Analysis of Florida IOU Fuel Costs and Rate Impacts on Residential Customers

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Table of Contents

1. Introduction & Summary

1.1 Synopsis of Report Contents

EQ Research was engaged to conduct a three-phase study of fuel cost impacts and management across Florida's major investor-owned utilities (IOUs): Florida Power and Light (FPL)[1], Duke Energy Florida (DEF) and the Tampa Electric Company (TECO).[2] This report comprises Phase One of this larger study, which is focused on developing a picture of how fuel costs have varied over time, their relative role as components of residential retail rates, the sources and magnitude of customer rate volatility, and how this may change in the future. Given the IOUs' collective high reliance on natural gas generation, the report devotes specific attention to natural gas costs. The specific topics explored in this report are listed below:

- The changes in IOU generation mixes over time, with a specific focus on natural gas generation.
- The historical impact of fuel costs on residential customer bills, as represented by the proportion of customers' bills that are attributable to fuel costs.
- Trends in natural gas prices in comparison to trends in fuel cost charges on customers' electric bills.
- A projection of the future impacts of fuel costs on customer bills based on variations in projected amounts of natural gas generation and natural gas prices.

The analysis provided in this report is supported by monthly data on: (i) each individual component of residential customer rates, and (ii) the IOUs' estimated and actual determinants of natural gas generation costs (e.g., natural gas prices, heat rates). Both monthly datasets use a time horizon starting in January 2016 through May 2025 although some presentations of the data only extend through the end of 2024 because a partial 2025 year is not comparable to a full calendar year due to seasonal variations. Unless otherwise stated, all dollar amounts and rates in this report are specified in nominal terms.

1.2 Key Findings

The key findings from this evaluation are as follows:

1. The generation supply mix of Florida's major IOUs has as a whole become moderately more concentrated in natural gas generation since 2016, increasing from roughly 66.0% in 2016 to 75.3% in 2024. On an individual utility level DEF and TECO show significant

[1] This includes FPL's Northwest Florida division, which was served by Gulf Power prior to the purchase of Gulf Power by FPL's parent company NextEra Energy in 2019. The former Gulf Power territory was fully consolidated into FPL operations in January 2022. In a historic context, we sometimes refer to FPL and Gulf Power separately, or to the two utilities combined (FPL/Gulf Power) depending on the context. On a forward-looking basis, we refer to the merged utilities as FPL.
[2] Florida Public Utilities, a small IOU has not been included in this analysis.

increases (27% and 32%, respectively) while reliance on natural gas generation by FPL/Gulf Power collectively has remained fairly flat.

2. All of the IOUs project declining amounts of natural gas generation starting in the mid- to late-2020s, but the trajectory of those declines varies as well, with DEF and TECO lagging substantially behind FPL.
3. Higher reliance on natural gas as a generation fuel is associated with higher fuel costs and increased fuel rate volatility. For instance, in recent years DEF and TECO have become relatively more reliant on gas generation than FPL, and their fuel rates have also become noticeably more volatile. In other words, even though natural gas price volatility is relatively uniform across all utilities, higher reliance on natural gas generation exposes a greater portion of the overall fuel rate to that price volatility.
4. Storm damage costs are an additional source of rate volatility and tend to exacerbate overall rate volatility because the recovery of storm damage costs sometimes coincides with periods of higher fuel rates brought on principally by volatility in natural gas prices. The average year-over-year (YOY) change in fuel rates and storm recovery charges combined ranged from 11% - 58% higher than the average YOY change in fuel rates alone depending on the utility in question.
5. The combination of heavy reliance on natural gas generation and Florida's high vulnerability to major storm costs from tropical systems makes Florida electric customers uniquely vulnerable to rate volatility.
6. Because their present resource planning filings show significantly higher reliance on natural gas generation during the next decade, rate volatility for customers of DEF and TECO is likely to continue to be significantly higher than for customers of FPL in future years.
7. Under a future scenario with high natural gas prices, the incremental costs to ratepayers from 2025-2034 could approach, or even exceed $21 billion. Under the High Price natural gas price scenario the incremental cost for a typical residential customer that uses 1,000 kWh/month averages roughly $9/month for FPL customers and $11/month for DEF and TECO customers compared to a Base Case natural gas price scenario.

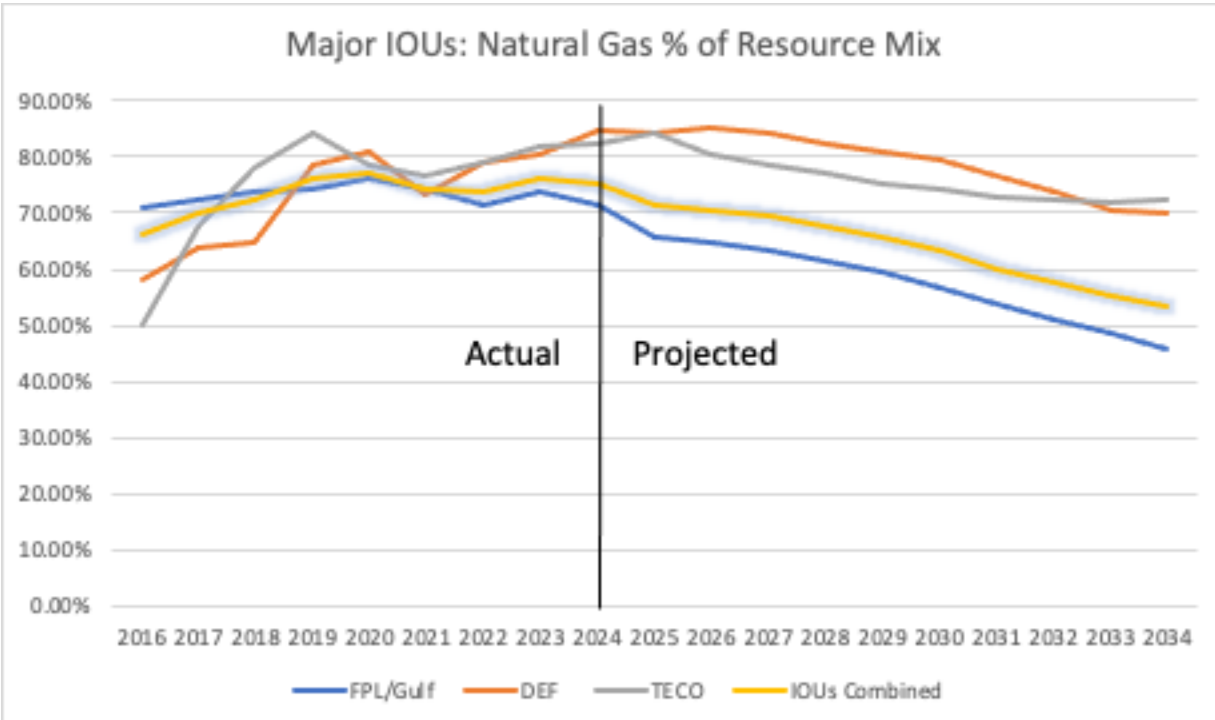
2. Background on Energy Supply and Fuel Rates

