Assessment of Wholesale Power Options for Memphis Light, Gas and Water

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Submitted to:
Nuclear Development, LLC

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1. Introduction

ICF Resources LLC (ICF), a subsidiary of ICF, was engaged by Nuclear Development, LLC (the Client or ND) to assess wholesale electric supply options for Memphis Light, Gas and Water (MLGW) including the proposed Bellefonte Power Purchase Agreement (PPA) offered by ND. MLGW is a municipal utility serving Memphis, Tennessee. MLGW currently purchases all its wholesale power and transmission services exclusively from the Tennessee Valley Authority (TVA).

Nuclear Development, LLC, is developing the Bellefonte 1 project in northwest Alabama. Bellefonte 1 is a proposed 1,350 megawatt (MW) nuclear powerplant that TVA sold partially complete to ND in November 2016. ND projects completion of the nuclear unit within five to six years. The electric load MLGW serves is large enough to consume nearly all the power produced by Bellefonte 1, with the small remainder available for sale to third parties. MLGW also needs incremental power during peak demand periods.

ICF assumed that the Bellefonte 1 project is completed by Q4 2023 and sells its full output to MLGW at a rate schedule starting around $39 per megawatt-hour (MWh), according to information Nuclear Development, LLC provided to ICF. ICF's scope did not include reviews of the Bellefonte 1 project's cost, performance, and feasibility. However, ICF assessed Nuclear Development, LLC's ability to deliver power to MLGW on the wholesale transmission grid and made an economic comparison of supply options built around the Bellefonte 1 PPA.

ICF is a nationally recognized, independent consulting firm headquartered in the Washington, DC area with approximately 5,000 employees and revenues of $1.2 billion. We find the main questions to be the following:

1. What rate would MLGW pay for TVA power over the next 30 years?
2. Is the Bellefonte 1 PPA competitive against this rate?
3. What is the cost of procuring the remaining power needed by MLGW after Bellefonte 1?
4. How can MLGW best go about procuring this remaining power?
5. Can Bellefonte 1 power be transmitted to MLGW?
6. How can MLGW access backup generation reserves to ensure reliable service?
7. Overall, given the above, is it economically attractive for MLGW to purchase power from Bellefonte 1 plus additional sources, as compared to the normal full TVA rate?
8. If so, how can MLGW go about implementing this change? What challenges might be faced in implementation and how can MLGW address them?
9. What are the risks of not going forward?

A thorough assessment of the above questions necessarily touches on a range of legal and regulatory issues. ICF treats these issues in accordance with our experience in power systems and their regulation. Importantly, however, we are ***not*** lawyers, and we are ***not*** offering legal opinions or legal guidance on the issues involved. Where appropriate, we highlight our non-lawyer understanding of the relevant rules and statutes and in some cases, the range of potential outcomes.

ICF's findings are presented in this report.

2. Executive Summary

2.1 Current MLGW-TVA Contract

TVA currently supplies MLGW with all wholesale power requirements. MLGW has approximately 431,000 retail customer accounts and sells 13.3 terawatt-hours (TWh) of electricity to end-users as of 2017[1]. It is our understanding that MLGW purchases wholesale power (i.e., generation- and transmission-related services) from TVA under a long-term firm supply contract. It is also our understanding that MLGW can terminate service by providing at least five-year notice, while TVA can terminate service with at least 10-year notice.[2] TVA rates under the contract reflect the average cost of service of TVA. In 2017, that rate was $74/MWh.[3] The contract is referred to as an "All-Requirements" or "Full-Service Requirements" contract because TVA provides all the wholesale power and high-voltage transmission used by MLGW. MLGW distributes the power at lower voltages to its customers on its own system.

MLGW is the largest single buyer of power from TVA and consumes approximately 11% of TVA power sold to Local Power Companies (LPCs). MLGW is also the closest major LPC to the large, deregulated competitive wholesale market known as the Midcontinent Independent System Operator (MISO). This market is on the other side of the Mississippi River from MLGW.

2.2 Economic Analysis

ICF analyzed the costs of wholesale power over 30 years from the year 2024 to 2053 period. ICF analyzed two principal scenarios:

- **Business as Usual** – First, ICF forecasted the cost of TVA power assuming the current contract with MLGW continues (i.e., a Business as Usual (BAU) case). ICF based its forecast on public information from TVA and ICF's modeling of the future costs of commodities such as fuel, power and debt as well as capital expenditures and O&M.
- **Bellefonte 1 Plus Market Based Incremental Power** – Second, ICF forecasted the cost of power assuming the Bellefonte 1 PPA is in place and MLGW or its agent purchases incremental power requirements, including energy and capacity, at wholesale market prices. ICF also assessed the deliverability of both Bellefonte power and the incremental power required by MGLW. ICF relied on ND for the Bellefonte 1 PPA parameters.

[1] MLGW Annual Report 2017: http://www.mlgw.com/images/content/files/pdf/MLGWAnnualReport2017-web.pdf

[2] ICF has not reviewed the TVA/MLGW contract and is not offering legal opinions. Also, ICF has not reviewed all of TVA's other contracts; rather, ICF presents our understanding of TVA's general contracting situation.

[3] Based on TVA 10-k 2017, where the LPC price is calculated as LPC operating revenues divided by LPC sales.

2.2.1 Results of Economic Analysis – Bellefonte PPA vs. BAU

ICF PROJECTS LARGE SAVINGS – $15.6 BILLION NET OVER 30 YEARS – PRIMARILY BECAUSE THE BELLEFONTE PPA COSTS ARE SIGNIFICANTLY LESS THAN PROJECTED TVA COSTS.

TVA currently provides MLGW wholesale power supply at $74/MWh, and hence an annual cost of approximately $1.0 billion per year.[4] As show in Exhibit 2-1, ICF projects in 2024, the first year of our study, MLGW's cost under the TVA contract (referred to the Business as Usual case) to be approximately $1.15 billion. In contrast, switching MLGW to a combination of the Bellefonte 1 PPA and market-based incremental power results in a net savings of $416 million: the total cost to MLGW decreases to approximately $738 million. This equals wholesale power cost savings of approximately 40%. Over the 30-year period, there is aggregate net savings of approximately $15.3 billion.[5]

Exhibit 2-1: A Selected Case Review of Memphis Savings Relative a "Business as Usual" Case ($MM)

Business as Usual ($MM)

Business as Usual	Levelized Costs (2024-2053)	Cumulative Cost (2024-2053)	2024	2030	2035	2040	2045	2050	2053
TVA Rate Cost - Business as Usual Case	1,417	46,776	1,154	1,356	1,431	1,502	1,698	2,026	2,162

Option #2A: MISO is Balancing Authority and Incremental Power is Hedged ($MM)

Option #2A: MISO is BA / Inc. Power Hedged	Levelized (2024-2053)	Cumulative Savings (2024-2053)	2024	2030	2035	2040	2043	2050	2053
Gross Savings ($MM)	**686**	**22,132**	**567**	**699**	**702**	**697**	**756**	**946**	**1,015**
Incremental Other Cost/Revenue ($MM)	**199**	**6,785**	**152**	**176**	**201**	**229**	**261**	**298**	**323**
Capacity Cost	105	3,589	78	92	106	121	139	159	172
Transmission Upgrade	58	1,927	47	53	59	65	72	80	85
Regulatory Cost	34	1,161	26	30	34	39	44	51	56
Ancillary Cost	10	333	8	9	10	11	13	15	16
Excess Energy Sold in Spot Market	-8	-226	-8	-8	-8	-7	-7	-7	-6
Net Savings ($MM)	**487**	**15,347**	**416**	**522**	**502**	**468**	**495**	**648**	**692**

Source: ICF

The cumulative gross savings are even higher at $22.1 billion and $567 million for the year 2024 alone. We define gross savings as BAU less Bellefonte PPA and the costs of incremental electrical energy. Net savings take into account further costs for capacity reserves, transmission, and management costs.[6] For example, in 2024 the incremental costs between gross and net are $152 million. Nevertheless, gross savings can be useful because capacity procurement (to cover peak and reserve requirements) is the main cost difference between gross and net. Over the last several years, capacity has been essentially free in the MISO spot capacity market. While we do not recommend reliance on spot capacity purchases, we recognize the amount and cost of hedging is a strategic decision of MLGW. Notwithstanding, our primary economic conclusion is based on net savings.

[4] The $1.0 billion cost represents the MLGW purchase power expense in 2017, MLGW Annual Report 2017.

[5] This is the cumulative undiscounted savings over the 30-year period of 2024 to 2053.

[6] Please refer to Chapter 10 for a full description of "regulatory" costs and Exhibit 10-5 for a more detailed breakdown.

MLGW has 431,000 retail customer accounts. On average, in the first year (i.e., 2024) savings per customer is approximately $964. On a net present value basis, the **total net savings per customer** ranges from $14,000 to $21,230 using a discount rate of 7% to 3.5%. These savings are also very significant when compared to other parameters, including the Memphis municipal budget of approximately $0.7 billion per year not including MLGW.[7]

The savings primarily reflect Bellefonte PPA's low cost compared to projected TVA full-service rates, as the plant supplies on average over 70% of MLGW electrical energy needs over the study time period. In the BAU case, TVA sells MLGW approximately 14 million[8] MWhs at an approximate cost of $81/MWh starting in 2024. In contrast, in 2024 the Bellefonte PPA would provide approximately 70% of MLGW's power at a cost of $39/MWh, or 52% of the TVA rate. For comparison, the PPA rate is comparable to the variable costs of TVA power (fuel, O&M, and purchase power), and thus the PPA allows MLGW to effectively avoid the large capital recovery component built into TVA rates, which include depreciation and income. The PPA rate reflects Bellefonte's low short-run variable costs (mostly fuel) and implied capital recovery requirements that are lower than TVA's on a going forward basis. Secondarily, even incremental power (the remaining 30% after Bellefonte) is less costly than the average TVA rate.

2.2.2 Economic Analysis – Incremental Power

Incremental power costs from neighboring systems are low compared to TVA's costs for incremental power. This is in part due to excess capacity in the market. Also, attractive physical and financial hedges are available: MLGW is across the river from and has easy access to the nation's largest organized wholesale power marketplace.

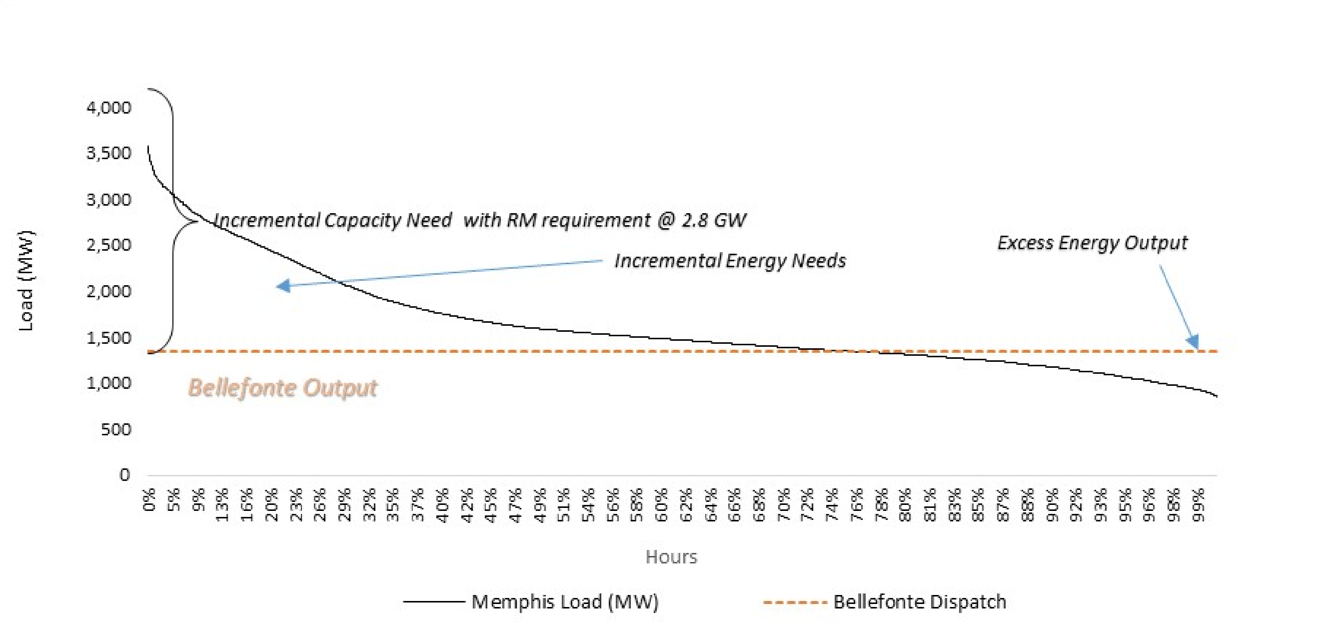
Bellefonte would meet over 70% of MLGW's needs on an energy basis (i.e., MWhs). We refer as the remaining MLGW needs, approximately 3.4 million MWh, as incremental power (see Exhibit 2-2). MLGW also requires an additional 2,800 MW of capacity for reliability – i.e., to meet peak annual demand (approximately 2,200 MW – see graph) plus the reserve margin requirements (approximately 600 MW, see graph).[9]

[7] The City of Memphis budget for 2019 is projected at approximately $685M

[8] FERC Form 714

[9] Utilities must maintain reserves to ensure reliable operation at the summer peak and during outages. This amount equals peak plus approximately 15% to compensate for unit outages and the possibility that peak demand is higher than expected. The 15% also assumes reserve sharing is in place to handle plant outages; the industry has sophisticated reserve sharing mechanisms, requirements, and regulations to ensure reliability. MLGW might be required to have modestly higher reserves due to the size of Bellefonte 1, approximately 150 to 300 MW. See later discussion in Chapter 3.

Exhibit 2-2: Memphis Load Relative to Bellefonte 1 Output



Source: FERC 714, ICF and Nuclear Development, LLC

Several options exist to obtain this incremental power:

- MLGW may be able source incremental power from the TVA grid under a "Partial-Requirements Service" contract. This is similar to the existing All-Requirements contract except TVA would provide less power, and only what is needed to supplement Bellefonte. This option requires TVA's agreement, which is not expected to be obtained easily.
- MLGW can source incremental power from nearby utilities.[10] Indeed, wholesale sales between large utilities and public power entities are common. The current TVA contract is an example of such a contract.
- MLGW can buy incremental energy and capacity in the spot markets. MLGW is adjacent to the nation's largest organized wholesale power market in terms of geographic extent, namely MISO. MISO has had prices for "adjusted all-in" incremental power of $110/MWh[11]. However, spot prices can be volatile, and capacity markets can be illiquid. Therefore, we do not recommend exclusive reliance on MISO spot prices as an option, but rather recommend a combination of long term contracts such as the Bellefonte PPA and other long terms arrangements to supplement spot purchases.

[10] https://www.gpo.gov/fdsys/pkg/GAOREPORTS-GAO-01-327/pdf/GAOREPORTS-GAO-01-327.pdf

[11] Over the last five years, the average MISO incremental price for "pure" energy was $40/MWh as published in their market reports. However, to this must be added a reasonable price for MISO capacity, transmission costs and inflation adjustments to estimate an "adjusted all-in" price for incremental power of approximately $110/MWh. This "all-in" incremental power is much higher than the $50/MWh for "all-in" base power as the capacity prices and firm transmission costs are spread over fewer MWh. TVA's LPC rate over last five years averaged around $72/MWh but a higher price has been estimated for incremental power of $107/MWh using the TVA 2015 tariff, refer to Chapter 8.4. See also later discussions related to volatility, hedging, and capacity market liquidity in Chapter 7.

- MLGW can transact spot and short-term energy combined with physical and financial hedges implemented by itself or an agent (e.g., another utility or third-party supplier). The most attractive option for incremental power is purchasing power from the wholesale power market combined with physical hedges, especially the purchase or long-term contracting of existing combined cycles (CC) owned by Independent Power Producers (IPP) in the Southeastern US.[12] The spot market purchases will likely be from MISO, although other options exist including bilateral sales. We recommend this hybrid, hedged approach (spot market purchases and long-term contracts/powerplant purchases) to decrease price volatility and take advantage of currently depressed prices for powerplants in the market.

Throughout the document, whenever we refer to market options (such as buying powerplants as a physical hedge) we emphasize that this can be done by a third party under contract or by MLGW itself. For example, a third-party provider of a Partial-Requirements Service contract built around the Bellefonte 1 PPA and market options built up with a mix of existing CC and combustion turbines (CT) assets. This emphasizes the likely economics of such a contract (for example, what the price will be), the flexibility MLGW will have in directing the hedging program and making trade-offs between savings and potential volatility. We also emphasize that whatever volatility exists is highly moderated by the Bellefonte 1 PPA and must be compared to the volatility of rates under the TVA contract. TVA rates have historically been volatile, and TVA's increasing reliance on non-baseload options (such as natural gas) can increase volatility. There is also the risk that if MLGW does not contract for Bellefonte, someone else may, which could put upward pressure on TVA rates as the fixed costs per MWh may increase as the remaining LPC load decreases.

Bellefonte 1 plus market options is facilitated by the ability to purchase power from open markets. MLGW is geographically adjacent to the nation's largest competitive deregulated wholesale power market, MISO.[13] MISO is an independent, not-for-profit entity regulated by the US Federal Energy Regulatory Commission (FERC). MISO has both energy and capacity markets.[14] MLGW can more easily access this very large and liquid marketplace than any other LPC or other load entity currently supplied by TVA because it is the only major (large load) LPC/entity adjacent to MISO.

The current costs of incremental wholesale power, energy, and capacity available in MISO at $60/MWh are lower than current TVA rates at $72/MWh.[15] One would expect the costs to be higher because MLGW's incremental needs are largely on-peak power and capacity reserves, which should cost more than average costs or baseload

[12] Other capacity purchase options are also possible – e.g., peakers. This is discussed later as a mix is recommended.

[13] We often refer to Entergy or MISO South when referring to the adjacent MISO marketplace. Size is measured in geographic area. It is the second largest in terms of load.

[14] Capacity refers to first call on generation capacity. The MISO capacity market has very low prices, but also low liquidity. The energy market is large and liquid.

[15] Of the $60/MWh, $40/MWh is pure energy and $20/MWh is for capacity. Note, this excludes the cost of firm transmission. If firm transmission ($50/MWh) was included to incremental power, then the price would be $110/MWh. $60/MWh +$50 MWh = $110/MWh.

power.[16] However, this is not the case because the market has excess low-cost, gas-fired capacity available for MLGW to contract or purchase.[17]

Purchases of IPP CCs and other powerplants occur frequently; a significant transaction was announced on August 22, 2018 involving a plant that can deliver to either TVA or neighboring Entergy.[18] Other recent transactions in this region indicate that gas fired plants can be purchased at less than half of new plant replacement costs due to excess capacity.[19] This "locks in" attractive market conditions. The report identifies potential sources of incremental capacity.

2.2.3 Incremental Power Volatility and Hedging

As attractive as current market conditions are, we emphasize a balanced view of market and contract is important. For reasons discussed later, the costs of gas-fired power and spot market power purchases can be volatile. Furthermore, the reported spot market price can increase in response to a large increase in demand, such as all of MLGW's incremental load coming onto market, especially its demand for capacity to meet annual peak demand plus reserves. While TVA would also have supply it would need to place, it could sell in a way that does not prevent an increase in capacity prices.

Two very important characteristics unique to MLGW's situation mitigate concerns about market volatility. First, the volatility of MLGW rates would be low primarily because 70% of the power is under the Bellefonte PPA, which has prices pre-set by a pricing formula that is fixed to a very large extent.[20] Low-cost baseload power (such as coal or nuclear) from an IPP like Nuclear Development, LLC is not typically available. Indeed, TVA itself has increasingly moved away from baseload power to gas. Slice-of-system deals at average costs are the norm, and these transactions do not allow for direct access to baseload supply but rather a mix. Second, MLGW can partially hedge these costs via a strategy of ownership of capacity (physical) and other mechanisms such as short- to medium-term gas or power hedges (financial).

[16] Because power cannot be easily stored, and demand and supply must be equal, as demand increases during on peak hours – e.g. afternoon, increasingly expensive units are used, and these units become the incremental or marginal-price setting source of power.

[17] For example, on August 22, 2018, Entergy, the utility adjacent to MLGW, announced purchase of modern advanced combined cycle for less than $400/kW – see MW Daily August 23, 2018, page 3. The article estimates the price equals 41% of the cost of a new combined cycle.

[18] Ibid.

[19] In 2017 Capital Power bought Decatur Energy Center from LS Power for $489/KW. In February 2015, TVA bought 760 MW of Quantum Ackerman Choctaw CCGT for $450/kW and in December 2014, Entergy bought ~2 GW of Union Power Station CCGT for ~$470/kW. See Exhibit 37 for list of recent transactions.

[20] The only non-fixed price component of the Bellefonte PPA price is the ability of ND to recover actual O&M including excess over the budgeted amount. As a proxy to any excess over budget, ICF has used 2.1% as an inflation factor associated with the underlying O&M component of price over time. This translates to only a 0.4% escalation on the full PPA price. ND did provide ICF with a draft PPA. While ICF does not have the individual components of the PPA, we estimate this impact to be approximately 30% of the total all-in costs on a going forward basis. See Chapter 5.2 for a full description of this derivation.

2.3 Feasibility

We assessed several aspects of the feasibility of a new contractual arrangement for MLGW's wholesale power including:

- **Availability of Firm Transmission** – Can Bellefonte power be delivered to MLGW? Who can deliver it? How much will it cost? Can incremental power be delivered to MLGW?
- **Availability of Reserve Sharing Arrangements** – What happens if there is an outage of Bellefonte 1 during peak demand periods? Are reserves available from other utilities to keep the lights on? How does reserve sharing work in the power sector?
- **Availability of Alternative Procurement and Contracting Arrangements** – What is involved in replacing TVA beyond power supply? Can this be self-supplied? Can it be purchased from others; that is, can MLGW expect availability of alternative providers of Partial-Requirements Service contracts organized around the Bellefonte PPA?[21]

2.3.1 Transmission

ICF power flow analysis concludes that power from Bellefonte 1 is deliverable to MLGW on the existing transmission grid without major upgrades.

MLGW is surrounded on three sides by high capacity, 500-kV transmission lines owned by TVA. These 500-kV lines are part of the backbone or highway portion of TVA's power transmission system. MLGW's 161-kV lines draw power from these lines. On the fourth side, MLGW is bounded by the Mississippi River and the MISO competitive power market (see Exhibit 2-3).

ICF believes that MLGW can likely obtain open access service from TVA to transmit the power from Bellefonte to MLGW.[22] The basis for this opinion is discussed in this report. In addition, ICF conducted a detailed transmission grid modeling exercise and found that transmitting Bellefonte power to MLGW does not require major new transmission investments on TVA's or any other system (though interconnection service and immediate upgrades in the Bellefonte area are required).

MLGW also has options to bring in Bellefonte power via alternative open access transmission systems. For example, MLGW can obtain incremental power via the MISO system. In our analysis of MLGW economics, we find it advantageous in some cases for MLGW to construct its own lines to MISO. When this is the case, we also conclude that power from Bellefonte 1 can be delivered over these lines as an alternative to service on TVA's system.

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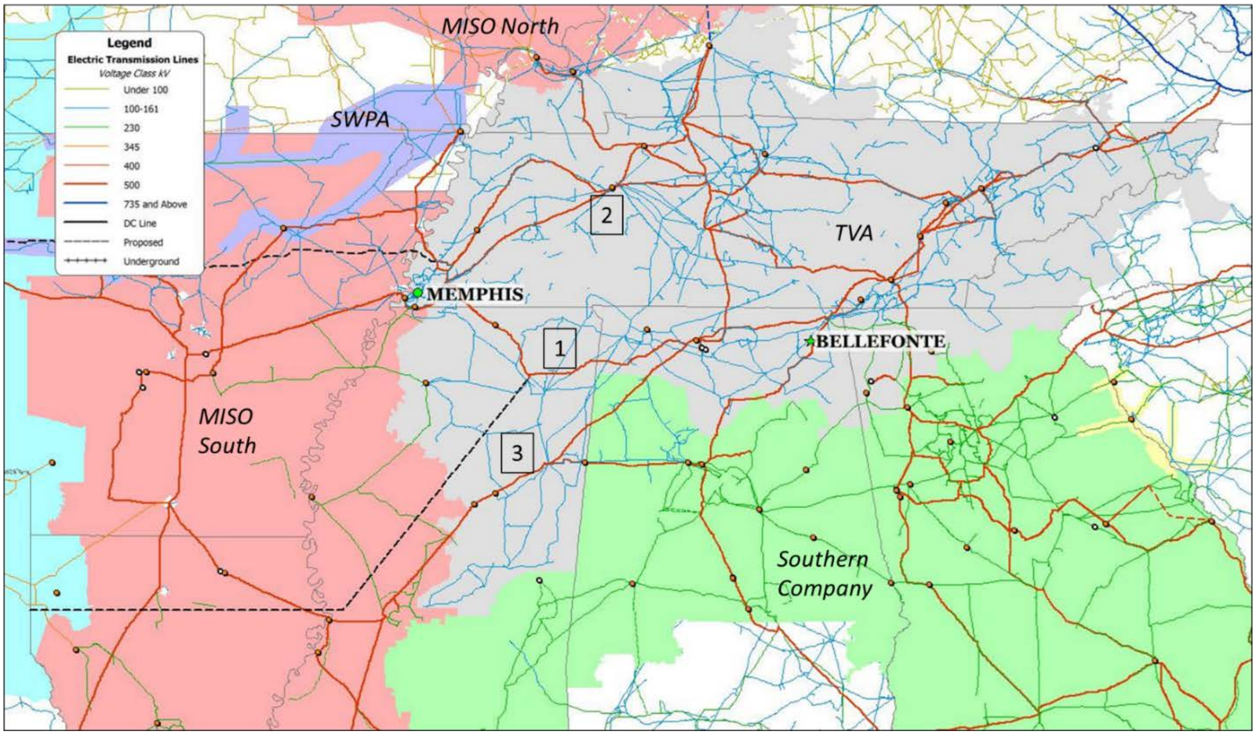
[21] Wholesale supply arrangements that are built around a receiving utility's own generation is common and referred to as Partial-Requirements Service contracts. Wholesale power contracts are subject to FERC regulation if one of the parties is FERC jurisdictional or the contract involves transmission (see discussion in a later chapter) and or reliability.

[22] https://www.ferc.gov/legal/maj-ord-reg/land-docs/rm95-8-0aa.txt

Exhibit 2-3: Transmission Lines and Balancing Authorities around Memphis



Source: Ventyx and ICF

2.3.2 Open Access Transmission and TVA

In accessing transmission service on the TVA system, MLGW would purchase firm transmission service in accordance with the FERC's open access transmission rules. FERC requires Transmission Providers (TP) like TVA to comply with requests for transmission service in accordance with their published open access transmission tariff. For example, in the case of Bellefonte, we anticipate that MLGW would purchase long-term, firm, point-to-point service with rights to extend transmission service over time.

Under FERC rules, if the transmission service requires transmission system upgrades, the TP can recover the costs from the buyer of the service and can delay service provision as long as it is making appropriate efforts to implement the identified grid upgrades. Therefore, a key issue is how costly and involved the upgrades will be if any are required. ICF analysis, using detailed grid "power flow" modeling and Critical Energy Infrastructure Information (CEII), finds no major upgrades on TVA's system are required.

There are some specific TVA aspects of transmission service; TVA is expected to resist providing service based on past TVA actions and recent statements by TVA in their tariff, reports, and other public documents. TVA claims it is not subject to open access as it pertains to its LPCs. TVA relies in large part on its reading of section 212(j) of the Federal Power Act. We are not lawyers and are not opining on the legal issues involved, but believe that these TVA-specific conditions notwithstanding, open access transmission is available from TVA. This belief has two supporting rationales. First, our conclusion derives from our general understanding of transmission rules and regulation. Second, our conclusion also derives from very relevant FERC decisions. In light of the lower costs that TVA service provides, we discuss open access at some length here and elsewhere in the report. However, it is not a prerequisite, transmission alternatives exist for MLGW that even TVA stipulates to.

We base our expectation that TVA will provide open access transmission in part on a reading of a parallel case involving TVA and another TVA wholesale customer.[23] In this case, the US FERC Order "Denying Rehearing", issued on June 20, 2006 in Docket No. TX05-1-006, FERC addresses the ability to obtain transmission service on the TVA system (paragraph 22). FERC states that, "our authority to implement portions of the open access policy established in the OATT (Open Access Transmission Tariff) derives from the requirement under sections 205 and 206 of the FPA (Federal Power Act) to remedy undue discrimination, not sections 210 or 211."[24] Our understanding is therefore that even if Section 212(j)[25] prohibits FERC from ordering TVA to provide transmission services under Section 211, which it appears to do, FERC can effectively order open access transmission under sections 205 or 206 via what is referred to as "reciprocity."[26] That is, FERC can prevent jurisdictional utilities from providing open access transmission to TVA unless TVA provides open access to other jurisdictional utility systems. Put another way, access to transmission is based on "belts and suspenders." Even if one rule is vitiated, the other rule remains.

TVA states it voluntarily has an open access tariff in that it voluntarily agrees to reciprocity and can change its view were it to involve service to one of its LPCs. While true, this exaggerates TVA's flexibility. Were TVA to decline to provide open access transmission via reciprocity to other systems (such as MLGW), to our knowledge TVA would be the only major entity in the United States (US) to do so. Furthermore, such a unique circumstance may result in adverse implications for many of TVA's current transmission activities. This is because TVA would lose open access transmission on other systems. Transmission is required for reserve sharing, transmission for economic reasons with neighbors, power purchase agreements, interconnection, and handling inadvertent flows on other systems. These are core utility activities. Accordingly, while theoretically possible, it is not practical to refuse reciprocity – that is, to refuse open access.[27]

TVA opposition may manifest itself in other areas including stranded costs and fees for returning to TVA service later. However, we believe the threat of stranded costs is a red herring because MLGW would honor its contract, which allows it to give termination notice without a charge. Even if stranded costs were an issue, which we do not believe, stranded costs can only be calculated for a period where TVA expected to serve MLGW that but for open access was being shortened. In the event MLGW terminates the contract, the terms of the contract preclude TVA from seeking stranded costs, provided however, the termination notice is given no earlier than after 2012 (i.e., ten years after the 2003 Supplemental contract with TVA). When this ten-year period is combined with the five year termination notice, this results in a 15 year period i.e., after 2017 no costs can be recovered (see Chapter 9.1.4 for further discussion). However, because MLGW is fulfilling its contract, there would be no such period, and thus, the calculation would be zero stranded costs.[28] This is discussed further later in Chapter 9.

[23] We are not lawyers and are not opining on the legal issues involved.

[24] TVA appealed the FERC rejection of its appeal in federal court, but the case was settled and hence not decided by the court.

[25] Referred to as the TVA anti-cherry-picking provision.

[26] We are not lawyers and are not opining on the legal issues involved.

[27] Even if TVA could reject reciprocity, and withdraw from FERC's competitive construct, Congress could still change the law in this regard. We have no opinion on the prospects for legislation, but note proposals were made in the late 1990s to open TVA to further deregulation.

[28] All ICF statements on the TVA contract are caveated as our understanding in the absence of review and our inability as non-lawyers to opine on legal issues.

2.3.3 Generation Reserve Sharing

Reserve sharing is a form of insurance and regulated by the FERC. The idea is that plant outages are highly independent, and it is not likely that everyone will need generation back-up at the same time. If during peak, one utility has an outage (for example, MLGW loses Bellefonte 1), it can purchase back-up power from its neighbors. Historically, transmission was built between utilities in significant measure to allow for this sharing of reserves.

Utilities, or groups of utilities, also referred to Balancing Authorities (BA), are the sharing entities. Reserve sharing agreements cover the entire grid. In exchange for maintaining approximately 15% reserve capacity on a planning basis, maintaining their share of operating reserves (a category of quick response reserves such as spinning reserves), and meeting other requirements, BAs can obtain power from their neighbors in the event of an unexpected power plant outage.

All utilities are subject to mandatory FERC reliability regulation rules and regulations on reserve sharing and reliability. The US Electric Reliability Organization (ERO), the North American Electric Reliability Corporation (NERC), establishes and enforces these requirements. BA agreements must conform to NERC compliance rules and standards.

MLGW qualifies for reserve sharing like any other US utility. The exact form reserve sharing takes depends on the contractual arrangements of MLGW. For example:

- In the case where MLGW has partial-requirements service with TVA, TVA would still provide the reserve sharing service.
- In the case where MLGW joins MISO, MISO would provide the reserve sharing service.
- In the case in which another utility provides partial-requirements service, that utility would provide the reserve sharing services.
- Finally, in the case where MLGW becomes its own BA, it would form an agreement with a neighboring BA (such as MISO or other Southeastern Electric Reliability Coordination (SERC) utilities) to provide reciprocal reserve sharing.[29]

We are not aware of a circumstance in which a BA with transmission access to neighbors was denied access to a reserve sharing agreement that meets NERC requirements. This allows the BA to hold a reasonable level of reserves as opposed to going it alone, holding huge amounts of reserves and acting as if it is on an island when it is in fact not. If large neighbors unfairly deny a neighbor access to reserve sharing agreements, this might be considered an anti-competitive exercise in market power.[30]

[29] SERC covers the southeastern US except Florida.

[30] Requiring a new entity to cover any incremental costs of their joining a reserve sharing agreement would not be unduly discriminatory or anti-competitive behavior. In general, the larger the sharing group, the lower the costs and the lower the reserve requirements. Very large units can increase the costs and the incremental costs could be allocated to the entity with that unit. However, these costs are likely to be small because most groups already have at least one very large unit. In the absence of an agreement, the BA would have to obtain NERC approval for its reserve plan. It may also rely on best efforts from neighbors with payment at rates regulated by FERC but potentially not as attractive as the rates it would incur if there was an agreement.

2.3.4 MLGW Can Procure Wholesale Requirements Supply from Other Suppliers

MLGW already has decades of experience contracting for wholesale power. However, the form of the contract is an All-Requirements contract in which TVA handles the full set of MLGW's wholesale requirements, including baseload and peaking power, scheduling, reserves, balancing services, compliance with regulatory requirements, transmission procurement, planning, and security coordination. TVA also is large and has a diverse fleet of plants.

Most likely, some other entity will become the new requirements provider building the power supply and services around the Bellefonte 1 PPA and incremental power. This is feasible and common in the industry. We describe in later sections the activities involved and resources required; while MLGW can self-provide these services, a more likely arrangement is some outsourcing with MLGW involved in setting strategic direction on hedging incremental power.

2.4 Results

In this section, we present more detailed results of our economic analysis.

ICF analyzed the economics of several contracting strategies and are shown below in Exhibit 2-4. We report both gross and net savings relative to a Business as Usual (BAU) case:

- **Gross Savings** – We define gross savings as the BAU case less the combined cost of the Bellefonte PPA and incremental energy costs.
- **Net Savings** – We define net savings as gross savings less additional costs incurred to implement a scenario. These costs could include but are not limited to building new transmission lines, securing firm transmission, and securing physical reserves needed to maintain the reliability of the Memphis distribution system.

As discussed, we present both estimates because the main difference between gross and net is the cost of procuring MLGW's incremental capacity needs, and this may involve trade-offs between hedging and costs.

