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**MEMO TO:** Memphis Light, Gas and Water Team

**FROM:** Siemens PTI IRP team

**DATE:** January 13, 2020

**SUBJECT:** Pipeline Tariff and Capacity Availability Assessment + Natural Gas Forecast

For the development of the self-supply options, thermal units—in particular combined cycle gas turbine (CCGT) and combustion turbine (CT) —will be offered for the long term capacity expansion plan. At this moment it is not known how many of these units will be added by the plan however for their assessment it is necessary to: a) Identify to which pipeline(s) the units will interconnect, b) produce a delivered gas forecast and c) identify where these units are likely to be located so the construction of gas laterals is minimized.

For item (c) we would need information on the available capacity on MLGW local gas distribution system (locations and capacity). On this item we have requested MLGW provide support in obtaining this information as owner of the gas distribution system. To help in this assessment, the table below shows the expected maximum gas supply rate (MMBTU/hr and MCf/hr) to the various units that we will be considered. MLGW was requested to use this information to assess known locations in the system that could host these units.

**Exhibit 1: Gas Consumption by Unit Type**

| Technology | Advanced 2x1 Combined Cycle | Conventional 1x1 Combined Cycle | Simple Cycle Advanced Frame CT | Simple Cycle Aero CT |
|---|---|---|---|---|
| Fuel | Nat. Gas. | Nat. Gas. | Nat. Gas. | Nat. Gas. |
| Size (MW) | 950 | 350 | 343 | 50 |
| Baseload Heat Rate (Btu/kWh), HHV | 6,164 | 6,560 | 8,704 | 9,013 |
| Gas Consumption MMBTU /hour (100% CF) | 5,855 | 2,296 | 2,985 | 451 |
| Gas Consumption Mcf /hour (100% CF) | 5,712 | 2,240 | 2,913 | 440 |

Source: Siemens

For item (a) we need to form a view of the available capacity at the three pipelines serving MLGW territory. MLGW provided several pieces of information that were incorporated into the assessment of available capacity. These included a map of the three pipeline that cross MLGW service territory (ANR, Trunkline, Texas Gas) and the number of existing gates for each pipeline, the seasonal pipeline transmission rates for the previous 12 months on the three pipelines, a monthly ANR transport cost estimate (using 157,000 Dth/d for 16 hours as inputs) and meter station upgrade estimate together with an FTS-3 calculator for ANR rates (same inputs) (FTS-3 is the rate schedule for generators). The monthly ANR transport cost estimate also included information on ANR available capacity, specifically that 181,000 Dth/day is available in the winter and 340,000 Dth/day is available in the summer and this is expected to be the case in five years but is subject to change. There was additional information that Texas Gas is expected to have 67,000 Dth/day available in the winter and 179,800 Dth/day in the summer in five years, subject to change. Finally, Trunkline is expected to have 157,000 Dth/day in the winter and 430,000 Dth/day in the summer in five years. In a later discussion, it was mentioned that Substation 86 has access to fuel supply, sufficient land, and available transmission interconnection capacity for siting a CCGT or CT.

To assist in item (a) to identify the pipeline(s) to which the units will interconnect, Exhibit 2 provides the firm transportation tariffs for each of the three pipelines (ANR, Texas Gas, and Trunkline), which are also shown in the map at the end of this memo. For example, the ANR FTS-3 tariff plus 2-hour notice enhanced service from SE to ML-2 (the Southeast Area to Southeast Southern Segment) assuming 157,000 Dth/d has a unit rate of $0.8055/Dth. Using the same assumptions with Texas Gas tariff rates, we estimate a unit rate of $0.4965/Dth. Similarly, for Trunkline we estimate a unit rate of $0.3811/Dth.

Each of these three pipeline tariffs are approximately the same in terms of level of tariff design that is best able to service a power generator. This includes firm transportation service that is enhanced with no-notice service and seasonal storage and balancing services. Firm service is assumed for any combined cycle builds, whereas a simple cycle gas peaking unit would be more likely to incur a lower fuel supply cost, closer to the interruptible transportation service tariff, which is shown in Exhibit 3. Note that while ANR has an ITS-3 schedule, the maximum rate of $1.6266/Dth is much higher than the FTS-3 rate. Siemens confirmed with an ANR representative that there is very little capacity on their Southeast Mainline currently, so ITS-3 rates would be near to the maximum rate. For this reason, it is not included in Exhibit 3, although conditions could change in five years.