2.1 Generation Mix Over Time & Relevance for Fuel Costs

Resource mix is a central driver of a utility's fuel costs since it determines what portion of overall fuel costs are sensitive to changes in the price of any given fuel. All of the major IOUs are presently highly reliant on natural gas generation although the historic and future trajectories differ somewhat by utility. Figure 1 shows the historic changes in natural gas penetration in each major IOU's resource mix from 2016 to 2024, and projected reliance on natural gas through 2034 based on the IOUs' 2025 Ten-Year Site Plans filed with the Florida Public Service

Commission (FPSC).[3] [4] The highlighted line in Figure 1 reflects a combined statewide summation of the major IOUs, which tends to be driven by FPL/Gulf Power because FPL/Gulf Power has a significantly larger footprint than DEF and TECO combined.

Figure 1: Florida's Natural Gas Generation Reliance Over Time



As illustrated in Figure 1, both DEF and TECO increased their natural gas reliance considerably from 2016 to 2024, and both projected continued higher reliance on natural gas over the next decade than FPL. The historic changes were driven primarily by retirements of coal units that were balanced largely by additions of natural gas generation capacity, which carries into forward resource mix projections because significant portions of their natural gas generation portfolios are new units. On the other hand, FPL differs in several respects:

- FPL (even combined with Gulf Power) was historically less reliant on coal generation so coal retirements affected its resource mix to a lesser degree.
- FPL was historically relatively more reliant on natural gas generation, so its natural gas generation fleet is generally older.

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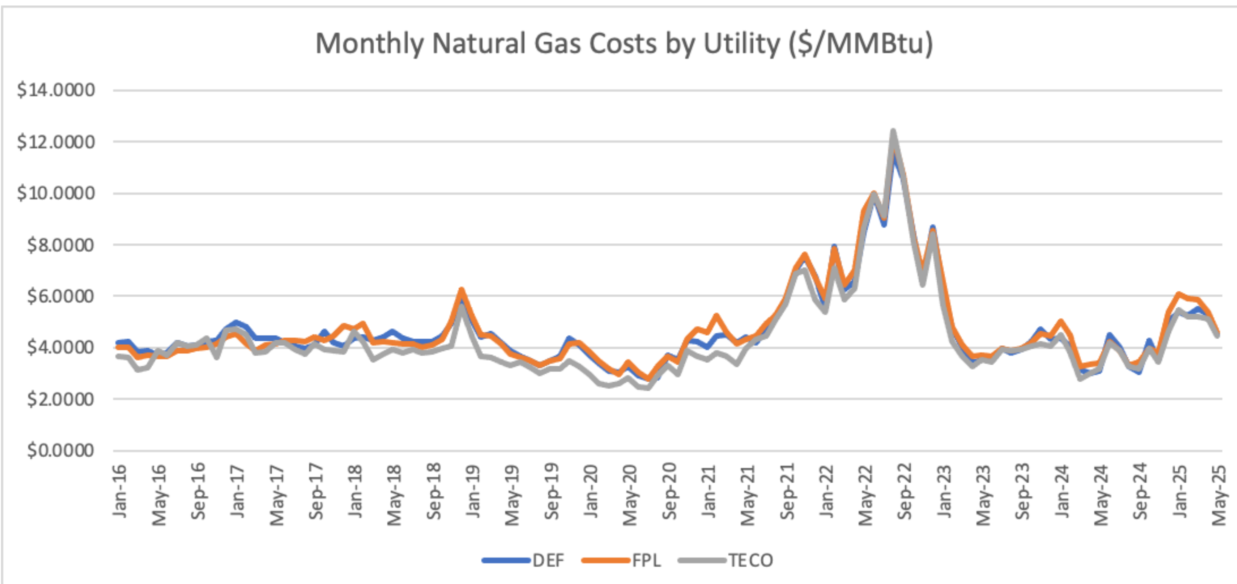
[3] FPSC. Ten-Year Site Plans. https://www.psc.state.fl.us/ten-year-site-plans. The Ten-Year Site Plans are similar to integrated resource plans (IRPs), but have a number of key differences (e.g., informational only, less extensive, etc.).
[4] Note that Figure 1 shows FPL and Gulf Power as a single entity for the entire time horizon even though they did not fully consolidate operations until 2022. In practice, the consolidation did not significantly affect FPL's resource mix because FPL was roughly 13 times larger than Gulf Power in terms of system energy generation at the time of the consolidation.

- FPL has a significant amount of nuclear generation (roughly 20% of its resource mix on average) whereas DEF and TECO have none.
- On a forward-looking basis, FPL has a more aggressive plan for solar deployment than either DEF or TECO, although FPL's solar penetration as a percentage of the generation energy mix lagged TECO's in 2024 and was only slightly higher than DEF's.[5]

The concentration of energy supply in natural gas generation results in fuel rates that are highly tethered to natural gas prices, which are notoriously volatile. Figure 2 illustrates this volatility in the form of each utility's actual monthly cost of natural gas from January 2016 - May 2025.

Figure 2: Actual Natural Gas Prices Over Time



Since all of the utilities are dependent on the same regional market for natural gas, the prices they pay are nearly identical, with only small differences attributable to transportation costs and their specific fuel purchasing practices.[6] However, since DEF and TECO are more reliant on gas generation than FPL, their fuel rates are driven by natural gas prices to a relatively greater extent than FPL's are at present, or are likely to be in the future based on the utilities' respective 2025 Ten-Year Site Plan projections.[7]

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[5] It is worth noting here that the 2025 Ten-Year Site Plans pre-date changes to federal tax credits for solar associated with 2025 H.R. 1. Those changes, which include an overall phase-out but also contain elements that could stimulate a rush for construction of new projects, will undoubtedly affect utility planning for solar deployment going forward.

[6] Appendix A provides further background information on differences in the full delivered prices that individual IOUs pay for natural gas.

[7] Total natural gas costs are also influenced by the relative efficiency of a utility's natural gas generation portfolio, commonly known as the heat rate measured in Btu/kWh. The heat rate is primarily a product of the breakdown of natural gas generation between different types of units (e.g., combined cycle vs. simple cycle turbines) and the respective ages of individual units (i.e., older units are typically less efficient).