2.4.1 Business as Usual (BAU) Case

Under the BAU, MLGW continues to purchase under TVA's full-service requirements contracts and the wholesale power costs reflect the average costs of service from TVA including average fuel, non-fuel O&M, purchased power, capital recovery, and profits. In 2024, costs are projected to equal approximately $1.15 billion. Over the 30-year period of 2024 to 2053 the average cost is $1.4 billion. This escalates over time in part as a function of general inflation, but also due to other factors (see Chapter 4.3 for a full review of our TVA rate projections). Over the past 10 years (2008-2017) the TVA rate for LPCs has ranged from a low of $62/MWh in 2008 to a high of $74/MWh in 2017, with about two-thirds of the rate reflecting recovery of fixed costs.[31] TVA rates have grown at an average of 2.2% per year over the past 10 years, and the rate is projected to grow at an average of 1.7% from 2024 to 2053. All the other cases that follow are discussed relative to this BAU case.

[31] Fixed cost includes fixed O&M, interest expenses, depreciation, and tax equivalents.

Exhibit 2-4: Summary of Memphis Gross and Net Savings Relative a "Business as Usual" Case ($MM)

Business as Usual ($MM)

Business as Usual	Levelized Costs (2024-2053)	Cumulative Costs (2024-2053)	2024	2030	2035	2040	2045	2050	2053
TVA Rate Cost - Business as Usual Case	1,417	46,776	1,154	1,356	1,431	1,502	1,698	2,026	2,162

Option #1: TVA is Balancing Authority and Partial Service Requirements from TVA ($MM)

Option #1: TVA is BA / Partial Service Requirements from TVA	Levelized (2024-2053)	Cumulative Savings (2024-2053)	2024	2030	2035	2040	2043	2050	2053
Gross Savings ($MM)	**466**	**15,565**	**363**	**459**	**472**	**480**	**561**	**713**	**763**
Incremental Other Cost/Revenue ($MM)	**0**	**7**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Regulatory Cost	0	7	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Net Savings ($MM)	**466**	**15,558**	**362**	**459**	**472**	**480**	**561**	**713**	**763**

Option #2A: MISO is Balancing Authority and Incremental Power is Hedged ($MM)

Option #2A: MISO is BA / Inc. Power Hedged	Levelized (2024-2053)	Cumulative Savings (2024-2053)	2024	2030	2035	2040	2043	2050	2053
Gross Savings ($MM)	**686**	**22,132**	**567**	**699**	**702**	**697**	**756**	**946**	**1015**
Incremental Other Cost/Revenue ($MM)	**199**	**6,785**	**152**	**176**	**201**	**229**	**261**	**298**	**323**
Capacity Cost	105	3,589	78	92	106	121	139	159	172
Transmission Upgrade	58	1,927	47	53	59	65	72	80	85
Regulatory Cost	34	1,161	26	30	34	39	44	51	56
Ancillary Cost	10	333	8	9	10	11	13	15	16
Excess Energy Sold in Spot Market	-8	-226	-8	-8	-8	-7	-7	-7	-6
Net Savings ($MM)	**487**	**15,347**	**416**	**522**	**502**	**468**	**495**	**648**	**692**

Option #2B: MISO is Balancing Authority and Incremental Power is Purchased from the Spot Market ($MM)

Option #2B: MISO is BA / Inc. Power Spot Market	Levelized (2024-2053)	Cumulative Savings (2024-2053)	2024	2030	2035	2040	2045	2050	2053
Gross Savings ($MM)	**686**	**22,132**	**567**	**699**	**702**	**697**	**756**	**946**	**1015**
Incremental Other Cost/Revenue ($MM)	**349**	**11,299**	**299**	**328**	**347**	**378**	**413**	**451**	**476**
Capacity Cost	253	8,051	224	242	251	269	289	310	323
Transmission Upgrade	58	1,927	47	53	59	65	72	80	85
Regulatory Cost	34	1,161	26	30	34	39	44	51	56
Ancillary Cost	12	385	10	11	12	13	15	16	17
Excess Energy Sold in Spot Market	-8	-226	-8	-8	-8	-7	-7	-7	-6
Net Savings ($MM)	**337**	**10,833**	**269**	**371**	**355**	**318**	**343**	**495**	**539**

Option #3A: MLGW is Balancing Authority and Incremental Power is Hedged ($MM)

Option #3A: MLGW is BA / Inc. Power Hedged	Levelized (2024-2053)	Cumulative Savings (2024-2053)	2024	2030	2035	2040	2045	2050	2053
Gross Savings ($MM)	**522**	**16,533**	**445**	**555**	**537**	**507**	**539**	**698**	**746**
Incremental Other Cost/Revenue ($MM)	**177**	**6,062**	**134**	**156**	**178**	**204**	**234**	**269**	**292**
Capacity Cost	105	3,589	78	92	106	121	139	159	172
Transmission Upgrade	58	1,927	47	53	59	65	72	80	85
Regulatory Cost	12	438	9	10	12	14	17	22	25
Ancillary Cost	10	333	8	9	10	11	13	15	16
Excess Energy Sold in Spot Market	-8	-226	-8	-8	-8	-7	-7	-7	-6
Net Savings ($MM)	**345**	**10,471**	**311**	**398**	**359**	**303**	**305**	**430**	**454**

Option #3B: MLGW is Balancing Authority and Incremental Power is Purchased from the Spot Market ($MM)

Option #3B: MLGW is BA / Inc. Power Spot Market	Levelized (2024-2053)	Cumulative Savings (2024-2053)	2024	2030	2035	2040	2045	2050	2053
Gross Savings ($MM)	**522**	**16,533**	**445**	**555**	**537**	**507**	**539**	**698**	**746**
Incremental Other Cost/Revenue ($MM)	**327**	**10,576**	**281**	**307**	**325**	**354**	**386**	**421**	**444**
Capacity Cost	253	8,051	224	242	251	269	289	310	323
Transmission Upgrade	58	1,927	47	53	59	65	72	80	85
Regulatory Cost	12	438	9	10	12	14	17	22	25
Ancillary Cost	12	385	10	11	12	13	15	16	17
Excess Energy Sold in Spot Market	-8	-226	-8	-8	-8	-7	-7	-7	-6
Net Savings ($MM)	**195**	**5,957**	**164**	**247**	**212**	**154**	**153**	**277**	**302**

Source: ICF

2.4.2 Bellefonte PPA Plus Physical Hedges to Cover Incremental Needs [32]

Most-Economic Strategy: MLGW becomes part of MISO, purchases Bellefonte 1 power plus incremental MISO power, and buys contracts and/or existing powerplants as part of a physical hedging strategy to further control the volatility of incremental power costs.

2.4.2.1 Results

We consider Option 2A the main alternative procurement strategy for MLGW compared to the BAU case. This is because it does not depend on the approval of TVA, does not heavily rely on unhedged spot market purchases for incremental power, and offers the most savings relative to BAU. The annual gross savings is estimated at almost $567 million in the first year. The annual average net savings is estimated at $487 million per year, and $416 million starting in 2024, the first year of this study[33]. This is over 35% savings in 2024 relative to the $1.15 billion in cost in the BAU case. This savings primarily reflects the lower costs of the Bellefonte PPA; the PPA costs equal the variable costs of TVA and allows MLGW to effectively avoid paying TVA's fixed costs. Savings per MLGW customer equal approximately $1,129 per year. These savings are significant: in comparison, Memphis's

[32] Also referred to as $25/kW-yr case. This is because the upfront purchase of the plants costs $25/kW-yr (i.e. fixed costs less energy margins) rather than forecasted higher levels due to eventual tightening in the market for capacity.

[33] Net savings is defined as gross savings less the costs incurred to implement a particular scenario. These cost incurred could include but not limited to the building of new transmission lines, the securing of firm transmission, and securing of physical reserves need to maintain the reliability of the MLGW distribution system.

2019 annual projected budget, excluding MLGW, is approximately $685 million.[34] Over 20 years, cumulative gross savings is projected at $22 billion, and cumulative net savings is projected at $15 billion.

In addition to purchasing Bellefonte power and the associated firm transmission for delivery, MLGW either purchases the needed transmission service to become part of MISO or builds the transmission to directly interconnect, whatever costs the least. Large transmission lines link MLGW to TVA and then across the river to contiguous MISO. If new lines are needed, the distance to key MISO substations would likely be small (about 75 to 100 miles). Nevertheless, our estimate assumes and includes the cost of new line construction.

2.4.2.2 Hedging and Capacity Costs

MLGW would also purchase contracts and/or existing powerplants located in MISO to partly hedge against price volatility of incremental power – that is, to hedge the approximately 30% of energy and 3,000 MW of capacity not covered by the Bellefonte PPA (this capacity covers peak plus required reserves).[35] This would supplement MLGW's main hedge in the Bellefonte PPA, which has costs that are largely fixed. This "buy-capacity-now" hedge strategy is attractive because there is excess capacity in the wholesale power market that can be locked in via purchases of capacity. Recent comparable transactions (powerplant sales) strongly support the view that existing CCs can be purchased at approximately 40%-50% of replacement costs.[36] These plants provide hedges against the potential for higher MISO energy and capacity prices later. We assume these plants, a mix of CCs and peakers, can be purchased at an estimated $230/kW.[37]

These plants can also hedge their fuel costs, but this type of hedge most likely will have to be renewed periodically at prices then prevalent; it is not a perfect hedge on its own.[38] Other hedging strategies may exist. In addition, other capacity purchases may be economic, including some peakers and other plants such as existing renewables and otherwise-retiring coal plants. These strategies would be investigated as part of the Partial-Requirements Service contracts MLGW would undertake.

2.4.2.2 Recent Spot Prices Versus ICF Forecasts

ICF forecasts the economics of this arrangement including future power prices using industry standard computer modeling, as described in the appendix. This forecast shows rising spot prices. However, it should be noted that MISO spot prices have been very low, and if power were to be available in the future at these low prices, even greater savings would occur. MISO energy prices are volatile and over the last five years, the average all hours energy price in MISO was $31.5/MWh while the range was $13/MWh or from $24/MWh to $37/MWh. MISO capacity prices have been near zero, but supply curve in the MISO capacity market is very steep. Adding the

[34] https://www.memphistn.gov/UserFiles/Servers/Server_11150732/File/Gov/Financial%20Division/FY_2019_Adopted_Budget/Budget%20Overview.pdf

[35] We focus here on energy and capacity because these are the largest wholesale services. Also required is transmission, ancillary services (usually the smallest portion after energy, capacity, and transmission), and system operations. We account for all these items and discuss them in later chapters.

[36] Choctaw at less than $400/kW in August 2018. Choctaw interconnects with TVA and Entergy.

[37] We estimate an 1/3 combined cycle and 2/3 simple cycle combustion turbine mix based on the incremental load requirements of MLGW after Bellefonte 1 capacity is considered.

[38] Long term financial hedging can require mark to market collateral requirements, and hence long term financial hedging is not typical practice. Hedging is unlikely to be perfect, due to basis differences, but likely to be efficacious overall.

components of MISO capacity, transmission costs and inflation adjustments translates to a higher MISO all-in price of approximately $50/MWh. We do not recommend exclusive reliance on spot sales without hedges for incremental power in part because we expect higher prices (particularly for capacity) over time, but the exact extent of hedging as opposed to spot or short-term transactions would be determined over time.

The hedging costs assume that the capacity purchased is located in MISO and has no basis difference with MLGW.[39] If the capacity is purchased outside of MISO, additional transmission charges may be needed in order to sell the power output of the capacity in MISO/MLGW. However, even plants that are purchased outside MISO may still generate revenue from power that can be sold outside MISO.[40] If half the capacity is bought outside MISO and one wheel of firm transmission to MISO is required, then costs increase tens of millions of dollars per year.

Finally, additional costs are incurred to become part of MISO, namely the socialization of on-going and future transmission infrastructure and MISO admission fees.

A variation on this “buy-capacity-now” strategy was analyzed with MLGW being its own BA. We refer to this as Option #3A in the Exhibit 2-4 above. Savings are less than in Option #2A since the cost of securing firm transmission to access contracts in the MISO market outweighs is much larger than costs of joining MISO.

2.4.3 Bellefonte PPA Plus Spot Market to Cover Incremental Needs [41]

In the Option 2B case above, MLGW becomes part of MISO, purchases Bellefonte power plus incremental MISO spot power, and does *NOT* hedge – that is, MLGW does not buy contracts or existing powerplants as part of a hedging strategy for incremental power volatility risk.

This is the same as the previous case except MLGW does not purchase generation capacity to hedge incremental power risks but rather relies on spot purchases. This is not only a more volatile strategy but is expected to have higher costs and less savings relative to BAU. This is because we expect the low costs of existing units will not be available over time. Rather, a temporary buying opportunity currently exists. Thus, we do not recommend a highly spot-market oriented approach; this option illustrates that early attention to incremental power offers the potential for lower expected costs and less volatility.

Annual net savings equal $337 million per year, and $269 million starting in 2024, the first year of this study. This is over 20% savings in 2024 relative to the $1.15 billion in cost in the BAU case.

[39] Basis difference refers to differences in prices by location. For example, if market prices rise, the value of owning the power plants increases, offsetting the impact of higher prices. However, if the percent increase of power delivered to MLGW increases faster than prices at the busbar of the powerplant, the hedge could have basis risk.

[40] For example, one can think of all incremental energy being purchased from MISO, and all incremental capacity purchased through contracts. The net energy profits from operating the purchased capacity being used to offset the costs of the MISO purchase power.

[41] Also referred to as “Option #2B: MISO is BA / Inc. Power Spot Market” case. This is because without upfront purchase of the plants, capacity value eventually increases (i.e., fixed costs less energy margins) than $25/kw-yr due to the eventual tightening market for capacity as explained in Chapter 7.

A variation on this "spot purchases" option strategy was analyzed with MGLW being is own BA. We refer to this as Option #3B in the Exhibit 2-4 above. Savings are less than in Option #3A, as the cost of securing firm transmission to access the MISO spot market is larger than the costs of joining MISO.

2.4.4 Bellefonte PPA Plus TVA Partial-Requirements Service to Cover Incremental Needs

In this scenario, MLGW buys power under the Bellefonte PPA, and incremental power is purchased from TVA under a Partial-Requirements Service contract. This is referred to Option #1 in the Exhibit 2-4 above.

We do not consider this case as attractive to MLGW because its costs are likely higher than what the current market alternative suggests. This may also not be feasible to the extent it requires agreement by TVA. Because TVA provides primarily incremental on-peak power rather than both on-peak and off-peak, and because on-peak is usually more costly than off-peak, the costs are higher than TVA's average for full-requirements service, and higher than the market alternative discussed above. Note the premium for on-peak power is based on TVA's tariff, but a negotiated outcome might differ.[42]

2.5 Implementation Challenges

Historically TVA has resisted the departure of its full-service customers. Based on this record and TVA statements in their public materials, TVA may challenge the use of its transmission lines to serve MLGW load and may attempt to claim its right to physically disconnect MLGW from the grid. TVA may also attempt to impose stranded costs on MLGW, and if MLGW reverses its decision back sometime in the future, TVA may impose some type of "re-integration" fee.[43] TVA is also likely to tout its experience, its diverse portfolio, and its average-cost approach to rates.

However, we believe that MLGW can save significantly on power costs and can successfully overcome implementation challenges because:

Past FERC Transmission Decisions – While we are not lawyers, and cannot offer legal opinions, TVA's claim that it does not have to provide open access transmission to MLGW is implausible. This is because:

- It violates the open access principles that are at the core of the industry deregulation and structure. It is also strongly in opposition to the principles underlying 20 years of deregulation and reliance on open access including the reciprocity principle, a cornerstone of FERC policy since Order 888 in 1996.
- Furthermore, and most importantly, FERC has repeatedly addressed this specific TVA claim in another case of a utility desiring to terminate its contract. FERC ruled on this matter and concluded that TVA's claims that it has the ability to deny transmission services are incorrect. We discuss this further in the Chapter 9 on transmission access. This view is expressed in a FERC decision and FERC sustained this decision on an appeal. FERC effectively has a belts and suspenders approach to requiring open access, and TVA's argument eliminates the suspenders but leaves the belt.

[42] http://www.florenceutilities.com/Electricity_Department/Rate_Chart/Wholesale%20Power%20Rate%20-%20Schedule%20WS.pdf

[43] See previous examples of Warren County and City of Bristol.

- We are not aware that any major power system in the US has chosen not to implement reciprocity, that is provide open access to have open access. TVA operations might be so hampered and become less competitive with other sources of power that FERC has directly addressed the opposite concern; namely that open access system can deny TVA access. In 1996, in the original FERC Order 888,[44] FERC assured TVA it will be able to obtain open access on other systems.[45]
- Furthermore, with the caveat that we are not offering a legal opinion, TVA actions to withhold open access transmission could be seen as an exercise in market power and manipulation. Open access is a predicate for competitive markets.

Past Instances – Customers have successfully departed TVA requirements contracts without adverse circumstances, namely the City of Bristol in 1997.

Bellefonte 1 Risks – It was not within our scope to assess the degree of completion or the costs of finishing Bellefonte. Rather, ICF assumed the costs and performance of the Bellefonte PPA would perform as contracted. However, ICF has assessed the availability of transmission, the costs of incremental power, and the costs of TVA service. ICF has also assessed important feasibility issues such as access to transmission service and reserve sharing.

Recontracting Risks – Of course, were MLGW's current TVA contract to be terminated, a new TVA/MLGW contract, if desired by both parties, would have to be negotiated. However, as we have shown, MLGW has many options.

2.6 Conclusions

ICF analysis indicates very large expected savings from the Bellefonte PPA relative to a continuation of TVA full-requirements service. MLGW has a rare opportunity to have baseload power at low cost. It would also be able to take advantage of low costs for incremental power existing in the market today. Other advantages exist, including:

Contractual Flexibility – While we have not reviewed the contract between TVA and MLGW, it is our understanding that TVA must give at least 10-year notice to terminate requirements service while MLGW must only give at least five-year notice. This asymmetry favors MLGW and provides protection. Five years versus 10 years is important because the lead-time to complete Bellefonte is approximately five years, not 10 years[46].

Location – MISO – The specific circumstances give considerable optionality and back-up to MLGW. MLGW is located at the western extremity of the area currently served by TVA via sale of wholesale services, and the western area of the contiguous US not served by an organized market (the southeastern US is the last remaining major area not to have an organized electrical energy market). It is adjacent to MISO, the nation's largest organized competitive market place. MLGW can access incremental power via TVA – MISO to TVA to MLGW – but also directly from MISO by constructing new transmission over a very short distance to tie in into the massive and liquid MISO system.

[44] https://www.ferc.gov/legal/maj-ord-reg/land-docs/rm95-8-00w.txt

[45] https://www.ferc.gov/legal/maj-ord-reg/land-docs/rm95-8-0aa.txt

[46] The five year notice cannot be given in the first ten years following the 2003 contractual supplement. That period has now ended, and hence, termination with five-year notice is now permitted. See later discussion.

Open Access Transmission – Available – "First Come First Serve" – TVA – As discussed, the TVA system can accommodate the transfer of power from Bellefonte to MLGW without upgrades. Under open access rules, there is a "first-come first-serve" allocation of transmission capability. Later customers cannot access the system's current available transmission capacity, but rather can only access what would be left over after accounting for the usage by the Bellefonte to MLGW move. MLGW's first mover advantage could be lost by dilatory action regarding transmission service.[47]

Location – Southern Company – While not likely required, the Bellefonte plant is also located on the edge between the Southern Company and the TVA systems. It can readily interconnect to the Southern Company system and wheel the power through Southern to MISO and then to MLGW. This is not as economic as moving power directly through TVA but is an option in the unlikely case TVA blocks the transmission transfer of Bellefonte.

Baseload Option – Even if there is a resource option available at a low cost to a utility provider like TVA, the buyer (such as MLGW) currently accesses only average costs, not the cost of the new, low-cost option. This is especially the case for nuclear power, which is built by utilities with costs, recovered not for the nuclear powerplant alone but in the context of an average cost accounting and ratemaking. MLGW has a chance to access a nuclear unit with low costs, and not have to pay average TVA costs. The plant is also close in size to the MLGW's baseload demand and thus MLGW can leverage a single contract to hedge over 70% of its energy requirements. This is not likely to be a common option for entities of MLGW's size.

Buyer's Market – Existing, modern gas-fired powerplants are available at low cost compared to new units and can be purchased to handle incremental power and reserve requirements as an alternative to relying on spot markets. Rarely is a comparable transaction as apropos as the one announced August 22, 2018 in Mississippi where neighboring Entergy bought a plant at reportedly 41% of replacement cost (the cost of a new gas-fired combined cycle).

Bellefonte is a Hedge – Underlying this recommendation of physical hedging of incremental power is our experience that rate stability is often a goal of municipal utilities like MLGW. However, we emphasize that decisions related to risk and volatility will likely have to be made by MLGW in counsel with their experts and/or contractors. Further, since 70% of MLGW's needs would be met at very stable pricing according to our understanding of the Bellefonte PPA, some risks for lower costs can be attractive. Finally, a claim that the recommended strategy is risky and volatile would be hyperbolic considering that TVA's LPC price over the last ten years has varied quite a bit, between $62/MWh and $74/MWh.

Lastly, we find that Bellefonte's low rate may, in part, be due to circumstances unique to the project, and there may be an advantage to being the primary/first off-taker of power in a market like TVA where system costs are spread across a wide customer base. If others exit the system based on the Bellefonte 1 opportunity, TVA's fixed costs would have to be borne, in whole or in part, by the remaining customers.

In summary, we find the following and detail our analysis in the remainder of this report:

- Bellefonte 1 can serve a majority of MLGW's energy needs at a rate significantly lower than TVA (see Chapters 3-5)

[47] We have not estimated the amount of remaining transmission service. However, in general, each firm transaction decreases it, all else equal.

- MLGW has multiple options for sourcing its remaining “incremental” needs including hedging options (Chapter 6);
- Accessing the MISO market offers a wider range of purchase power options at affordable prices (Chapters 7-8);
- Though MLGW has legal rights to pursue alternate power, TVA may push back but lacks the ability to deny transmission or otherwise impede the transaction (Chapter 9); and
- We detail incremental capabilities required by MLGW should it choose to source power outside of TVA, which we expect to be available (Chapter 10).

3. Overview of Memphis Light, Gas, and Water

Memphis Light, Gas and Water is the nation's largest three-service municipal utility, serving nearly 421,000 customers. Founded in 1939, MLGW meets the utility needs of Memphis and Shelby County by delivering reliable and affordable electricity, natural gas, and water services. MLGW is led by a President and Board of Commissioners who are appointed by the mayor of Memphis and approved by the Memphis City Council. The remainder of this chapter of the report focuses solely on the provision of electricity. Summary statistics for MLGW electric sales are shown in Exhibit 3-1.

Exhibit 3-1: Breakdown of MLGW Electric Customers and Sales

2017 Summary	Customer (Count)	Sales (TWh)
Residential	370,693	5.04
Commercial - General Service	43,469	6.14
Industrial	118	1.87
Outdoor Lighting and Traffic Signals	17,186	0.17
Interdepartmental	36	0.09
Total	**431,502**	**13.31**

Source: MLGW Annual Report 2017[48]

MLGW does not own or directly contract with any significant generation resources. As a result, the reliability and affordability of the power it provides to its customers depend in large part on the reliability and affordability of the wholesale power and grid services it purchases from third parties. Historically, all of these services have been provided by TVA, the largest federal power agency in the US. Further, MLGW is TVA's largest single customer, representing 11% of TVA's total load.

Wholesale power needs can be summarized into the following major buckets:

- **Energy and load shape –** total electric energy (TWh) provided at the right levels instantaneously throughout the year;
- **Peak demand plus reserves –** total maximum electric capacity (GW) needed during the peak hour in a year, plus a reserve margin to insure against contingency;
- **Transmission –** connection from generation to interface points between the distribution and transmission grids, resilient against transmission outages;
- **Ancillary services –** operating reserves (spinning and non-spinning), voltage regulation, and others that ensure grid stability; and
- **System operation –** technical needs for managing, scheduling, and regulating a wholesale grid interface with its existing distribution system.

Finally, MLGW needs the technical capabilities to interface and contract with the required services above.

MLGW's average expected energy and peak demand for the period 2018 to 2027 are 14,219 GWh and 3,561 MW, respectively, as reported in FERC's latest Form 714, released in 2017. The expected annual energy growth

[48] http://www.mlgw.com/images/content/files/pdf/MLGWAnnualReport2017-web.pdf

from 2018 to 2027 averages 0.43% and total peak demand reaches 3,631 MW by 2027. Exhibit 3-2 below shows ICF's projection of energy and peak for MLGW.

Exhibit 3-2: MLGW Projected Peak and Energy Demand

Year	Memphis, Light, Gas and Water			
	Summer Peak Demand (MW)	Peak Demand Growth (%)	Net Energy for Load (GWh)	Net Energy Growth (%)
2018	3,496		13,959	
2019	3,508	0.34%	14,006	0.34%
2020	3,522	0.40%	14,064	0.42%
2021	3,537	0.43%	14,124	0.43%
2022	3,552	0.42%	14,184	0.42%
2023	3,567	0.42%	14,245	0.43%
2024	3,583	0.45%	14,307	0.44%
2025	3,599	0.45%	14,370	0.44%
2026	3,615	0.44%	14,434	0.45%
2027	3,631	0.44%	14,500	0.46%
2028	3,647	0.44%	14,564	0.44%
2029	3,663	0.44%	14,629	0.44%
2030	3,679	0.44%	14,693	0.44%
2031	3,695	0.44%	14,758	0.44%
2032	3,712	0.44%	14,824	0.44%
2033	3,728	0.44%	14,889	0.44%
2034	3,745	0.44%	14,955	0.44%
2035	3,761	0.44%	15,021	0.44%
2036	3,778	0.44%	15,087	0.44%
2037	3,794	0.44%	15,154	0.44%
2038	3,811	0.44%	15,221	0.44%
2039	3,828	0.44%	15,288	0.44%
2040	3,845	0.44%	15,356	0.44%
2041	3,862	0.44%	15,424	0.44%
2042	3,879	0.44%	15,492	0.44%
2043	3,896	0.44%	15,561	0.44%
2044	3,913	0.44%	15,629	0.44%
2045	3,930	0.44%	15,699	0.44%
2046	3,948	0.44%	15,768	0.44%
2047	3,965	0.44%	15,838	0.44%
2048	3,982	0.44%	15,908	0.44%
2049	4,000	0.44%	15,978	0.44%
2050	4,018	0.44%	16,049	0.44%
2051	4,035	0.44%	16,120	0.44%
2052	4,053	0.44%	16,191	0.44%
2053	4,071	0.44%	16,262	0.44%
Average (2018-2053)	3,774	0.44%	15,071	0.44%

Source: FERC Form 714 and ICF

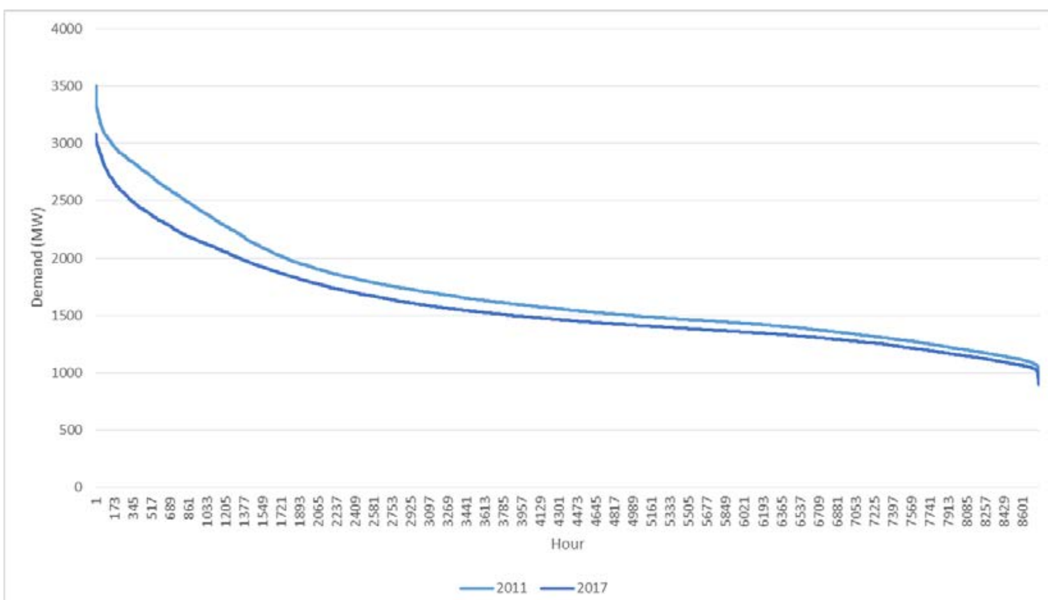
In service territories connected to broad regional networks with reserve sharing (such as the Eastern Interconnect), standard reserve margin requirements are often around 13%-15%. Therefore, MLGW's capacity need including reserves (15% reserves) in 2018 is estimated at approximately 4 GW. In 2040, this will grow to 4.4 GW.

Separately, MLGW will require sufficient operating reserves to handle contingencies such as the loss of the largest unit. Elaborate procedures and contracts exist and are standard in the industry; these are discussed separately in Chapter 10. Because the Bellefonte unit 1 is very large at 1,350 MW, some additional modest costs associated with operating reserve increments may exist. By complying with planning and operating reserve requirements, MLGW can access long standing, highly regulated "insurance" in the form of reserves to handle operations. These options have historically existed and will continue to exist, though these arrangements are currently contracted out to TVA.

MLGW's load shape for 2017 is presented below in Exhibit 3-3 in the form of a load duration curve – demand levels and their frequencies are shown. The maximum single-hour demand was 3,500 MW in 2017, and all-hours service is required above approximately 900 MW of load. Critically, and as discussed later, in most hours there is enough demand to absorb the entire output of the Bellefonte 1 plant – that is, 1,350 MW or more.

MLGW's load variation over the course of a year reflects its primarily residential and commercial customers. One measure of the shape is the load factor, which was 51% in 2017. The average load was 1,576 MW in 2017 and it is projected to be 1,633 MW in 2024.

Exhibit 3-3: MLGW Hourly Energy Demand



Source*:* FERC Form 714

Ancillary service needs are estimated based on energy requirements, shape (for example, ramping needs), and uncertainty in the generation supply and peak load of the system. In general, a utility with adequate capacity reserves and flexible, dispatchable generation will be able to meet the ancillary service needs of the grid. On average, ancillary service costs generally range from $0.40-$2.00/MWh of load served.[49]

Finally, MLGW is not only a wholesale power customer of TVA but also relies on TVA for transmission service and system operation. TVA manages and constructs new transmission lines to maintain NERC reliability standards and apportions the costs to its customers.

[49] Over the last 5 years (2013-2017), MISO system-wide ancillary services cost averaged $0.11/MWh while PJM was $0.93/MWh.

4. TVA Supply and Ratemaking

This chapter provides an overview of the TVA system and discusses typical LPC contracts with TVA. We provide a summary of TVA's average system cost approach to ratemaking. We also provide a historical time series of TVA system average costs and sales rates to LPCs. Finally, we provide a detailed discussion on ICF's approach (based on average system costs) to forecasting TVA rates over the 2024 to 2053 time period. These projected LPC rates are used in our BAU case to project Memphis annual purchase power costs.

TVA has a unique and complex legal and institutional situation. This has important implications for MLGW. This also requires special attention to TVA statements. At the same time, however, MLGW has unique circumstances of its own increasing its options and making them more advantageous compared to other LPCs.

4.1 TVA System

TVA is a corporate agency instrumentality of the US that was created in 1933 by legislation enacted by the US Congress. TVA supplies power to a population of over nine million people in most of Tennessee, northern Alabama, northeastern Mississippi, southwestern Kentucky and in portions of northern Georgia, western North Carolina, and southwestern Virginia.

TVA operates as a traditional regulated utility to the extent that it maintains the functions of transmission and generation system operation together. Power supply in TVA is largely procured from TVA-owned generating units and secondarily from units owned by independent third-party entities. Another feature common to traditional utilities is its rates. Rates in TVA are based on average embedded costs.[50]

However, unlike other traditional utilities, TVA's sales are mostly wholesale under long-term contract rather than to native load customers. TVA sells wholesale power to LPCs, mostly municipalities and cooperatives, which in turn resell the power to their end use customers at retail rates. LPCs accounted for 87% of TVA power sales in 2017. TVA sells 13% of its power directly to certain end-use customers, primarily large commercial and industrial loads and federal agencies with loads larger than 5,000 kW.

TVA also differs from traditional regulated utilities in that it is not subject to rate regulation by an independent state-level public utilities commission. Rather, the TVA board sets rates and policies affecting decisions such as the mix of powerplants, the disposition of assets, costs, and cost volatility. TVA's board is appointed by the President and confirmed by Congress with members having five-year terms.

TVA's financial structure also differs from traditional utilities. Most very large traditional utilities with large generation fleets have a mix of debt and equity financing. If approved by the state commission, a utility can raise capital as needed – for example, to finish a nuclear plant. However, TVA is debt-financed and subject directly to the US Congress in this regard. Initially, all TVA operations were funded by federal appropriations. Direct appropriations for the TVA power program ended in 1959, and appropriations for TVA's stewardship, economic development, and multipurpose activities ended in 1999. Since 1999, TVA has funded its operations from sale of electricity and power system financings consisting primarily of sale of debt securities. TVA is not authorized to issue equity securities. TVA also has a debt ceiling set by Congress, and hence TVA activities can be limited by financial constraints. For example, as the total debt approaches the ceiling, and in the absence of

[50] TVA uses a ratemaking approach formally called the debt-service coverage (DSC) approach. Under the DSC approach, rates are set so that operating costs and obligations on principal and interest on debt are covered.

congressional action, TVA may not be able to implement certain activities, even economic activities, due to financial limitations.[51]

Debt is supported by the US government. This can be thought of as the reason why under the TVA Act, TVA is limited by the “fence” provision limiting power sales activity (such as firm, long-term sales to distribution entities for use by end users) to within a defined service area.

TVA also differs from traditional utilities in the legal provisions regarding its sales of electricity, with direct immediate implications for MLGW. A traditional US utility has a franchised territory provided by the state in which they have the monopoly on the sale of power to “native” load customers with the expectation that this franchise will continue indefinitely. As noted, TVA makes the vast majority of its sales under contract, and municipal utilities and other public power entities make end use sales. TVA does not rely on a franchised utility territory with native load customers. Expectations about service duration are clearly set out in contracts. We return to this issue in the context of TVA potentially wishing to collect “stranded” costs.

The Federal Power Act (FPA) includes a provision that is frequently mentioned, especially by TVA itself, as facilitating TVA’s ability to sell power within its service area. This provision, often called by TVA the "anti-cherry-picking” provision.[52] It is the view of FERC, however, that this FPA provision prevents FERC from ordering TVA, under section 211, to provide open access to its transmission lines to others to deliver power to LPC customers after a certain date. However, as discussed, FERC has ordered that this provision not be construed as preventing FERC from ordering “reciprocity” in all jurisdictional tariffs, and hence FERC can effectively require TVA to provide open access transmission. Reciprocity requires any entity to only be able to access the open access transmission of others if that entity reciprocates; the entire US portion of the power grid operates under open access. See further discussion in Chapter 9.

Another characteristic distinguishing the TVA market, along with other parts of the southeastern US, is the absence of a competitive electrical energy power market operated by a FERC-regulated entity, such as an independent RTO or ISO. The southeastern US is the only major region in the contiguous US not to have an organized exchange-style electrical energy market run by a not-for-profit entity regulated by FERC. Since 1999 one region after another, with this one exception, has adopted these markets.[53] For the southeastern US, this reduces price transparency, and causes greater reliance on cost-based pricing. However, bilateral transactions facilitated by open access transmission are common in this region and there are many IPP powerplants in the region. Lastly, this wholesale bilateral market is still subject to FERC regulation.

Notwithstanding its location within the non-competitive TVA market, MLGW is adjacent to MISO, a large organized market. Prices in wholesale power on the other side of the Mississippi River from MLGW can be accessed by the public in real time via the internet. In addition, TVA is contiguous to the PJM market, another organized market located to the north and east of TVA.