**Exhibit 2: Enhanced Firm Transportation Rates as of November 2019 ($/Dth)**

| Pipeline (Zone to Zone) | Tariff | Demand Rate ($/Dth) | Commodity Rate ($/Dth) | ACA Rate ($/Dth) | Equivalent Fuel Rate ($/Dth) | Unit Rate ($/Dth) |
|---|---|---|---|---|---|---|
| ANR (SE to ML-2) | FTS-3 w/ 2hr+balancing | $0.7257 | $0.0347 | $0.0013 | $0.0438 | $0.8055 |
| Texas Gas (1-1) | FT+WNS+SNS | $0.4028 | $0.0553 | $0.0020 | $0.0364 | $0.4965 |
| Trunkline (Field Zone to 1A) | QNT+FSS | $0.3364 | $0.0080 | $0.0013 | $0.0354 | $0.3811 |

Source: Pipeline published tariffs, MLGW, Siemens.

**Exhibit 3: Interruptible Transportation Rates as of November 2019 ($/Dth)**

| Pipeline (Zone to Zone) | Tariff | Demand Rate ($/Dth) | ACA Rate ($/Dth) | Equivalent Fuel Rate ($/Dth) | Unit Rate ($/Dth) |
|---|---|---|---|---|---|
| Texas Gas (1-1) | IT | $0.1593 | $0.0013 | $0.0213 | $0.1819 |
| Trunkline (Field Zone to 1A) | QNIT | $0.2845 | $0.0013 | $0.0354 | $0.3212 |

Source: Pipeline published tariffs, MLGW, Siemens.

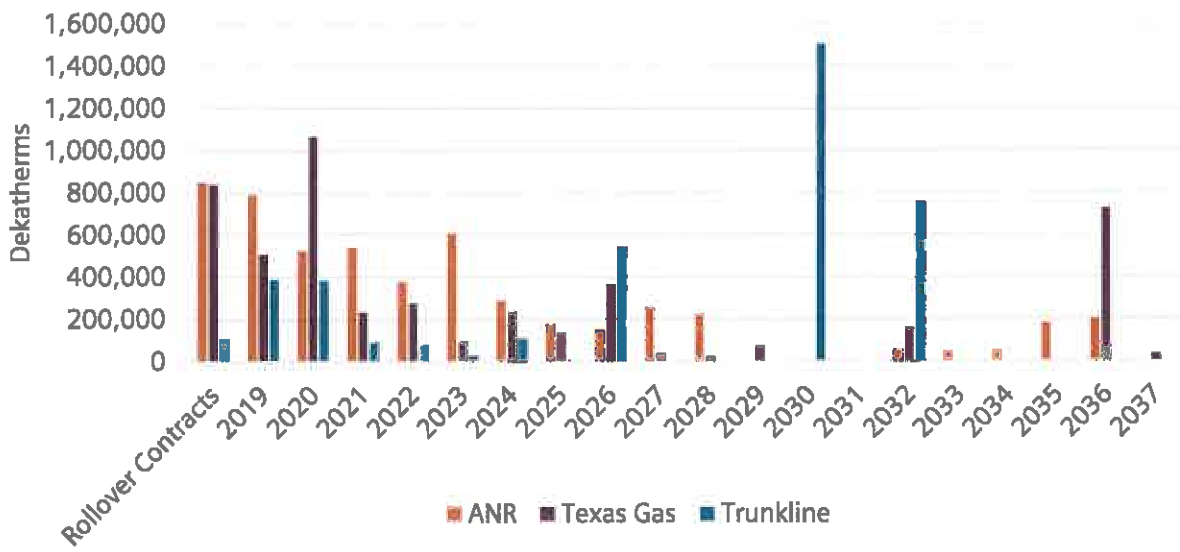
The FT rates range from $0.3811/Dth to $0.8055/Dth. A reasonable assumption for enhanced FT service to CCGTs in MLGW's service territory would be to use the Trunkline rate of $0.3811/Dth. Trunkline also happens to be the pipeline with the most available capacity in five years (see Exhibit 5). Similarly, a reasonable assumption for enhanced IT service to gas peaker CTs in MLGW's service territory would be to use the $0.3212/Dth rate offered by Trunkline. In addition, three other regions are being modeled, including Arkansas, Mississippi, and TVA's service territory. We recommend using the same Trunkline firm and interruptible rates for each of these three regions in order to provide internally consistent modeling assumptions for fuel transport rates.[1]