2.2 Summary of Fuel Cost Rate Recovery in Florida

The IOUs' fuel costs are recovered through a rate rider outside of their base rates. Fuel costs are a full pass-through cost, meaning that utilities recover the full amount of their actual costs from ratepayers without earning a margin or return. No matter how fuel costs change, or how they differ from prior projections, utilities are entitled to recover the full amount of their actual fuel costs from ratepayers. In other words, the full pass-through character places 100% of fuel price risk on ratepayers (and zero risk on the utility).

The FPSC establishes an annual docket to update fuel charges. As a default, fuel rates are updated on an annual calendar year basis in order to reflect: (i) projected fuel costs for the upcoming calendar year, and (ii) a true-up of actual fuel costs vs. fuel cost revenue for the prior rate period (i.e., an under- or over-recovered balance). However, within this general annual cadence is a mechanism under which utilities may seek a Mid-Course Correction to the annually established rates in order to update fuel rates during the middle of a calendar year. Under the Mid-Course Correction rules, a utility must notify the FPSC if its under- or over-recovered balance based on current fuel rates exceeds 10% of the adopted fuel cost revenue requirement. When they make this notice, they must request a change to their fuel rate or provide an explanation of why implementing a correction would be impractical (e.g., insufficient time to establish an update before the next scheduled update). Utilities are also permitted to request a Mid-Course Correction even if the imbalance has not yet reached the 10% threshold.

The Mid-Course Correction mechanism mitigates volatility in fuel rates to some degree by limiting the growth of cost recovery imbalances (i.e., projected vs. actual costs), which principally stem from errors in a utility's natural gas price forecast. The result is the potential for more frequent, but smaller, incremental rate changes, as opposed to the wider swings that could occur under a strict annual update schedule.[8] Nevertheless, despite the Mid-Course Correction feature of fuel cost ratemaking in Florida, fuel rates charged to customers generally tend to lag the pattern of incurrence of actual fuel costs, such that customers only see the impacts of changes in natural gas prices on their bills after the time during which those costs were incurred.[9] Figures 3 and 4 below illustrate this lag for DEF and TECO.

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[8] The Mid-Course Correction mechanism may also provide a more accurate price signal to customers of the cost of their energy usage by reducing the lag between when persistent changes in fuel prices are reflected in fuel rates (e.g., signaling them to reduce usage due to high costs).

[9] This refers to the combination of natural gas price forecasting ($/MMBtu) and natural gas generation heat rate forecasting (Btu/kWh), which in combination translate to the natural gas generation cost ($/kWh).

Figure 3: DEF Fuel Rate Lag Illustration

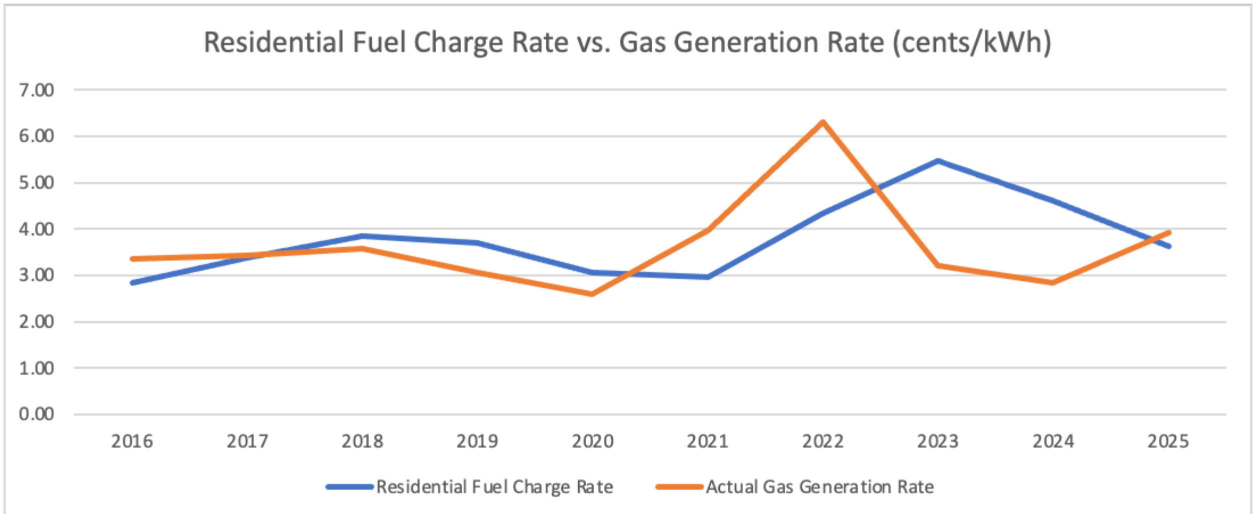
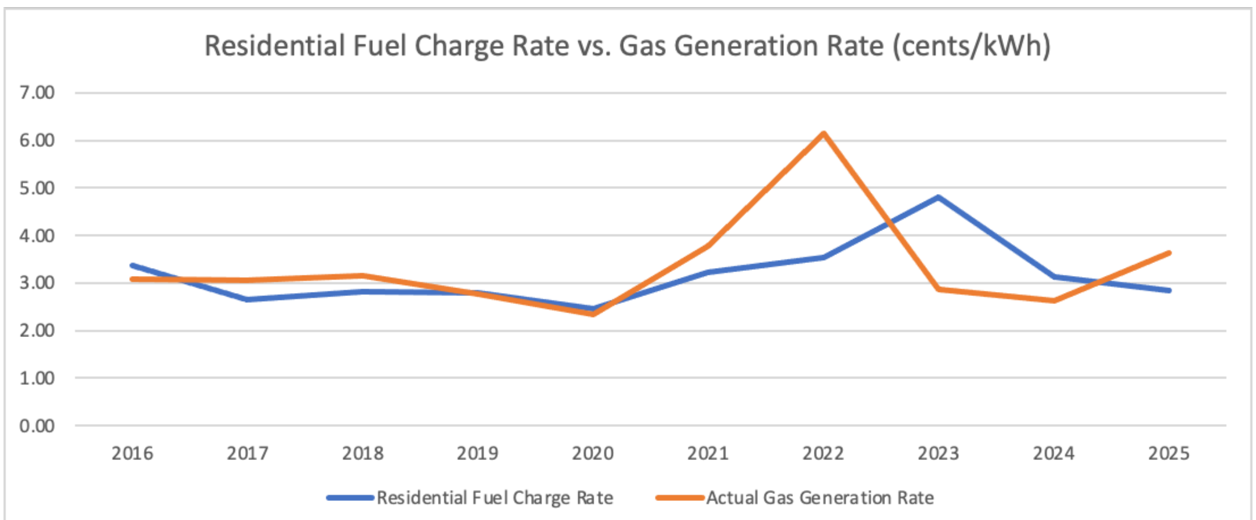


