand per month
	Winter Period	$2.61	$2.97	$0.36	14%	per kW of Maximum Billing Demand per month
	Transition Period	$2.61	$2.97	$0.36	14%	per kW of Maximum Billing Demand per month
Non-Fuel Energy Charge:	Summer Period	3.670	4.154	0.484	13%	cents per kWh per month (as adjusted by TOU Amount below)
	Winter Period	3.366	3.827	0.461	14%	cents per kWh per month (as adjusted by TOU Amount below)
	Transition Period	3.243	3.694	0.451	14%	cents per kWh per month
TOU Amounts to be added to Non-Fuel Energy Charge:						
	Summer Period					
	During onpeak hours:	1.500¢	1.500¢	0.000		per kWh per month
	During offpeak hours	-0.700¢	-0.700¢	0.000		per kWh per month
	Winter Period					
	During onpeak hours:	0.800¢	0.800¢	0.000		per kWh per month
	During offpeak hours	-0.200¢	-0.200¢	0.000		per kWh per month
In addition to the charges in this schedule there are Fuel Cost Adjustments which vary from month to month and can be a significant part ot the total bill.						
2015 Schedule is dated October 2015						
2018 Schedule is dated October 2018-September 2019						

[63] TVA Income Statement in Appendix A.

Appendix D. TVA Risk Factors

The TVA 2018 10-K document,[64] which is reproduced on the following pages of Appendix D, lists a number of risk factors that might affect future TVA costs and revenues. The probabilities of any of these are uncertain and likely small, but these events could happen. We explore five risk factors in this report.

[64] TVA 2018 10-K filing, pages 6-7.

FORWARD-LOOKING INFORMATION

This Annual Report on Form 10-K ("Annual Report") contains forward-looking statements relating to future events and future performance. All statements other than those that are purely historical may be forward-looking statements. In certain cases, forward-looking statements can be identified by the use of words such as "may," "will," "should," "expect," "anticipate," "believe," "intend," "project," "plan," "predict," "assume," "forecast," "estimate," "objective," "possible," "probably," "likely," "potential," "speculate," the negative of such words, or other similar expressions.

Although the Tennessee Valley Authority ("TVA") believes that the assumptions underlying the forward-looking statements are reasonable, TVA does not guarantee the accuracy of these statements. Numerous factors could cause actual results to differ materially from those in the forward-looking statements. These factors include, among other things:

- New, amended, or existing laws, regulations, or administrative orders or interpretations, including those related to environmental matters, and the costs of complying with these laws, regulations, or administrative orders or interpretations;
- The cost of complying with known, anticipated, or new emissions reduction requirements, some of which could render continued operation of many of TVA's aging coal-fired generation units not cost-effective or result in their removal from service, perhaps permanently;
- Significant reductions in demand for electricity produced through non-renewable or centrally located generation sources that may result from, among other things, economic downturns, increased energy efficiency and conservation, increased utilization of distributed generation and microgrids, and improvements in alternative generation and energy storage technologies;
- Changes in customer preferences for energy produced from cleaner generation sources;
- Changes in technology;
- Actions taken, or inaction, by the U.S. government relating to the national or TVA debt ceiling or automatic spending cuts in government programs;
- Costs or liabilities that are not anticipated in TVA's financial statements for third-party claims, natural resource damages, environmental clean-up activities, or fines or penalties associated with unexpected events such as failures of a facility or infrastructure;
- Addition or loss of customers by TVA or the local power company customers of TVA ("LPCs");
- Significant delays, cost increases, or cost overruns associated with the construction and maintenance of generation, transmission, navigation, flood control, or related assets;
- Changes in the amount or timing of funding obligations associated with TVA's pension plans, other post-retirement benefit plans, or health care plans;
- Increases in TVA's financial liabilities for decommissioning its nuclear facilities or retiring other assets;
- Risks associated with the operation of nuclear facilities or coal combustion residual ("CCR") facilities;
- Physical attacks on TVA's assets;
- Cyber attacks on TVA's assets or the assets of third parties upon which TVA relies;
- The outcome of legal or administrative proceedings, including the CCR proceedings involving the Gallatin Fossil Plant ("Gallatin") as well as any other CCR proceedings that may be brought in the future;
- The failure of TVA's generation, transmission, navigation, flood control, and related assets and infrastructure, including CCR facilities, to operate as anticipated, resulting in lost revenues, damages, or other costs that are not reflected in TVA's financial statements or projections;
- Differences between estimates of revenues and expenses and actual revenues earned and expenses incurred;
- Weather conditions;
- Catastrophic events such as fires, earthquakes, explosions, solar events, electromagnetic pulses ("EMP"), geomagnetic disturbances ("GMDs"), droughts, floods, hurricanes, tornadoes, or other casualty events or pandemics, wars, national emergencies, terrorist activities, or other similar events, especially if these events occur in or near TVA's service area;
- Events at a TVA facility, which, among other things, could result in loss of life, damage to the environment, damage to or loss of the facility, and damage to the property of others;
- Events or changes involving transmission lines, dams, and other facilities not operated by TVA, including those that affect the reliability of the interstate transmission grid of which TVA's transmission system is a part and those that increase flows across TVA's transmission grid;
- Disruption of fuel supplies, which may result from, among other things, economic conditions, weather conditions, production or transportation difficulties, labor challenges, or environmental laws or regulations affecting TVA's fuel suppliers or transporters;
- Purchased power price volatility and disruption of purchased power supplies;
- Events which affect the supply of water for TVA's generation facilities;
- Changes in TVA's determinations of the appropriate mix of generation assets;
- Ineffectiveness of TVA's efforts at adapting its organization to an evolving marketplace and remaining cost competitive;
- Inability to obtain, or loss of, regulatory approval for the construction or operation of assets;
- The requirement or decision to make additional contributions to TVA's Nuclear Decommissioning Trust ("NDT") or Asset Retirement Trust ("ART");