[51] TVA can issue bonds in an amount not to exceed $30.0 billion outstanding at any time and TVA has a total debt of $25 billion on its balance sheet as of September 30, 2017.

[52] Federal Power Act s.212(j) is “anti-cherry-picking” provision. The term anti-cherry picking is not mentioned in the statute.

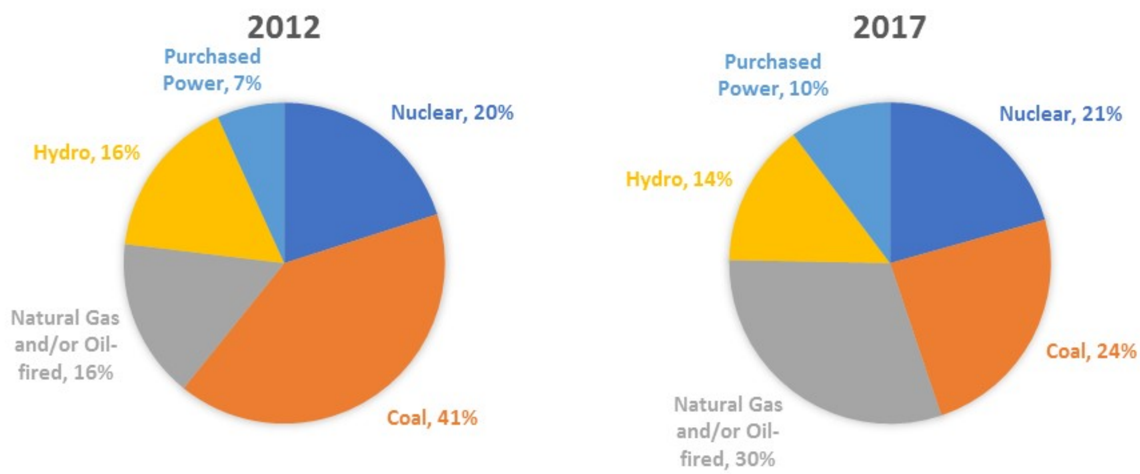
[53] The interior western states, except for Colorado, have FERC-regulated electrical energy markets for balancing.

4.1.1 Capacity and Generation Mix

TVA is similar to the broader southeastern US in that it has relied significantly on coal generation in the past. However, TVA differs from other regions in the southeast in that it also has a high reliance on hydro-electricity. TVA is also distinguished from some other US regions by substantial reliance on nuclear power.

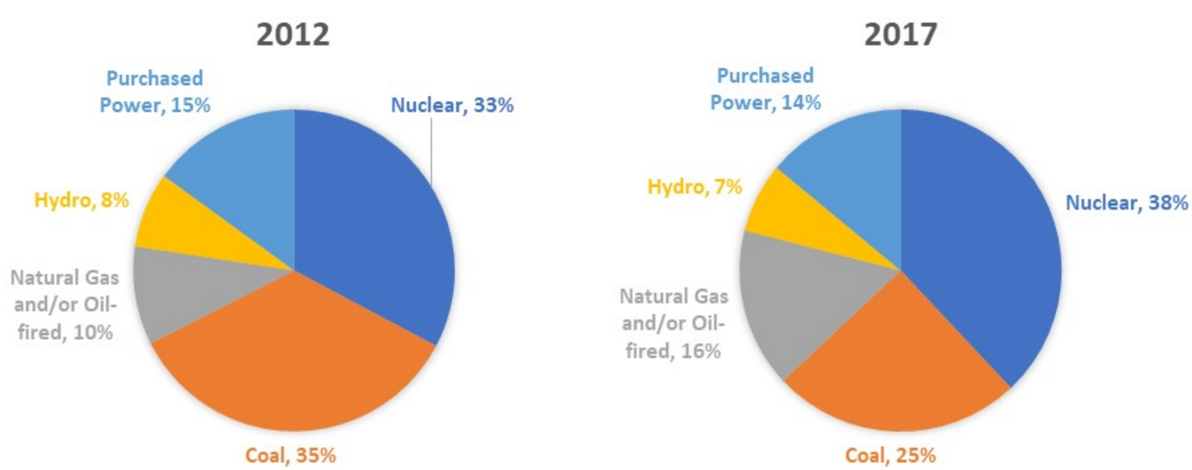
However, consistent with the trend being observed across much of the country, natural gas-fired generation is now increasingly replacing coal in the region. In 2017, coal accounted for 24% of TVA's capacity mix as opposed to 41% in 2012 (see Exhibit 4-1). Among the coal powerplants that TVA retired was the Allen coal-fired power plant located near Memphis. Increasing reliance on gas has caused greater volatility in average costs.

Exhibit 4-1: TVA Existing Capacity and Contracts by Fuel Type



Source: TVA 10K Reports
Note: Purchased power includes coal, natural gas and/or oil-fired, wind, solar, hydro, and landfill gas resources.

Exhibit 4-2: TVA Generation by Primary Fuel-Type



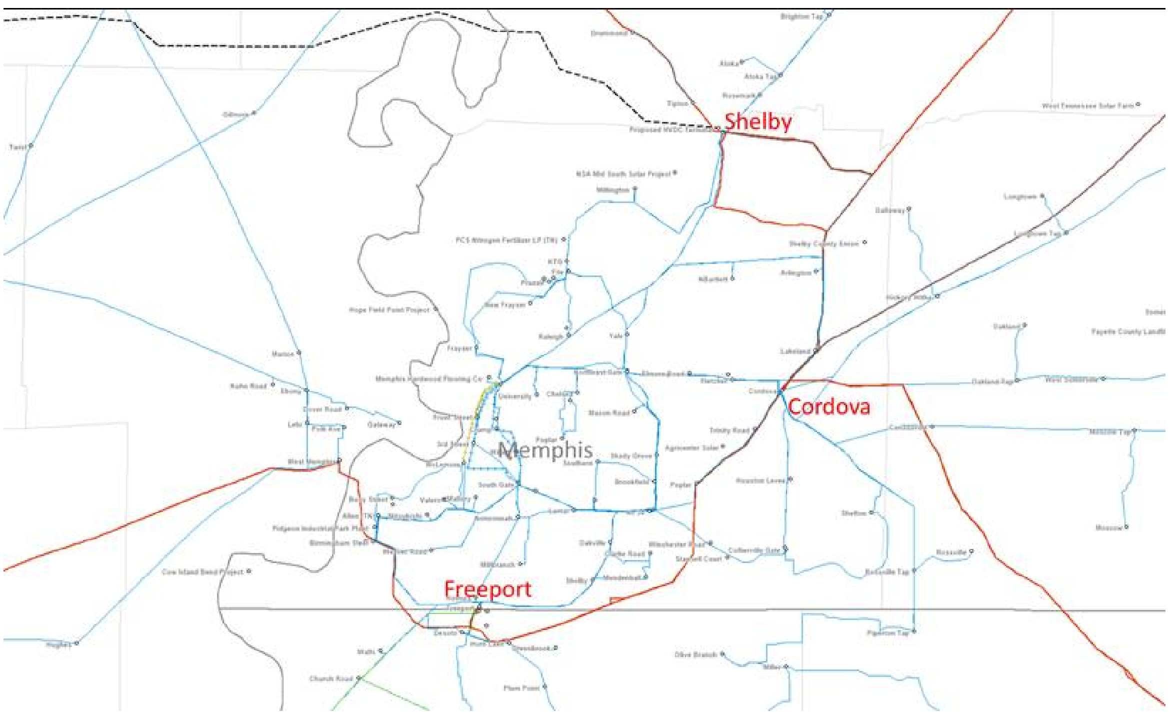
Source: TVA 10K Reports
Note: Purchased power includes coal, natural gas and/or oil-fired, wind, solar, hydro, and landfill gas resources.

In TVA's most recent IRP issued in October 2015, TVA emphasized compliance with the Clean Power Plan (CPP).[54] At the time, the CPP established state-specific emission goals to lower CO_2 emissions from power plants, targeting a 32% nationwide reduction in CO_2 emissions from 2005 levels by 2030.[55] TVA has reduced GHG emissions from both its generation stations and its operations. Since the 2016 general election, the CPP has been changed and policy direction is less clear. TVA board members are appointed by the President and confirmed by Congress for five-year terms.

4.2 MLGW Contract with TVA

TVA supplies into Memphis: three major delivery points at Cordova, Freeport, and Shelby.

Exhibit 4-3: Transmission Grid around Memphis (with major 500kV substations noted)



Source: Ventyx and ICF

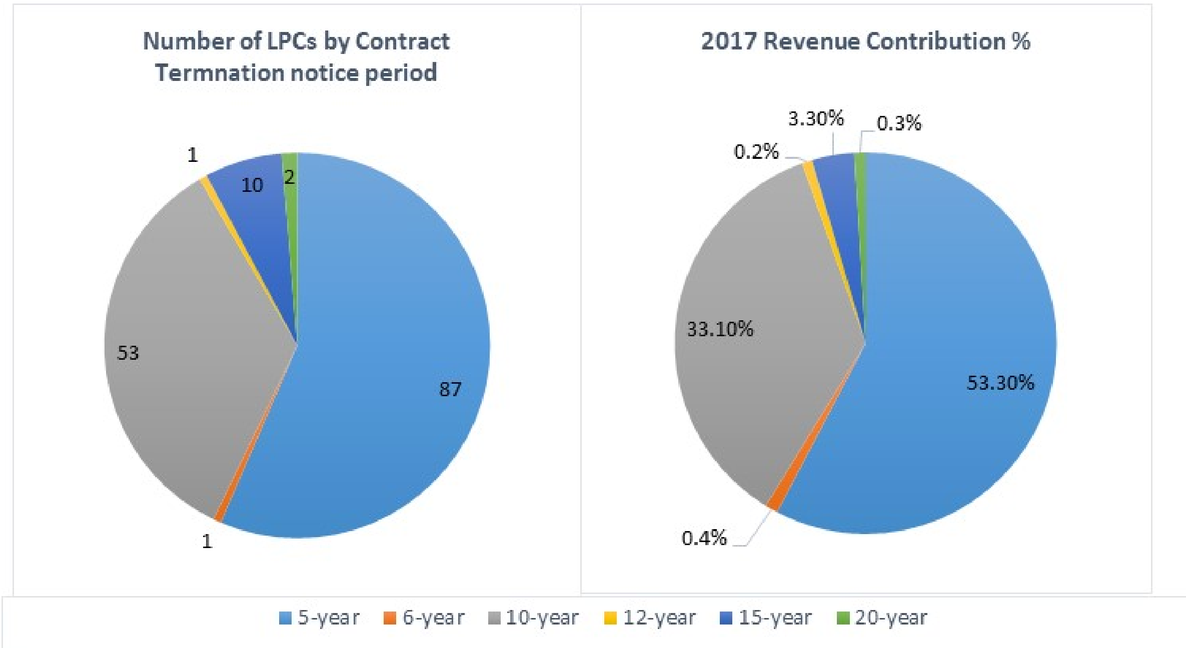
TVA had wholesale power contracts with 154 LPCs as of September 30, 2017. These LPCs purchase power under contracts that require notices of five, ten, or fifteen years to terminate. However, it is our understanding that for five of the LPCs with five-year termination notices, TVA has a 10-year termination notice that becomes a five-

[54] "From a portfolio planning perspective, we think the TVA's carbon emission rate is a better customer-focused planning metric for use in the IRP. While the IRP models the amount of carbon contained in the delivered energy to our customers it does not model a potential compliance strategy for TVA with the Proposed Clean Power Plan. However, as a crude comparison, TVA has made a 30 percent reduction in CO_2 emissions from a 2005 baseline, the stated objective of the regulation. One might assume that TVA would then have a low compliance hurdle with the CPP".

[55] TVA 2017 10-K

year termination notice if TVA loses its discretionary wholesale rate-setting authority. Furthermore, it is our understanding that MLGW's contract carries at least five-year termination notice.

Exhibit 4-4: Number of LPCs and their revenue contribution by contract termination notice period



Source: TVA 2017 10-K

LPCs with five-year and ten-year termination notices accounted for 53% and 33% of operating revenues in 2017 respectively. MLGW, TVA's largest LPC, has a contract with a five-year termination notice period, and accounts for approximately 10% of TVA's revenues. Long-term firm contracts enable wholesale customers to be treated the same as a utility's native load in terms of access to average costs.

4.3 TVA Full-Requirements Service Rate Forecast

As noted, according to the TVA Act, the TVA board has the authority to establish the rates TVA charges for power. These rates are not set by any independent state or federal regulatory body. The rates are revised over the time to reflect change in costs, including the changes in fuel, non-fuel operation and maintenance (O&M), and power purchase costs.

Average costs are determined by TVA's revenue requirements, including interest, depreciation, and other costs, divided by sales; revenue requirements are distinguished by rate class (for example, industrial versus municipal). Average costs are calculated as the sum of depreciation and interest on legacy and new power plants, fuel costs, purchase power costs, O&M costs, emission allowance costs, and payments to states and counties in lieu of taxes ("tax equivalents") divided by sales volumes. The majority of TVA generation costs are fixed costs such as O&M, depreciation, and interest, and the capital structure reflects debt at interest rates close to that of federal government debt. TVA maintains the high-voltage transmission system, and transmission cost is embedded into the average system costs for requirements service. Therefore, the price for requirements service would also include transmission, provided either at average transmission costs, or at a network tariff rate.

TVA rates to LPC customers also include additional margin as the TVA Board may consider desirable for investment in power system assets, retirement of outstanding bonds, notes, or other forms of indebtedness in advance of maturity.

TVA uses a wholesale rate structure that is comprised of a base rate and a fuel rate. In setting the base rates, TVA derives annual revenue requirements such that all its operating costs and obligations to pay principal and interest on debt are recoverable. Power rates are adjusted by the TVA Board to a level deemed to be sufficient to produce revenues approximately equal to projected costs (exclusive of the costs collected through the fuel rate). In 2015, TVA restructured its base rates to improve cost alignment with capacity-related on-peak demand charges and seasonal time-of-use (TOU) energy rates, which differ by on-peak and off-peak periods to better reflect how TVA incurs generation costs.

Fuel costs include costs for natural gas, fuel oil, coal, purchased power, emission allowances, nuclear fuel, and other fuel-related commodities.

4.3.1 Historical Rate Trends

As shown in Exhibit 4-5 below, in 2017 the average system cost for TVA was $66/MWh and the average selling price to LPCs was $74/MWh, with the additional $8/MWh used to cover for retirement of outstanding bonds, notes, or other bonds in advance of maturity, and investment in power system assets. Average cost of power increased on an annual average basis of 2.8%, from $54/MWh in 2008 to $66/MWh in 2017. The selling price to LPCs increased on an annual average basis of 2.2%, from $62/MWh in 2008 to $74/MWh in 2017.

The additional margin above average cost of power for LPC customers is 11%, or $8/MWh in 2017.

Exhibit 4-5: Historical Average System Cost for TVA (2008-2017)

Cost Parameters	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Fuel Cost	4,176	3,114	2,092	2,926	2,680	2,820	2,730	2,444	2,126	2,169
O&M	2,307	2,395	3,232	3,617	3,510	3,428	3,341	2,838	2,842	3,362
Emission Cost	0	0	0	0	0	0	0	0	0	0
Purchased Power	NA	1,631	1,127	1,427	1,189	1,027	1,094	950	964	991
Interest Expenses	1,376	1,272	1,294	1,305	1,273	1,226	1,169	1,133	1,136	1,346
Depreciation	1,224	1,598	1,724	1,772	1,919	1,680	1,843	2,031	1,836	1,717
Tax Equivalent	491	544	457	662	622	548	540	525	522	525
Total Cost of Power ($MM)	9,574	10,554	9,926	11,709	11,193	10,729	10,717	9,921	9,426	10,110
Total Sales (GWh)	176,304	163,804	173,662	167,730	165,255	161,925	158,057	158,163	155,855	152,362
Average Cost of Power ($/MWh)	**54**	**64**	**57**	**70**	**68**	**66**	**68**	**63**	**60**	**66**
Selling Price to LPC ($/MWh)	**62**	**72**	**66**	**74**	**72**	**72**	**73**	**72**	**71**	**74**

Source: TVA 10-K

Over the last 10 years, TVA sales declined by 1.6% per year on average. All else being equal, this tends to increase average costs because fixed costs are spread over fewer sales.

The capacity mix of TVA transitioned from a coal- to gas-dominant portfolio with major coal retirements occurring in the past decade. With the reduction in gas prices from 2008 to 2017, fuel cost declined from $24/MWh in 2008 to $14/MWh in 2017. O&M cost increased by an annual average of 5% per year, from $13/MWh in 2008 to $22/MWh in 2017.

Hydro, which accounts for 8% of TVA generation, is dependent upon amount of precipitation and runoff, initial water levels, and generating unit availability. When these factors are unfavorable, TVA increases its reliance on purchased power. A portion of TVA's capability provided by power purchase agreements is provided under contracts that expire between 2023 and 2038, and the most significant of these contracts include the Red Hills coal (440 MW) plant, Decatur and Morgan Energy Center gas plants (1,335 MW total), and wind plants totalling 1,540 MW. During 2017, TVA acquired approximately 12% of the power that it purchased on the spot market, approximately two percent through short-term power purchase agreements, and approximately 86% through long-term power purchase agreements.

TVA had a total debt of $25 billion on its balance sheet as of September 30, 2017. The average maturity of long-term power bonds was 16.6 years, and the average interest rate was 4.67%. TVA plans to reduce total debt to approximately $20 billion by 2023.[56] TVA also uses short-term debt to fund short-term cash needs, as well as to

[56] In review of TVA's historical record in paying down debt, we do not believe this will happen and project this target not to be achieved until in the early 2030s.

pay scheduled maturities and other redemptions of long-term debt. TVA's average interest expense over last 10 years remained close to $1.3 billion, equivalent to $8/MWh.

Depreciation and amortization expenses increased from $1.2 billion in 2008 to $1.7 billion in 2017, and the contribution of depreciation and amortization to the total TVA costs increased from 13% in 2008 to 17% in 2017. This was primarily driven by gas and nuclear capacity additions.

The TVA Act requires TVA to make tax-equivalent payments to states and counties in which TVA conducts its power operations. The total amount of these payments is 5% of gross revenues from sales of power during the preceding year, excluding sales or deliveries to other federal agencies and off-system sales with other utilities, with a provision for minimum payments. Tax equivalents averaged $0.5 billion over last 10 years.

4.3.2 Forecast Rate Trends

In projecting future rates for TVA, ICF used the previously described average system cost approach. From 2018 to 2021, ICF derived the rate projections using the revenue requirement forecasts provided in TVA's August 2018 Board presentation.[57] TVA's effective price, i.e. Average cost of power including net income range from $72/MWh in 2018 to $71/MWh in 2021. Applying historical LPC price premium of 5% to TVA's effective price results into a range of LPC price of $76/MWh in 2018 to $75/MWh in 2021.

Beyond 2021, rate components such as fuel cost, O&M cost, emission cost are based on ICF modeling projections for TVA. Average cost of power increased from $60/MWh in 2021 to $65/MWh in 2022, primarily due to increase in gas prices and depreciation expenses. Depreciation expenses increase due to increase in capital expenditure estimates associated with capacity expansion, environmental, transmission, and reliable operation of generating assets. Net income margin in 2022 is $10/MWh, consistent with TVA board projections for 2018 to 2021. Including an LPC cost premium of $4/MWh, the LPC price increase from $75/MWh in 2021 to $78/MWh in 2022.

In the period 2022-2024, LPC price increases from $78/MWh in 2022 to $81/MWh in 2024. Average cost of power increased from $65/MWh in 2022 to $67/MWh in 2024 driven by increase in fuel, O&M costs and depreciation expenses. Net income margin and premium to LPC price remain flat at $10/MWh and $4/MWh respectively.

Annual LPC price increase from $81/MWh in 2024 to $133/MWh in 2053, averaging $102/MWh over the period. The LPC price increases at rate of 1.7% over the forecast. This LPC rate is used in BAU case to project MLGW annual purchase power costs.

The LPC price reflects the following total cost components divided by sales volume:

- **Fuel costs** – are based on ICF modeling projections for TVA. Fuel costs increase 2.9% per year from $14/MWh in 2024 to $32/MWh in 2053, primarily due to increases in gas prices. With more reliance on gas in long term, fuel costs increase. ICF expects 1 GW of economic coal retirement in 2025 and another 1 GW in 2030, all of which are replaced by combined cycle builds.

- **O&M costs** – are based on ICF projections for the TVA fleet. O&M costs increase from $21/MWh in 2024 to $39/MWh in 2053, growing at our assumed inflation rate of 2.1%.

[57] TVA Board Meeting August 22, 2018 Presentation: *https://www.snl.com/Cache/1500112522.PDF?O=PDF&T=&Y=&D=&FID=1500112522&iid=4063363*

- **CO_2 allowance costs** – are based on ICF modeling projections. ICF assumes region-specific charges on CO_2 from the power sector beginning as early as 2026, consistent with an expected delay in US CO_2 regulation. CO_2 prices increase from $1/ton in 2026 to $65/ton in 2053.

- **Purchase power costs –** are based on reported contracts. Purchase power cost declines from $7/MWh in 2024 to $5/MWh in 2053. Power purchase agreements for Decatur and Morgan Energy Center gas plants expire in 2023 and 2026 respectively. ICF assumed no contract extension for TVA-contracted thermal assets. Based on TVA's interconnection queue, TVA is expected to negotiate new solar and wind power purchase agreements. With the expiry of gas, coal, and wind contracts between 2023 and 2038, ICF expects new solar in TVA and wind contracts in MISO will be negotiated at the levelized cost of approximately $56/MWh and $73/MWh respectively.[58] These costs are approximately 40% lower than previous solar and wind contracts, which were reported to have prices of $80-$90/MWh in 2016. In years where TVA self-generation and energy purchased from contracts are not able to meet energy demand, the residual energy is purchased at spot firm all-hours price from neighboring regions (i.e., MISO, PJM, and Southern). SEPA hydro purchases are assumed to continue through 2053.

- **Interest expenses –** are assumed to be based on short- and long-term debt. Details were obtained from TVA's 2017 10K and TVA's website.[59] Incremental capital needs for capital expansion, environmental compliance, transmission, and major maintenance are assumed to be financed through net income margin and new debt raised for 10 to 20-year durations at a debt rate of approximately 5%.[60] Also, short-term financing needs including working capital are met by short-term bond issuances. With increasing long-term debt maturities, total long-term debt declines over forecast leading to a reduction in interest expenses through 2053.

- **Depreciation of costs** – are based on legacy plant depreciation levels reported in the 2017 TVA 10-k and on ICF's assumption on new power plants (new plants include firm builds and model-forecasted capacity additions in the absence of Bellefonte 1).[61] Depreciation expense increased at an annual rate of 1.3% from $13/MWh in 2024 to $19/MWh in 2053. TVA's 2017 annual report provides 2018 to 2020 annual capital expenditures estimates associated with capacity expansion, environmental, transmission, and reliable operation of generating assets. Based on the TVA annual report, ICF assumed environmental, transmission and reliability capital expenditures from the year 2021 to remain flat throughout the entire forecast.

[58] The levelized cost of $56/MWh and $73/MWh for solar in TVA and wind in MISO respectively are based on ICF views. $80-90/MWh are from a recent TVA presentation found at *https://www.tva.gov/file_source/TVA/Site%20Content/About%20TVA/Our%20Leadership/Board%20of%20Directors/Meetings/2016/August%2025/Aug%202016%20Board%20Deck.pdf*.

[59] *https://www.snl.com/IRW/CustomPage/4063363/GenPage.aspx?IID=4063363&GKP=1073746881*

[60] Illustratively, we assume the debt rate is the weighted average cost of long term debt sourced from TVA's 2017 10K.

[61] For depreciation calculations, property, plant, and equipment depreciation rates are performed by asset classes. For example, coal, gas and nuclear, hydro, and transmission assets are assumed from 2017 10K. Other capital expenditures associated with capacity expansion, environmental, transmission, and reliability are assumed to depreciate using fixed depreciation method over a 30-year book life. Amortization expenses are calculated as the delta between the reported 'Depreciation' and 'Depreciation and Amortization' in the 2017 10K. The average of 2014 to 2017 amortization expenses are assumed in above calculations.

- **Tax-equivalent costs** – reflect 5% of gross revenues from sales of power during the preceding year. Tax equivalents cost increase from $4/MWh in 2024 to $6/MWh in 2053.

- **Sales** – are based on TVA and other projections such as found on FERC Forms.[62] ICF projects energy demand to remain essentially flat, consistent with the growth rates projected in 2019 IRP Working Group presentation.[63] The sales forecast is driven by energy demand, including 4% losses estimate based on TVA's historical time series.

- **Premium for LPC Costs** – includes two premiums: 1) net income margin and 2) an additional premium that TVA charges to LPC and both are primarily used for retirement of outstanding debt. Based on TVA's historical debt trends, ICF assumes the total debt in our rate forecast to decline to $20 billion by 2030 from current debt outstanding of $25 billion. ICF's forecast for net income margin during 2022 to 2030 ranges from $10/MWh to $12/MWh, consistent with TVA board projections for 2018 to 2021. The second premium that TVA charges to LPC is estimated to be in the range of $4/MWh to $6/MWh from 2022 to 2053 as shown in Exhibit 4-7. The total premium for LPC cost including net income margin and the second premium is 21% higher than average cost of power, representing a mix of recent TVA historical trends and TVA's four-year (2018 – 2021) forecast. The LPC premium steadily declines from 21% in 2030 and reaches the long-term historical average of 11% in 2040, reflecting the reduced need for debt redemption.

Appendix A has further details on modelling assumptions used for TVA (including fuel prices, capital costs, and CO_2 prices).

Exhibit 4-6 summarizes ICF estimates of the average system cost of power for TVA and the sales price to the LPC class of customers in the TVA service territory over select forecast years. The 30-year average system cost is $89/MWh and the 30-year average sales price to LPCs is approximately $102/MWh. The LPC sales price increased 1.7% on average, from $81/MWh in 2024 to $133/MWh in 2053 in nominal terms.

[62] Sales volume and sales revenue for residential, commercial and LPC customers are sourced from TVA's 10-K. Net energy demand forecasts for the years 2018 to 2027 are sourced from FERC Form 714. Post 2027, ICF assumes net energy demand will grow at last five-year average (2023-2027) annual growth rate.

[63] *https://www.tva.com/file_source/TVA/Site%20Content/Environment/Environmental%20Stewardship/IRP/2019%20Documents/2019%20IRP%20Working%20Group%20Meeting%20%202.pdf*

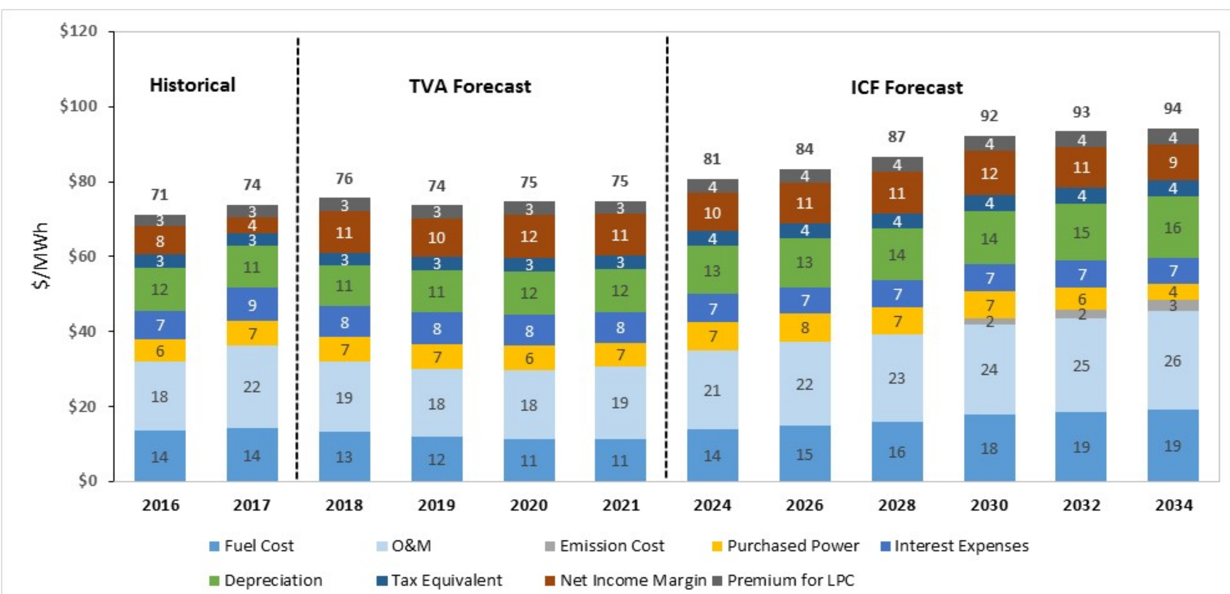
Exhibit 4-6: Average System Cost Approach Projections for TVA

Cost Parameters	Average (2024-2053)	2024	2026	2028	2030	2034	2040	2045	2050	2053
Fuel Cost	3,304	2,110	2,272	2,417	2,714	2,931	3,414	3,700	4,555	4,789
O&M	4,434	3,234	3,405	3,549	3,651	3,963	4,485	4,976	5,538	5,934
Emission Cost	904	5	53	138	250	479	844	1,260	2,181	2,321
Purchased Power	829	1,135	1,142	1,079	1,082	650	680	761	772	791
Interest Expenses	838	1,130	1,071	1,100	1,093	1,031	754	592	527	512
Depreciation	2,467	1,963	2,003	2,111	2,172	2,489	2,473	2,714	2,771	2,827
Tax Equivalent	723	586	598	617	651	679	709	761	868	942
Total Cost of Power ($MM)	13,498	10,163	10,542	11,011	11,613	12,222	13,359	14,763	17,212	18,116
Total Sales (GWh)	151,758	152,250	152,065	152,057	152,000	151,887	151,717	151,575	151,433	151,348
Average Cost of Power ($/MWh)	89	67	69	72	76	80	88	97	114	120
Selling Price to LPC ($/MWh)	102	81	84	87	92	94	98	108	126	133

Source: ICF projections

Exhibit 4-7 shows ICF's projected LPC sales prices build up price for TVA relative to the historical build-up of LPC sales prices as well as recent TVA forecasts. Historical LPC sale price range from $71/MWh to $74/MWh between 2016 to 2017. In a recent August 2018 board presentation, TVA provided projections from 2018 to 2021 that, when combined with other data, ranged from $74/MWh to $76/MWh.[64]

Exhibit 4-7: Comparison of Historical and Forecast Projections of LPC Sales Price for TVA ($/MWh)



Source: Historical data is from TVA's 10K. TVA forecast is from TVA Board Presentation (August 22, 2018). ICF projections are ICF.

[64] https://www.snl.com/Cache/1500112522.PDF?O=PDF&T=&Y=&D=&FID=1500112522&iid=4063363. TVA provided income statement estimates for FY2018 to FY2021. Fuel and purchased power estimates are reported as aggregate expenses. ICF assumes purchase power expenses for 2018 to 2021 reported in TVA forecast in Exhibit 13 to remain flat and equivalent to 2017 actuals. To calculate a $/MWh value for 2018-2021, this combined estimate was divided by energy sales assumed to be similar to ICF's forecast over this same period.

5. Bellefonte 1 Nuclear Plant

The chapter provides a review of the Bellefonte nuclear station, describes our understanding of the proposed Bellefonte 1 PPA, and provides a detailed analysis regarding the deliverability of Bellefonte 1 power to the City of Memphis.[65]

5.1 Overview of Plant

Bellefonte is a proposed nuclear generating plant located in the TVA service territory in northeastern Alabama, as shown in Exhibit 5-1. Development started at the Bellefonte site by TVA in 1975, and at various points up to four separate nuclear units had been proposed. However, TVA only made meaningful progress on units 1 and 2, though development proceeded in fits and spurts through TVA's ownership of the site.

Exhibit 5-1: Bellefonte Nuclear Plant Location

Source: TVA

In 2015, TVA determined that it would be unlikely to need a large plant like Bellefonte for the next 20 years, and in May 2016 elected to declare the plant surplus and sell the 1600-acre site at an auction. Nuclear Development, LLC purchased the Bellefonte nuclear plant at the auction, which took place on November 14, 2016.

The Bellefonte nuclear generating station is geographically located within the TVA region but is also in close proximity to the Southern Company power system. The station's option to connect directly to these two very large utility systems at similar grid upgrade costs is a critical advantage of the project.

[65] We have not reviewed the draft PPA in detail.

Exhibit 5-2 summarizes the key parameters of Bellefonte 1 power plant.

Exhibit 5-2: Bellefonte 1 Nuclear Plant Parameters

Plant Parameters	*Value*
Plant Capacity	1,350 MW
Online Year	Q4 2023
Forced Outage Rate	1.0%
Planned Outage Rate	4.4%
Net Availability	94.6%
Net Energy per Year (avg)	11.2 TWh

Source: Nuclear Development, LLC

5.2 Bellefonte 1 Power Purchase Agreement

ICF's understanding is that the offer is for the full 1,350 MW of capacity available from Bellefonte 1. We estimate that the available energy would be 11.2 TWh, based on the plant's 94.6% availability. We further understand that the first-year offer price is for $39/MWh. This rate is essentially held flat for the term of the PPA, except that the seller of Bellefonte power has the right to collect actual expenses for O&M (i.e., any overage of projected O&M can be collected by seller). As actual O&M expenses are unknown at this time, ICF uses an inflation factor applied to the O&M component of the first year cost of $39/MWh. In ICF's experience, the three main components to nuclear costs are recovery on and of capital, O&M, and fuel expense. Of those, O&M is approximately 30% of the total cost recovery. Applying a 2.1% annual inflator[66] to the O&M component translates into an annual growth of approximately 0.4% for the total PPA rate of $39/MWh. ICF has reviewed the tenure of the PPA, and for the purposes of this study, we have assumed thirty years starting in 2024. As a result, the PPA starts at $39/MWh in 2024 and reaches only $44/MWh by 2053. This is one of the drivers of savings for MLGW: initial savings are large compared to the TVA rate ($81/MWh vs $39/MWh), and over time the TVA rate increases at 1.7% per year in our projections whereas Bellefonte's PPA rate escalates at only 0.4% per year, increasing savings over time.

5.3 Deliverability of Bellefonte Capacity to Memphis

Under FERC Open Access transmission rules, transmission providers (TPs) are required to meet requests for transmission service in accordance with their published open access transmission tariffs. We anticipate that transmission would involve long-term, firm, point-to-point service with rights to extend transmission service over time. However, if the transmission service requires transmission system upgrades, the TP can recover the costs from the entity requesting the service and can delay service provision as long as it is making appropriate efforts to implement the identified grid upgrades. In this context, a key need is to assess the cost and nature of upgrades required, if any, to facilitate the dispatch of power from Bellefonte 1.

The assessment of transmission availability and system upgrades typically involves the use of commercially available alternating current (AC) transmission power flow models to simulate grid operation and assess the impact of the proposed injections or supply under normal and contingency conditions. The power flow data files

[66] From the Bureau of Labor Statistics, the most recent 30-year GDP deflator is 2.1%. The CPI average over this same time period is 2.55%.

used in the simulations are protected under the Critical Energy Infrastructure Information (CEII) protocol. FERC regulates access to the power flow data files provided by NERC, the transmission providers, and SERC through FERC 715 filings. In recent years, ICF has applied for and secured CEII clearance to access these data files and for its current power flow assessment. ICF used the transmission providers' 2017 FERC 715 filings. ICF then used the PowerWorld™ transmission model together with FERC-provided CEII data to evaluate power system impacts and system upgrade requirements associated with the proposed dispatch. ICF supplemented the CEII data with information from ABB Velocity Suite and publicly available data.