Figure 4: TECO Fuel Rate Lag Illustration



On an historical annual basis, this lagging effect is more visible for DEF and TECO than FPL, which appears likely to be due to FPL's: (i) modestly lower reliance on natural gas generation in recent years, (ii) more efficient gas generation portfolio, and (iii) generally more accurate reflection of the costs of natural gas generation in rates, on average, during the time frame of natural gas price volatility from 2021-2023. In other words, FPL is less exposed to high natural gas prices, and appears to have better anticipated the spike in natural gas prices in forecasting its estimated costs and seeking fuel charge rate changes to reflect refreshed cost estimates in rates closer to the timing of cost changes.[10]

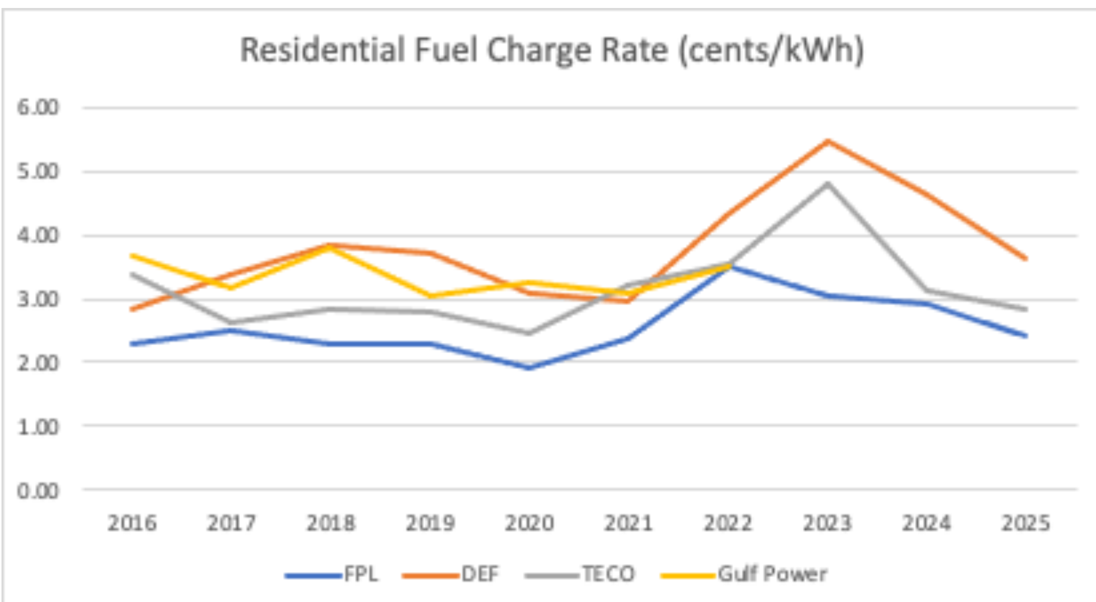
[10] This is not to say that FPL is necessarily better at natural gas price and cost forecasting in an overall sense. Rather, it only means that during the 2021-2023 time frame, it managed to achieve a smoother trajectory in fuel

3. Customer Rates & Rate Volatility

3.1 Fuel Costs & Residential Bill Impacts

Fuel costs constitute a significant portion of residential electricity bills. The specific proportion (%) during any given month or year varies based primarily on three factors: (i) a utility's resource mix in relation to prices for different fuels, (ii) the timing of rate changes in response to differences between forecasted and actual fuel costs (e.g., the lagging effect discussed in Section 2.2 of this report), and (iii) the amount and timing of changes in other rate components that tend to have a relatively lumpy character (e.g., base rate changes and storm cost recovery charges). In the long run, during which the timing aspects of ratemaking tend to smooth out, changes in fuel rates ultimately tend to fluctuate in proportion to the price of the dominant fuel resource. In the case of the major Florida IOUs, the dominant fuel source for generation is natural gas, so fuel rates tend to track changes in natural gas prices in rough proportion to a utility's relative dependence on natural gas. Figure 5 below shows a history of the average annual residential fuel charge from January 2016 through May 2025 by utility.[11]

Figure 5: IOU Fuel Rates Over Time



rates. In general, FPL better anticipated the price spike in late 2021 and decline in 2023 than DEF or TECO. Again, part of this outcome also stems from relatively less exposure to high natural gas prices in the first place. It is also possible that the consolidation of rates between FPL with Gulf Power in January 2022 introduced an exogenous artifact into the data that disguised the most pronounced lagging effect that is visible for DEF and TECO during the 2022-2023 time frame.

[11] The fuel charge rate for Gulf Power becomes identical to the FPL rate in 2022, as shown by the convergence of the yellow and blue lines. The specific rates used are for the lower tier of residential fuel rates that applies to usage up to 1,000 kWh during a monthly billing period.

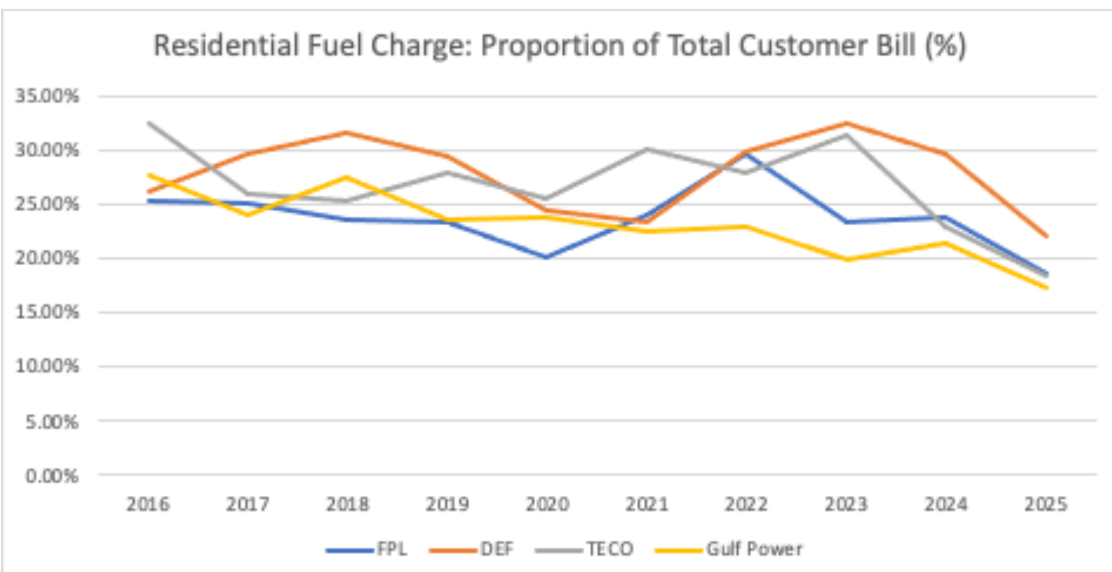
Table 1 shows this level of fuel rate variability numerically in the form of the average, maximum, minimum, and range (maximum minus minimum) of average fuel rates by year since 2016. A higher range in particular is indicative of greater rate volatility. Furthermore, annual averaging has a diluting effect on the range in relation to monthly rates for DEF and TECO which are higher at 3.28 cents/kWh (DEF) and 2.62 cents/kWh (TECO) than the amounts shown in Table 1. For FPL and Gulf Power, the monthly range is essentially identical to the annual range.