In addition, ANR (one existing gate) provided an estimate of $10 million for a meter station upgrade or replacement. It is unclear if Trunkline (two existing gates) or Texas Gas (five existing gates) would also need a similar upgrade. On the basis of the tariff analysis above (see below for capacity availability), any potential new gas-fired generation should be sited near Trunkline or possibly Texas Gas if negotiated rates are similar to the tariffs shown in Exhibits 2 and 3. Furthermore, the two gas hubs associated with Trunkline and Texas Gas (Trunkline Z1A and Texas Gas Z1, respectively) are expected to have lower basis to Henry Hub than ANR Patterson LA, meaning commodity costs will be lower in addition to firm transportation rates.

As a check on available pipeline capacity, we reviewed contract expirations as reported by S&P Global for 19Q3 and shown in Exhibit 4. ANR shows a steady decline in contract expirations through the 2020s, but not shown is 2,100,00 Dth post-2044. Texas Gas shows more than 2,000,000 Dth in contract expirations through 2022. Trunkline shows 935,000 Dth in contract expirations through 2022, with an incremental 675,000 Dth from 2023 to 2026 but with several large contract expirations in 2030 (1,500,000 Dth) and 2032 (750,000 Dth). These contract expiration figures represent total contracts and aren't specified by pipeline zone, but further analysis of the data can provide additional detail on shippers and delivery points.

[1] Note that the lower cost Texas Gas FT rate including WNS and SNS and Fayetteville Lateral access to provide supply into Arkansas is roughly equivalent to the Trunkline FT rate.

**Exhibit 4: 19Q3 Contract Expirations**

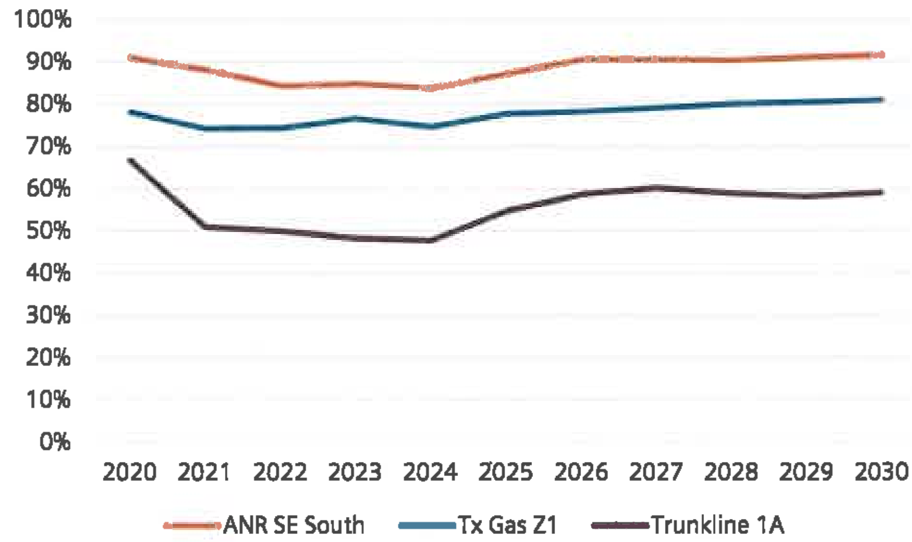



Source: Siemens, S&P Global.