- Limitations on TVA's ability to borrow money which may result from, among other things, TVA's approaching or substantially reaching the limit on bonds, notes, and other evidences of indebtedness specified in the Tennessee Valley Authority Act of 1933, as amended, 16 U.S.C. §§ 831-831ee (the "TVA Act");
- An increase in TVA's cost of capital that may result from, among other things, changes in the market for TVA's debt securities, changes in the credit rating of TVA or the U.S. government, or, potentially, an increased reliance by TVA on alternative financing should TVA approach its debt limit;
- Changes in the economy and volatility in financial markets;
- Reliability or creditworthiness of counterparties;
- Changes in the market price of commodities such as coal, uranium, natural gas, fuel oil, crude oil, construction materials, reagents, electricity, or emission allowances;
- Changes in the market price of equity securities, debt securities, or other investments;
- Changes in interest rates, currency exchange rates, or inflation rates;
- Ineffectiveness of TVA's disclosure controls and procedures or its internal control over financial reporting;
- Inability to eliminate identified deficiencies in TVA's systems, standards, controls, or corporate culture;
- Inability to attract or retain a skilled workforce;
- Inability to respond quickly enough to current or potential customer demands or needs;
- Events at a nuclear facility, whether or not operated by or licensed to TVA, which, among other things, could lead to increased regulation or restriction on the construction, ownership, operation, or decommissioning of nuclear facilities or on the storage of spent fuel, obligate TVA to pay retrospective insurance premiums, reduce the availability and affordability of insurance, increase the costs of operating TVA's existing nuclear units, or cause TVA to forego future construction at these or other facilities;
- Loss of quorum of the TVA Board of Directors (the "TVA Board");
- Changes in the priorities of the TVA Board or TVA senior management; or
- Other unforeseeable events.

Appendix E. TVA PARTNERSHIP TERM SHEET

LONG-TERM PARTNERSHIP PROPOSAL TERM SHEET
TENNESSEE VALLEY AUTHORITY (TVA)
FOR DISCUSSION PURPOSES ONLY
[TVA DISCUSSION DRAFT – 07-31-19]
[WORK IN PROGRESS AND UNDER DELIBERATION]
PROPRIETARY AND CONFIDENTIAL MATERIAL

THIS TERM SHEET DOES NOT CONSTITUTE A BINDING OFFER AND SHALL NOT FORM THE BASIS FOR AN AGREEMENT UNDER ANY LEGAL OR EQUITABLE THEORY.