5.3.1 Methodology

It is necessary to model the flows on the grid assuming power injection at Bellefonte 1 to assess its impacts. Bellefonte 1 was assumed to inject at the Widow's Creek 500kV substation as proxy.[67] This in turn requires other power plants' power injections to be commensurately decreased (dispatched down) in order to comply with the grid requirement that supply and demand be balanced instantaneously.[68] The most common practice among transmission providers assessing transmission service or interconnection requests is to dispatch down *pro rata* the output/injection of generators in the region.[69]

ICF used the PowerWorld™ load flow model for the simulation and ran the *pro rata* case assuming reductions from TVA (excluding reductions from nuclear units in TVA) and two alternative dispatch-down cases in response to the injection of Bellefonte power into the TVA system. ICF also ran a case dispatching down TVA units but interconnecting Bellefonte 1 within Southern territory. In each case, ICF assessed grid conditions (that is, line-by-line and transformer-by-transformer) to determine the resulting flows and whether there were any element overloads or voltage violations. In the event of overloads or violations, ICF sought to increase grid capacity via the addition of another transmission circuit – that is, double circuiting. Adding another circuit or element is usually more expensive compared to other grid modifications (such as re-dispatch, reconductoring, and terminal equipment upgrades), and hence ICF's cost estimates may be considered upper-end estimates. The analysis incorporates assessment of numerous contingency conditions in accordance with standard industry practice.[70] Involving multiple configurations of contingencies is part of the complexity involved in power flow analysis, but it helps ensure that the delivery can be treated as firm.

ICF's Base Case for this deliverability modeling review was SERC's latest power flow case for the summer peak of year 2021, the closest released year to the proposed online date of Bellefonte 1.[71] ICF tabulated existing overloads and violations in the Base Case, and then assessed incremental overloads and violations due to the addition of Bellefonte 1 and a concomitant reduction (that is, re-dispatch) in generation from other units. Only incremental line overloads have been identified across the three cases. ICF estimated the costs of double-circuit

[67] The Bellefonte node currently exists at 161 kV.

[68] Incremental losses, if any, need to be supplied, and hence, the amount dispatched down may not precisely equal the injection, and vice versa.

[69] See later discussion of protocols in SPP and MISO. We did not find documentation of the TVA protocol. Thus, we investigated multiple cases based on protocols elsewhere.

[70] ICF monitored violations at lines, transformers, and buses at 115 kV and above within TVA, Southern Company and MISO South.

[71] This is the latest FERC provided CEII data set, vintage 2016. ICF also reviewed other materials to determine whether major changes have occurred since the case was developed.

upgrades using NREL's JEDI Transmission Line Model.[72] As noted, lower costs might be possible (for example, via terminal upgrades rather than double circuiting), especially if the overloads are small. Overloads in the Affected (as opposed to Host) system are treated in accordance with standard practice.[73]

5.3.2 Deliverability Results

Transmitting power from Bellefonte to MLGW did not result in any overloads on the TVA system, and hence no TVA upgrade costs were allocated to Bellefonte (see Exhibit 5-3). The pro rata case (Case A) yielded a few incremental overloads, but all were in another Affected system, at 230kV and 115kV lines within Southern Company's Georgia Power service territory. These Affected system costs would not be allocated to Bellefonte. Not even these Affected system overloads were found in alternate cases where changes in re-dispatch were more localized in Memphis (for example, Case B: Allen and Southaven) or otherwise away from the boundary of TVA and Georgia Power (Case C). Case D is similar to Case A but with Bellefonte interconnected to Southern. This case also yielded a few incremental overloads, but all were in other Affected systems.

Exhibit 5-3. Re-Dispatch Cases Analyzed and Resulting Incremental Line Overloads

	Case A	Case B	Case C	Case D
Interconnection	TVA	TVA	TVA	Southern
Re-Dispatch Adjustments for Case	Proportional generation reduction across TVA, except nuclear	Allen and Southaven CCs reduced to 50%; remaining energy proportional across TVA except nuclear	Proportional generation reduction across TVA combined cycles west of Bellefonte	Proportional generation reduction across TVA, except nuclear
Additional Lines Overloaded (#)	3	0	0	3
Total Length of Addt'l. Overload Lines (miles)	26	0	0	18
Location of Affected Lines	Southern Company – GA	-	-	TVA-Memphis and MISO-Arkansas
Double-Circuit Upgrade Costs	There are $66 million of estimated costs in an Affected System; see discussion.	-	-	There are $63 million of estimated costs in the Affected Systems; see discussion.

[72] The Jobs and Economic Development Impacts (JEDI) Transmission Line Model is developed by NREL. The JEDI models are tools that estimate the economic impacts of constructing and operating power assets and the JEDI Transmission Line Model specifically provides cost estimations including construction capital costs and operation and maintenance expenses associated with transmission line projects. Inputs to the JEDI model include transmission line type (voltage and AC/DC), line length, and more. We assume that all of the proposed MLGW transmission projects are 500 kV AC lines and line lengths are based on ABB's Ventyx database.

[73] Here we emphasize shift factor based cut offs – i.e. cost allocation excludes injections where the shift factor is lower than the cutoff point – e.g. 4%-5%. Shift factors represent the percentage of power injected that flows on a particular element; for each injection there are as many shift factors as grid elements. While there is some variation across TPs regarding the exact cut-off percentage, it is small and not enough for any cutoff in use to be triggered.

Source: ICF using data from PowerWorld and Ventyx

We therefore conclude that physical deliverability of power from Bellefonte 1 to MLGW is feasible at no upgrade cost or time hurdle for the project. This is not surprising because TVA actively pursued the Bellefonte project through 2013; presumably, TVA's internal studies verified general deliverability of power from the local area.

An alternative means of assessing transmission availability is to review of the transmission provider's Open Access Same-Time Information System (OASIS) sites where near-term firm transfer capability is sometimes reported. This is not the preferred method even when available because it is uncommon to provide availability in the period when Bellefonte 1 will come on-line – four to five years in the future. In this case, an OASIS review of contractual availability of firm transmission was an even more challenging approach as no information was reported for firm internal (that is, within TVA) transmission.

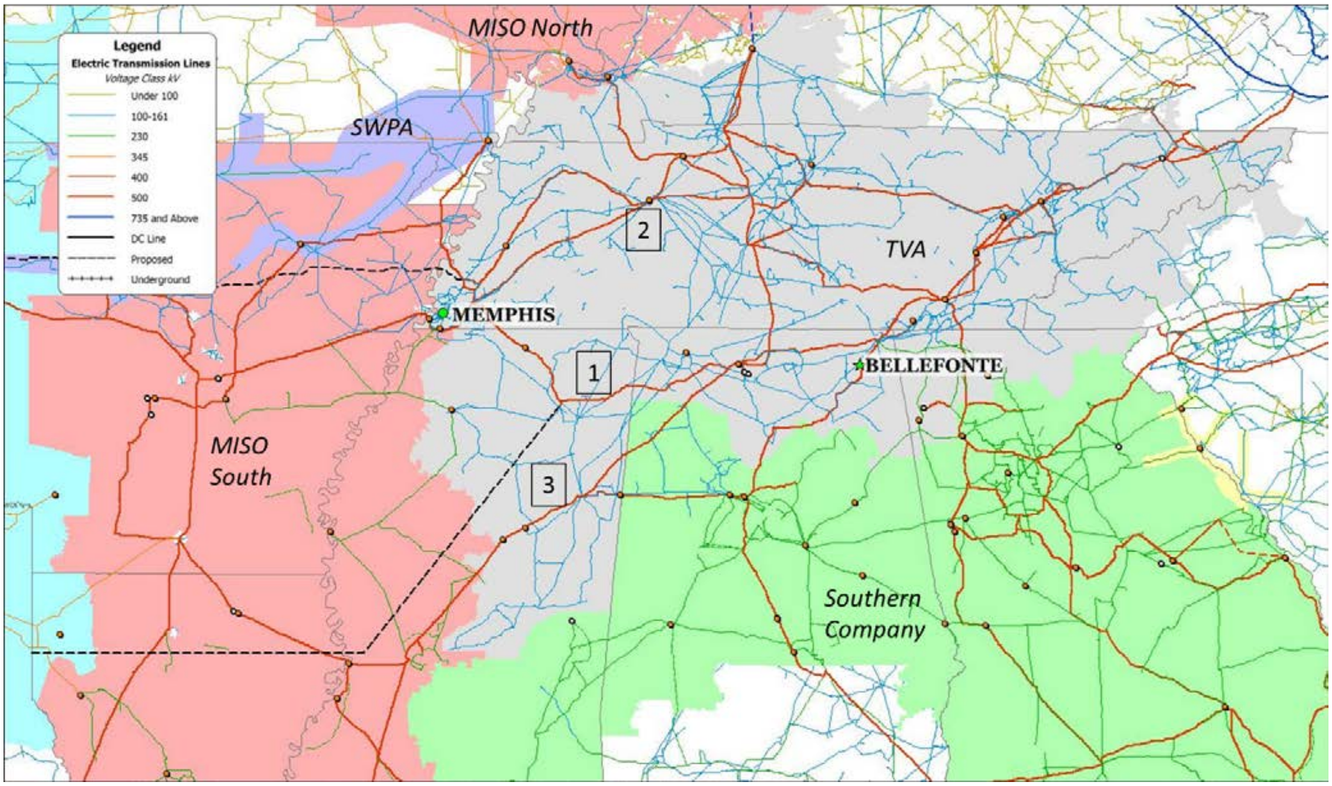
5.3.3 Potential Pathways Examined and Re-Dispatch Method Employed

Exhibit 5-4 shows the transmission grid near Bellefonte and MLGW. MLGW, covering the city of Memphis plus a small surrounding area, is currently a TVA full-requirements service customer and therefore interconnects with TVA. While not directly interconnected to MISO at a local level, MLGW is across the river from and very near to MISO-Arkansas due west (also referred to as MISO South).[74] Major 500 kV lines run from the TVA system to MISO South near the service area of MLGW. The 500 kV lines are shown in red and are the highest voltage lines in the region; transfer capability is proportional to the square of the voltage, all else equal. While reviewing the 500 kV backbone pathways provides a heuristic view of the power flow, actual flows occur in a manner to minimize impedance, and hence some flow is on lower voltage lines as well.[75]

[74] MLGW is south of the MISO South/North boundary; there is a major transfer constraint across this boundary and greater excess capacity exists in the south. All else equal, this is a benefit for MLGW.

[75] Lower voltage lines shown in blue in the graphic are at 161 kV. Power flow is a non-linear phenomenon and minimizes impedance which, while lower for high voltage lines, all else equal, increases as the lines load up so that some power automatically redistributes to lower voltage lines.

Exhibit 5-4. Transmission Lines and Balancing Authorities around MLGW



Source: Ventyx and ICF

As shown, if interconnected to the 500 kV system near the plant, there are several 500 kV transmission paths that run directly to the Memphis area (labeled 1-3 in Exhibit 5-4). Paths 1 and 2 use exclusively TVA lines; path 3 crosses through Southern Company and MISO but there are parallel path flows on the TVA system, and therefore TVA is an Affected system. We do not consider this significant.[76]

Since MLGW is currently served exclusively by TVA, we constructed our re-dispatch cases on the assumption that TVA would back down a subset of existing units. As noted, given that supply and demand must be balanced and is held constant in these cases, other generators within the TVA system must decrease their output. The cases analyzed are:

- **Case A** – The simplest solution is to reduce output at all dispatchable non-nuclear units across TVA territory – this constituted Case A. This is also consistent with the way transmission providers conduct generation interconnection and deliverability studies.[77]

[76] TVA does not claim parallel path flows are not permitted. TVA in their most recent 10-k, on page 23 states "However, other utilities may use their own transmission lines to serve customers within TVA's service area, and third parties are able to avoid the restrictions on serving end-use customers by selling or leasing a customer generating assets rather than electricity."

[77] MISO sinks queued generation to the entire classic MISO region according to MISO DPP 2016 West February West Area Phase 1 Study, Table 5. SPP Guidelines for Generator Interconnection Requests states that for interconnection studies, "the existing on-line generation is backed down across the SPP footprint on a load ratio basis in accordance with

• **Case B** – The TVA generating units closest to Memphis are the combined cycles Allen (replacing an existing coal plant at the same site) and Southaven. With MLGW served primarily by Bellefonte 1, the output of these units for local load would be reduced, and it is possible that TVA would dispatch down the units.

• **Case C** – We constructed Case C assuming that TVA primarily adjusts dispatch against its combined cycles (including contracted IPPs) between Bellefonte 1 and Memphis.

• **Case D** – Finally, we constructed Case D using the same reduction methodology as outlined in Case A but with Bellefonte interconnected with Southern. We performed an additional step due to the interconnection with Southern, whereby dispatch reductions come from Southern units to estimate interconnection upgrades needed in Southern, then analyzed deliverability to MLGW. Costs shown in Exhibit 5-6 are additive of both steps.

As noted, *pro rata* dispatch down is common practice. Further, to validate these redispatch cases, we used ABB's PROMOD model and ran ICF's latest Base Case with and without Bellefonte #1 included in 2021. The results from this simulation indicate that Case A is the closest representation of economic dispatch across TVA (using $3.05/MMBtu gas prices at Henry Hub): across TVA, coal and combined cycles as a fleet each reduced dispatch by approximately the same amount, while Allen and Southaven continued to dispatch the same with or without Bellefonte #1. However, to ensure a robust result, we considered three additional cases (B, C and D). Other cases are possible depending on factors such as TVA operations, actual fuel prices, and demand.

In Cases A, B and C, we assumed Bellefonte would interconnect at 500 kV at the existing Widow's Creek bus, near the existing plant location.[78] Localized capital expenditures for infrastructure necessary to step up the plant output to 500 kV and interconnect at the existing bus were not included in the study.[79] As part of the study, ICF tested 1,855 contingencies. These include all N-1 contingencies within TVA at 161 kV and above, plus key N-1-1 contingencies identified by TVA's transmission reliability margin (TRM) reports.[80] We also tested N-1 contingencies at 500 kV in Southern Company and MISO South transmission areas. As discussed above, Case D assumed Bellefonte would interconnect with Southern. For case D, we did 3,358 N-1 contingencies within TVA, SOCO, and MISO South at 161 kV and above.

Exhibit 5-5 and Exhibit 5-6 show the overloaded lines in Case A and Case D (all are in Affected Systems), and our estimate of the cost to fully double-circuit each line:

dispatch orders presented by individual transmission owners." Case A is consistent with SPP's method as TVA is the only owner of the analyzed transmission system.

[78] Except when the alternative path (path 3) with interconnection into Southern in Alabama.

[79] According to information Nuclear Development, LLC gave to ICF, these 500kV interconnection expenditures are captured in the total construction cost estimates for Bellefonte unit 1.

[80] TVA's flow gates TRM values released in January 2018 (http://www.oatioasis.com/TVA/TVAdocs/TVA_FlowGates_TRMValues_01312018.pdf) indicate three key N-2 contingencies, namely loss of Bwn-Seq and Norcross-Oconee 500 kV lines, loss of SSHD TVA – SSHD EKPC line and SSHD 161/69 kV transformer, and loss of Shawnee 500/161 kV transformer and Shawnee FP1/FP2.

Exhibit 5-5. Case A Overloaded Lines and Double-Circuit Cost Estimate – Affected System Impacts

Lines	Voltage (kV)	Ending Bus Area	Loading (%)	Bellefonte to MLGW Shift Factor	Length (miles)	Est. Cost per Mile ($MM/mile)	Total ($MM)
6SRS2! To 6VOGTLE	230	SCEG and SoCo-GA	101.00%	0.68%	21	$1.57	$32.9
3GAINES FRY to 3GWINCO WFP	115	SoCo-GA	106.50%	0.09%	5	$6.59	$33.0
3SHOAL CREEK to 3GWINCO WFP	115	SoCo-GA	109.50%	0.09%	Section of above line	$6.59	-
Total							$65.9

Source: ICF using data from PowerWorld and Ventyx

Exhibit 5-6. Case D Overloaded Lines and Double-Circuit Cost Estimate – Affected System Impacts

Lines	Voltage (kV)	Ending Bus Area	Loading (%)	Bellefonte to MLGW Shift Factor	Length (miles)	Est. Cost per Mile ($MM/mile)	Total Cost ($MM)
5FREEPORT #1 to 5SHELBY DR74	161	TVA	100.30%	3.23%	7	$3.98	$29.8
3PINNACLE! to 3NATURAL STP	115	MISO-AR	100.40%	0.04%	10	$3.17	$33.0
3NATURAL STP to 3MAYFLOWER%	115	MISO-AR	102.20%	0.04%	Section of above line	$3.17	-
Total							$62.8

Source: ICF using data from PowerWorld and Ventyx

We do not include these costs in our analysis because:

- The Bellefonte shift factor on each of these lines is very small. Affected system impacts are ignored in cases in which the shift factor is below approximately 5%, which is the case for each of the above.

- Furthermore, the results of the other cases show that overloads can be avoided on these lines with slightly different re-dispatch patterns. This further mitigates the potential for cost allocation to the transmission service.

- To the extent that the identified system elements are almost at maximum usage in the non-Bellefonte case (that is, the Base Case or Reference Case), it is more appropriate for load or other system users to pay all or part of the cost.

- Additionally, the low overload percentages suggest that full double-circuits across the lines may not be needed to relieve the constraints. As noted earlier, terminal upgrades such as phase shifting transformers, reactance devices, may suffice.

In summary, pathways 1 and 2 shown in Exhibit 5-4 reflect the simplest contract path for firm transmission from Bellefonte 1 to MLGW: namely TVA interconnection and firm transmission service.[81] Both paths are fully contained within TVA territory. In our study, there are no attributable overloads indicated on any of the 500kV lines between Bellefonte and Memphis, nor any overloads on lower voltage lines, nor any local overloads in the Memphis area under any of the cases studies. Our study suggests that there is adequate transmission capacity in place to deliver the full output of Bellefonte 1 to MLGW.

[81] In this case, the Interconnection and Transmission service grid studies are the same from the perspective of analyzing grid upgrades.

6. MLGW Incremental Wholesale Needs and Options

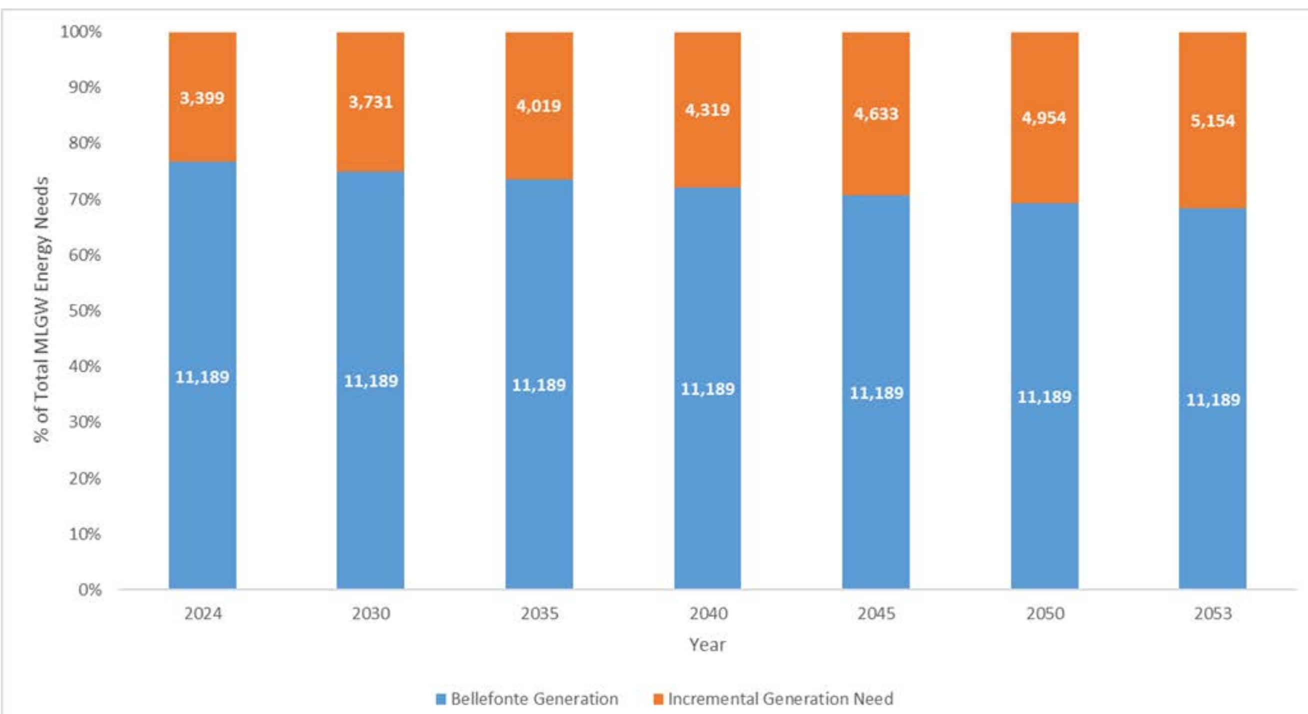
In this chapter we discuss both the incremental need of MLGW outside of the Bellefonte PPA and the supply options for MLGW, e.g., to become its own balancing authority. We assume that this could likely be in the context of a Partial-Requirements Service contract with a third party such as a power company, including traditional regulated companies or deregulated companies. The key is that it can be "do it yourself" or contracted out.

6.1 Incremental Demand

The full output of Bellefonte 1 would serve most of MLGW's total energy needs by providing nearly around-the-clock baseload power. However, some remaining intermediate and peak energy, planning capacity reserves, and ancillary services would have to come from other sources.

MLGW is expected to have nearly 3.6 GW of peak (4.1 GW including reserve) and 14.3 TWh of energy requirement in 2024 increasing to 4.1 GW (4.5 GW including reserve) and 16.2 TWh by 2053. We assume a 15% reserve capacity requirement for MLGW. As shown in Exhibit 6-1 and 6-2, Bellefonte could provide an average of 74% for energy and an average of 36% for peak (or 32% including reserve) requirement for MLGW over 2024-2053 period. Hence, the incremental needs for energy and peak are on average 3.9 TWh and 2.4 GW (or 2.9 GW including reserve) respectively, which MLGW would need to procure from alternative sources along with ancillary services.

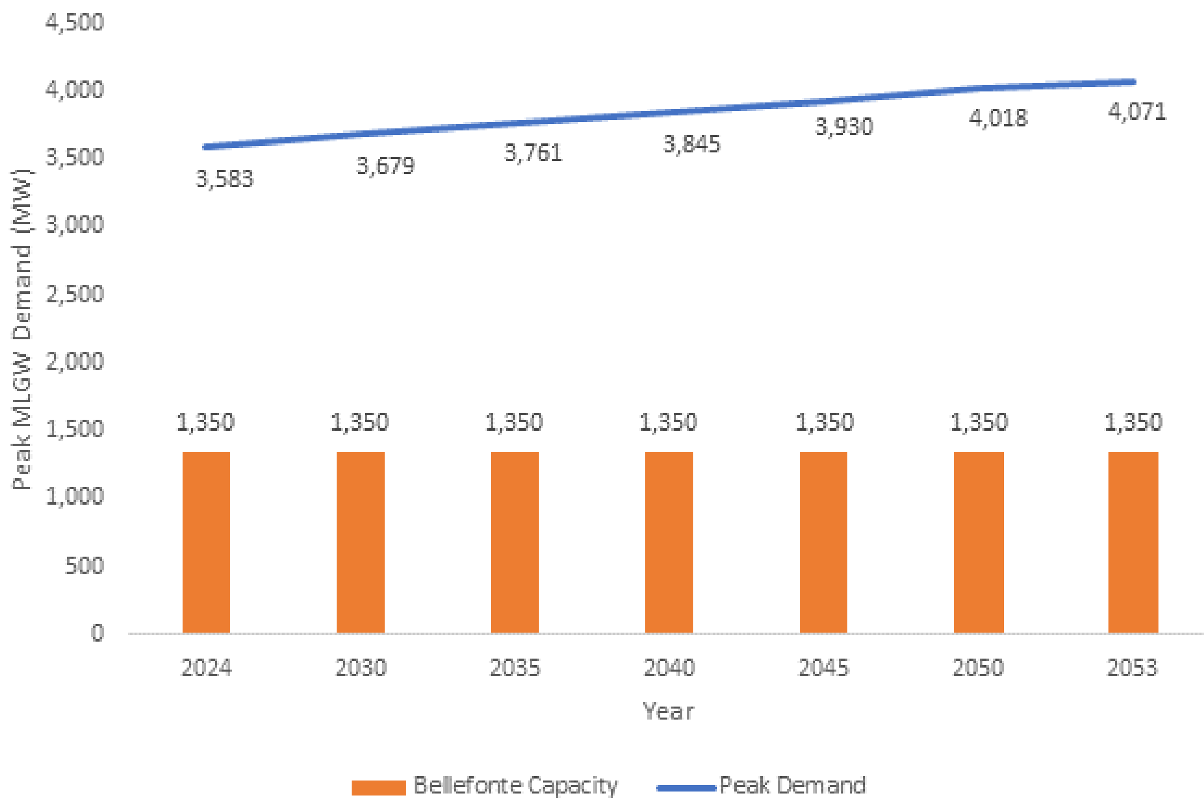
Exhibit 6-1. MLGW Incremental Energy Needs with Bellefonte 1 (MWh)



Source: ICF

Going forward there would be potential spare capacity, primarily driven by uncontracted merchant capacity (IPP) and capacity rolling off PPA contracts, that would help MLGW meets its peak requirements optimally going forward.

Exhibit 6-2. MLGW Incremental Peak Demand Needs with Bellefonte 1



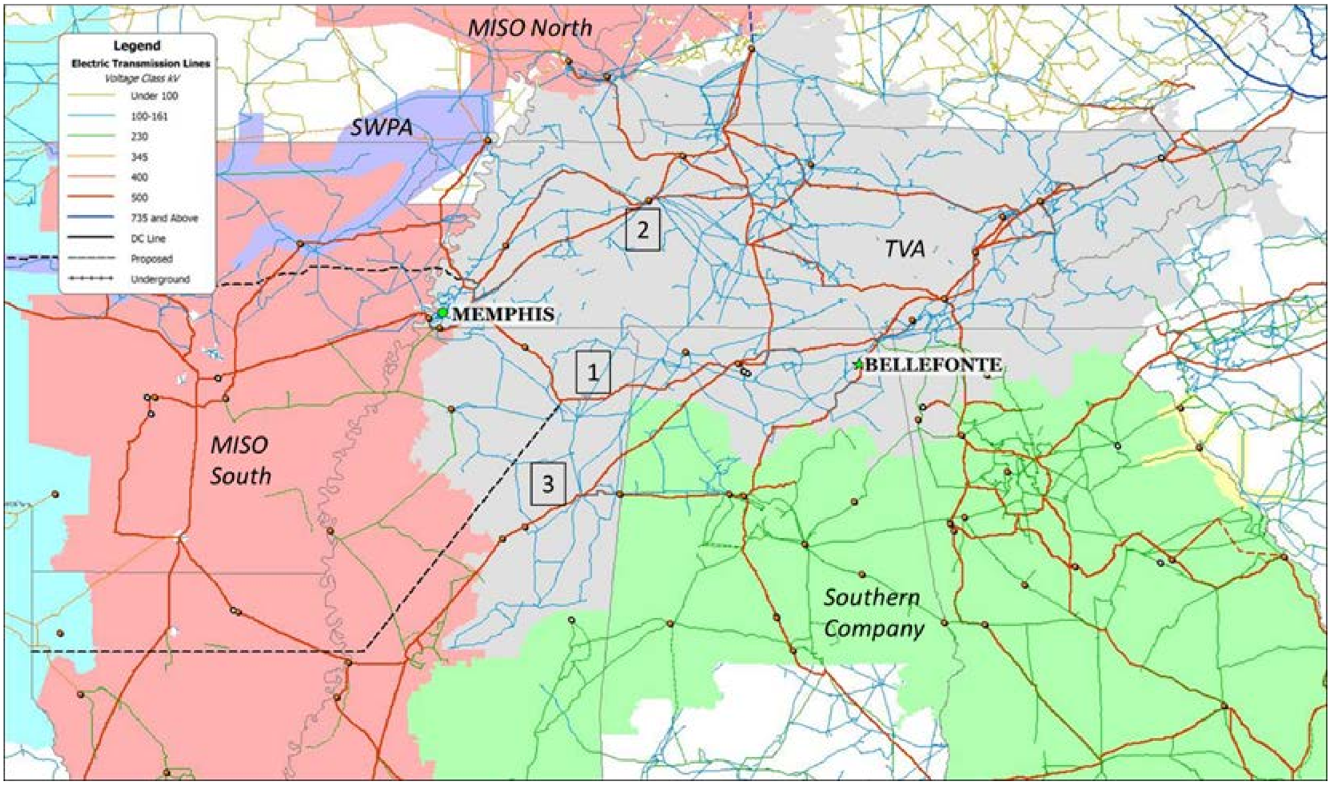
Source: ICF

Were MLGW to contract for Bellefonte's output, it would have to restructure its current wholesale power contract with TVA or source its remaining needs from other entities.

6.2 Energy Landscape and MLGW Options

The energy geography surrounding MLGW is shown below in Exhibit 6-3:

Exhibit 6-3. Memphis Sits at the Juncture of Three Major Power Markets



Source: Ventyx and ICF

MLGW sits near the intersection of three major regions that operate and are regulated very differently. Currently MLGW is a part of TVA, a federally-owned, nonprofit, vertically integrated utility. It borders the southern portion of the MISO, a partially deregulated area with functional Day-2 energy, capacity, and ancillary service markets, but largely comprised in the south of the Entergy operating companies. Nearby to the south is Southern Company, an investor-owned, regulated, and vertically integrated utility. Additionally, further to the north and west are other ISO territories in SPP and PJM.

Our focus in this report is on TVA, MISO, and to a limited extent Southern Company. If MLGW opts out of TVA, it is certainly possible for it to source power from SPP, PJM or other regions. Power coming from these regions will have to be transmitted across the intervening MISO or TVA territory at the cost of firm transmission. The same is true for power coming from Southern Company, however, we include this region in our analysis since it is part of SERC, a region that includes TVA (and by extension MLGW) and is also a key alternate transmission pathway for Bellefonte as described in Chapters 5 and 8.

Exhibit 6-4 summarizes the key characteristics of the markets in this study:

Exhibit 6-4. Characteristics of Surrounding Power Markets

Market	Real-Time Energy Market		Day-Ahead Energy Market		Capacity Market	Ancillary Services Market	Financial Transmission Rights (FTR)
	RTO/ISO	Bilateral	RTO/ISO	Bilateral	RTO/ISO	RTO/ISO	RTO/ISO
MISO	Yes-liquid	Yes	Yes-liquid	Yes	Yes – prompt auctions	Yes	Yes
TVA	No	Yes-illiquid	No	Yes-illiquid	No	No	No
SOCO	No	Yes – slightly more liquid	No	Yes-illiquid	No	No	No

Source: ICF

The different operations in each market affect the wholesale power procurement options available to MLGW. For example, in TVA or Southern Company, the lack of liquid centralized exchange-style markets limits MLGW to purchasing power from TVA, or at most, bilaterally contracting with the IPPs interconnected in TVA. In MISO, by contrast, MLGW could still bilaterally contract with individual plants or utilities, but it could also participate in liquid markets and conceivably meet its entire needs via spot purchases of energy, capacity, and ancillary services.

6.3 MLGW Contracting Options

Broadly, we see three main alternatives for MLGW that will be explored in depth in this chapter of the report:

Option 1: Continue with TVA for Partial-Requirements Service

The most straightforward option, if available, is to simply contract for Bellefonte 1's power and source all remaining requirements from TVA. This would require minimal change on the part of MLGW operations and comparably less upfront investment. In effect, the TVA contract would be similar in character to the current one, except that TVA would serve a smaller quantity of MLGW load. This option relies on TVA's willingness to offer such a contract and what the terms would be.

Option 2: Join MISO

Our "intermediate" option in terms of complexity for MLGW is to exit from TVA service and interconnect itself with MISO. This would allow it to access the MISO energy, capacity, and ancillary markets and reduce the cost to contract existing plants in MISO. MISO would serve as the balancing authority and would coordinate inter-regional transmission, among other services. This could be achieved via TVA lines or new lines from MLGW across the river.

Option 3: Become an Independent Balancing Authority

Our final option is for MLGW to separate from TVA and serve as its own BA. In this case, MLGW could still interface with MISO energy markets via interchange schedules or a pseudo-tie but would face requirements such as balancing its own grid and contracting with external plants for services.

Options 2 and 3 involve fairly broad changes in MLGW's operations. Our assessment shows that MLGW would likely need to construct and own new high-voltage transmission lines, plan and contract much more actively for their future wholesale needs and face greater exposure to market pricing. However, these options each offer the advantages of access to a broader set of energy resources (as they are not tied to TVA's set rate) including the ability to source from Bellefonte 1. Option 1 involves considerably less change but is subject to availability. MLGW's exit from full-services contracting with TVA *could* negatively affect TVA, and historical experience shows that TVA has vigorously resisted attrition of its full-service customers (we detail some of these challenges in Chapters 7 and 9). Exhibit 6-5 summarizes the three options:

Exhibit 6-5. Options for MLGW

Case	Option 1: TVA Partial-Requirements Service	Option 2: Join MISO	Option 3: Independent Utility
Balancing Authority	TVA	MISO	MLGW
Remaining Power Needs	TVA	MISO	MISO/SERC
Reserve Sharing Group	TVA	MISO	SERC

Source: ICF

Importantly, while we will refer to these three options throughout this report, they do not represent the only options for MLGW. Alternative combinations of balancing authority and power sources may be possible. Additionally, there are various ways to interface with MISO that can carry differing costs and qualitative benefits for MLGW. Our report details some of these options in Chapter 7. The remainder of the report builds out our estimate of costs, benefits, and qualitative considerations for these cases.

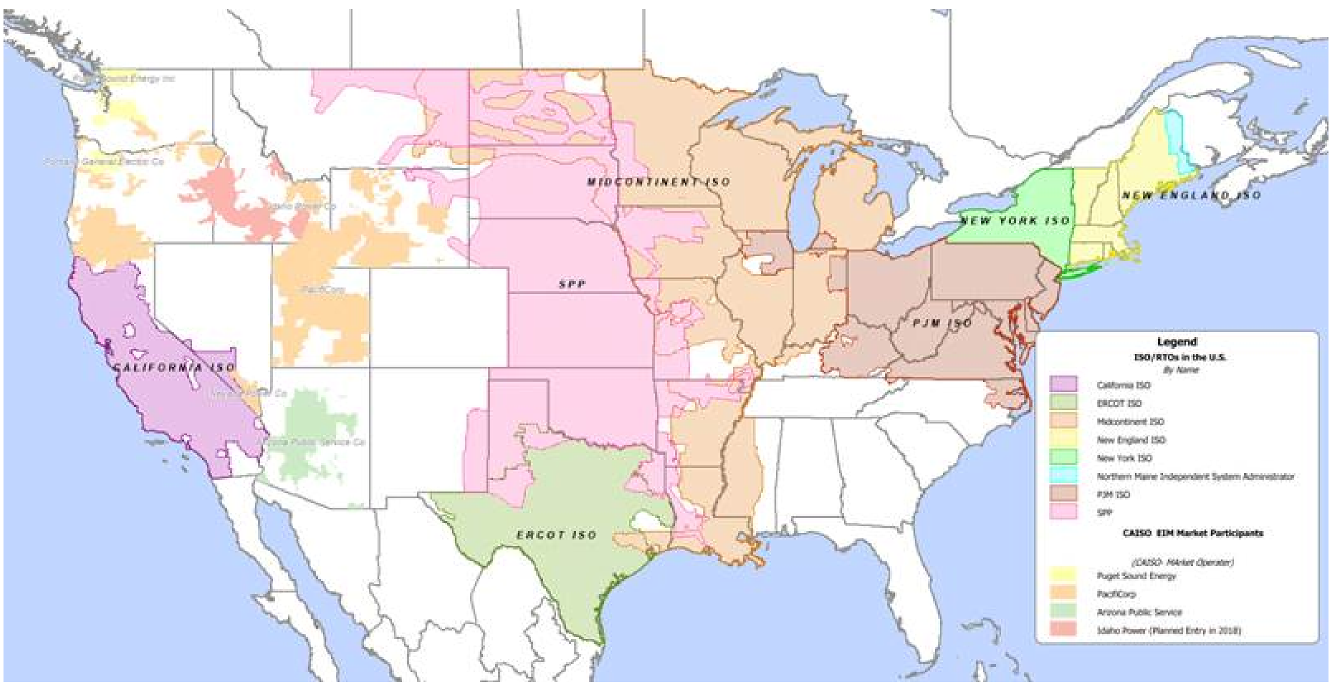
7. MISO Wholesale Power Market

7.1 Market Background

MISO is an organized RTO power market. Wholesale spot prices have been very low compared to TVA rates in recent years.