In addition, during the winter months of December 2018 through February 2019 when demand was elevated, the average utilization rate on ANR's mainline segment through Haywood County, TN (Shelby County was not listed) was 61% or 783,500 Dth/d out of 1,287,000 Dth/d. The average utilization rate on Texas Gas mainline at the Covington compressor station in Tipton County during these same months was 53% flowing north (882,000 Dth/d out of 1,670,000 Dth/d) and 74% flowing south (444,000 Dth/d out of 600,000 Dth/d). Texas Gas also lists a Shelby County Memphis Shipper delivery point with a 58% utilization rate (198,000 Dth/d out of 344,000 Dth/d). Finally, the average utilization rate on Trunkline to MLGW Division North & South was 7% (30,000 Dth/d out of 400,000 Dth/d).

Because we are mostly interested in available pipeline capacity in 3-5 years when a new-build CCGT or CT would enter into service, Siemens also reviewed the monthly pipeline capacity utilization factors in its national forecast model (modeled using GPCM or Gas Pipeline Competition Model) through 2030. The modeled average annual capacity utilization factors are shown below in Exhibit 5. When looking at monthly utilization factors for the period of January 2020 to December 2030 (n=132 months), the ANR SE South zone shows an average monthly utilization factor at or above 90% in 33% of the months. The Trunkline 1A zone shows an average monthly utilization factor at or above 90% in 8% of the months. And the Texas Gas Z1 zone shows an average monthly utilization factor at or above 90% in only 2% of the months.

**Exhibit 5: Modeled Annual Average Pipeline Zone Capacity Utilization Factors**




Source: Siemens.

Finally, it was the goal of item (2) to produce a delivered gas forecast. The balance of this memo will discuss the gas forecast.

## US Natural Gas Market Outlook

The U.S. natural gas market outlook is expected to see low Henry Hub pricing in the short-term to 2021, despite increasing LNG demand and with higher storage refill requirements coming out of the 2018-19 winter. Low prices are primarily due to supply remaining dominant over demand, particularly with the ongoing natural gas production increases out of the Permian Basin and the Marcellus Shale. The main drivers of Henry Hub pricing in the short-term are:

1. LNG exports, which are expected to grow from 4.5 Bcf/d in 2019 to 9-10 Bcf/d by 2021. Furthermore, Elba Island and Cameron T1 are in final commissioning and there have been three new Gulf Coast LNG projects approved by FERC in 2019, with one reaching FID (Golden Pass) indicating a growing second wave of LNG export buildout on the Gulf Coast;

2. U.S. production growth, most of which is coming from the Marcellus Shale and Permian Basin; and

3. Over 43 Bcf/d of U.S. pipeline projects under construction or expected to become operational through 2021 (of which 15.5 Bcf/d is Marcellus takeaway capacity and 8.6 Bcf/d is Permian takeaway capacity).

The 10.6 Bcf/d of LNG export capacity expected by 2021 is mostly under take-or-pay contracts, meaning demand for LNG feedstock gas will be baseload with liquefaction capacity expected to run at an 85 percent capacity factor. As mentioned, long-term global demand for LNG may prompt a second wave of U.S. LNG export capacity buildout, with the mid-2020s as the target in-service period for most projects. LNG export demand will continue to put modest upward pressure on prices, particularly as new projects are approved. However, we expect the downward price pressure from supply/production growth and pipelines will largely moderate any such increase in prices.

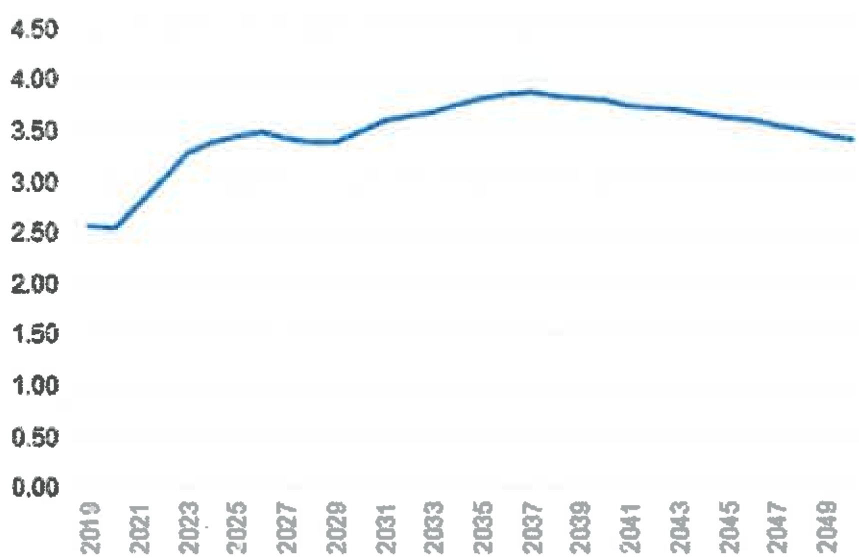
Generally, a trend has emerged of increased gas usage in the power sector at the expense of coal burn. With natural gas prices still relatively cheap compared to historical levels and coal facing other economic and regulatory pressures, there has been some switching to gas-fired units from coal-fired units in the dispatch order in certain power regions, particularly during shoulder-season months. Utilities in regions where gas transportation costs are relatively low and coal transportation costs are high, for example the SERC region, have announced the shutdown of certain coal units in favor of increasing utilization at intermediate gas units. Annual electricity generation from coal declined 31% in the past decade (2009-2018) from 1,756 TWh to 1,204 TWh, while generation from natural gas increased 43% from 921 TWh to 1,319 TWh, with natural gas surpassing coal beginning in 2016.