Table 1: Fuel Rate Summary Statistics (2016-2025)

Year	FPL	DEF	TECO	Gulf Power
Average	2.55	3.78	3.16	3.19
Maximum	3.49	5.47	4.81	3.81
Minimum	1.90	2.85	2.46	2.42
Max-Min Range	**1.59**	**2.62**	**2.35**	**1.39**

Figure 6 shows what these fuel charges translate to as a percentage of the overall monthly bill for a residential customer that uses 1,000 kWh/month.[12]

Figure 6: Effects of Fuel Costs on Customer Bills



One noticeable difference in the shape of the lines between Figures 5 and 6 is that the considerable spike in fuel charge rates in Figure 5 that is visible in 2023 is more muted when

[12] The percentages reflected in Figure 6 are similar, but not identical, to the percentage arrived at by dividing the fuel rate by the total aggregate volumetric ($/kWh) rate. However, they differ from that result to a small degree due to the impact of fixed charges on total monthly costs.

translated to a percentage of a customer's average monthly bill in Figure 6. This difference is reflective of changes in other rate components, most specifically storm cost recovery, that overlapped changes in the fuel charge rate and muted the overall percentage change in relation to total rates. Similarly, during the first part of 2025, the fuel charge percentages of a customer's total monthly bill are lower than any point since the start of 2016, even though the fuel charge rate itself is generally similar to or slightly higher than fuel charge rates during 2016 and 2017. That is, the percentage of total bill metric during 2025 is not lower because fuel rates are lower, it is lower because other charges are higher.[13]

One other notable detail that is visible in Figures 5 and 6 is that DEF's and TECO's fuel charge rates, and to a lesser extent the fuel charge percentage of bill metric, spiked during 2023 and have fallen precipitously since then. This change in fuel costs is associated with a spike in natural gas prices that began in late 2021 and continued through 2022. By contrast, the collective FPL/Gulf fuel rate spiked in 2022 at a lower magnitude, then fell more gradually during 2024 and the first part of 2025. This difference is attributable to factors that were previously noted regarding FPL's relatively lower exposure to high natural gas prices and relatively more accurate reflection of natural gas costs in rates during the 2021-2023 time period. Both factors collectively helped FPL avoid the delayed spike in fuel rates that occurred for DEF and TECO during 2023.

3.2 Impacts of Storm Cost Recovery Charges

In addition to the analysis described above, EQ Research also investigated the degree to which charges for storm cost recovery might influence, and possibly disguise, the pattern of changes in the percentage of a customer's total bill attributable to fuel rates. This aspect was chosen for additional analysis because the incurrence of storm costs is inherently unpredictable, Florida is uniquely vulnerable to damage from tropical systems, and accumulated storm damage amounts can become extreme due to high impact storms and multiple storms that occur in quick succession (or a combination of both).

Consequently, charges for storm damage recovery can significantly impact total rates. In any given month since 2016 storm recovery charges have ranged from zero in many months up to more than 3 cents/kWh in some cases, equivalent to up to nearly 19% of a customer's monthly bill in that instance. On an annual calendar year average basis, the range is lower because storm recovery charges tend to be set for 12-month periods that do not align with calendar months, resulting in some months of a given year having a zero charge. Nevertheless, the annual range is still significant, up to nearly 2 cents/kWh and 11% of a residential customer's total monthly bill.

[13] The fuel charge as a percentage of total rates differs between FPL and Gulf Power after 2022 due to the presence of a merger transition credit for historic FPL customers and a transition charge for historic Gulf Power customers in their total rates. So even though all other rate components, including fuel rates, were aligned starting in 2022, the percentage of total bill metric differs due to the difference in the total retail charges attributable to the merger transition mechanism.

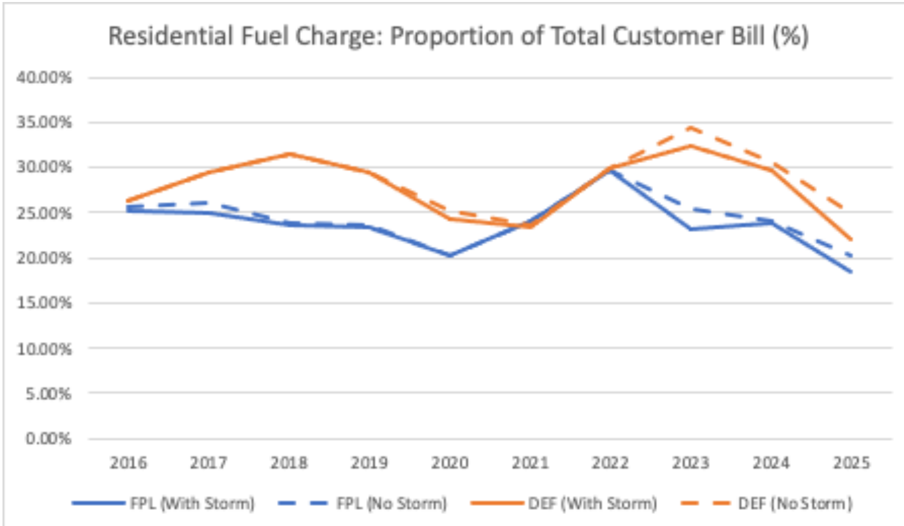
To evaluate how storm recovery charges affect the fuel rate percentage of bill metric, we calculated an alternative set of monthly and annual averages with storm recovery charges excluded from the total customer bill. As long as a utility has had a storm recovery charge for at least part of the reference time period, this shifts the curve upward. The scale of the effect is relatively small because most of the time, the fuel rate is still significantly higher than the storm recovery charge, and both are only a fraction of the customer's total bill. The scale is also likely to be affected by the parameters of ratemaking mechanisms and regulators' decisions, which influence the timing and magnitude of rate changes. The effect of ratemaking adjustments is explored in more detail in Section 3.3 discussing rate volatility.