MLGW has not had much direct interaction with MISO, which is a result of an anomalous situation: MLGW is part of one of the few regions not in an organized exchange style RTO market. In Exhibit 7-1 below, shaded areas have (or will have by [estimated year]) an organized electrical energy market using nodal pricing for real-time markets; most also have day-ahead markets. Therefore, among major regions in the contiguous US, only the southeastern (including TVA) US lacks an organized market. However, the southeastern region borders organized markets to the north, west and east, with MISO largely northwest and southwest. Fortuitously for MLGW, it sits on the seam between MISO and the Southeastern US.

Exhibit 7-1. MISO and Other ISO/RTOs in the US



Source: Ventyx

In terms of load served, MISO is the second-largest ISO/RTO in the country after PJM. However, MISO serves a much larger geographic area than [PJM]. Exhibit 7-2 details the MISO market statistics for year 2017.

Exhibit 7-2. MISO 2017 Statistics

Market Statistic	MISO
2017 Total Generation Capacity	173 GW
2017 ICAP Capacity [net of in-operable capacity + de-rates]	150 GW
2017 Peak Demand	121 GW
2017 Forecasted Peak	125 GW
ICAP Reserve Margin (%)	24.0%
2017 Energy Served	665,012 GWh
States Covered	15
Population Served	~42 MM
2017 Installed Wind Capacity	16.4 GW
2017 Installed Solar Capacity	0.2 GW

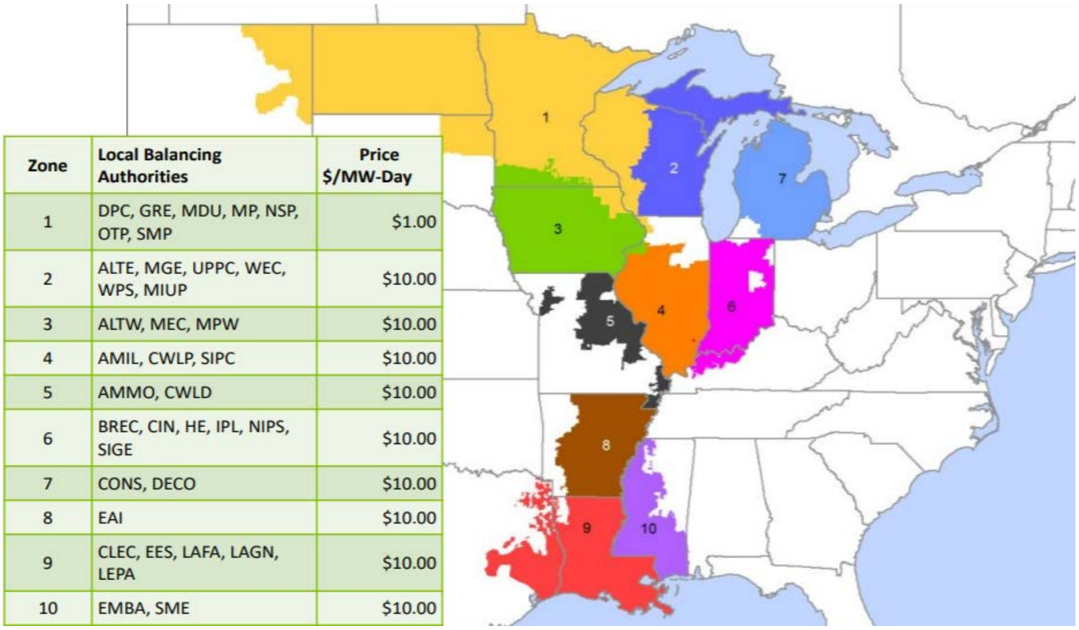
Source: MISO

MISO's role varies regionally, especially vis-a-vis Canada. While the MISO market area covers 15 states in the US, and is limited to US coverage, the reliability coordination coverage extends into Canada, covering the central Canadian province of Manitoba. In the United States, MISO covers areas of Wisconsin, Minnesota, and Michigan, large sections of Indiana, Illinois, Iowa, Arkansas, Mississippi, Louisiana, Missouri, Kentucky, North Dakota, Montana, South Dakota, and Texas.

Most of the areas in the MISO market are served by vertically integrated utilities which own or have long-term PPAs for a significant amount of existing capacity. In the MISO territory, only two areas (lower Michigan and Illinois) are open for limited retail competition.

MISO is organized into ten Local Resource Zones (LRZ). In 2013, Entergy's accession into MISO resulted in the integration of MISO South (Zone 8 and 9), which occurred in response to strong regulatory pressure from FERC to join an RTO. Entergy has five operating companies. Within the service territory of the five operating companies are numerous public power entities including cooperatives, municipalities, and a few other utilities. In 2015, MISO created LRZ 10, a separate capacity that includes Entergy – Mississippi and South Mississippi Electric Power Association. Collectively, LRZ 8-10 are referred to as MISO South (see Exhibit 7-3). MLGW borders MISO South (LRZ 8 – Arkansas, and LRZ 10 – Mississippi). In some respects, MISO treats MISO South separately from the rest of MISO due to transmission limitations (i.e., bottleneck) between Zones 5 and 8 (see Exhibit 7-3).

Exhibit 7-3. MISO Local Resource Zones

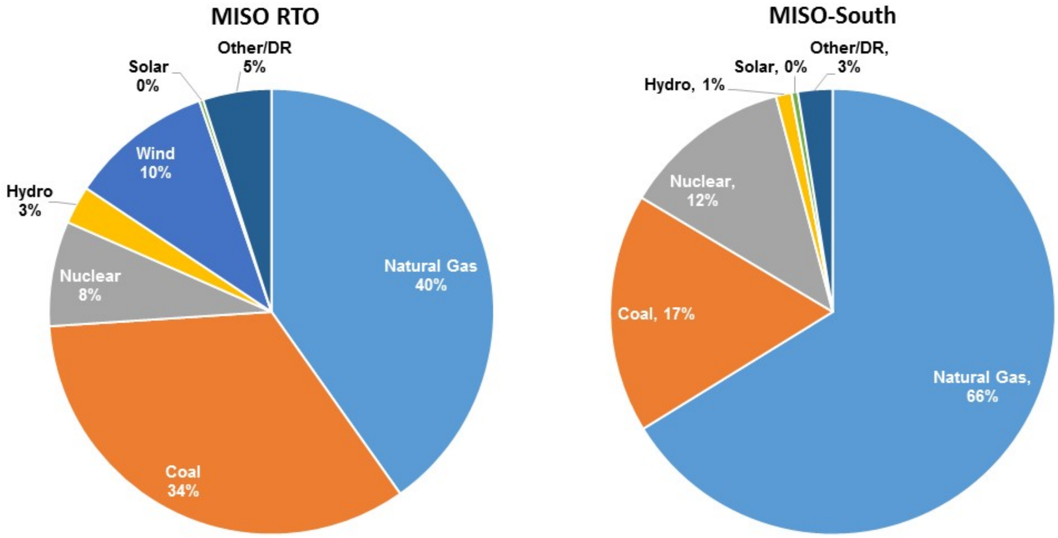


Zone	Local Balancing Authorities	Price $/MW-Day
1	DPC, GRE, MDU, MP, NSP, OTP, SMP	$1.00
2	ALTE, MGE, UPPC, WEC, WPS, MIUP	$10.00
3	ALTW, MEC, MPW	$10.00
4	AMIL, CWLP, SIPC	$10.00
5	AMMO, CWLD	$10.00
6	BREC, CIN, HE, IPL, NIPS, SIGE	$10.00
7	CONS, DECO	$10.00
8	EAI	$10.00
9	CLEC, EES, LAFA, LAGN, LEPA	$10.00
10	EMBA, SME	$10.00

Source: MISO

MISO has installed capacity (ICAP, de-rated) of approximately 150 GW. The historically dominant fuel types are natural gas and coal, although each of these have declined in absolute terms and as shares of capacity in recent years. Between 2010 and 2018, coal and natural gas/oil capacity fell by approximately 11 GW and 9 GW, respectively. In the same period, wind capacity expanded by around 11.5 GW, primarily in the plains states (especially Iowa) with comparably little expansion in MISO-South. The capacity mix in MISO South remains dominated by natural gas/oil (nearly 68%), followed by coal (18%) and nuclear (13%). Exhibit 7-4 details the composition of total nameplate capacity in MISO, as a whole and in MISO South. This means that MLGW, were it to access MISO South, would be frequently accessing gas-fired generation in terms of the marginal price setting unit. However, on average, Arkansas has more coal than MISO South, and hence, coal could be a price setting source as well.

Exhibit 7-4. MISO Installed Capacity Mix 2018[82]



Source: Ventyx, 2017 MISO State of the Market Report

7.1.1 Energy and Ancillary Service Markets

MISO's energy market structure is based on locational marginal pricing (LMP), also referred to as nodal pricing. Under an LMP-based market, market prices can vary significantly by location as transmission constraints and losses develop, and potentially create, thousands of different prices across the grid.

The largest contributor to price separation across LMPs is when energy is constrained by transmission limitations. In an unconstrained system, power could flow from the least expensive generators to the load centers and incur only small physical loss charges along the way. However, transmission constraints mean that more expensive units, favorably located on the transmission grid, must be run instead, creating a higher price behind the binding transmission. Generally speaking, areas with more load than generation experience higher prices than areas with more generation than load.

In practice, the variation in pricing is usually more limited. MISO is required to plan the system to eliminate persistent and significant congestion.

MISO operates two main energy markets: day-ahead (DA) and real-time (RT)[83]. Prices in both markets are established according to cost minimization across the system, subject to cost-based offers for generation, projections of load and ancillary service requirements, operational constraints on generators, and transmission constraints across the system. Ancillary services are provided by energy and capacity products, though ancillary services are priced by zone, and not individually at each LMP node. MLGW, were it part of MISO could buy all its energy requirements from MISO. As discussed elsewhere [in this report], hedging is likely to be an important activity supplementing spot purchase.

[82] This is based on Nameplate Capacity - renewables are not de-rated

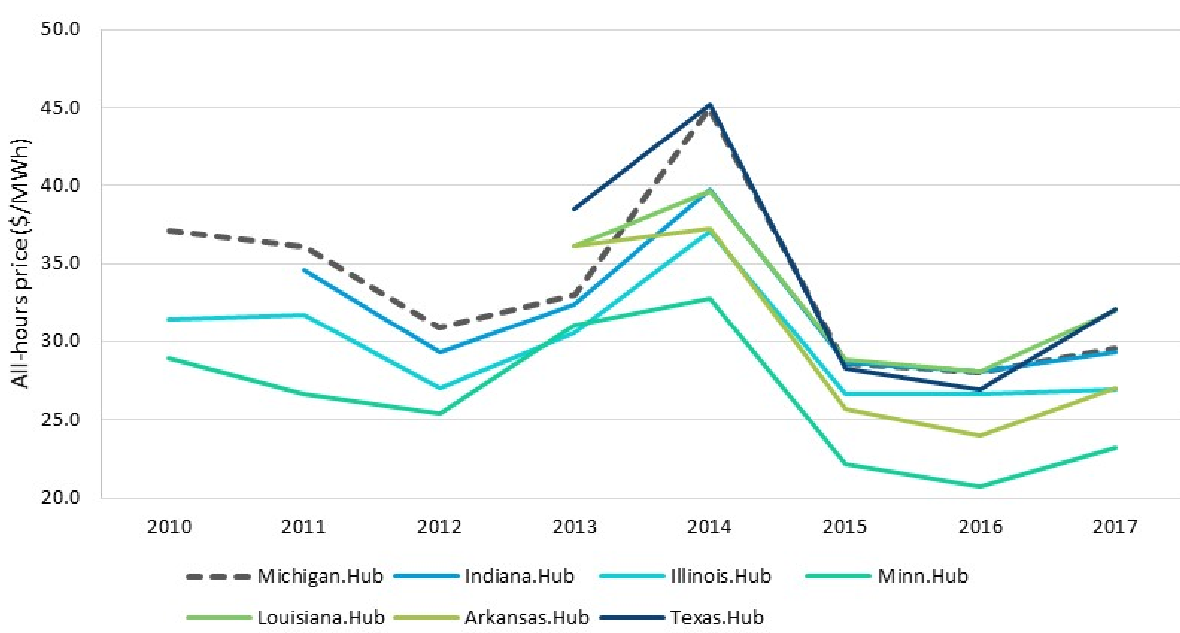
[83] The only LMP markets without both day ahead and real time are in the western US.

The day-ahead market results in commitments to dispatch the following day, and the real-time market results in instruction from MISO to plants for electricity generation. In [the MISO territory], when the market is unable to meet demand, the LMP price is administratively set based on the level of shortage and can reach up to $3,500/MWh, under the most extreme scarcity conditions.

At trading hubs, specific nodal prices are aggregated to create a reference price. The ISOs/RTOs calculate and post the prices at the trading hubs to create a price index, which can then be used to establish a reference for forward markets. Trading hub-based contracts can be used to purchase forward power. Bilateral and forward-market transactions for power are also allowed. These contracts may govern financial settlements (covering the cost for a specified quantity of energy at a given time) or schedule physical delivery across the grid.

Exhibit 7-5 shows historical all-hours DA electrical energy prices at major MISO trading hubs. As reflected in the graph, the Arkansas hub price for all-hours energy over the past three years has averaged approximately $26/MWh. Over the last five years, prices averaged approximately $31/MWh. Not shown, capacity prices have been close to zero. Implementing needed adjustments to compare apples-to-apples, the all hours firm prices would be approximately $50/MWh in 2024, and hence, significantly above the Bellefonte PPA price of approximately $39/MWh. The adjustments are as follows: (1) adding realistic MISO capacity purchase costs, (2) adding transmission costs (to MISO border plus either over TVA lines or newly constructed MLGW lines), and (3) inflation adjustments from 2015 to 2024. This results in a higher MISO all-in price of approximately $50/MWh. In addition, the historical price does not necessarily account for the potentially higher volatility of MISO spot prices compared to the Bellefonte PPA. Over the last five years, the average all hours MISO electrical energy price was $31.5/MWh while the range was $13/MWh or from $24/MWh to $37/MWh. In contrast, Bellefonte PPA price is not volatile.

Exhibit 7-5. Historical DA Prices at Major MISO Trading Hubs



Source: Ventyx

As noted, the five year average MISO energy price is above the most recent three-year average price. This is because energy pricing in MISO follows the prices of natural gas, coal, and weather, as well as other factors. In the past three years, all-hours prices across MISO have been low (~$25-26/MWh) in large part due to low natural gas prices. Prices were much higher in 2014 due to the "polar vortex" extreme cold event that resulted in natural gas price spikes, plant outages and unexpectedly high winter demand. Prices at Arkansas Hub, the closest to MLGW, in general are slightly lower than the rest of the market but otherwise follow the same trends.

7.1.2 Capacity Market

The goal of capacity markets is to maintain system reliability at peak demand (i.e. having more than enough resources to meet peak [demand] including contingencies such as unit outages, higher-than-expected demand, etc.) by compensating units for providing needed going-forward reserve capacity. Some peaking reserve units are needed even though they may rarely or never be called on to produce energy and therefore would otherwise earn no revenues[84].

The capacity market is enacted through requirements placed on load-serving entities (LSEs) such as utilities. LSEs in MISO must meet two reserve requirements: The Planning Reserve Margin Requirement (PRMR) and the Local Clearing Requirement (LCR). The LCR is the amount of capacity a zone must procure internally to meet its own peak demand requirements. The PRMR is the amount of capacity a zone must procure, which can include imports, to fulfill its share of MISO's peak demand reliability requirements. An LSE can meet its obligations by owning or contracting for capacity from existing generators, or by purchasing capacity in the spot Planning Resource Auction (PRA).

The PRA results in capacity commitments for one-year periods. The commitment period is June to May; with the auction clearing two months prior to the start of the commitment period. The bids are cleared through a single, sealed-bid clearing price auction against a vertical demand curve, unlike ISO-NE, PJM, and ISO-NE, where bids are cleared against sloping demand curves. Exhibit 7-6 below summarizes the key aspects of MISO's capacity market construct.

Exhibit 7-6. Key Capacity Market Attributes in MISO

Parameter	MISO
Commitment Term	12 months
Timing	Prompt
Demand Curve	Vertical
Locational Sub-Markets	10
Performance Incentives	No

Source: MISO

Exhibit 7-7 below shows the 10 capacity zones with the most recent clearing prices:

[84] Bid prices are also restricted by market manipulation rules. Thus, revenues can still be too low to cover costs; this is referred to as the missing money problem.

Exhibit 7-7. MISO Capacity Market Zones and PRA Results ($/MW-day)

Zone	2013/2014	2014/2015	2015/2016	2016/2017	2017/2018	2018/2019
Zone 1	1.05	3.29	3.48	19.72	1.50	1.00
Zone 2	1.05	16.75	3.48	72.00	1.50	10.00
Zone 3	1.05	16.75	3.48	72.00	1.50	10.00
Zone 4	1.05	16.75	150.00	72.00	1.50	10.00
Zone 5	1.05	16.75	3.48	72.00	1.50	10.00
Zone 6	1.05	16.75	3.48	72.00	1.50	10.00
Zone 7	N/A	16.75	3.48	72.00	1.50	10.00
Zone 8	N/A	16.44	3.29	2.99	1.50	10.00
Zone 9	N/A	16.44	3.29	2.99	1.50	10.00
Zone 10	N/A	N/A	N/A	2.99	1.50	10.00

Source: MISO

MISO capacity market offers are not subject to a Minimum Offer Price Rule (MOPR) requirement. With the dominance of the utilities (which can include owned generation in their rate base and therefore not require additional revenues from the PRA), and a general lack of buy-side market power mitigation measures, MISO capacity auctions often see most generators bid at or near $0, and therefore clear at very low prices. For perspective, if MLGW were able to procure 3000 MW of capacity at the most recent MISO capacity prices of $10/MW day, the annual costs would be approximately $11 million, or $3-4/MWh if allocated to the 3 million MWhs of incremental energy required. For additional perspective, total costs for MLGW of the TVA contract were approximately $1 billion. However, as stated in this report, the volumes in the capacity market are thin.

7.2 Forecasted Market Prices

ICF uses two primary models to simulate market evolution and prices in the US. First, we utilize our proprietary IPM zonal production cost model to simulate plant economics and project economic [for] new-builds, retirements, and capacity prices over time. We then use the results of this model in conjunction with ABB's PROMOD nodal security-constrained economic dispatch (SCED) model, to further add detail of hourly energy pricing at the nodal level. Further details of these models can be found in Appendix.

7.2.1 Energy and Ancillary Service Prices

Exhibit 7-8. MISO Arkansas Hub Historical and Projected Energy Prices, Fuel Prices, and Implied Heat Rates

MISO Arkansas Hub	Year	All-Hour Energy Price ($/MWh)	On-peak Energy Price ($/MWh)	Off-peak Energy Price ($/MWh)	Delivered Gas Price ($/MMBtu)	CO2 Price ($/ton)	All-Hour Energy IHR (Btu/kWh)	On-peak Energy IHR (Btu/kWh)	Off-peak Energy IHR (Btu/kWh)
Historical	**2013**	36.1	37.5	34.9	3.8	0	9,421	9,785	9,107
	2014	37.3	41.3	33.6	4.4	0	8,389	9,287	7,570
	2015	25.7	28.4	23.2	2.7	0	9,598	10,622	8,666
	2016	24.0	27.2	21.1	2.5	0	9,498	10,753	8,361
	2017	27.1	30.6	23.9	3.0	0	9,017	10,195	7,952
Projected	**2018**	28.8	33.0	24.9	2.9	0	9,962	11,422	8,632
	2019	28.8	32.9	25.1	2.7	0	10,566	12,057	9,207
	2020	28.4	32.4	24.7	2.6	0	10,945	12,502	9,522
	2023	34.9	40.3	29.9	4.0	0	8,796	10,173	7,550
	2025	36.2	41.6	31.2	4.2	0	8,706	10,019	7,510
	2030	46.6	53.4	40.4	5.1	5.4	9,072	10,404	7,859
	2035	56.3	64.1	49.3	5.9	13.2	9,586	10,896	8,392
	2040	65.5	74.7	57.1	6.6	21.7	10,116	11,546	8,820
	2045	76.1	87.2	66.1	7.4	35.5	10,675	12,234	9,270
	2050	99.4	113.0	87.2	8.1	60.7	12,477	14,180	10,938
	2053	105.3	120.3	91.7	8.7	64.6	13,214	15,102	11,506

Source: Ventyx and ICF

Notes: Energy prices reflective of MISO-Arkansas hub and delivered gas for Texas Gas Zone 1+$0.05/MMBtu (in 2012$) LDC and 2.75% tax;

Both coal and natural gas are major energy sources in MISO South, and as such, the market dynamics depend on the interplay of natural gas and coal pricing trends. As gas prices have dropped, coal plants have increasingly been on the margin, and energy prices have decreased more slowly than gas (see Exhibit 7-8).

All-hour energy prices for MISO Zone 8 are projected to increase over the 2018 to 2040 period. The escalation is driven primarily by increases in gas prices, inflation, and the projected national regulation of carbon emissions starting in 2026 and beyond. These factors are partially offset by new capacity entry in MISO, consisting mainly of solar and natural gas in the near term and natural gas in the mid- to long-term. Decreasing gas prices in the near term lead to nearly flat or dipping power prices.

Forward prices indicate a weak outlook for gas prices in 2018 and 2019, as growth in shale gas production continues to outpace demand growth. We project that coal will remain marginal in many hours in 2018 to 2020, leading to high system heat rates. In subsequent years, ICF projects modest upward pressure on gas prices, as demand growth accelerates (from new LNG export capability, growing exports to Mexico, and increases in industrial and power sector demand). Despite the projected long-term increase over recent levels, gas prices are expected to remain below pre-recession levels (i.e., pre-2007/08).

In the long run, as gas prices track higher, gas is expected to become the marginal fuel in most hours and thus energy prices track more closely with natural gas prices. Implied heat rates begin increasing after 2025 due to the influence of assumed carbon regulation; the carbon-adjusted system heat rates after 2030 are essentially flat or falling. ICF assumes carbon pricing in MISO to take effect with an allowance price of $1/ton in 2026, $5.4/ton in 2030, $13.2/ton in 2035, and $21.7/ton in 2040 for existing sources.

7.2.2 Capacity Prices

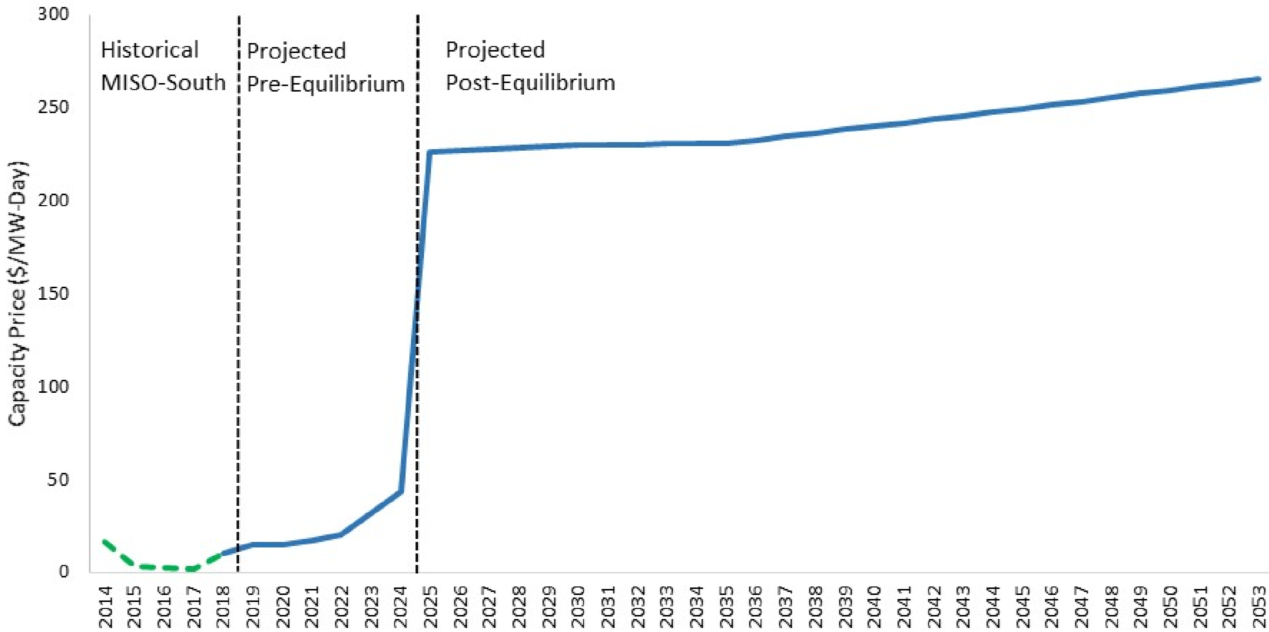
Exhibit 7-9 summarizes the Base Case merchant capacity price forecast for MISO. ICF projects low capacity prices in the near term owing to a surplus of supply in MISO and the lack of value placed on this surplus capacity in the MISO capacity market.

In the equilibrium period, ICF assumes that the existing units will not realize a net CONE [85]capacity price, as the utilities in MISO would prefer to contract with new technologies and build their own capacity rather than re-contracting with an old facility at net CONE prices. ICF's view of capacity prices for an existing capacity during the equilibrium period reflects going forward fixed cost of a combine cycle facility ($25/kW-yr in 2018$), increasing with inflation. Over time, capacity oversupply is projected to decline leading to tightening reserve margins, and thereby, increasing capacity prices in the mid-2020s. Prices for new units are projected to increase to $226/MW-day ($82/kW-yr) by 2025 as the system comes into equilibrium. See the full capacity price data set in Appendix Exhibit A-4.

The current capacity surplus market reflects a "buyers' market" and so MLGW can lock in or buy the capacity at most competitive and discounted rates, whereas once the market is in equilibrium – the market would turn to a "sellers' market" and the entering into a contract or purchasing plant would be relatively costly which is implied by the net CONE type pricing.

[85] CONE stands for "cost of new entrant", i.e., the capital cost required to build a power plant. The term Gross CONE typically includes the going forward fixed costs along with capital recovery. Net CONE = Gross CONE (capital + fixed costs) – Energy Margin (Energy Revenue –fuel – consumables – major maintenance).

Exhibit 7-9. MISO Capacity Price Projection

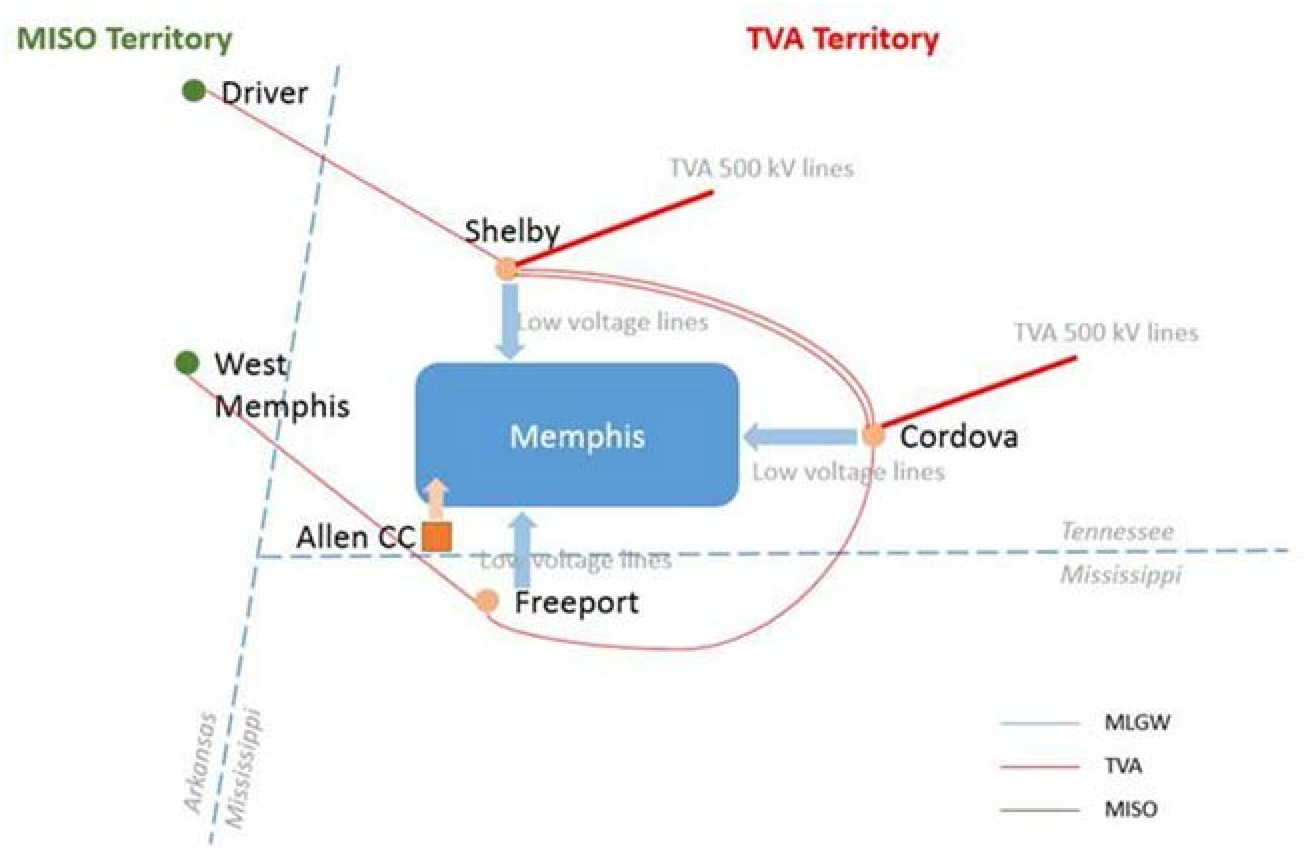


Source: Historical data was obtained from MISO PRA and projections are ICF

7.3 Transmission between MLGW and MISO

TVA, MISO and the MLGW service areas are all interconnected through at least one 500kV line and many lower voltage connections. TVA interconnects with Southern through four 500kV lines including one branch within Alabama, two at the Alabama-Mississippi border, and one in Georgia. There is only one 500 kV connection between Southern and MISO which begins in Jackson, Mississippi and ends in East Feliciana Parish, Louisiana. TVA and MISO South are interconnected through four 500 kV branches, with two bridging the transmission area border in Choctaw, Mississippi and another two linking Arkansas and Memphis.

Exhibit 7-10. Representation of Existing 500kV Network around Memphis



Source: ICF

As shown in Exhibit 7-10 above, the two Arkansas-Memphis linkages begin in the West Memphis substation and Driver substation in Arkansas, and feed into Freeport substation and Shelby substation in Memphis, respectively. The Shelby and Freeport substations in Memphis, together with the Cordova substation, then form a horseshoe shape 500 kV transmission loop that surrounds Memphis. A set of 161 kV and lower voltage lines come out of the three substations to deliver power into the MLGW load service territory in Memphis. These low voltage lines are owned by MLGW.[86]

MLGW does not own significant generation assets and the sole large-scale power plant located in Memphis is the TVA-owned 1,200 MW Allen CC plant[87]. More specifically, in 2017 around 24% of MLGW energy demand was served by the Allen plant, while the remaining 76% of demand was dependent on the stability and reliability of the surrounding transmission loop.[88] Exhibit 7-11 below details the key characters of the 500 kV lines forming the loop.

[86] Ventyx

[87] There are a few small solar projects in Memphis, but the sizes are minimal. The retired Allen coal plant is still on site and might be a source of power under revised regulations.

[88] Calculated by ICF based on EIA Form 923 and FERC Form 714.

Exhibit 7-11. Characteristics of 500 kV forming the loop

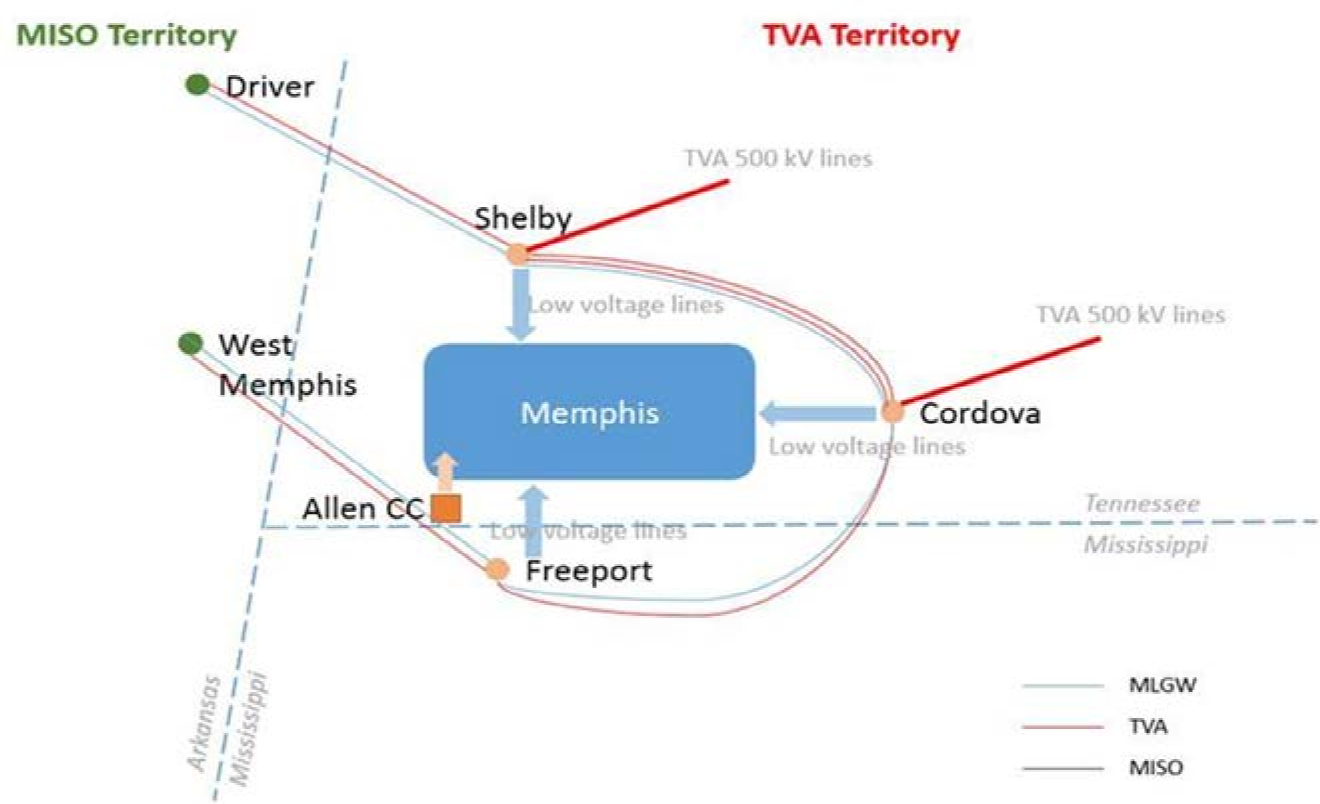
Line Name	# of circuits	Mileage	Ownership
Driver - Shelby 500 kV	1	18	TVA
Shelby - Cordova 500 kV	2	20.5	TVA
Cordova - Freeport 500 kV	1	25.3	TVA
Freeport - West Memphis 500 kV	1	15	TVA

Source: ABB Ventyx database, compiled by ICF

As has been established in Chapter 5.3, MLGW is able to meet its power needs with the existing physical transmission connections and the corresponding system upgrades, depending on the interconnection assumption for Bellefonte. MLGW joining MISO through a contractual movement would not affect physical deliverability.