Major uncertainties on the demand side include the power sector response to new environmental regulations and rapidly declining renewables and battery costs that will displace gas-fired generation. While a carbon regime is not likely to advance in the current administration, the finalized Affordable Clean Energy (ACE) rule has been promulgated and is expected to lead to heat rate improvements for coal plants >25MW that will in turn lead to greater dispatch of coal units.

Nevertheless, utilities and other generators are beginning to plan for the rising probability of a carbon-constrained future. This helps to explain in part the downturn in Henry Hub prices in the long-term outlook, as demand is curtailed due to a rising price of carbon.

On the supply side, shale gas accounted for over 70 percent of U.S. gas production in 2018, up from 17 percent in 2008. During this time, unconventional gas production has changed the perception of gas markets and has been the primary driver of Henry Hub pricing, causing prices to drop from the 2008 records that topped $13/MMBtu. The cost of production in 2019 ranges widely, from core Marcellus shale play acreage able to generate breakeven returns at only $0.80/MMBtu compared to higher-cost conventional or non-core shale that might require prices of $4/MMBtu or more to break even. U.S. gas production is influenced to a relatively substantial degree by oil prices. When oil prices are high, incentivizing producers to drill for oil and natural gas liquids, a significant amount of associated gas can be produced as a by-product. Associated gas now accounts for 20 percent of total U.S. production, with notable recent growth in associated gas in areas like the Permian Basin in West Texas. In addition, the nature of drilling in shale plays is that, while initial production can be strong, the production curve declines very rapidly. A sustained or growing level of production requires ongoing drilling programs. This has resulted in U.S. supply becoming more responsive to market conditions, with shale wells acting as virtual storage to adapt quickly to changes in the market.

**Exhibit 6: Annual Henry Hub Natural Gas Forecast (2018$/MMBtu)**

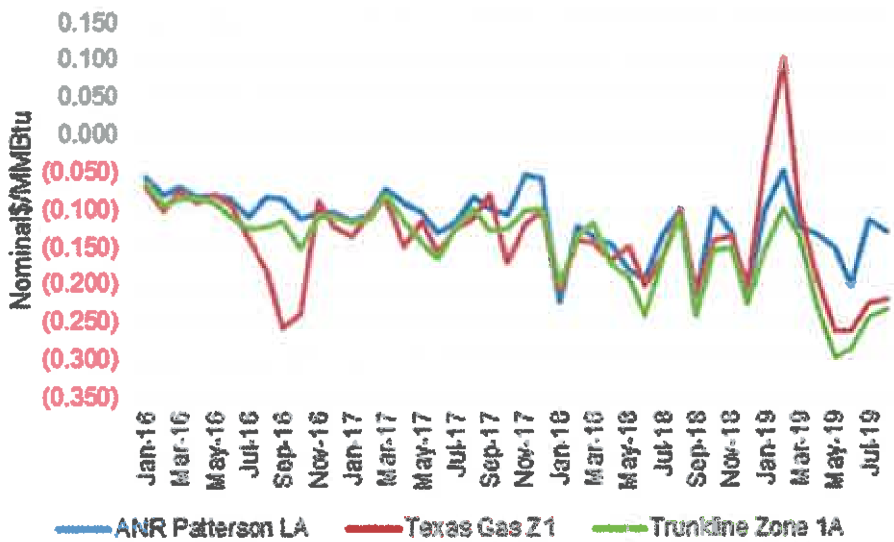



Source: Siemens EBA.