The effects on the minimum percentage, maximum percentage, and range are inconsistent because they depend on the timing of storm recovery charges in relation to changes in fuel rates and other charges. The minimum percentage is higher in all cases because the minimum fuel rate percentages all occur during 2025 at a time when each utility has a storm recovery charge. The maximum percentages are higher for DEF and TECO because the highest fuel rates in relation to total rates coincided with a period where storm recovery charges were present, but remain the same for FPL and Gulf Power because neither had a storm recovery charge at the time when the maximum occurred. Ultimately, excluding storm recovery charges increased the percentage range of fuel costs as a portion of total customer bills for DEF and TECO, while it reduced the range for FPL and Gulf Power. This occurred because the increase in the minimum percentage was smaller than the increase in the maximum percentage for DEF and TECO, while the minimum percentage increased for FPL and Gulf Power but the maximum remained unchanged.

Figure 7 shows the differences between the fuel percentage bill metric with and without storm recovery costs included in the total bill to illustrate comparative effects for FPL and DEF.[14]

[14] The graphic is limited to FPL and DEF to simplify the visualization, but the pattern would be similar in a graphic including Gulf Power and TECO (or comparing them).

Figure 7: Effects of Storm Cost Recovery on Fuel Charge Percentage of Bill Metric



Our analysis indicates that there is a discernible, but relatively small amount, of the annual variation in the fuel rate as a percentage of residential customer bills metric that is caused by storm recovery charges and their timing relative to changes in fuel rates. However, excluding storm recovery charges from the customer's total bill in the calculation of the fuel rate as a percentage of a residential customer's total bill does not significantly change the pattern of annual variations seen in the bill percentage metric, nor does it necessarily make the range in the average annual values either larger or smaller (i.e., create a systematic distortion).

3.3 Discussion of Fuel Rates & Bill Volatility

As previously illustrated, fuel rates for Florida customers are driven by the costs of natural gas given the IOUs' collective high reliance on natural gas generation. Fuel rates in turn can be volatile because natural gas prices are vulnerable to volatility. The Mid-Course Correction aspect of Florida's fuel cost recovery mechanism has a smoothing effect on fuel rate changes in response to fuel cost volatility, allowing for more frequent rate updates that can help prevent cost recovery imbalances from becoming too large. However, the Mid-Course Correction feature has an important limitation. It does not, and cannot, affect the core cause of fuel rate volatility: volatility in natural gas prices. Any prolonged spike in natural gas prices will eventually show up in the fuel rates charged to customers, with the magnitude correlated with a utility's relative reliance on natural gas generation. The ability of the Mid-Course Correction feature to effectively mitigate rate volatility is also dependent to some degree on factors like the timing of imbalances and the accuracy of utility price forecasts.

One way to evaluate fuel rate volatility is to look at the year-over-year (YOY) (or month over month) changes in rates. Figure 5 above showed that FPL's, and collectively FPL/Gulf Power's, fuel rates have had a considerably narrower range over time largely because they avoided the

2023 fuel rate spike and steeper drop off in the fuel rate in 2024 that occurred for DEF and TECO customers. Table 2 shows the YOY change in the fuel charge using the same average annual fuel rate data, starting with the change from 2016 to 2017.[15] The average in the bottom row is shown as the absolute value of year over year changes. The lower variability of FPL's and Gulf Power's fuel rates is evident in the lower average values as compared to those shown for DEF and TECO.

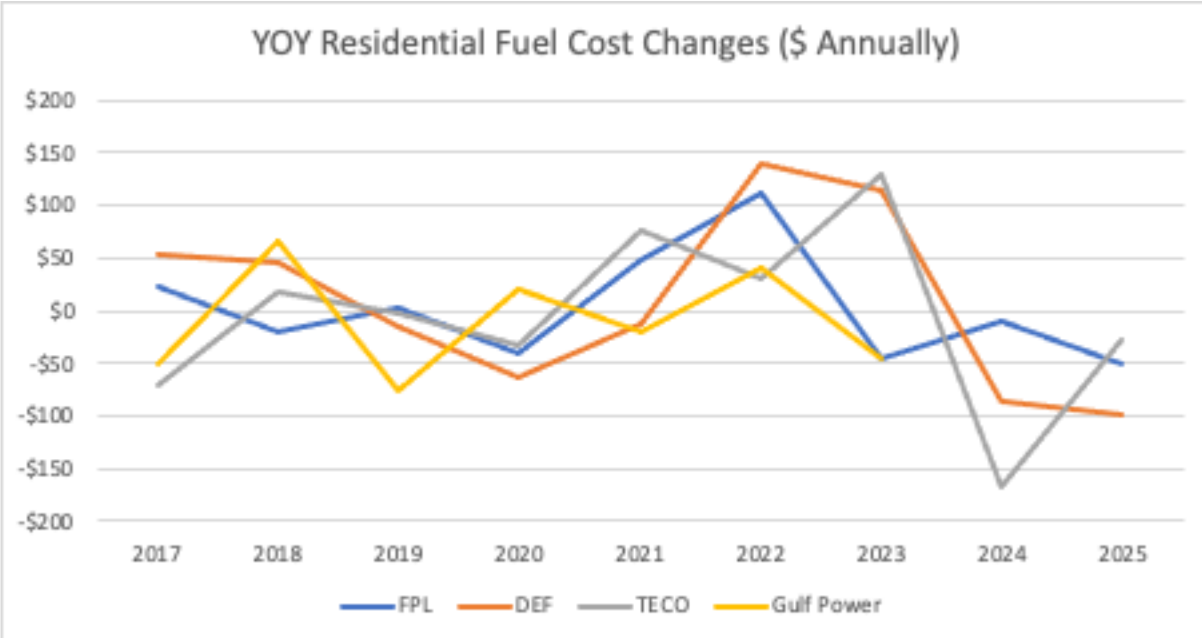
Table 2: YOY Change in Fuel Rates (Cents/kWh)

Year	FPL	Duke	TECO	Gulf Power
2016 - 2017	0.22	0.53	-0.72	-0.52
2017 - 2018	-0.21	0.46	0.18	0.65
2018 - 2019	0.02	-0.14	-0.03	-0.76
2019 - 2020	-0.40	-0.63	-0.33	0.22
2020 - 2021	0.48	-0.12	0.76	-0.19
2021 - 2022	1.11	1.39	0.31	0.42
2022 - 2023	-0.46	1.13	1.28	-0.46
2023 - 2024	-0.11	-0.86	-1.68	-0.11
2024 - 2025	-0.51	-0.98	-0.28	-0.51
Average (Absolute Value)	0.39	0.69	0.62	0.42

Figure 8 depicts these amounts in graphical form, allowing the time signature to be more easily understood, and scaled to reflect the annual fuel cost for a residential customer that uses 1,000 kWh/month. The years shown in Figure 8 refer to the end year, such that 2017 refers to the 2016-2017 change and so forth.

[15] Note that FPL's and Gulf Power's fuel rates were aligned in 2022, but the alignment in terms of YOY changes does not occur until the 2022-2023 time period.