Nevertheless, MLGW may still want to build its own physical connections with MISO for several reasons. For example, as will be discussed further in Chapter 10, it is more economic to build a physical transmission connection than to pay the transmission charges that TVA and MISO can impose on MLGW for using their transmission lines. Moreover, the capacity of the existing TVA-MISO [transmission line] may be less sufficient for meeting MLGW's load growth from a long-run perspective. In this case, MLGW can consider building a single-circuit loop in parallel to the existing one as shown in Exhibit 7-12 below.

Exhibit 7-12. Representation of 500kV Network with Additional Single Circuit



Source: ICF

ICF estimated the cost to build and operate such single-circuit loop using NREL's JEDI Transmission Line Model as listed in Exhibit 7-13. This cost has been included in the following options- Option #2A, Option #2B, Option #3A, and Option #3B. This cost is listed under the 'Incremental Other Cost/Revenue' when ICF computes the net savings from gross savings in Exhibit 2-4. These costs are also shown in Exhibit 10-5 under 'MLGW Ownership of Transmission Line' when discussing the regulatory cost associated with each option.

Exhibit 7-13. New Lines to be constructed for Single-Circuit Direct MLGW Connectivity with MISO

From Bus	To Bus	Voltage (kV)	length (mile)	# of circuits	Capital Cost (Million 2018$)	Annual O&M Costs (Million 2018$)
Memphis-MISO single-circuit loop case						
Freeport	West Memphis	500	15	1	94.6	0.28
Shelby	Driver	500	18	1	96.6	0.3
Shelby	Cordova	500	20.5	1	99.6	0.32
Freeport	Cordova	500	25.3	1	109.2	0.38
Total			**78.8**		**400**	**1.28**

Source: ICF using data from PowerWorld and Ventyx

8. Procuring Incremental Power

MLGW has several methods available at its disposal for procuring its incremental power needs. The choice of contracting and procurement strategy could have a significant impact on the ultimate cost of this capacity. We discuss the provision of both energy and firm capacity, however, in many cases the considerations are similar.

8.1 Spot Market Contracting

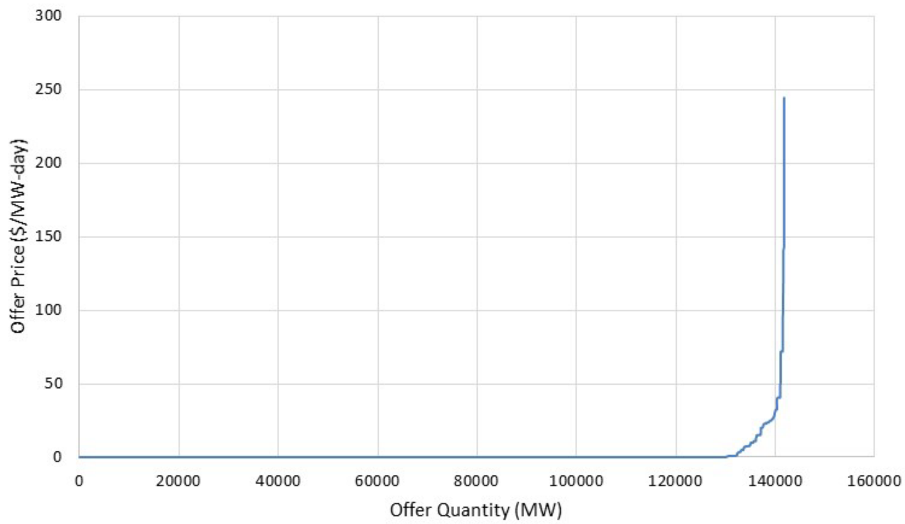
As discussed in Chapter 6, the only organized, transparent and highly liquid spot market for energy in the region is operated by MISO. There is also a MISO capacity market with close to zero prices and liquidity limitations. While Southern Company operates power exchanges across its transmission grid, actual trading volume is limited, and MLGW would additionally have to secure transmission from Southern Company to the MLGW service territory through either TVA, MISO, or both, adding cost. Therefore, we do not recommend exclusive or high reliance on bilateral non-RTO markets, and in general, recommend careful use of spot and hedging opportunities.

Spot markets can be volatile, especially capacity markets

Recently, spot market prices have been extremely attractive compared to TVA rates. MISO energy prices are volatile and over the last five years, the average all hours energy price in MISO was $31.5/MWh while the range was $13/MWh or from $24/MWh to $37/MWh. MISO capacity prices have been near zero, but the supply curve in the MISO capacity market is very steep. Adding the components of MISO capacity, transmission costs and inflation adjustments translates to higher MISO all-in price of approximately $50/MWh.

However, MISO's energy markets are day-ahead and real-time, and its capacity market extends out only to the upcoming year. As such, MLGW cannot hedge forward its needs very far by exclusively participating in MISO's formal spot markets. Spot energy prices depend heavily on natural gas prices, especially in southern parts of MISO, which historically has been one of the most volatile commodities traded. They are also heavily weather dependent, as either weather extreme (hot or cold) will tend to increase power prices. Spot capacity prices can also increase unexpectedly, especially due to the use of a vertical demand curve in the MISO capacity market, the PRA. As shown in Exhibit 8-1, the tail end of MISO's capacity offer curve becomes extremely non-linear, so tightening in the market can result in a concomitant non-linear increase in capacity prices.

Exhibit 8-1. MISO 2018/2019 Capacity Price Offer-Curve



Source: ICF using data from MISO

MLGW is a large enough consumer to influence the MISO-South merchant market, specifically the spot capacity market

MISO South is dominated by Entergy, which largely meets its own needs through self-owned generation plants or long-term contracts. The merchant markets, while liquid in comparison to all other regions in the Southeastern US, might not be able to fully absorb MLGW without experiencing price increases, especially capacity price increases. This [scenario] exists even if MLGW tries to buy longer-term energy in forward markets, since the physical power would still have to be procured from the same resource base. Put another way, historically low spot prices would not be a good benchmark if a load the size of MLGW joins the market. It should be noted that MLGW has limited energy requirement averaging 4 TWh, which comprises ~2% of the MISO-South load, whereas the peak requirement (including reserves) is 3 GW or ~9% of the MISO-South load.

The MISO spot market is forecasted to tighten because of the number of retirements exceeding the number of new-builds over the next 3-5 years; if this does not happen, savings could be higher than estimated

Much of the IPP capacity was the result of new-builds 10 to 15 years ago. Over time, there have been a significant number of retirements and few merchant IPP additions in this region. For example, TVA has retired 8.18 GW over the last ten years. This tightening in the supply and demand for electric power increases the chances of price increases in both energy and, more notably, capacity. MLGW's integration into MISO would hasten the tightening need for capacity. While one might argue TVA adds as much capacity on the supply side as MLGW demands incrementally, TVA might have market power – i.e. is not a pure price taker unaware of the extent to which their decisions might affect prices.

Overall, we believe that the presence of spot markets in MISO does provide a benefit to MLGW in offering a competitive, liquid source of energy and for small amounts of capacity, and especially for opportunistic purchases when the prices are very low. Further, given that around 70% of MLGW's energy needs are met by the Bellefonte PPA at very stable pricing, some exposure to markets that may have even low but volatile costs can be manageable or even attractive. However, we do not recommend heavy reliance on these markets for going-forward needs.

8.2 Contracting with Existing Power Plants

A second option for MLGW involves purchasing or long-term contracting existing power plants. For reasons that will be discussed in greater depth in Chapter 10, if MLGW does join MISO, it becomes less costly to source power plants within the MISO footprint, especially for firm capacity that is the bulk of MLGW's remaining needs after Bellefonte. There are several ways MLGW can financially own a plant without owning the physical infrastructure.

- **Tolling contracts and other physical power purchase agreements:** these allow MLGW to purchase long-term physical power from a specific plant or portfolio, usually at a rate indexed to fuel prices plus a fixed payment. MLGW therefore owns either a portion of or the entirety of the physical output of a plant without owning the physical plant itself. This serves as a natural hedge: if the plant under contract becomes uneconomic over the long run, it means that market prices are necessarily less than the cost of the contract, so MLGW can source from the spot markets instead and its downside risk is capped by the contract. There is risk of high fuel prices, however, this is common across all cases, and downside risk is capped by the spot price.

- **Financial PPAs / contract for differences / heat rate call options, etc.:** these function similarly to the physical contracts above, only they operate on a purely financial basis and do not track the power from plant to load. MLGW purchases physical power from the market and is paid according to the revenues of the plant. Financial contracts for gas or power usually require mark-to-market collateral, or the potential need to post collateral. The amount of collateral required increases when there is a problem with the utility's financing, exacerbating the liquidity risks facing the utility. Also, the greater the volume and the longer the term, the greater the potential collateral requirements. Thus, there is usually a continual resetting of short term contracts to manage that risk. As a result, the gas or power prices generally then reflect the then-current market conditions. Therefore, hedging against market risk is helpful but not perfect. This often leads to the purchase of power plants which do not have this collateral risk.

- **Physical purchase of plants:** actual ownership of the equipment and the physical production of the plant.

Each of the above modes is common within MISO, and results in essentially the same stream of costs to MLGW (usually a fixed price plus a variable rate according to the capability of the plant). However, as we discuss, there is a discrepancy between our forecasts and market prices in that we expect the market to eventually tighten and have higher prices than recent spot prices, but the costs of buying existing gas fired power plants is low. Alternatively, the market seems to have a very high, unrealistic discount rate or lack of buyers, and hence prices for existing plants are low.

The crucial difference between buying a plant and buying from the spot market is that MLGW can lock in its costs over the long term, and existing prices are very low.

The recent combined cycle (CCGT) transactions in SERC, TVA and MISO suggest a value of less than $400/kW. For example, Entergy recently purchased the Choctaw combined cycle for a value around 1/3 to 40% of replacement costs. Other recent transactions for gas plants in SERC have traded for similar values, often between 1/3 and 1/2 of replacement value, as shown in Exhibit 8-2. Savings can further be obtained in terms of initial price by buying peaking units versus CCGTs. Our analysis assumes a 1/3, 2/3 split in purchases between combined cycle and peaking gas fired power plants.

Exhibit 8-2. Recent Combined Cycle and Combustion Turbine Transactions in SERC

Year of Announcement	PLANT NAME	OWNER	TECHNOLOGY TYPE	CURRENT OPERATING CAPACITY (MW)	BUYER NAME	SELLER NAME	Value ($/kW)
2018	Choctaw Energy Facility	Entergy Mississippi	Combined Cycle	810	Jacksonville	GenOn Energy	387
2017	Decatur Energy Center	Capital Power Corporation	Combined Cycle	805	Capital Power Corporation	LS Power Development, LLC	489
2015	Ackerman Combined Cycle Plant (Quantum)	Tennessee Valley Authority	Combined Cycle	765	Tennessee Valley Authority	Investor group	447
2014	Union Power Facility	Entergy Louisiana, LLC	Combined Cycle	1980	Entergy Corporation/ Union power station	Entegra TC LLC	470
2014	Columbia Energy Center (SC)	LS Power Development, LLC	Combined Cycle	633.2	LS Power Equity Advisors, LLC	Calpine Corporation	402
2014	Decatur Energy Center	LS Power Development, LLC	Combined Cycle	805	LS Power Equity Advisors, LLC	Calpine Corporation	402
2014	Hog Bayou Energy Center	LS Power Development, LLC	Combined Cycle	245	LS Power Equity Advisors, LLC	Calpine Corporation	402
2014	Carville Energy Center	LS Power Development, LLC	Combined Cycle	545	LS Power Equity Advisors, LLC/ Power plant portfolio	Calpine Corporation	402
2014	Santa Rosa Energy Center	LS Power Development, LLC	Combined Cycle	247.9	LS Power Equity Advisors, LLC	Calpine Corporation	402
2013	Bayou Cove	Alexandria City of LA	Combustion Turbine	320	Alexandria City of LA	NRG Energy, Inc.	257
2012	Broad River Energy Center	Energy Capital Partners LLC	Combustion Turbine	984.8	Energy Capital Partners LLC	Calpine Corporation	434
2011	Calhoun Energy Center	LS Power Group	Combustion Turbine	752	LS Power Group	NextEra Energy, Inc.	441
2011	Cherokee County Cogeneration	LS Power Group	Combined Cycle	101	LS Power Group	NextEra Energy, Inc.	441
2011	Magnolia Combined Cycle Gas Plant	Tennessee Valley Authority	Combined Cycle	999	Tennessee Valley Authority	Kelson Energy Inc.	436
2010	Thomas A. Smith Energy Facility (Murray Energy)	Oglethorpe Power Corporation	Combined Cycle	1340	Oglethorpe Power Corporation	KGen Power Corporation	396
2009	Acadia Energy Center	Entergy Louisiana, LLC	Combined Cycle	1205.5	Entergy Corporation/ Acadia Power Partners unit 2		436
2008	Southaven Energy Center	Tennessee Valley Authority	Combined Cycle	891	Tennessee Valley Authority/ Southaven power plant	Goldman Sachs Group, Inc.	518

Source: ICF and SNL

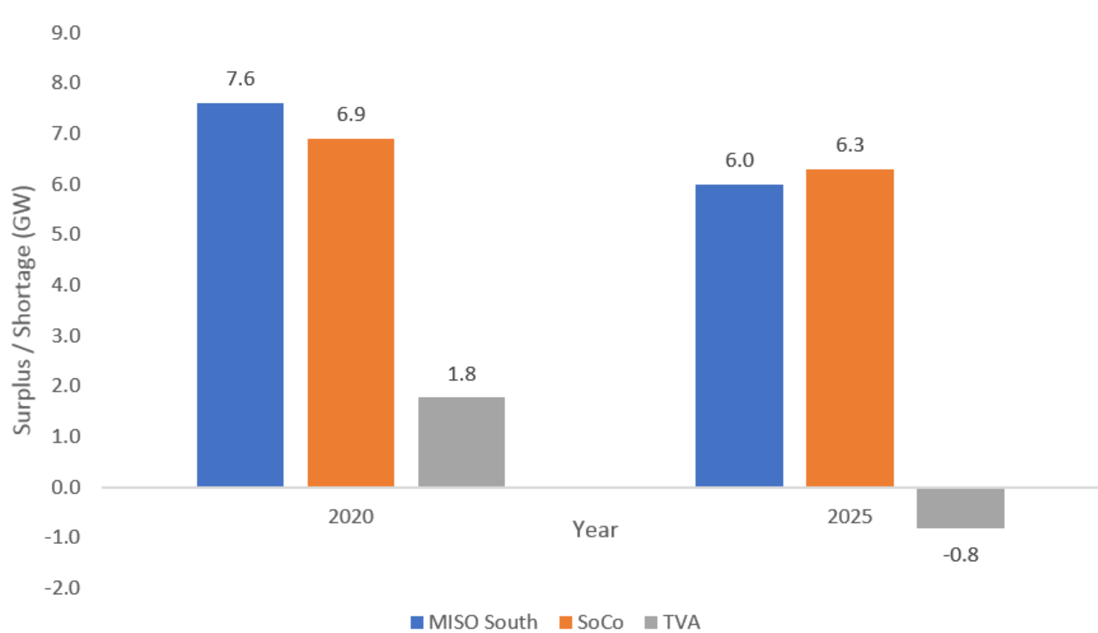
8.3 Supply/Demand Outlook and Available Plants

MLGW's ability to source energy, capacity and ancillary service from neighboring markets at reasonable rates depends in large part on the availability of excess capacity in those markets. In markets where supply is tight, buyers will either find a lack of available counterparties to contract or will have to pay very high prices since the bargaining power of suppliers increases non-linearly. Therefore, in order to establish whether MISO, Southern Company and TVA are viable options, we need to investigate the supply/demand dynamics of the markets. Second, a general understanding of the supply makeup in each market is important for understanding price formation and market dynamics over time.

At the same time, actual prices are valuable indicators of current conditions. As noted, existing gas plants trade at discounts to replacement costs and MISO prices are significantly below TVA prices. This reinforces the conclusions regarding current excess capacity.

Over the last ten years, most of the regions across the US are experiencing low to flat demand growth driven largely by increasing penetration of energy efficiency. The three regions of interest, MISO, Southern and TVA, are expected to have peak and energy demand growth of 0.5%, 0.2% and 0.1%, respectively over the 2019-2045 period. Exhibit 8-3 shows projected capacity surplus/shortage in 2020 and 2025 over the peak demand including target reserve margin requirement. ICF expects 1 GW of economic coal retirement in 2025 and another 1 GW in 2030. Of the three regions, MISO-South and Southern are expected to be long in 2025 with 6 GW of surplus capacity in each region, whereas TVA is relatively short. A market with surplus will reflect a "buyer's market" and will allow MLGW to be able to better bargain the purchase or contract price relative to a market which is short in capacity ("seller's market") where buyer has limited choice.

Exhibit 8-3. Projected Capacity Surplus/Shortage in 2020 and 2025 by region adjusted for Economic Retirements (GW)



Source: ICF

Exhibit 8-4 shows potential IPP contracting opportunities for the MLGW's incremental energy and peak requirement. As discussed in Chapter 6.1, MLGW would need around 3 GW of incremental capacity to meet its peak and reserve requirement. We have summarized the IPP capacity in MISO South, Southern and TVA, which MLGW can look at for buying or contracting. We have categorized the capacity as merchant un-contracted and merchant contracted, and then categorized by its cogen status. The contracted capacity is further broken down by its PPA expiration vintage (pre- and post-2023).

- Of 14 GW of contracted merchant capacity, there is over 4 GW of capacity where the PPA is expiring by end of 2023 (consistent with MLGW's contract expiration with TVA). Similarly, there is around 11 GW of merchant capacity, of which approximately 5 GW is cogen and the remaining is non-cogen. While some of the cogen capacity may not be available due to its captive use requirements, but there would still be enough capacity that can help MLGW to meet its needs.
- TVA: TVA currently has limited excess capacity and any economic retirement will bring the system in supply/demand. However, migration of MLGW could delay the need for new capacity. By 2023, contract for two CCGT (Decatur and Morgan) will expire and these plants would be available in the market for re-contracting.
- Southern: Southern is currently long in capacity and there is around 6 GW of capacity which is either fully merchant or where the contract is expiring before 2024. Southern is projected to have flat demand growth of 0.2%, so it is expected the long position will continue without further retirements.
- MISO South: MISO South is currently long in capacity and there is around 6 GW of capacity which is either merchant or where the contract is expiring before 2024. There is over 4 GW of cogen capacity and some of this capacity may not be available due its other captive and steam obligations.
- There are ample contracting opportunities available for MLGW to source power from neighboring regions as shown below in Exhibit 8-4.

Exhibit 8-4: IPP Capacity Available for Contracting

Utility Region	Tech Type	Cogen Capacity (MW)	Merchant Capacity (MW)	Contracted Capacity (MW)		Total Capacity Region wise (MW)
				PPA Expiring before 2023	PPA Expiring after 2023	
TVA	CC		766	725	749	2,240
	Coal				440	440
SERC-SE	CC	552	1,434	2,328	3,647	7,961
	Peaker		2,024	632	2,210	4,866
MISO-South	CC	3,316	1,180			4,496
	Coal	202		473	1,349	2,024
	OGS	100			575	675
	Peaker	974	300		210	1,484
Total		5,144	5,704	4,158	9,180	24,185

Source: ICF

8.4 TVA Partial Services Contract

TVA's wholesale rate structure includes two components: a demand charge and an energy charge. The demand charge is based on the customer's peak monthly usage and increases as the peak increases. The energy charge is based on the kilowatt hours ("kWh") used by the customer. The rate structure also includes a separate fuel rate that includes the costs of natural gas, fuel oil, purchased power, coal, emission allowances, nuclear fuel, and other fuel-related commodities; realized gains and losses on derivatives purchased to hedge the costs of such commodities; and tax equivalents associated with the fuel cost adjustments.

A comprehensive rate restructuring was approved by the TVA Board on August 21, 2015, and implemented on October 1, 2015 which is summarized as (see Exhibit 8-5):

Exhibit 8-5. TVA Rate Tariff 2015

Standard Service		
On Peak Demand Charge	Summer Period	\$7.13 per kW of on-peak Billing Demand per month
	Winter Period	\$6.27 per kW of on-peak Billing Demand per month
	Transition Period	\$6.27 per kW of on-peak Billing Demand per month
Maximum Demand Charge	Summer Period	\$2.61 per kW of Maximum Billing Demand per month
	Winter Period	\$2.61 per kW of Maximum Billing Demand per month
	Transition Period	\$2.61 per kW of Maximum Billing Demand per month
Non-Fuel Energy Charge	Summer Period	3.670 cents per kWh per month (as adjusted by TOU Amount below)
	Winter Period	3.366 cents per kWh per month (as adjusted by TOU Amount below)
	Transition Period	3.243 cents per kWh per month
TOU Amounts to be added to Non-Fuel Energy Charge	Summer Period	
	During on-peak hours	1.5 cents per kWh per month
	During off-peak hours	-0.7 cents per kWh per month
	Winter Period	
	During on-peak hours	0.8 cents per kWh per month
	During off-peak hours	-0.2 cents per kWh per month

Source: TVA 2015 Tariff

Recently, in an announced/approved 2018 rate change, TVA and LPCs have come to an agreement to propose to the TVA Board to reduce variable energy rates by 0.5 cents per kWh but concurrently establish a similar grid access charge to recover the equivalent amount of revenue, making the change revenue neutral for TVA.[89] TVA revised rates post 2018 rate change are not publicly available.

As a result, ICF built up the wholesale rate for MLGW for full service using the 2015 rate tariff schedule and adding fuel charges to the rate. The rate comes out to be \$71/MWh in 2015 (see Exhibit 8-6). For the partial service rate calculation, ICF used publicly available TVA 2015 rate schedule, which has standard service rates. The partial service rate is calculated with removing the Bellefonte load out of MLGW demand.

[89] https://www.tva.gov/Environment/Environmental-Stewardship/Environmental-Reviews/2018-Rate-Change

Exhibit 8-6. TVA Full Service and Partial Service Build Up Based on the 2015 Tariff

	Non Fuel Energy Charge (million $)	On Peak Demand Charge (million $)	Maximum Demand Charge (million $)	Total Charge (million $)	Total Load (TWh)	Rate Excluding Fuel Cost ($/MWh)	Fuel Cost ($/MWh)	TVA Rate ($/MWh)
Full Service	479	189	72	740	14	52	19	71
Partial Service	96	78	30	204	3	75	19	94

Source: TVA 2015 Tariff and ICF

For partial service requirements, ICF assumed that the baseload load will be served by Bellefonte 1 and that Memphis will be dependent on TVA only for the remaining energy requirement (i.e., Memphis will need only partial service from TVA). For example, in 2015, the partial service rate for Memphis if baseload was served by Bellefonte 1 is calculated to be $94/MWh. Fixed charges like on-peak and maximum demand charges calculated for partial service are spread over lower remaining Memphis load (Memphis load minus Bellefonte load), which in turn cause the rate to increase sharply.[90] The 2015 energy demand of MLGW was used to develop the full-service requirement and partial service requirement rate for MLGW. On-peak demand charges and maximum demand charges were calculated for every month using the on-peak demand and maximum demand, whereas non-fuel energy charges were calculated for every hour according to the rates provided by TVA in 2015 rate schedule. A constant fuel cost of $19/MWh mentioned in the TVA 10-K report is assumed in both full service and partial service rate. The premium of 32% calculated using rates derived for partial service requirements in comparison to full service requirements is applied to derive partial service rate projections for 2024 to 2053 period.

8.5 Other Requirements Service Providers

Requirements service and the associated contracts are common and usually involve a large generating utility selling to the nation's very large number of public power buyers, mostly municipal and cooperative entities. MLGW's contract with TVA is an example. Traditionally, utilities sell via requirements contracts, as opposed to native sales, 10-25 percent of their total sales. Big potential providers near MLGW are TVA, Southern Company, and Entergy. Historically, much of FERC regulation was orientated around ensuring that requirements customers, as long as they were long-term firm customers, were not discriminated against by larger utilities. In the pre-open access transmission period, rates were primarily cost-based and similar across similar customers in order to provide protection. Over time, FERC has migrated to greater emphasis on competition, especially in areas with RTOs.

[90] In comparing the partial service requirements rate with the full service rate, the on-peak demand charges increase by $16/MWh (from $13/MWh to $29/MWh) due to lower remaining Memphis load (i.e., less MWh). Similarly, the maximum demand charges increase by $6/MWh from $5/MWh to $11/MWh for the same reasons. Thus, the difference between the two rates is approximately $22/MWh or $16/MWh + $6/MWh.

Other companies can provide requirements service – e.g. a company with little or no generation. They can purchase the generation or contract for it and provide the same services that traditional requirements contractors provide.

8.6 Self-Build Options

As discussed earlier, the cost of existing capacity is well below that of new capacity and thus with availability of existing from various markets, this option was not explored further.

9. Previous Experience Exiting TVA and TVA Response

MLGW is a Local Power Company (LPC) of TVA. It has a wholesale power contract signed with TVA, which requires MLGW to purchase all its electric power consumed from TVA[91] for the duration of the contract. Under the contract, MLGW buys power from TVA, and resells the power to their retail customers. Per the contract term with TVA, MLGW can terminate the contract upon at least five-year notice and find other power supply sources. This chapter discusses issues related to terminating an LPC TVA contract and previous experience in that regard.

MLGW is TVA's largest LPC, and TVA's preference is to continue to sell power to LPCs. While LPCs have a legal right to terminate their service contracts with TVA, historical experience shows that TVA has resisted such departures. In past situations, TVA made claims that its unique legal situation under the TVA Act and Federal Power Act is relevant to contract termination and LPCs obtaining alternative service.

9.1 Possible TVA Actions

9.1.1 TVA claims ability to set reintegration fees for returning load

In the event that a customer terminates its contract, and then wants to become an LPC, TVA may attempt to charge a reintegration fee. In historical cases, when several distribution customers, including WRECC, filed notice to TVA indicating their intention of terminating the contracts, TVA granted a period of only several months for them to rescind their notices without incurring reintegration fees.

9,1.2 TVA claims it does not need to provide transmission service because of the "anti-cherry-picking" provision: Federal Power Act 212(j)

Our understanding of TVA's claim is subject to the caveat that we are not offering legal opinions.

As discussed elsewhere in this report, TVA has made the claim, rejected twice in FERC decisions (once in its decision and once on appeal) that TVA may reject transmission service requests to parties similar to MLGW after it leaves TVA system.

TVA agrees that, all else equal, FERC, under FPA Section 211, has the jurisdiction to order a transmitting utility, to provide transmission services to other electric utilities per their applications. However, TVA also claims FPA Section 212(j) grants TVA exemption from this rule as it pertains to territory-restricted utilities like TVA. The provision states that no order issued under Section 211 may require an electric utility, who is prohibited by federal law from selling power outside a defined area, to provide transmission services to another entity, if the power to be transmitted will be consumed within the area set forth for this utility[92].

TVA's service territory is restricted by law, and hence in TVA's view, it is the basis at least in terms of fairness, but also in law, that it receives special protection against competition under the Federal Power Act (FPA). The service territory of TVA is defined and restricted by the TVA Act. Specifically, per the requirement from the TVA Act, unless specifically authorized by the Congress or under certain minor exceptions, TVA cannot enter into contracts which would make TVA or its distributors "a source of power supply outside the area for which TVA or

[91] 10 K report, https://www.sec.gov/Archives/edgar/data/1376986/000137698615000047/tve-09302015x10k.htm

[92] FPA Section 212(j)

its distributors were the primary source of power supply on July 1, 1957"[93]. This provision restricts TVA's service territory to a historically defined area, and again in TVA's view lays out the foundation on which the FPA Section 212(j) may be applied to TVA. The provision of the FPA 212(j), referred by TVA as the "anti-cherry-picking" provision, precludes FERC from ordering TVA under FPA Section 211 ("under this chapter") to provide transmission access or services to others to serve the customers within TVA service area.

As noted here, FERC strongly asserts that open access transmission has a separate legal foundation (not within the chapter) namely in FPA Sections 205 and 206. In the U.S FERC Order Denying Rehearing, June 20, 2006, Docket No. TX05-1-006, related to the ability to obtain transmission service on the TVA system (paragraph 22), FERC states that:

> *"our authority to implement portions of the open access policy established in the OATT (Open Access Transmission Tariff) derives from the requirement under sections 205 and 206 of the FPA (Federal Power Act) to remedy undue discrimination, not sections 210 or 211" (parentheticals added).*

There is a further statement that Sections 824 I, j, l, m shall not be construed to modify, impart or supersede the anti-trust laws and protections against unfair methods of competition.

In our view, it effectively means there is a belt and suspenders basis for open access. The second part of the basis for open access, was the requirement that open access tariffs require reciprocity. Any entity that wanted to use open access transmission of a jurisdictional utility, had to reciprocate, and any agreement of the non-jurisdictional utility to accept reciprocity makes in incumbent on the jurisdictional utility to reciprocally provide open access. Also, there is nothing in Section 211 that makes it the exclusive basis for requiring open access, and Section 212 j is also very specific that it only applies to Section 211.

As discussed, we are not aware of any utility not abiding by the reciprocity requirement because it would put it at a significant disadvantage in its operations. Indeed, much of the original discussion during the development of Order 888 was how to prevent jurisdictional utilities denying utilities like TVA open access. Further, it would have to renegotiate transmission arrangements to address reserve sharing, economic short- and long-term transactions, inadvertent power flows, and short-and long-term transmission across its system, anti-competitive issues, etc. However, problems notwithstanding, TVA can decline reciprocal treatment; apparently, Congress left that open to TVA.[94] If TVA takes this step, and we do not think it will, MLGW has alternatives options which TVA would stipulate exist. These alternatives are discussed below in addition to seeking legal remedies.

TVA itself concedes transmission service is available under some circumstances. TVA in their most recent 10-k, on page 23 states:

> *"However, other utilities may use their own transmission lines to serve customers within TVA's service area, and third parties are able to avoid the restrictions on serving end-use customers by selling or leasing a customer generating assets rather than electricity".*

Although it appears to us that FERC will force TVA to provide transmission to MLGW or require TVA not to be able to reciprocally have transmission under open access rules, TVA has historically cited the so-called "anti-

[93] TVA Act

[94] This is an interpretation of Congressional intent and is not based on any specific information appertaining to intent except Sections 212 j and 211, and the overall context.

cherry-picking" provision to reject transmission service request from its competitors and to appeal against associated FERC orders. When Warren Rural Electric Cooperative Corporation (WRECC) intended to leave TVA and signed an agreement with East Kentucky Power Cooperative (EKPC) for alternative wholesale power supply, EKPC asked TVA to provide transmission access to deliver its power to WRECC. TVA denied the request saying that it was not required to do so under the "anti-cherry-picking" provision. When FERC issued a final order directing TVA to provide interconnection services to EKPC, TVA, considering that such interconnection would generate un-compensated transmission service from the TVA system, filed appeal in the U.S. Court arguing that this order was against the "anti-cherry-picking" provision. Our understanding is that there was not a court ruling because there was a settlement. These examples illustrate TVA's strong position and strategy in utilizing the "anti-cherry-picking" rule to protect itself from losing customers. Note, anti-cherry picking is terminology not mentioned in the act itself.

Elaborating on its view, TVA asserts that not being not a public utility under the FPA, it is exempt from the requirement to provide open access non-discriminatory transmission services under the FERC Order No. 888. While that is strictly true, in our view, this minimizes the impact of the reciprocity rule. Continuing, TVA argues it has elected to voluntarily comply with this order and has launched its Open Access Same-time Information System (OASIS) to assist potential customers to obtain transmission services from TVA. It emphasizes in its Standards of Conduct that the compliance of these regulations is only "to the extent they are consistent with TVA's responsibilities under the TVA Act and other applicable law"[95]. The TVA transmission service guidelines state that customers are not eligible for transmission services that FERC cannot order under Section 212 (j) of the FPA[96].

If TVA successfully blocks a transmission service request for service to MLGW based on the "anti-cherry-picking" provision, or any other basis, MLGW would have to serve its load and meet NERC requirements exclusively using MISO or its own lines. This would include delivery of Bellefonte 1 power to MLGW; additionally, Bellefonte 1 would likely have to construct its own line to Southern Company territory to interconnect. As noted, TVA does not dispute this – i.e. they do not claim a territorial service territory.

9.1.3 TVA may attempt physical disconnection of MLGW from TVA grid

In previous cases where LPC customers tried to leave TVA, TVA has indicated that it would physically disconnect the customer's system from the TVA system to avoid power flows from TVA to the load that is without appropriate compensation. TVA claimed that this is standard operating procedure when customers leave and did this to the City of Bristol when they left in 1995 and threatened to do to Warren Rural Electric Cooperative when they attempted to leave in 2006. There is a possibility that TVA might attempt to disconnect MLGW system from the TVA grid when the contract is terminated, bringing difficulty for MLGW to source alternative power supply or reserve sharing arrangements from TVA. The practical result would be equivalent to denial of service under the anti-cherry-picking rule but could introduce further complications around the physical substations and interfaces between MLGW's distribution and TVA's transmission grids.

We find this unlikely for the same reasons we find it unlikely that TVA will deny transmission service. Such an act may also be considered to be anti-competitive and violating reliability provisions of the Federal Power Act.

[95] http://www.oatioasis.com/TVA/TVAdocs/Implementing.pdf

[96] http://www.oatioasis.com/TVA/TVAdocs/TVA_TSG_FY2018.pdf

MLGW's proximity to MISO also creates potential backup options should TVA win the right to disconnect, as described further elsewhere in this report.

9.1.4 TVA may attempt to impose stranded costs upon termination of the contract

Traditionally, stranded cost is associated with native load customers being relieved of the obligation to pay for costs in rates due to deregulation, and those costs not being recoverable in a competitive market. In such a case, the utility had the expectation it would serve the customer in perpetuity, and but for deregulation, the costs would have been recovered.

In 1996, FERC adopted a definition of stranded costs caused by Order 888. This applied to requirements customers exiting contractual arrangements, resulting in assets whose costs cannot be recovered in a market situation.