## MLGW Regional Outlook

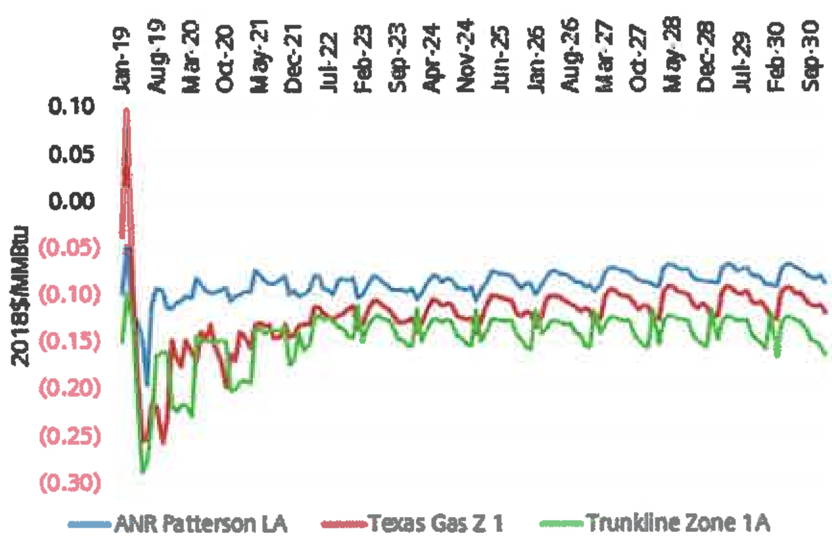
On a regional level, MLGW receives supply via three long-haul natural gas transmission pipelines that cross its service territory: Texas Gas, Trunkline, and ANR. The corresponding natural gas hubs include Texas Gas Zone 1, Trunkline Zone 1A, and ANR Patterson LA. In the past several years, these gas hubs have seen a trend downward in basis to Henry Hub, due to increasing supplies from natural gas production. Each of these pipelines sends supplies northward toward the Marcellus Shale play, production from which has grown dramatically in the past decade. Accordingly, Marcellus supply is displacing the need for south-to-north supply deliveries, increasing the supply at these gas hubs and driving down basis.

**Exhibit 7: Monthly Average Historical Gas Basis to Henry Hub (Nominal$/MMBtu)**




Source: Siemens EBA, S&P Global

**Exhibit 8: Monthly Forecast Gas Basis to Henry Hub (2018$/MMBtu)**




Source: Siemens EBA, S&P Global.

These same three hubs are expected to see a moderation in the basis decline seen over the last few years, with basis climbing up toward between -$0.06/MMBtu and -$0.15/MMBtu over the next decade to 2030. This moderation is expected as U.S. Gulf Coast LNG export projects come online through 2021, helping to alleviate the downward price and basis pressure from natural gas oversupply. Trunkline Zone 1A is expected to remain the most competitive natural gas pricing point among these three gas hubs (from the point of view of the consumer), and also has a relatively low-cost firm transportation rate compared to the other two pipelines. ANR Patterson LA will have the narrowest negative basis (and thus highest price) among the three gas hubs and also has a relatively high firm transportation tariff (albeit it has the lowest interruptible transport tariff among the three pipelines for delivery into MLGW service territory – see tariff discussion below).

### Natural Gas Forecast Methodology

The Gas Pipeline Competition Model (GPCM) was used to develop long-term price forecasts by incorporating the fundamental drives of supply, demand, and infrastructure described above. In the short-term, recent natural gas forwards (dated 7/9/19, 7/16/19, and 7/23/19) were averaged and used explicitly for the first 18 months of the forecast after historical. In the subsequent 18 months, the forecast is blended away from forwards to the fundamental GPCM forecast, after which the forecast is purely fundamentals-based. This provides a view of natural gas prices and basis to Henry Hub delivered to liquid market trading points throughout the United States. The price forecast does not include delivery from the market trading hub to each plant gate, as not all of these transportation costs align with the published tariffs nor can it be certain which hub is indexed in each plant's supply contract.