Figure 8: YOY Variation in Residential Fuel Costs[16]



The range of annual variations for FPL and Gulf Power, shown by the blue and yellow lines, is considerably lower than the range for DEF and TECO shown by the orange and gray lines, respectively. The spike in 2022 is not as high for FPL and Gulf Power as it is for DEF and TECO, nor is the fall off in 2023 and 2024 as steep.

A similar pattern is visible if YOY changes are evaluated on a percentage basis, but the magnitude of the YOY percentage change differences is lower because the DEF and TECO have higher fuel rates overall. For instance, the average YOY rate change for DEF is 0.69 cents/kWh compared to 0.39 cents/kWh for FPL, roughly 78% higher. However, DEF's average YOY percentage change is 18.53%, only 17.3% higher than FPL's average YOY percentage change of 15.80%. In other words, the fact that DEF's average fuel rate is roughly 50% higher than FPL's average fuel disguises the difference in volatility if changes are measured in percentage terms.

3.4 Impacts of Storm Cost Recovery Charges on Rate Volatility

Storm cost recovery charges are another potential source of significant volatility in customer rates, since they are highly variable and can be relatively large. However, those characteristics do not necessarily mean that storm cost recovery charges enhance rate volatility because volatility is sensitive to the timing of changes in both fuel rates and storm recovery charges. When storm charges change in the same direction at the same time as fuel rates, volatility is enhanced, while if both sets of charges move in opposite directions during the same time period, the total change

[16] Appendix B includes a version of Figure 8 (Figure B-1) that reflects inflation-adjusted values denominated in 2025 dollars. Applying an inflation adjustment does not affect the conclusions that result from this comparison.

in customer rates is lower than would be the case for either charge in isolation. Furthermore, individual rate change events at different times may display different patterns. For instance, in one year storm recovery charges and fuel rates may move in opposite directions, whereas in another year they move in the same direction.

These timing differences may occur due simply to the timing and magnitude of the "cost events", but typically also reflect intentional and targeted ratemaking decisions by regulators to mitigate overall rate volatility and bill impacts. For example, regulators tend to be inclined to authorize higher storm cost recovery rates during a period of lower fuel rates than they would during a period that coincides with relatively higher fuel rates, such that upward and downward changes offset one another and produce a smoother overall rate trajectory. The central issue here with respect to storm cost recovery rates is the recovery period. Extending the recovery period for a longer duration produces a lower rate, but incurs additional financing costs (i.e., interest on the balance) and longer recovery periods may result in the duration of the storm recovery charge overlapping with other future rate increases, exacerbating bill impacts (at least temporarily).

That said, the history of residential rates in Florida indicates that the general effect of storm cost recovery rates in concert with fuel rates is enhanced volatility in residential customer rates. Table 3 shows the absolute value of YOY changes in fuel rates compared to YOY changes in fuel rates and storm cost recovery rates combined for each major IOU since 2016. Since the average of combined YOY average rate changes is higher than for fuel charges alone, we can conclude that storm costs have historically increased residential rate volatility.

Table 3: Storm Cost Recovery Impacts on YOY Rate Changes

Metric	FPL	DEF	TECO	Gulf Power
Avg. Fuel Rate (YOY Change)	0.39	0.69	0.62	0.42
Avg. Fuel + Storm Cost Rate (YOY Change)	0.60	0.77	0.98	0.52
Difference (cents/kWh)	0.21	0.08	0.36	0.10
Difference (%)	54%	11%	58%	23%

The differences between utilities stem from several sources. First, storm damage costs from individual tropical systems tend to be concentrated in different locations and utility service territories. Certainly, in some cases damage is widespread, but the worst effects generally tend to be relatively geographically concentrated such that one utility may experience major damage from a given storm while another sees little to none. This speaks to the overall magnitude of storm recovery costs that make their way into rates. Second, and related to the first reason, charges for storm recovery differ in their timing in relation to the timing of the major storms that caused that damage, as well as exogenous rate factors like fuel costs. Third, as previously noted, regulators have ratemaking tools at their disposal to mitigate overall rate volatility through strategically managing the timing of rate changes so that rate changes in different directions from different sources offset, rather than enhance one another.[17]

The overall and across the board increase in rate volatility associated with fuel costs and storm recovery costs combined is a reflection of the limitations of ratemaking mechanisms for managing rate volatility associated with unpredictable risks. In other words, ratemaking tools, and the constraints under which they operate, only go so far in the face of factors that are inherently not controllable in the short term. The confluence of these uncontrollable factors: (i) natural gas cost volatility accompanied by very heavy natural gas reliance, and (ii) the risk of major storm damage from tropical systems, makes Florida electric customers uniquely vulnerable to rate volatility.

4. Projection of Future Natural Gas Generation Costs & Rate Impacts

4.1 Background on Forward Natural Gas Price Projections

As previously described, as of their 2025 Ten-Year Site Plan filings made in April 2025, all of the major Florida IOUs project declining levels of reliance on natural gas generation, to varying degrees (see Figure 1). On a broad level, if these projections are borne out, future electric rates would become less exposed to natural gas price volatility. However, this does not necessarily mean that the costs that customers pay for natural gas generation will decrease over time because natural gas prices may also increase over time.[18] Furthermore, there is a reasonable question of whether the declines in reliance on natural gas generation will actually occur consistent with the projections in the 2025 Ten-Year Site Plans. In this section, we evaluate how variations in future natural gas prices and utility reliance on natural gas generation would affect customer bills.

EQ Research developed a projection of future natural gas generation costs from 2025-2034 for each utility based on projections for: (i) natural gas prices, (ii) natural gas generation heat rates, and (iii) natural gas generation as a portion of a utility's energy generation mix. The natural gas price projections are based primarily on two scenarios from the U.S. Energy Information (EIA) 2025 Annual Energy Outlook (AEO), a Base Case scenario and a High Price scenario.[19] The