Historically, TVA has attempted to impose these stranded costs on departing customers. TVA estimated the stranded costs using the FERC "revenue loss" methodology, which calculates the potential wholesale revenue loss due to the departure of a customer over a length of period that TVA expected the customer to stay in its system. When the 4-County Electric Power Association intended to leave, TVA estimated a stranded cost for it ranging from $57 to $133 million[97]. When the City of Bristol, Virginia considered leaving, TVA estimated its stranded cost allocation to be around $54 million[98]. The estimated stranded costs are significant: 4-County Electric Power Association and the City of Bristol have annual electric consumption of around 1.1 TWh and 0.9 TWh respectively, compared to MLGW's 14 TWh. These so-called stranded costs were primarily a result of TVA's uneconomic nuclear assets and high debt rate. Prior experience also shows that TVA is willing to negotiate the stranded cost charges. In the example of the City of Bristol (VA), the City ultimately reached an agreement with TVA where Bristol would not be charged for stranded costs but would purchase transmission and ancillary services from TVA.

We do not expect TVA to attempt to recover stranded costs if MLGW terminates its power supply contract with TVA contract. In the event MLGW terminates the contract, the terms of the contract preclude TVA from seeking stranded costs, provided however, the termination notice is given no earlier than after 2012 (i.e., ten years after the 2003 Supplemental contract with TVA). When this ten-year period is combined with the five year termination notice, this results in a 15 year period i.e., after 2017 no costs can be recovered[99]. Thus, stranded costs are no longer an issue.

TVA's willingness to concede the stranded cost issue makes sense. FERC issued Order 888 more than twenty year ago, thereby deregulating the industry via open access, and FERC decided more than twelve years ago that

[97] https://books.google.be/books?id=9G6zqNvscVQC&pg=PA36&lpg=PA36&dq=bristol+leaving+TVA+stranded+cost+calculation&source=bl&ots=ujohqUgcgH&sig=aRkMLgSicT56-vj5B1twOHRtglM&hl=en&sa=X&ved=2ahUKEwiB9raYlczcAhUCI6wKHbZLAn0Q6AEwAHoECAAQAQ#v=onepage&q&f=false

[98] https://books.google.be/books?id=9G6zqNvscVQC&pg=PA36&lpg=PA36&dq=bristol+leaving+TVA+stranded+cost+calculation&source=bl&ots=ujohqUgcgH&sig=aRkMLgSicT56-vj5B1twOHRtglM&hl=en&sa=X&ved=2ahUKEwiB9raYlczcAhUCI6wKHbZLAn0Q6AEwAHoECAAQAQ#v=onepage&q&f=false

[99] *Electric System Subordinate Revenue Refunding Bonds, Series 2010*: https://emma.msrb.org/EP398313-EP313238-EP709326.pdf

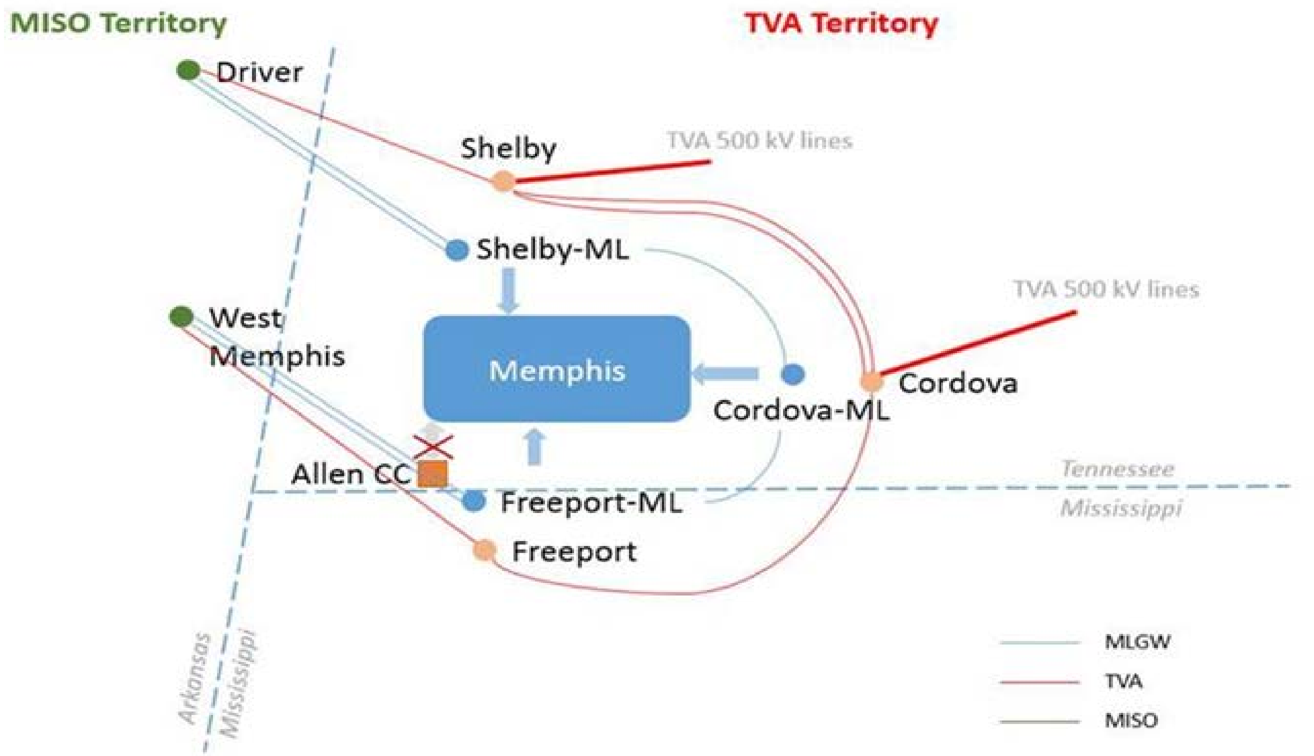
specifically TVA must provide open access transmission on a reciprocal basis. Therefore, TVA cannot claim departure of LPCs was unexpected, and it did not have the opportunity to address stranded costs via contract.

9.2 Direct Interconnection to MISO

If TVA is able to disconnect and or deny service, MLGW can invest in transmission to maintain its ability to source power and maintain reliability in accordance to NERC standards. As the existing Driver-Shelby and West Memphis – Freeport connections are owned by TVA, MLGW will need to build its own connections with MISO for power intake and transmit the power into the city of Memphis. One option is to replicate the existing transmission configuration surrounding Memphis to avoid a cross-board disturbance and thus needs for reconfiguration within MLGW. Therefore, the proposed transmission projects [would] include three new substations at the same location as Shelby, Cordova, and Freeport, and the same parallel horseshoe 500 kV connection looping Driver – Shelby – Cordova – Freeport – West Memphis.

The three new substations will take over the corresponding load serving lines owned by MLGW as shown in Exhibit 9-1. Furthermore, the MISO-MLGW connections need to be double-circuited to ensure reliability under N-1 contingency conditions. This is mainly due to two reasons. First, currently the 1,200 MW Allen CC serves MLGW directly and can provide almost a third of its peak demand; with Allen removed from the Memphis transmission area, the total MLGW demand would rely on power injection from the new Shelby, Cordova, and Freeport substations. Second, within the existing system, power can flow into Shelby, Cordova, and Freeport through multiple 500kV lines including the two from MISO and another three from inner TVA to Shelby and Cordova; in the disconnection case, Memphis loses power injection from TVA and would solely depend on MISO import.

Exhibit 9-1. Memphis-TVA physical disconnection case



Source: ICF

ICF estimated the costs to build the proposed incremental transmission facilities using the Jobs and Economic Development Impacts (JEDI) Transmission Line Model developed by National Renewable Energy Lab (NREL). We assume that all the proposed MLGW transmission projects are 500 kV AC lines and line lengths are based on ABB's Ventyx database. ICF has not considered the physical disconnect case in its analysis and thus costs shown in Exhibit 9-2 and 9-3 have not been included in any of the options studied.

Exhibit 9-2. Cost to Build and Maintain New Lines Under Physical Disconnect Case

From Bus	To Bus	Voltage (kV)	length (mile)	# of circuits	Capital Cost (million 2018$)	Annual O&M Costs (million 2018$)
Freeport-ML	West Memphis	500	15	2	129.2	0.32
Shelby-ML	Driver	500	18	2	132.8	0.33
Shelby-ML	Cordova-ML	500	20.5	1	99.6	0.32
Freeport-ML	Cordova-ML	500	25.3	1	109.2	0.38
Total			**111.8**		**470.8**	**1.35**

Source: ICF using data from PowerWorld and Ventyx

Additionally, ICF also tested this configuration through load flow modeling using PowerWorld and identified system upgrades required for the configuration change. This physical disconnection case was constructed based on the same SERC power flow case as described in Chapter 5.3. We first implemented the configuration change. After that, as all MLGW demand will be sourced from MISO import, we assume that the Bellefonte 1 plant is interconnected within Southern and the remainder of the demand is met by Southern and MISO generation. That is, we dispatch down TVA generation on a pro rata basis by the size of MLGW demand, inject Bellefonte within Southern, and scale up MISO South and Southern generation proportionally by the delta between MLGW demand and Bellefonte 1 output. ICF tested 3,390 "N-1" contingencies for the physical disconnection case to identify thermal and voltage violations under contingency conditions. Exhibit 9-3 below outlines the overloaded lines in the physical disconnection case. One of the lines is in TVA, an Affected System in this case, while all other violations are in MISO South. We estimate the system upgrade costs using NREL's JEDI Transmission Line model as developed earlier, assuming that the overloaded lines would be double-circuited.

Exhibit 9-3. Overloaded Lines in Physical Disconnection

Lines	Voltage (kV)	Ending Bus Area	Affected System	Loading (%)	Bellefonte to MLGW Shift Factor	Length (mile)	Est. Cost ($MM/mile)	Total Cost ($MM)
3PINNACLE! to 3NATURAL STP	115	MISO.S-AR	N	100.5%	0.04%	5	$2.87	$16.5
3NATURAL STP to 3MAYFLOWER%	115	MISO.S-AR	N	102.3%	0.04%	5	$2.87	$16.5
5BATESVILLE to 5TALLHACH IP	161	TVA	Y	109.2%	1.87%	4	$3.03	$12.6
5OXFORD MS to 5BRTTNY WDS	161	TVA	Y	112.5%	3.18%	0.5	$16.94	$8.4
3PLUM POINT to 3GREENBROOK	115	MISO.S-MS	N	106.9%	0.28%	6	$2.3	$14.7
3GREENBROOK to 3HORN LAKE!	115	MISO.S-MS	N	123.9%	0.28%	3	$3.82	$11.3
3HORN LAKE! to 3DESOTO MS	115	MISO.S-MS	N	155.8%	0.67%	3	$3.78	$11.4
Total								$91.4

Source: ICF using data from PowerWorld and Ventyx

As the Bellefonte to MLGW shift factor for all overloaded lines are below 5%, such costs would not be allocated to Bellefonte or MLGW.[100] TVA may argue that despite the physical disconnection of MLGW, the existing TVA-MISO lines remain intact, the physical power continues to flow through TVA's system in Tennessee and Mississippi, wheels through MISO, and comes back to MLGW, rather than completely looping through Southern and MISO. The TVA argument for physical flow would be the most extreme case and further studies would be needed to tackle the physical flow impact on the TVA system.

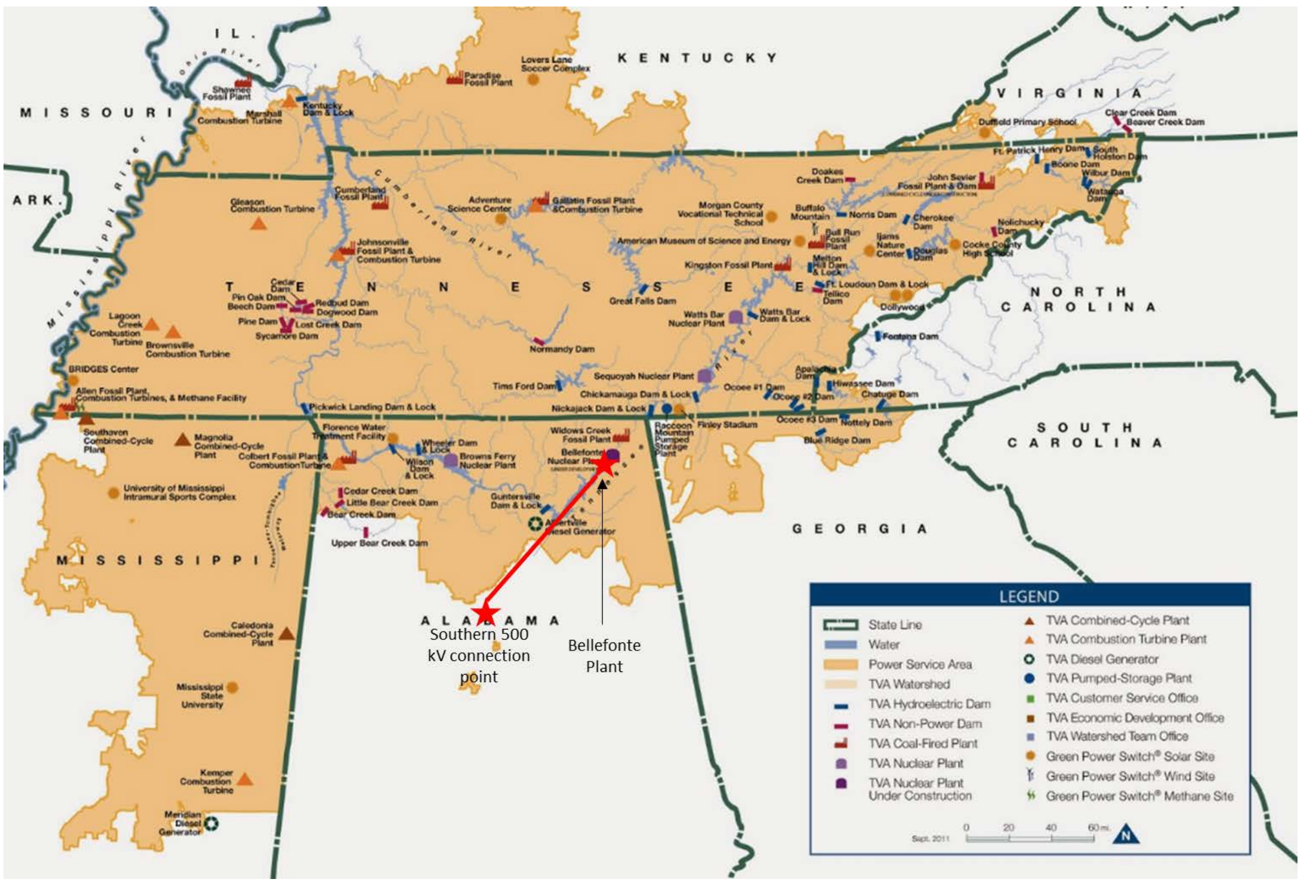
Denial of transmission: Bellefonte can interconnect with Southern

[100] For TVA lines, impacts on affected systems are not required to be ameliorated if the shift factor is very small – i.e. the percentage of the injected power flowing on the affected system element is < ~5% or some similar lower percentage. For the MISO lines, MISO's generator interconnection manual notes that if a study generator does not contribute more than 5% of the DFAX (shift factor) on any flow gate with a loading violation, it is considered fully deliverable.

An issue related to denial of transmission service to TVA would be denial of firm transmission from Bellefonte. In effect, Bellefonte could be prevented from using TVA lines, since its power would be flowing to MLGW. In this case, Bellefonte, which sits in TVA territory, would have to construct its own line out of TVA territory and interconnect in a neighboring grid. The most logical choice for a neighboring grid is Southern Company.

As discussed in Chapter 5.3, ICF estimated the deliverability of Bellefonte to MLGW using a case in which Bellefonte interconnects in nearby Southern Company territory. Our modeling indicates that minimal to no grid upgrades would be necessary, except for the dedicated new line to transmit power from the Bellefonte site directly to the Southern Company grid. Exhibit 9-4 below indicates the location of this line.

Exhibit 9-4. Bellefonte Interconnection with Southern



Source: TVA

We estimate the cost of this line to be approximately $273 million of capital investment plus an operation and maintenance cost of $1.5 million per year, or an equivalent of $3/MWh when annualized and compared to Bellefonte's output.

10. MLGW System Operations

10.1 Alternate Contractual Arrangements

MLGW may need to establish alternative operating structures and arrangements to procure power from Bellefonte. The most important decision for MLGW to consider is how it will balance its system power supply and demand. Based on the choice of what entity will be the Balancing Authority for Memphis, different regulatory and operational requirements will be considered, and different arrangements will be made for power supply, compliance of reserve requirements, and transmission services. We describe in this Chapter three alternative structures that MLGW could pursue: 1) TVA as the BA, 2) MISO as the BA and 3) Memphis as the BA. For each option, we discuss the potential arrangement of the following aspects:

- Power supply source
- Compliance of contingency and regulation reserve requirements
- Transmission services
- Infrastructure development
- Personnel costs
- Administrative costs

10.1.1 TVA as Balancing Authority

In this option, MLGW will become a partial customer of TVA. Instead of buying wholesale power exclusively from TVA, it will be allowed to shop for more competitive power supply. TVA will continue providing wholesale dispatch and balancing services for MLGW. Similar arrangements have been made for smaller LPCs in TVA. The specific arrangements of this option are discussed below:

- **Power supply source**
  MLGW will look for more competitive power supply source within the TVA territory. It may choose to contract with Independent Power Producers (IPPs) with lower rates than TVA. MLGW can utilize TVA power as a backstop resource.
- **Compliance of contingency and regulation reserve requirements**
  TVA, as the balancing authority, will be directly responsible for complying with NERC reliability standards, including meeting the contingency and regulation reserve requirements. Since MLGW will become a partial customer, it is a possibility that TVA will seek to recover some of the compliance costs from MLGW. For example, TVA may set certain reserve requirements for MLGW. Elaborating on this example, if TVA experiences a large contingency (loss of Bellefonte-1), it may increase total operating reserve requirements, and the costs presumably would be allocated to MLGW. In this case, MLGW will be responsible for owning or contracting enough capacity to meet these requirements.
- **Transmission services**
  MLGW would not need to purchase firm transmission services as the TVA rate charged to MLGW would already include charges for firm transmission.
- **Infrastructure development**
  No major infrastructure development will be needed in this option. MLGW will be able to continue using existing TVA grid and associated meters. The existing billing infrastructure can handle the billing. Memphis becomes a sink in Transmission System Information Networks (TSIN) to allow the power to be

scheduled to Memphis by the supplier. Confirmation of the schedules should be able to be handled by the existing personnel or it could be set up as an auto confirmed schedule.

- **Personnel costs**
  There is minimal to no incremental personnel cost for this arrangement. The existing billing area of the utility should be able to handle the supplier bills and TVA bills. While the utility could add a position for an energy contract manager to facilitate the creation of RFPs for additional supply and serve as the contact point for TVA and suppliers, they could also contract for the service.
- **Administrative Costs**
  Balancing authorities incur costs for providing reliability coordination and system operation services, and for paying FERC administrative fees. In this case it is assumed that TVA administrative costs would be continued to be recovered through their rates.

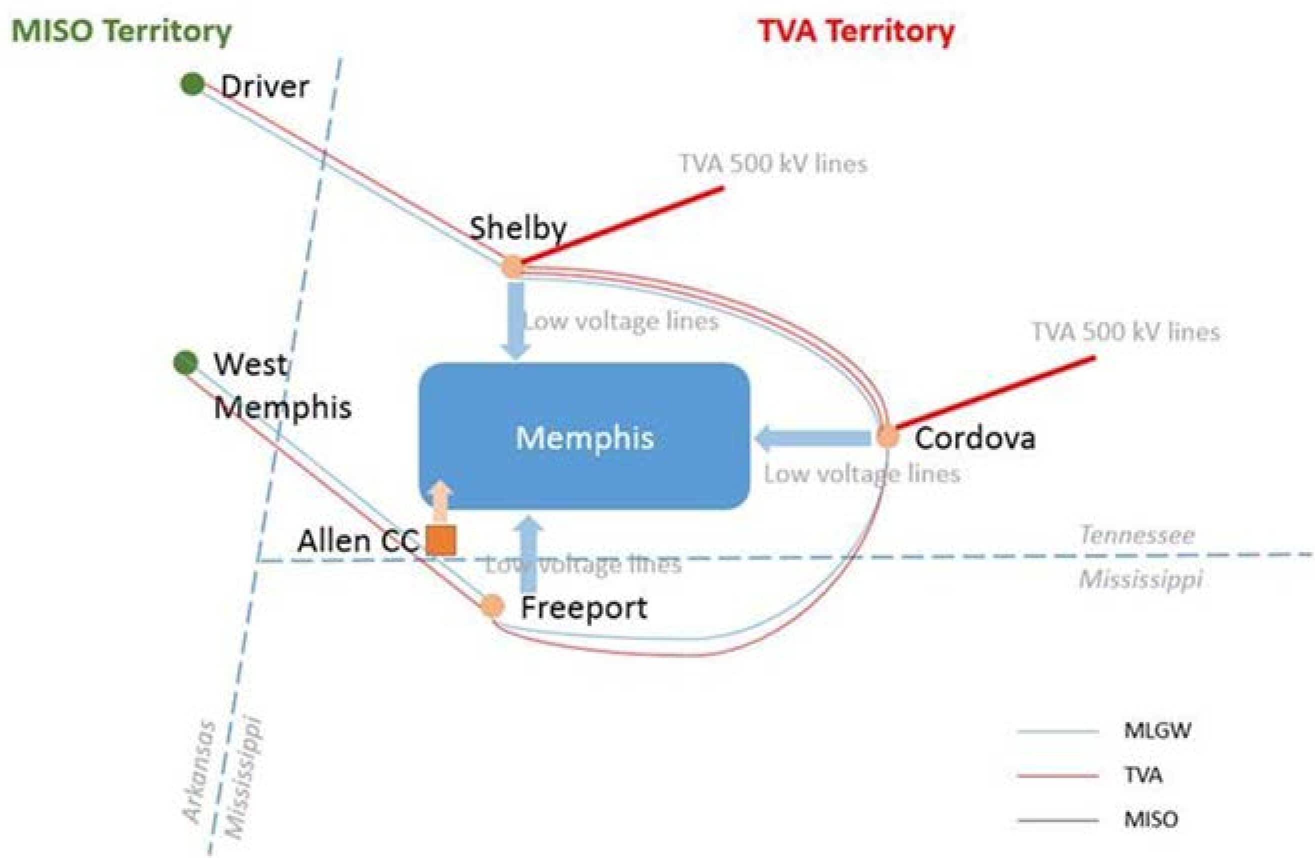
10.1.2 MISO as Balancing Authority

In this option, MLGW will join the MISO market as an RTO member. MISO will provide all market services for Energy, Operating Reserve, and Transmission Service. Specific arrangements of this option are discussed below:

- **Power supply source**
  MLGW will source alternative power supply from the MISO market, either by spot purchase from the energy market or by contracting with IPPs within the MISO territory.
- **Compliance of contingency and regulation reserve requirements**
  In this option, MISO as the balancing authority will take direct responsibility for complying with NERC reliability standards, including meeting the contingency and regulation reserve requirements. MISO assigns a Resource Adequacy (RA) requirement to individual load serving entities (LSEs). LSEs can choose to comply by either bilateral contracting or by participating in the MISO capacity auction. As such, it is possible certain costs might have to be borne by MLGW to meet its RA requirement other than what ICF has assumed for this case.
- **Transmission services**
  As a member of the MISO RTO, MISO allocates the cost of transmission projects to its members. As a result, ICF assumes that these costs will be allocated to MLGW as well when they join the RTO. No other transmission related cost has been assumed for this case. [101]
- **Infrastructure development**
  It is assumed that the existing billing infrastructure can handle the billing with the supplier and MISO. Additionally, it is anticipated that the existing Transmission and Distribution (T&D) Control Center can handle all communications with MISO, as they do now with TVA. Lastly, to receive its incremental needs, MLGW will have to build its own transmission lines to receive power from MISO South. ICF assumes that MLGW will construct a line that connects Driver – Shelby – Cordova – Freeport – West Memphis to receive power from MISO. Exhibit 10-1 illustrates the loop described above.

Exhibit 10-1. Loop Connecting Driver – Shelby – Cordova – Freeport – West Memphis

[101] ICF's preliminary analysis does not show any significant cost due to violations on the Entergy Arkansas system, and hence, no additional cost is being assigned.



Source: ICF and Ventyx

- **Personnel costs**
  It is expected that a small number of new full-time positions will be necessary to support this option. In addition to a contract manager position, a full-time position for MISO regulatory support and an additional position for settlements would be required.
- **Administrative costs**
  MLGW would have to pay a MISO administration fee as MISO handles operating the market and providing other services to their footprint. An additional annual FERC charge would also be levied on MLGW.

10.1.3 MLGW as Balancing Authority (BA) - Pseudo tie load with MISO

Under this case, MLGW will establish themselves as a BA and will exit TVA. For its incremental needs beyond Bellefonte, MLGW will source power from MISO. While MLGW can rely solely on imports from MISO there are reliability concerns associated with this option. Therefore, ICF proposes that MLGW pseudo ties its load with MISO. Pseudo tie refers to the situation in which there is firm transmission, and dispatch is directed by another entity. In this case, MLGW would act like a local balancing authority in MISO.

Specific arrangements of this option are discussed below:

- **Power supply source**
  Loads pseudo-tied into MISO are included in the Local Balancing Area load calculation and assigned a Load Zone defined in the MISO LBA. The load will be subject to the MISO Energy and Operating Reserves Market and accounted for in centralized dispatch. MLGW will be responsible for short-term supply adequacy and long-term supply adequacy. Improper supply options will lead to compliance and potential reliability issues, as well as greater cost than anticipated.
- **Compliance of contingency and regulation reserve requirements**
  Similar to the previous case (Chapter 10.1.2), MISO will be directly responsible for complying with NERC reliability standards, including meeting the contingency and regulation reserve requirements. However, MLGW may be responsible for securing a contract for such services.
- **Transmission services**
  MLGW will need to purchase firm transmission services from MISO to deliver power from its contracted resources to MLGW load center. MISO requires that a non-interconnected network load which is pseudo-tied into MISO be part of a pricing zone in MISO, so that MLGW are subject to that rate for network service.
- **Infrastructure development**
  The infrastructure required in this case would be similar to what was discussed in Chapter 10.1.2
- **Personnel costs**
  Similar to the previous case, it is expected that a small number of new full-time positions will be necessary to support this option. In addition to a contract manager position, a full-time position for MISO regulatory support and an additional position for settlements would be required.
- **Administrative costs**
  Since the load would be dispatched by MISO, ICF assumes MLGW will be charged MISO's administration fee. Similar to the case of MISO serving as Balancing Authority, MLGW will pay FERC fees as well.

10.1.4 MLGW as Balancing Authority- Stand Alone Utility on Wholesale Level

Under this case, MLGW will establish themselves as a utility and will exit TVA. To fulfill its incremental needs beyond Bellefonte, MLGW will contract with either TVA or MISO. MLGW will also be responsible for securing reserve on its own.

The specific arrangements of this option are discussed below:

- **Power supply source**
  MLGW will operate independently. Apart from firm supply from Bellefonte, MLGW will need to contract or build and operate assets to provide all their incremental energy and capacity needs.
- **Compliance of contingency and regulation reserve requirements**
  MLGW will need to contract or build and operate assets to provide all their ancillary service needs. MLGW can join existing reserve sharing groups but these agreements must be negotiated with the entities and may have a lengthy application process.
- **Transmission services**
  MLGW will need to purchase firm transmission services from MISO/TVA to deliver power from these markets to MLGW load centers. While procuring capacity and energy from TVA is certainly possible, the uncertainty around TVA's use of the anti-cherry-picking provision creates a challenge in assessing such a case.

- **Infrastructure development**
  It is assumed that the existing Memphis T&D Control Center can be utilized for Dispatch. However, a Dispatch System that allows the Dispatchers to match supply to the load, and to meet NERC compliance requirements, will be required. There will also need to be other systems to support scheduling and trade capture. Lastly, if MLGW would contract or import power from MISO, similar to Chapter 10.1.2, then to receive its incremental needs, MLGW will have to build its own transmission lines to receive power from MISO South. ICF assumes that MLGW will construct a line that connects Driver – Shelby – Cordova – Freeport – West Memphis to receive power from MISO.
- **Personnel costs**
  MLGW will have to add a significant number of full-time positions to operate independently outside of TVA or MISO. The discussion below does not address services required if they decide to build and operate their own assets. The discussion assumes the assets are dispatchable by MLGW.

  - **Generation Dispatch** – it is assumed that MLGW, while contracting for a large portion of firm supply with Bellefonte, they will need to either contract dispatchable or own flexible supply (generation or demand response) to meet their spinning reserve, standby reserves, and regulation obligation. While this function can be contracted, if this function is staffed, MLGW will need five Dispatchers.
  - **NERC Compliance and Training** – MLGW will now have the responsibility, at a minimum, for Generator Operator and BA Operator NERC Compliance requirements. They will need to provide training for their Generation Dispatch team and create protocols to document adherence with NERC compliance standards. At a minimum, they will need two Compliance/Training coordinators.
  - **Trading** – MLGW will need the ability to hedge risk as well as buy physical power, both long and short term, to balance their load obligations. It is assumed they will need 2 traders. Initially, it is assumed that they will not require a full-time real-time trading desk and will balance their load with the dispatch desk using owned and contracted assets.
  - **Scheduling** – MLGW will need a scheduler that can reserve transmission for the traders and confirm schedules. This scheduling staff will need to be knowledgeable on the transmission paths around the area and the system used to reserve and confirm scheduled transactions.
  - **Back Office** – MLGW will have to add additional capability to receive, reconcile, and pay invoices. While it is assumed that existing infrastructure can manage a large portion of this, at a minimum, a single position should be added.
  - **Contract Management/Legal/Regulatory** – Similar to previous cases a contract manager is needed. In addition, it is assumed a full-time attorney knowledgably in FERC and state requirements would be required, as well as a paralegal that can perform regulatory support.
  - **IT Support** – Additional infrastructure will be added to support the trading, scheduling and dispatch functions. There also will be support from IT required to support NERC compliance requirements, especially in the area of Cyber Security standards. It is assumed two additional IT personnel will be required in this case.
  - **Other Support** – This case assumes that there are two full-time positions required to provide support for tasks such as load forecasting, long range adequacy planning, etc.
- **Administrative costs**
  MLGW will pay FERC fees similar to previously discussed cases.

According to the analysis above, we summarize the various constructs and their associated costs for each option in Exhibit 10-2.

Exhibit 10-2. Summary of Regulatory Construct

Alternative Structure	TVA as BA	MISO as BA	MLGW as BA		
			Pseudo tie load into MISO	Contract with TVA resources	Contract with MISO resources
Power supply	TVA resources	MISO resources	MISO resources	TVA resources	MISO resources
Compliance of reserve requirements	TVA	MISO RA requirement	MISO RA requirement	TVA	MISO RA requirement
Transmission service costs	YES - TVA	NO	YES - MISO	YES - TVA	YES - MISO
Allocated system transmission costs	NO	YES	NO	NO	NO
Infrastructure development costs	NO	YES	YES	NO	YES
Personnel costs	YES - Low	YES - Medium	YES - Medium	YES - High	YES - High
BA Administrative costs	YES - TVA	YES - MISO	YES - MISO	YES - MLGW	YES - MLGW
FERC Administrative costs	YES	YES	YES	YES	YES

Source: ICF

10.2 Assessment of Cost

Having discussed the basic structure of each alternative regulatory arrangement, we provide a quantitative assessment of regulatory cost for each option in this section.

10.2.1 Regulatory Costs – TVA as Balancing Authority (Option #1)

Additional regulatory costs associated with this case are minimal. As highlighted previously, TVA administrative costs are recovered through TVA rates. The only other additional cost considered for this case is if Memphis chooses to engage a contract manager. Therefore, the estimated costs are presumed to be the current cost (already covered by the TVA rate) plus additional personnel cost. ICF expects the first-year cost of this case to be approximately $175,000. This case is considered as the status quo state.

10.2.2 Regulatory Costs – MISO as Balancing Authority (Option #2A/#2B)

A breakdown of the methodology for estimating the regulatory cost in this case is discussed below -

- **MISO Administration Fee:** MISO 's administrative costs were estimated using $/MWh cost projections presented in the MISO 2017 Budget presentation and were applied to MLGW's Energy for load projections. ICF projected the MISO admin fee by utilizing the latest MISO forecast and applied the 2018-2022 real cumulative growth rate along with inflation.
- **FERC Fee:** For this analysis, the current FERC assessment charges in $/MWh were estimated based on historical data available in FERC Form 528 and were applied to MLGW's Energy for load projections. The FERC fee was projected by applying the 2015-2018 real cumulative growth rate, along with inflation, to the latest historical data.
- **Transmission Allocation Cost:** MISO does not socialize the cost of all the projects among their members and rather follows a specific methodology to allocate the cost of new projects. The methodology is based on project type and the projects' beneficiaries. Exhibit 10-3 details a breakdown of the allocation category and the allocation methodology.

Exhibit 10-3. Summary of MISO Cost Allocation Mechanisms

Allocation Category	Drivers	Allocation to Beneficiaries
Market Efficiency Project	Reduce market congestion when benefits exceed cost by 1.25 times	Distributed to Cost Allocation Zones commensurate with expected benefit, 345 kV and above 20 percent postage stamp to load.
Transmission Delivery Service Project	Transmission Service Request	Generally paid for by transmission customer, Transmission Owner can elect to roll in into local zone rates
Generation Interconnection Project	Interconnection Request	Primarily paid by the requestor, 345 kV and above 10 percent postage stamp to load.
Multi-Value Project	Address energy policy laws and/or provide widespread benefits across footprint	Postage Stamp to Load
Market Participant Funded	Transmission Owner-identified project that does not qualify for other cost allocation mechanisms; can be driven by reliability, economics, public policy or some combination of the three	Paid for by Market Participant
Baseline Reliability Project	NERC Reliability Criteria	Local Pricing Zone

Source: MTEP 2017

There are several complications associated with analyzing transmission allocation cost. For example, the cost of Generation Interconnection Projects (GIP) are primarily paid by requestors. Similarly, Baseline Reliability Projects are only allocated to respective planning zones. Given the complexity around the cost allocation mechanism, ICF conservatively assumes that MLGW will be assigned cost from all projects that are expected to be shared, regardless of the project type. Currently, MTEP 2017 lists approximately $6.6 billion of the transmission investments as being on a cost sharing basis. ICF assumes that the cost of all these projects will be shared equally across all planning zones and MLGW will be allocated cost based on a MISO wide peak load shape basis. The allocated cost growth factor is estimated throughout the forecast horizon using inflation. While this may over-estimate allocated cost to MLGW, MISO may undertake future projects and share the cost with MLGW and potentially increase the transmission allocated cost.

- **MLGW Operational Cost:** ICF assumes that the cost of hiring a full-time position for MISO regulatory support and an additional position for settlements, would be $300k to $350k per year, plus benefits at 40%, and will increase with inflation.
- **Ownership of Transmission Lines:** ICF assumes the cost of building a loop that connects Driver – Shelby – Cordova – Freeport – West Memphis to receive power from MISO will be, on average, $64.2MM between 2024 and 2053.