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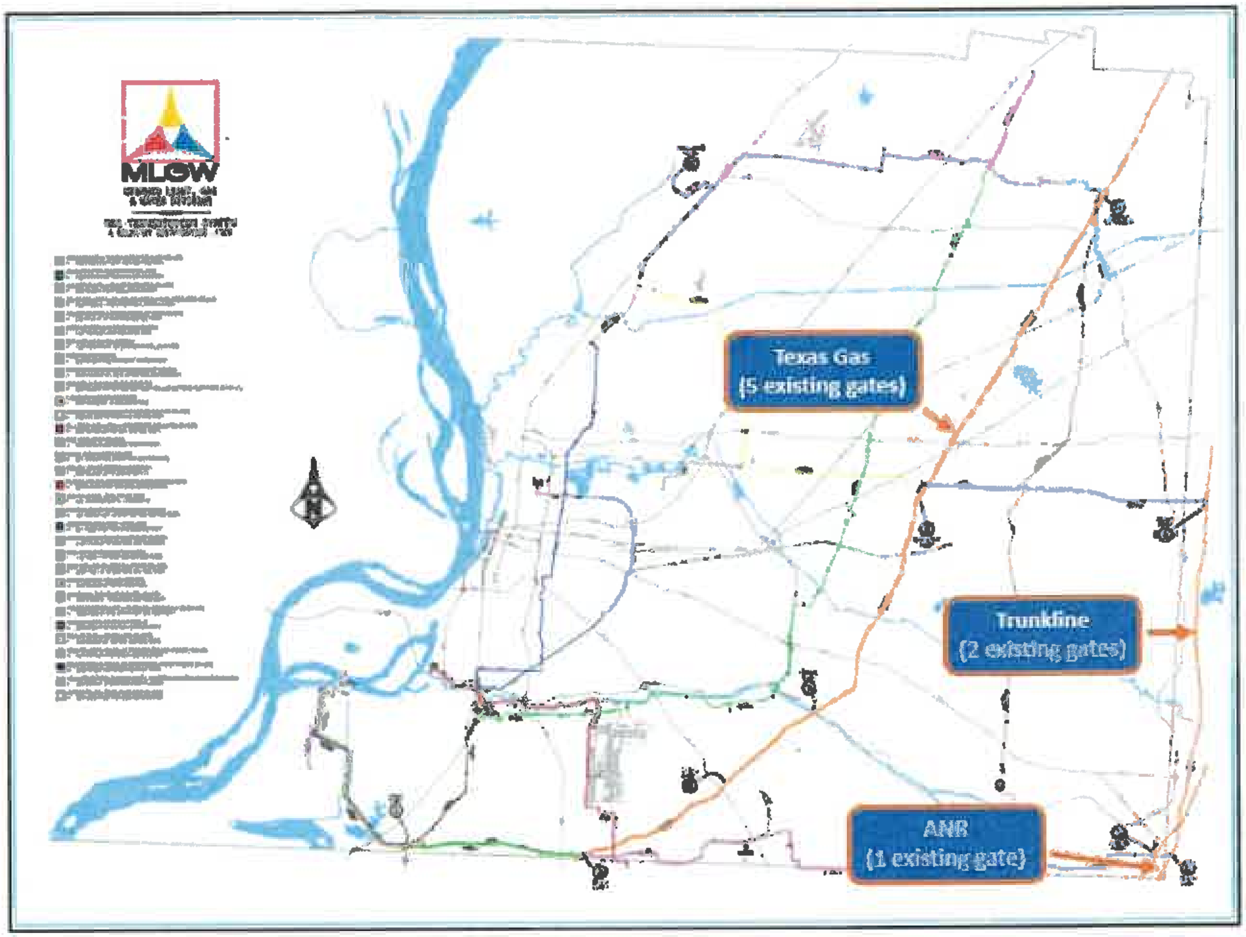
**Exhibit 9: Pipelines Crossing MLGW Service Territory**




Source: MLGW.

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