GENERAL TERMS	
Parties:	Tennessee Valley Authority (“**TVA**”) and [*local power company]* “**Distributor**”
Objective:	The Valley Public Power Model is unique and has an enduring legacy of improving life in the Tennessee Valley region. At present, there is an opportunity to secure the long-term success of the Valley Public Power Model by lengthening and strengthening the contractual relationship between Local Power Companies and TVA. These enhanced relationships will safeguard long-term access to the key elements of the model and can materially change the financial profile for the Valley, the benefits of which can be shared with participating Local Power Companies and consumers.
Documentation:	The transaction to be documented as an amendment (“**Amendment**”) under the existing Wholesale Power Contract (“**WPC**”) between Distributor and TVA.
Partnership Credit:	Long-term partnerships benefit TVA’s financial risk profile. Benefits will be shared with Distributor in the form of a bill credit of 3.1% of wholesale standard service demand, non-fuel energy, and grid access charges. The bill credit will start the first full billing month after signature. If notice is given, the credit will be phased out over the next 10 years in equal annual percentages.
Rate Commitment:	TVA is committed to provide Distributor power at rates as low as feasible under the Valley Public Power Model.
Full Requirements Commitment:	TVA commits to provide all the power supplied in the Distributor’s service area and Distributor commits to ensuring that all power supplied in Distributor’s service area is TVA power, unless otherwise agreed to by the Parties.
Termination Notice:	The Termination Notice under the WPC will be changed to 20 years.
Commitment to Explore Expanded Flexibility with Long-Term Partners:	TVA will commit to collaborate on flexibility solutions with long-term partners for addressing customer and system needs as well as provide research value. TVA will commit to providing enhanced flexibility for distribution solutions between 3-5% of load by October 1, 2021, with pricing and planning considerations mutually agreeable between Distributor and TVA. If TVA does not fulfill this commitment, Distributor may terminate this Agreement, return 50% of Program Credits received, and revert to original termination notice.

Pre-Decisional Deliberative Document Page 1 of 2

LONG-TERM PARTNERSHIP PROPOSAL TERM SHEET
TENNESSEE VALLEY AUTHORITY (TVA)
FOR DISCUSSION PURPOSES ONLY
[TVA DISCUSSION DRAFT – 07-31-19]
[WORK IN PROGRESS AND UNDER DELIBERATION]
PROPRIETARY AND CONFIDENTIAL MATERIAL

Additional Partnership Benefits:	During the term of this Amendment, TVA may provide additional benefits to long-term partners. Distributor would be eligible to receive any such additional benefits that are applicable to it. TVA will establish a practice of strong engagement with long-term partners for strategic resource and financial planning decisions.
Rate Adjustment Protection:	In the event that TVA implements rate adjustments that increase wholesale base rates by more than 5% within the next 5 years (ending FY2024) or 10% over any 5-year period within the initial 20 year term, the Parties will endeavor to negotiate new terms for 180 days after which Distributor may reduce WPC notice provision to 10 years, which will immediately terminate this Amendment.
Events of Default:	<u>TVA Defaults</u> A sale or transfer of all, or substantially all, of TVA's power properties, including generation or transmission properties, to a non-public entity that results in Distributor paying higher rates that are not based on the current TVA Act. TVA assigns the WPC without the consent of the Distributor. <u>Distributor Defaults</u> A sale or transfer of all, or substantially all, of Distributor's assets to any entity that results in a reduction in load served by TVA. Distributor sells or supplies non-TVA power, or facilitates non-TVA power being sold or supplied, to any end-use customer in Distributor's service area, without the consent of TVA. Distributor assigns the WPC without the consent of TVA.
Remedies:	<u>TVA Default</u> In the event of a TVA default, TVA would pay Distributor actual and potential losses over the remaining term of the WPC due to the increased rates charged by a new power provider or as required by TVA under any new law that would be higher than those otherwise charged by TVA in accordance with the current TVA Act. <u>Distributor Default</u> In the event of a Distributor default, Distributor would pay TVA actual and potential losses over remaining term of the WPC due to loss of TVA revenue and load due to either sale of non-TVA power to end-use customer(s) in Distributor's service area or sale or transfer of all or substantially all of Distributor's assets.