ICF expects the first-year cost of this case to be approximately $73.2MM

10.2.3 Regulatory Costs – MLGW as Balancing Authority, Pseudo Tie Load into MISO (Option #3A/#3B)

A breakdown of the methodology of estimating the regulatory cost for this case is discussed below -

- **MISO Administration Fee:** Similar to the case of MISO serving as Balancing Authority, ICF assumes the same methodology for calculating MISO administration fee.
- **FERC Fees:** Similar to the previous case, an annual FERC charge would be assessed to MLGW. The cost was assumed using the same methodology as in the case of MISO serving as a Balancing Authority.
- **MLGW Operational Cost:** Similar to the case of MISO serving as Balancing Authority, ICF assumes that the cost of hiring a full-time position for MISO regulatory support, and an additional position for settlements would be $300k to $350k per year, plus benefits at 40%, and will increase with inflation throughout the forecast horizon.
- **Network Integration Service Fees:** ICF assumes that MLGW will be charged the Entergy Arkansas zonal rate. ICF uses the 2018 Zonal Rate reported in Attachment O of Schedule 9 and adjusts for the new tax rate passed under the "*Tax Cuts and Jobs Act of 2017*".[102] The zonal rate is increased with inflation throughout the forecast horizon.
- **Ownership of Transmission Lines:** Similar to the case of MISO serving as Balancing Authority, to receive its incremental needs from MISO, MLGW will have to build its own transmission lines to receive power from MISO South. ICF assumes that MLGW will construct a line that connects Driver – Shelby – Cordova – Freeport – West Memphis to receive power from MISO. ICF assumes that the cost to build this loop (as shown in Exhibit 10-1) will be, on average, $64.2 MM between 2024 and 2053.
- **Local Balancing Authority Charges:** Pseudo-ties are charged Schedule 24 (Local Balancing Authority Cost Recovery) cost. ICF estimated the Local Balancing Authority Charges using the latest number available from MISO and applied the 2015-2018 real cumulative growth rate along with inflation throughout the forecast horizon.

Overall, ICF expects the first-year cost of this case to be approximately $177MM.

[102] Schedule 9 is reported in MISO's Open Access Transmission Tariff (OATT)

10.2.4 Regulatory Costs – MLGW as Balancing Authority, Contract with TVA/MISO Resources (Not Analyzed)

A breakdown of the methodology of estimating the regulatory cost for this case is discussed below -

- **FERC Fees:** Similar to the previous case, an annual FERC charge would be assessed to MLGW. The cost was assumed using the same methodology as in the case of MISO serving as a Balancing Authority.
- **MLGW Operational Cost:** A cost breakdown by Personnel is shown in Exhibit 10-4.

Exhibit 10-4. Personnel Cost

Personnel	Cost ($)
Generation Dispatch	700,000
NERC Compliance and Training	238,000
Trading	420,000
Scheduling	119,000
Back Office	105,000
Contract Management/Legal/Regulatory	350,000
IT Support	126,000
Other Support	224,000
Total	2,282,000

Source: ICF

Additionally, ICF assumes that the cost of a Critical Infrastructure Protection (CIP) Secure Dispatch Platform is $5 to $7 million. There will also be a need for other systems to support scheduling and trade capture. ICF assumes the cost of such support systems would be $2 million. These one-time costs amount to approximately $9MM in the first year. A maintenance charge is assumed every year to maintain these systems**.** As a result, the costs drop significantly after year one as the one-time system installation cost drops off. Throughout the forecast horizon, these costs are increased with inflation

- **Network Integration Service Fees:** ICF assumes that MLGW will be charged the Entergy Arkansas zonal rate if it chooses to meet its incremental requirement for power from MISO. Similar to the Pseudo-tie case, ICF uses the 2018 Zonal Rate reported in Attachment O of Schedule 9 and adjusts for the new tax rate passed under the *Tax Cuts and Jobs Act of 2017*. The zonal rate is increased with inflation throughout the forecast horizon.
  If MLGW chooses to meet the incremental requirement for power from TVA, since it is not a member of TVA anymore, it will have to pay TVA's zonal rate. TVA's zonal rate was obtained from the OATI Oasis website and increased with inflation throughout the forecast horizon.
- **Ownership of Transmission Lines:** Similar to previous cases, to receive its incremental needs from MISO, MLGW will have to build its own transmission lines to receive power from MISO South. ICF assumes that the cost to build the loop from Driver to West Memphis will be, on average, $64.2 MM between 2024 and 2053. MLGW may not have to build these lines if the incremental requirements are met from TVA. However, as highlighted previously, there is significant regulatory risk associated with that option.

Overall, ICF expects the first-year cost of this case to be approximately $95.6MM to $182MM, depending on whether it contracts with resources in TVA or MISO.

A comparison of first-year regulatory structures cost across each case is shown below in Exhibit 10-5. These costs are one of the many cost elements that drive the differences between Gross and Net savings. Please note that line items 1-5 are included under 'Regulatory Cost' in Exhibits 2-1 and 2-4. Similarly, line item 7 is also included as a cost under 'Transmission upgrade' in Exhibits 2-1 and 2-4. Ultimately both these costs are netted out of the gross savings to compute net savings under each option. Line Item 6 is included as a cost when ICF computes the gross savings.

Exhibit 10-5. Comparison of First Year Regulatory Structure Cost by Case ($)

Line Item	BA	TVA	MISO	MLGW		
	Power supply	TVA resources	MISO resources	MISO resources	TVA resources	MISO resources
	Option Included in	**Option #1**	**Option #2A/ #2B**	**Option #3A/ #3B**	**Not Analyzed**	**Not Analyzed**
(SUM Items 1-6)	**Regulatory Costs (2024) w/o MLGW Ownership of Transmission Line ($)**	**175,000**	**26,390,649**	**130,922,358**	**95,641,127**	**135,301,062**
(SUM Items 1-7)	**Regulatory Costs (2024) w MLGW Ownership of Transmission Line ($)**	**175,000**	**73,161,440**	**177,693,149**	**95,641,127**	**182,071,852**
1	**Allocated system transmission costs ($)**		18,124,276	0	0	0
2	**MISO Administrative Fee ($)**		6,157,353	6,157,353	0	0
3	**Local Balancing Authority cost ($)**		0	255,944	0	0
4	**MLGW Operating Cost ($)**	175,000	490,000	490,000	11,282,000	11,282,000
5	**FERC Administrative Fee ($)**		1,619,021	1,619,021	1,619,021	1,619,021
6	**Transmission service costs (NITS) ($)**		0	122,400,041	82,740,106	122,400,041
7	**MLGW Ownership of Transmission Lines ($)**		46,770,790	46,770,790		46,770,790

Source: TVA, MISO, and ICF

11. Cost-Benefit Analysis and Conclusions

11.1 Results

ICF analyzed the economics of several contracting strategies and are shown below in Exhibit 11-1. We report both gross and net savings relative to a "Business as Usual" (BAU). We define gross savings as the BAU case less the combined cost of the Bellefonte PPA, plus incremental energy costs. We define net savings as gross savings less the costs incurred to implement a particular scenario. The costs incurred could include, but not limited to, the building of new transmission lines, the securing of firm transmission, and securing of physical reserves needed to maintain the reliability of the Memphis distribution system.

11.1 Business as Usual (BAU)

Under the BAU, MLGW continues to purchase under TVA's full-service requirements contracts and the wholesale power costs reflect the average costs of service from TVA including average fuel, non-fuel O&M, purchased power, capital recovery, and profits. In 2024, costs are projected to equal approximately $1.15 billion. Over the 30-year period of 2024 to 2053 the average cost is $1.4 billion. This escalates over time in part as a function of general inflation, but also due to other factors (see Chapter 4.3 for a full review of our TVA rate projections). Over the past 10 years (2008-2017) the TVA rate for LPCs has ranged from a low of $62/MWh in 2008 to a high of $74/MWh in 2017, with about two-thirds of the rate reflecting recovery of fixed costs.[103] TVA rates have grown at an average of 2.2% per year over the past 10 years, and the rate is projected to grow at an average of 1.7% from 2024 to 2053. All the other cases that follow are discussed relative to this BAU case.

[103] Fixed cost includes fixed O&M, interest expenses, depreciation, and tax equivalents.

Exhibit 11-1. Summary of Memphis Gross and Net Savings Relative a "Business as Usual" Case

Scenarios	Levelized Costs (2024-2053)	Cumulative Cost (2024-2053)	2024	2030	2035	2040	2045	2050	2053
TVA Rate Cost - Business as Usual Case	1,417	46,776	1,154	1,356	1,431	1,502	1,698	2,026	2,162

Gross Savings: BAU Less Alternative Supply ($MM)	Levelized Savings (2024-2053)	Cumulative Savings (2024-2053)	2024	2030	2035	2040	2045	2050	2053
Option #1: TVA is BA / Partial Service Requirements from TVA	466	15,565	363	459	472	480	561	713	763
Option #2A: MISO is BA / Inc. Power Hedged	686	22,132	567	699	702	697	756	946	1,015
Option #2B: MISO is BA / Inc. Power Spot Market	686	22,132	567	699	702	697	756	946	1,015
Option #3A: MLGW is BA / Inc. Power Hedged	522	16,533	445	555	537	507	539	698	746
Option #3B: MLGW is BA / Inc. Power Spot Market	522	16,533	445	555	537	507	539	698	746

Net Savings: Gross Savings Less Regulatory/Transmission Costs ($MM)	Levelized Savings (2024-2053)	Cumulative Savings (2024-2053)	2024	2030	2035	2040	2045	2050	2053
Option #1 TVA is BA / Partial Service Requirements from TVA	466	15,558	362	459	472	480	561	713	763
Option #2A: MISO is BA / Inc. Power Hedged	487	15,347	416	522	502	468	495	648	692
Option #2B: MISO is BA / Inc. Power Spot Market	337	10,833	269	371	355	318	343	495	539
Option #3A: MLGW is BA / Inc. Power Hedged	345	10,471	311	398	359	303	305	430	454
Option #3B: MLGW is BA / Inc. Power Spot Market	195	5,957	164	247	212	154	153	277	302

Source: ICF

11.2 Bellefonte PPA Plus Physical Hedges to Cover Incremental Needs [104]

Most Economic Strategy: We consider Option #2A the main alternative procurement strategy for MLGW compared to the BAU case. This is because it does not depend on the approval of TVA, does not heavily rely on unhedged spot market purchases for incremental power, and offers the most savings relative to BAU. MLGW becomes part of MISO, purchases Bellefonte-1 power plus incremental MISO power, and buys contracts / existing powerplants as part of a physical hedging strategy to further control the volatility of incremental power costs.

11.2.1 Results

In Option #2A, the annual gross savings is estimated at almost $567 million in the first year. The annual average net savings is estimated at $487 million per year, and $416 million starting in 2024, the first year of this study[105]. This is over 35% savings in 2024 relative to the $1.15 billion in cost in the BAU case. This savings primarily reflects the lower costs of the Bellefonte PPA; the PPA costs equal the variable costs of TVA and allows MLGW to effectively avoid paying TVA's fixed costs. Savings per MLGW customer equal approximately $1,129 per year.

[104] Option #2A and Option #3A, are also referred to as $25/kW-yr case because the upfront purchase of the plants cost $25/kW-yr (i.e. fixed costs less energy margins) rather than forecasted higher levels due to eventual tightening in the market for capacity.

[105] Net savings is defined as gross savings less the costs incurred to implement a particular scenario. These cost incurred could include but not limited to the building of new transmission lines, the securing of firm transmission, and securing of physical reserves need to maintain the reliability of the MLGW distribution system.

These savings are significant: in comparison, Memphis's 2019 annual projected budget, excluding MLGW, is approximately $685 million.[106] Over 20 years, cumulative gross savings is projected at $22 billion, and cumulative net savings is projected at $15 billion.

In addition to purchasing Bellefonte power and the associated firm transmission for delivery, MLGW either purchases the needed transmission service to become part of MISO or builds the transmission to directly interconnect, whatever costs the least. Large transmission lines link MLGW to TVA and then across the river to contiguous MISO. If new lines are needed, the distance to key MISO substations would likely be small (about 75 to 100 miles). Nevertheless, our estimate assumes and includes the cost of new line construction.

11.2.2 Hedging and Capacity Costs

MLGW would also purchase contracts / existing powerplants located in MISO to partially hedge against price volatility of incremental power – i.e., to hedge the approximately 30% of energy and 3,000 MW of capacity not covered by the Bellefonte PPA (this capacity covers peak plus required reserves).[107] This would supplement MLGW's main hedge in the Bellefonte PPA that has primarily fixed costs. This "buy-capacity-now" hedge strategy is attractive because there is excess capacity in the wholesale power market that can be locked in via capacity purchases. Recent comparable transactions (i.e., powerplant sales) strongly support the view that existing combined cycles can be purchased at approximately 40-50% of replacement costs.[108] These plants provide hedges against the potential for higher MISO energy and capacity prices later. We assume these plants, a mix of combined cycles and peakers, can be purchased at $230/kW.[109]

These plants can also hedge their fuel costs, but most likely the hedge will have to be renewed periodically at prices then prevalent – i.e., it not a perfect hedge on its own.[110] Other hedging strategies may also exist. In addition, other capacity purchases may be economic, including some peakers and other plants – e.g., existing renewables, otherwise-retiring coal plants, etc. These strategies would be investigated as part of the partial requirements contracting MLGW would undertake.

11.2.3 Recent Spot Prices versus ICF Forecasts

ICF forecasts the economics of this arrangement including future power prices using industry standard computer modeling, as described in the appendix. This forecast shows rising spot prices. However, it should be noted that MISO spot prices have been very low, and if power were to be available in the future at these low prices, even greater savings would occur. MISO energy prices are volatile and over the last five years, the average all hours

[106] https://www.memphistn.gov/UserFiles/Servers/Server_11150732/File/Gov/Financial%20Division/FY_2019_Adopted_Budget/Budget%20Overview.pdf

[107] We focus here on energy and capacity because these are the largest wholesale services. Also required is transmission, ancillary services (usually the smallest portion after energy, capacity and transmission), and system operations. We account for all these items and discuss in later Chapters.

[108] Choctaw at less than $400/kW in August 2018. Choctaw interconnects with TVA and Entergy.

[109] We estimate a 1/3 combined cycle and 2/3 simple cycle combustion turbine mix, based on the incremental load requirements of MLGW after Bellefonte-1 capacity is considered.

[110] Long term financial hedging can require mark-to-market collateral requirements, and hence, long-term financial hedging is not typical practice. Hedging is unlikely to be perfect, due to basis differences, but likely to be efficacious overall.

energy price in MISO was $31.5/MWh while the range was $13/MWh or from $24/MWh to $37/MWh. MISO capacity prices have been near zero, but supply curve in the MISO capacity market is very steep. Adding the components of MISO capacity, transmission costs and inflation adjustments translates to higher MISO all-in price of approximately $50/MWh. In comparison, TVA costs averaged $72/MWh. That is, market prices for incremental power have been very low. Over the last five years, TVA's rates were approximately 44% higher than MISO's. We do not recommend exclusive reliance on spot sales without hedges for incremental power in part because we expect higher prices (particularly for capacity) over time, but the exact extent of hedging as opposed to spot or short-term transactions would be determined over time.

The hedging costs assume that the capacity purchased is in MISO and has no basis difference[111] with MLGW. If the capacity is purchased outside of MISO, additional transmission charges may be needed to sell the power output of the capacity in MISO. However, even if plants are purchased outside MISO, they may still generate revenue from power than can be sold outside MISO[112]. If half the capacity is bought outside MISO and one wheel of firm transmission to MISO is required, then costs increase tens of millions of dollars per year.

Finally, there are additional costs incurred in becoming part of MISO, namely the socialization of on-going and future transmission infrastructure and MISO admission fees.

A variation on this "buy-capacity-now/soon" strategy was analyzed with MLGW being is own Balancing Authority (BA). We referred to this as Option #3A in the Exhibit 11-1 above. Savings are less than in Option #2A as the cost of securing firm transmission to access contracts in the MISO market outweighs avoiding the costs of joining MISO.

11.3 Bellefonte PPA Plus Spot Market to Cover Incremental Needs [113]

In this case, MLGW becomes part of MISO, purchases Bellefonte power plus incremental MISO spot power, and does *NOT* hedge – e.g., does not buy contracts / existing power plants as part of a hedging strategy for incremental power volatility risk.

This is the same as the previous case except MLGW does not purchase generation capacity to hedge incremental power risks but rather relies on spot purchases. This is referred to Option #2B in the Exhibit 11-1 above. This is not only a more volatile strategy, but on an expected basis has higher costs and less savings relative to BAU. We expect the low costs of existing units will not be available over time but rather, there currently exists a temporary buying opportunity. Thus, we do not recommend a highly spot-market oriented approach, however we show it to emphasize the double benefit of attention to incremental power early – i.e., lower expected costs and less volatility.

[111] Basis difference refers to differences in prices by location. For example, if market prices rise, the value of having the power plants would increase, offsetting the impact. However, if the percent increase of power delivered to MLGW increases faster than prices at the busbar of the powerplant, the hedge could have basis risk.

[112] One can think of all incremental energy being purchased from MISO, all incremental capacity purchased, and the energy profits from operating the purchased capacity being used to offset the costs of the MISO purchase power.

[113] Also referred to as "Option #2B [MISO is BA / Inc. Power Spot Market]" case and also the Option #3B case. This is because without the upfront purchase of the plants, they eventually cost higher (i.e. fixed costs less energy margins) than $25/kw-yr due to the eventual tightening market for capacity as explained in Chapter 7.

Annual net savings equal $337 million per year, and $269 million starting in 2024, the first year of this study. This is over 20% savings in 2024 relative to the $1.15 billion in cost in the BAU case.

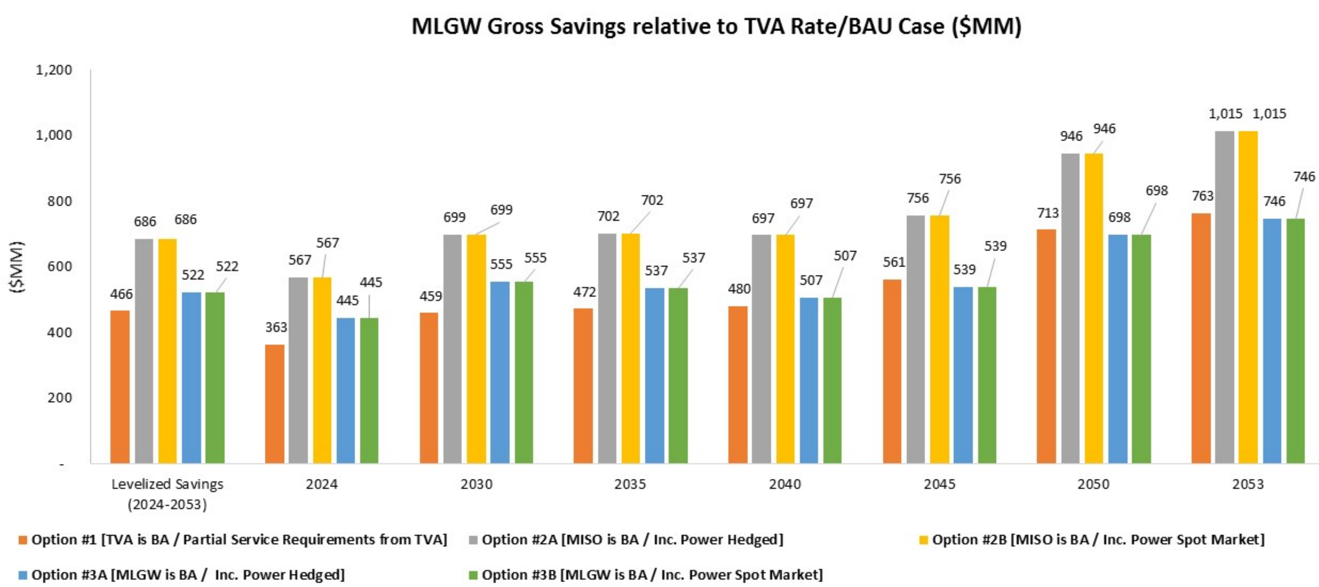
A variation on this "spot purchases" option strategy was analyzed with MGLW serving as its own Balancing Authority (BA). We referred to this as Option #3B in the Exhibit 11-1 above. Savings are less than in Option #3A as the cost of securing firm transmission to access the MISO spot market outweighs avoiding the costs of joining MISO.

11.4 Bellefonte PPA Plus TVA Partial Requirements Service to Cover Incremental Needs

In this scenario, MLGW buys power under the Bellefonte PPA, and incremental power is purchased from TVA under a Partial Requirements contract. This is referred to Option #1 in the Exhibit 11-1 above.

We do not consider this case as attractive to MLGW because its costs are likely higher than what the current market alternative suggests. This may also not be feasible to the extent it requires agreement by TVA. Because TVA provides primarily incremental on-peak power rather than both on-peak and off-peak, and because on-peak is usually more costly than off-peak, the costs are higher than TVA's average for Full Requirements. The costs are also higher than the market alternative discussed above. Note, the premium for on-peak power is based on TVA's tariff, but a negotiated outcome might differ.[114] Exhibit 11-2 and Exhibit 11-3 represent MLGW gross and net savings relative to BAU Case.

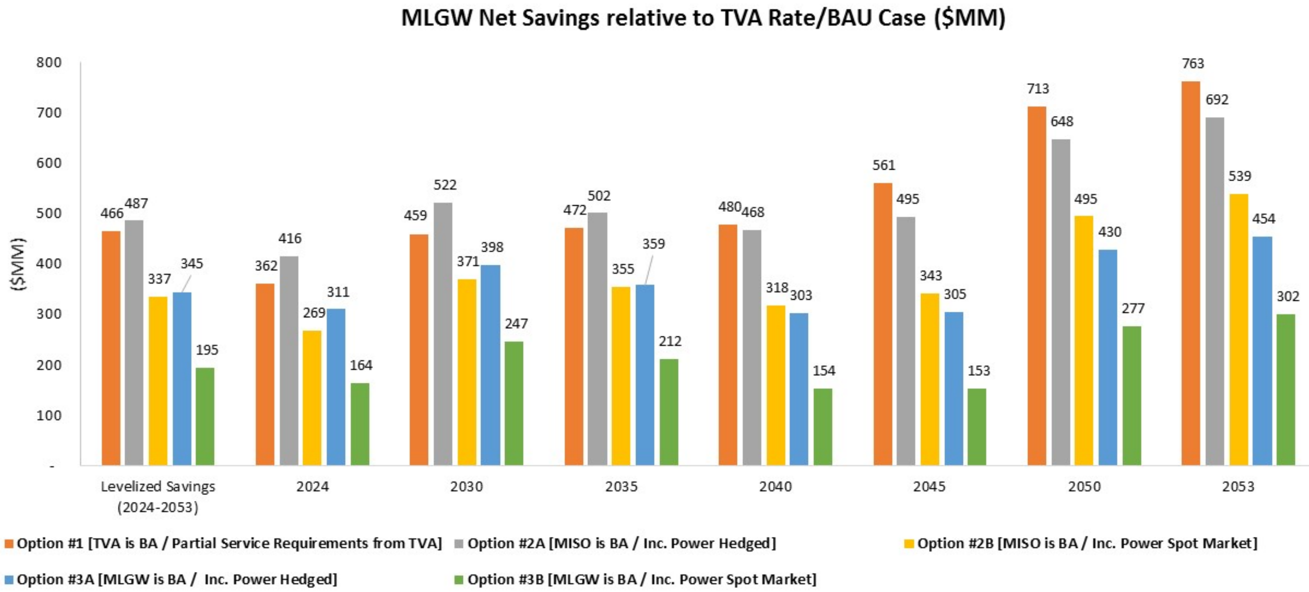
Exhibit 11-2. MLGW Gross Savings Relative to TVA Rate/BAU case ($MM)



Source: ICF

[114] http://www.florenceutilities.com/Electricity_Department/Rate_Chart/Wholesale%20Power%20Rate%20-%20Schedule%20WS.pdf

Exhibit 11-3. MLGW Net Savings Relative to TVA Rate/BAU case ($MM)



Source: ICF

12. Appendix A: Market Modeling Assumptions

12.1 Modeling Approach

ICF makes use of two primary models to simulate market evolution and prices in the US. First, we utilize our proprietary IPM zonal production cost model to simulate plant economics and project economic new-builds, retirements, and capacity prices over time. We then use the results of this model in conjunction with ABB's PROMOD nodal security-constrained economic dispatch (SCED) model, which adds further detail of hourly energy pricing at the nodal level.

ICF's forecasts of future power operations, including the wholesale power market price forecasts in this report, were generated using ICF's proprietary Integrated Planning Model (IPM®) and associated data system. IPM® is a simulation model projecting wholesale market power prices based on an analysis of the engineering economic fundamentals. The model does not extrapolate from historical conditions but rather for given future conditions (new demands, new firm plants, new fuel market conditions, new environmental regulations), IPM® determines how the industry will function.

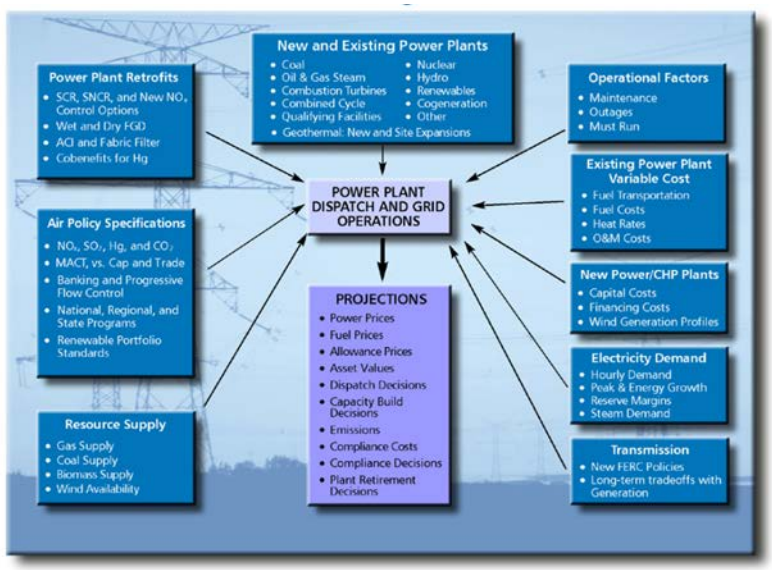
Specifically, the model projects plant generation levels (i.e., dispatch), merchant power plant revenues and costs, new power plant construction, mothballing, retirements, retrofitting, upgrades, fuel consumption, and inter-regional transmission flows. The model makes these projections by calculating production, and therefore production costs and prices, using a linear programming optimization routine with dynamic effects (i.e., it looks ahead at future years and simultaneously evaluates decisions over specified years).

Dispatch of plants is determined endogenously by the model through simulation of hourly market economics. The resultant capacity factors are a function of the competitive position of each plant, taking operational constraints into consideration. Effectively, plants with variable costs below hourly market-clearing prices are dispatched and more expensive plants are not, subject to additional constraints. The realized energy prices reflect average prices for spot supply during the hours in which the plant is dispatched.

ICF's IPM® power model is widely accepted by rating agencies and investment banking institutions. The model has been used in hundreds of industry and plant valuation assignments for power industry participants. The model has also been used extensively in litigation and administrative regulatory settings. Lastly, the model has been used extensively internationally and by industry-wide entities such as Electric Power Research Institute (EPRI), Edison Electric Institute (EEI), and CRIEPI (Japan's EPRI).

ICF also used an additional transmission model (GEMAPS) to set transfer limits in IPM®. Transmission constraints are identified by key bottlenecks in the region. The power flows take into consideration firm and non-firm transmission constraints. Hence, effective plant operations are limited by major interface constraints to define the correct level of disaggregation of sub-markets in IPM, and to validate our near-term analysis. These models employ either AC load flow or nodal DC load flow analysis. These models are very helpful for detailed transmission analysis, but cannot be readily used for valuation. This is because they cannot conduct integrated assessments of investment decision-making.

Exhibit A-1: IPM® Modeling Structure



ICF is also a licensed user of ABB's PROMOD. PROMOD performs a chronological nodal security constrained unit commitment (SCUC) and security constrained economic dispatch (SCED) of generation resources to serve load and reserve requirements, similar to the current implementation in the nodal markets in the U.S. PROMOD is a highly detailed model that chronologically calculates hour-by-hour production costs while recognizing the constraints on the dispatch of generation imposed by the transmission system. It uses a detailed electrical model of the entire transmission network, along with generation shift factors that determine how power from generating plants will flow over the AC network. This enables PROMOD to capture the economic penalties of re-dispatching generation to satisfy transmission line flow limits and security constraints. PROMOD captures the hour-by-hour, node-by-node flows of power, given the topology of the grid, the location of power plants, and dozens of other data inputs.

The output of PROMOD IV includes hourly locational marginal prices (LMP) for all generator and load buses, hourly forecast of congestion across transmission lines and interfaces along with associated congestion costs, system-wide congestion costs, and hourly dispatch of generating units. The model also captures the effect of marginal losses on power prices. This approach is similar to the market design of most Independent System Operators (ISOs).

PROMOD IV is also able to perform probabilistic simulations of market operations using a Monte Carlo approach. This feature enables the assessment of the impact of uncertainty on key market parameters such as power prices and congestion patterns. The probabilistic simulation is especially useful for evaluating the effect of renewable generation variability and fuel price volatility.

12.2 Key Input Assumptions

The key modeling assumptions in this study include projections of natural gas prices, peak and energy demand, demand-side management, new build costs, financing costs, supply changes, environmental regulation and transmission changes. The Exhibit below summarizes the key assumptions ICF has used to model the TVA and MISO marketplaces.

Exhibit A-2: Summary of Key Assumptions for TVA

TVA				
Peak and Energy Demand Growth (Annual Avg. %)	**Peak (MW, annual avg. growth)**		**Energy (GWh, annual avg. growth)**	
TVA	(2018: 28,662), 0.2% growth		(2018: 157,874), 0.0% growth	
Fuel and Emissions Prices	**Henry Hub ($/MMBtu)**	**TVA Delivered Gas ($/MMBtu)**	**Carbon ($/ton)**	**ILB Coal Commodity ($/MMBtu)**
2018	2.88	2.98	0.0	1.64
2019	2.76	2.77	0.0	1.61
2020	2.67	2.60	0.0	1.59
2022	3.44	3.58	0.0	1.68
2025	4.03	4.29	0.0	1.81
2030	4.99	5.27	5.4	2.07
2035	5.72	6.02	13.2	2.33
2040	6.41	6.76	21.7	2.45
2045	7.11	7.50	36.0	2.64
2050	7.89	8.33	60.7	2.84
2053	8.40	8.86	64.6	3.02
Firm Builds and Retirements	**2018**	**2019**	***2020***	**2021-2026**
Wind	0	0	*0*	0
Solar	1	68	*0*	0
Thermal Builds[115]	1,517	0	0	1,350
Thermal Retirements	1,169	0	*0*	0
Capital Costs and Financing	**2020 Cost ($/kW)**	**2025 Cost ($/kW)**	***Note***	**Real Capital Charge Rate**
CC	991	1,100	*All-in, summer kW*	4.7%
CT	645	715	*All-in, summer kW*	5.2%
Wind	1,604	1,719	*AC-basis before ITC*	4.4%
Solar	1,286	1,357	*AC-basis before ITC*	4.4%

Source: ICF

[115] Include TVA's Allen Plant CC which came online in 2018

Exhibit A-3: Summary of Key Assumptions for MISO

MISO				
Peak and Energy Demand Growth (Annual Avg. %)	**Peak (MW, annual avg. growth)**		**Energy (GWh, annual avg. growth)**	
MISO RTO	(2018: 119,507), 0.4% growth		(2018: 698,112), 0.4% growth	
MISO Zone 8	(2018: 7,110), 0.8% growth		(2018: 40,614), 0.8% growth	
Fuel and Emissions Prices	**Henry Hub ($/MMBtu)**	**Zone 8 Delivered Gas ($/MMBtu)**	**Carbon ($/ton)**	**PRB Coal Commodity ($/MMBtu)**
2018	2.88	2.89	0.0	0.70
2019	2.76	2.73	0.0	0.70
2020	2.67	2.59	0.0	0.70
2022	3.44	3.49	0.0	0.74
2025	4.03	4.15	0.0	0.80
2030	4.99	5.14	5.4	0.91
2035	5.72	5.88	13.2	1.04
2040	6.41	6.60	21.7	1.19
2045	7.11	7.33	36.0	1.35
2050	7.89	8.13	60.7	1.53
2053	8.40	8.65	64.6	1.62
Firm Builds and Retirements	**2018**	**2019**	***2020***	**2021-2026**
Wind	1,972	2,400	2,695	824
Solar	522	1,863	2,220	2,245
Thermal Builds	1,077	1,706	720	510
Thermal Retirements	2,943	450	151	520
Capital Costs and Financing	**2020 Cost ($/kW)**	**2025 Cost ($/kW)**	***Note***	**Real Capital Charge Rate**
CC	996	1,105	*All-in, summer kW*	4.1%
CT	645	715	*All-in, summer kW*	4.7%
Wind	1,602	1,717	*AC-basis before ITC*	3.8%
Solar	1,280	1,351	*AC-basis before ITC*	3.8%

Source: ICF

- **Natural gas:** ICF utilized forward traded over the month of March 2018 for 2018-2020 and its own fundamentals forecast (as of May 2018) from 2022 onwards, with 2021 reflecting transition from forwards to fundamentals.

- **Demand and energy:** Values through 2023 are sourced from the 2018 Loss of Load Expectation (LOLE) report. Thereafter, peak is assumed to grow at the average rate over 2021-2023. Energy demand is calculated based on the load factor from Purdue's Independent Load Forecast from November 2017.

- **Firm builds and retirements:** Firm builds are sourced from Ventyx and the MISO Generator Interconnection Public Queue. Retirements are sourced from MTEP 2018 and Ventyx. ICF considers thermal capacity as firm if the unit is under construction or unit meets two of the following criteria; a) it is fully permitted, b) it has a PPA for an amount 50% or more of the total output, and c) it has secured financing for at least 50% of the project costs.

  Wind and solar new-builds are assumed to be 15% (for 2020 and 2021) to 35% (2018 and 2019) of interconnection queue projects that are in the Definitive Planning Phase (DPP), System Impact Study. However, the model is allowed to build further capacity based on the economics throughout the forecast.

- **Coal prices:** ICF utilized coal forwards for 2018-2019 and its fundamental coal forecast from 2021 onwards, with 2020 reflecting transition from forwards to fundamentals. ICF generates coal production price curves and solves dynamically in the model based on usage.

- **Capital costs:** ICF generates bottom-up component cost assumptions for thermal and renewable projects.

- **Financing:** ICF assumptions include the tax changes enacted in late 2017. Notably, we use a lower-than-merchant equity return rate of 10% to reflect utility cost of capital and lack of full returns on merchant projects.

- **National Carbon:** ICF uses a probability-weighted approach of three cases: delayed-CPP, full legislative action, and no regulation over time.

12.3 MISO Capacity Prices

- **Two cases of capacity prices** were assumed – the near-term/hedged case assumes a $25/kW-yr (2018$) capacity price and reflects current capacity surplus market or a “buyers’ market” where MLGW can lock in or buy the capacity at most competitive and discounted rates. This is akin to buying a CCGT plant in current environment at 400-450/kW-yr. The second case assumes a high net CONE type $70/kW-yr in 2018$) for capacity pricing and reflects a “sellers’ market” where buying capacity from spot would be more costly than locking in today.

Exhibit A-4: MISO Capacity Prices ($/MW-day)

Year	Near Term/Hedged Price ($/MW - Day)	Net Cone Price ($/MW - Day)
2024	77.6	221.4
2025	79.2	226.0
2026	80.9	227.0
2027	82.6	228.0
2028	84.3	228.0
2029	86.1	229.0
2030	87.9	230.0
2031	89.7	230.0
2032	91.6	230.0
2033	93.5	231.0
2034	95.5	231.0
2035	97.5	231.0
2036	99.6	233.0
2037	101.7	235.0
2038	103.8	236.0
2039	106.0	238.0
2040	108.2	240.0
2041	110.5	241.9
2042	112.8	243.8
2043	115.2	245.7
2044	117.6	247.7
2045	120.0	249.6
2046	122.6	251.6
2047	125.1	253.5
2048	127.8	255.5
2049	130.5	257.5
2050	133.2	259.5
2051	136.0	261.6
2052	138.8	263.6
2053	141.8	265.7

Source: ICF