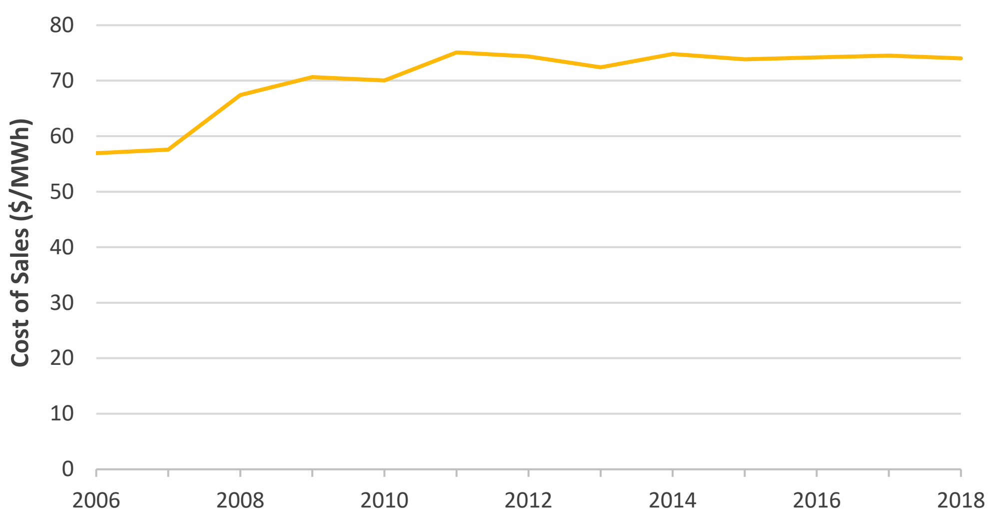
ANY ACTIONS TAKEN BY A PARTY IN RELIANCE ON THE TERMS SET FORTH IN THIS TERM SHEET OR ON STATEMENTS MADE DURING NEGOTIATIONS PURSUANT TO THIS TERM SHEET SHALL BE AT SUCH PARTY'S OWN RISK. UNTIL DEFINITIVE AGREEMENT(S) HAVE BEEN EXECUTED BETWEEN OR AMONG THE PARTIES, NO PARTY SHALL HAVE ANY LEGAL OBLIGATIONS, EXPRESS OR IMPLIED, OR ARISING IN ANY OTHER MANNER UNDER THIS TERM SHEET OR IN THE COURSE OF NEGOTIATIONS. SUCH DEFINITIVE AGREEMENT(S) ARE THE ONLY DOCUMENT(S) THAT WOULD CREATE A BINDING LEGAL OBLIGATION BETWEEN OR AMONG THE PARTIES WITH RESPECT TO THE SUBJECT MATTER OF THIS TERM SHEET.

Pre-Decisional Deliberative Document Page 2 of 2

Appendix F. Memphis Purchased Power Costs

Memphis Light, Gas and Water (MLGW) purchases its electricity through a wholesale power contract with TVA. Information about the historical purchases is provided in the MLGW annual reports which are available at their website.[65] Figure F-1 shows MLGW's electricity purchase costs in term of its own sales. The price trend shows a substantial increase from 2006 to 2011 and then remains fairly level thereafter. The cost increased from $57.00 per MWh in 2006 to $74.00 per MWh in 2018, for a net increase of 30 percent over 12 years. These imputed prices do not include tranmission line losses that occur between TVA to MLGW customers, and are thus slightly higher than the unit prices charged by TVA. Assuming a loss factor of 2 percent, the implied price paid to TVA in 2018 would be $72.60 per MWh. This is almost identical to the average TVA LPC price of $72.80 per MWh in 2018 as discussed in Section 3 of this report.

Figure F-1. MLGW historical electricity costs



Source: MLGW, Annual Reports 2008-2018.

The table below presents the purchases and sales data starting in 2006 and going through 2018. From 2006 to 2018 the purchased power costs increased from $864 million to $1,036 million, while consumption decreased by about 6 percent. The table also shows our estimates of the total power

---

[65] http://www.mlgw.com/about/annualreport.

purchase from TVA by Memphis, assuming a 2 percent line loss, as well as purchase power costs in terms of dollars per MWh.

Table F-1. MLGW purchase power costs, electric sales, and estimates of TVA per unit power cost

	Units	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Purchased Power Costs	Million $	846	878	992	969	1,033	1,074	1,045	1,008	1,030	1,016	1,018	992	1,036
Electric Sales	GWh	14,863	15,256	14,716	13,720	14,750	14,291	14,058	13,926	13,765	13,756	13,722	13,308	13,993
MLGW Losses	2%	297	305	294	274	295	286	281	279	275	275	274	266	280
Estimated TVA Purchases	GWh	15,160	15,561	15,010	13,994	15,045	14,577	14,339	14,205	14,041	14,031	13,996	13,574	14,273
Estimated Purchase Power Costs	$/MWh	55.83	56.45	66.08	69.27	68.66	73.64	72.91	71.00	73.34	72.41	72.74	73.04	72.58

Source: MLGW, Annual Reports 2008-2018.