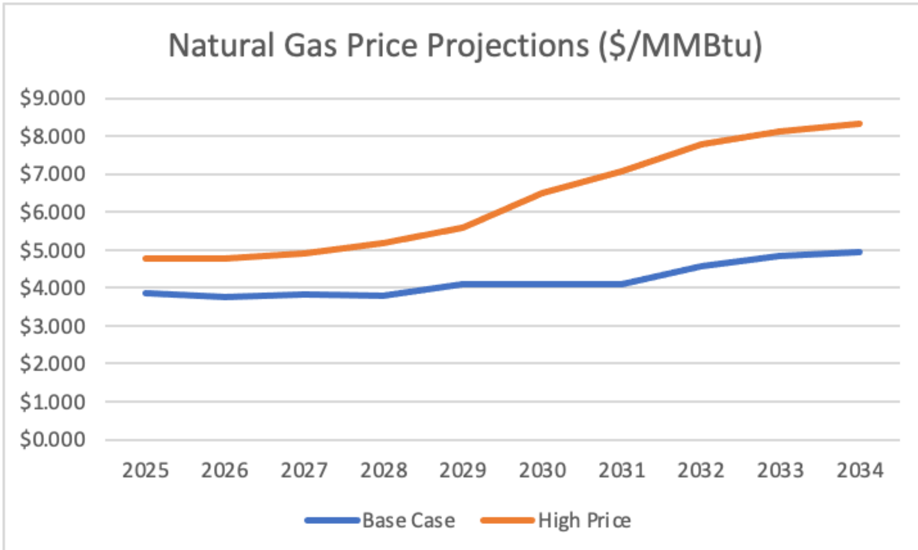
[17] It is also worth noting that the amounts for FPL and Gulf Power are affected by their merger and the timing of rate consolidation. Although the fuel rates for legacy service territories became aligned in January 2022, the storm recovery charges on customers within the two legacy service territories remained different until April 2023. This is a further example of regulator ratemaking discretion as an influence over rate volatility, although in this particular case the circumstances are unique.

[18] Improvements in the heat rate (Btu/kWh) of the natural gas generation fleet over time offset a portion of the upward rate pressure caused by natural gas price increases.

[19] Both scenarios use the AEO's South Atlantic regional projection for delivered natural gas prices for the electric power sector. The Base Case scenario uses the EIA Reference Case, while the High Price scenario uses the Low Oil and Natural Gas Supply Case. The source data tables are available at: https://www.eia.gov/outlooks/aeo/data/browser/#/?id=3-AEO2025&cases=ref2025&sourcekey=0

AEO values were adjusted slightly to reflect utility-specific differences in delivered natural gas costs.[20] Figure 9 shows both forward natural gas price curves.

Figure 9: Future Natural Gas Price Scenarios



Of course, there is considerable uncertainty associated with forward natural gas price projections. Average actual prices will deviate to some degree from any forward projection, and even if the actual average price over the entire reference period is reasonably close, history tells us that it is highly unlikely that the shape of the actual price curve will be as smooth as the projections. That is, even if the Base Case scenario proves to be accurate on average over the long term, prices during some years could be considerably higher, with offsetting lower price periods.

One particular area of uncertainty is to what degree increased electric demand from data centers will affect future natural gas prices. It is well-documented that numerous utilities in the South Atlantic region of the U.S. (e.g., Dominion Virginia, Duke Energy in the Carolinas, and Georgia Power) are projecting dramatic demand increases associated with new data center loads, and in many cases are planning new baseload natural gas generation to serve those new loads. The general dynamics of supply and demand dictate that those increased demands will drive up regional natural gas prices, and it is not clear to us to what degree those increased demands are incorporated into the AEO price projections. Although the 2025 AEO presents a relatively recent

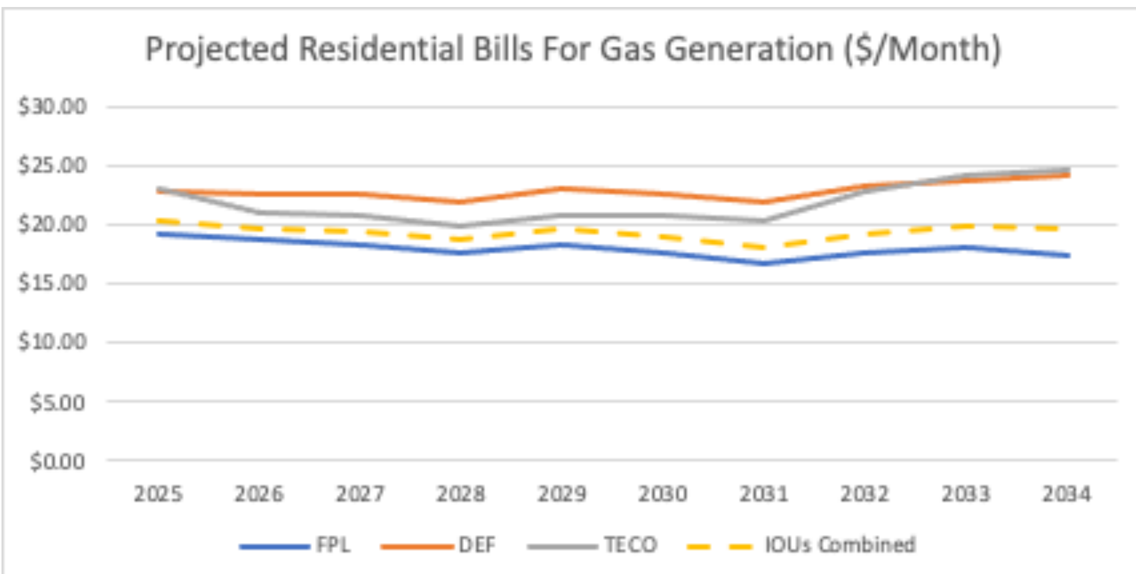
[20] The utility specific cost adjustment factors to the AEO South Atlantic forecast were roughly 1.08 for FPL and 1.01 for both DEF and TECO. The adjustment factors are based on each utility's actual natural gas costs during 2021, 2022, and 2024 compared to the historic average price data for those years reported in the AEO during the following year. Calendar year 2023 was not included because the EIA did not develop a 2024 AEO that reported actual 2023 price data and electric power sector natural gas price data for 2023 was not available from other sources. Appendix A contains further background information on how and why natural gas prices vary somewhat between the Florida IOUs.

projection, the utility resource planning landscape is evolving rapidly, and all signs point to higher expected electricity (and natural gas) demand than would have been apparent even during 2024. For that reason, there is good reason to expect that the 2025 AEO Base Case forecast may understate upward pressure on natural gas prices due to increased demand for natural gas used for electricity generation to serve new data center loads.[21]

4.2 Natural Gas Price Impacts on Customers (2025 Ten-Year Site Plan Scenario)

The 2025 Ten-Year Site Plan Scenario uses the IOUs' projected amounts of natural gas generation through 2034 as a base input for projecting costs and customer rate impacts.[22] Figure 10 shows the results of this forward projection in terms of the average monthly bill by year for a residential customer that uses 1,000 kWh/month for each IOU.[23] The amounts reflected in Figure 10 were developed by first calculating a utility's cost of natural gas generation ($/kWh) and then pro-rating that rate based on the projected percentage of the utility's resource mix sourced from natural gas generation.[24]

Figure 10: Future Residential Bill Impacts (Base Case - Ten-Year Site Plan Scenario)



[21] The 2025 AEO includes a scenario for high economic growth that we have not used in our analysis. However, that forecast scenario is based on Gross Domestic Product (GDP), a very generalized metric that does not necessarily capture the character of how new data center electricity demands could affect natural gas prices.

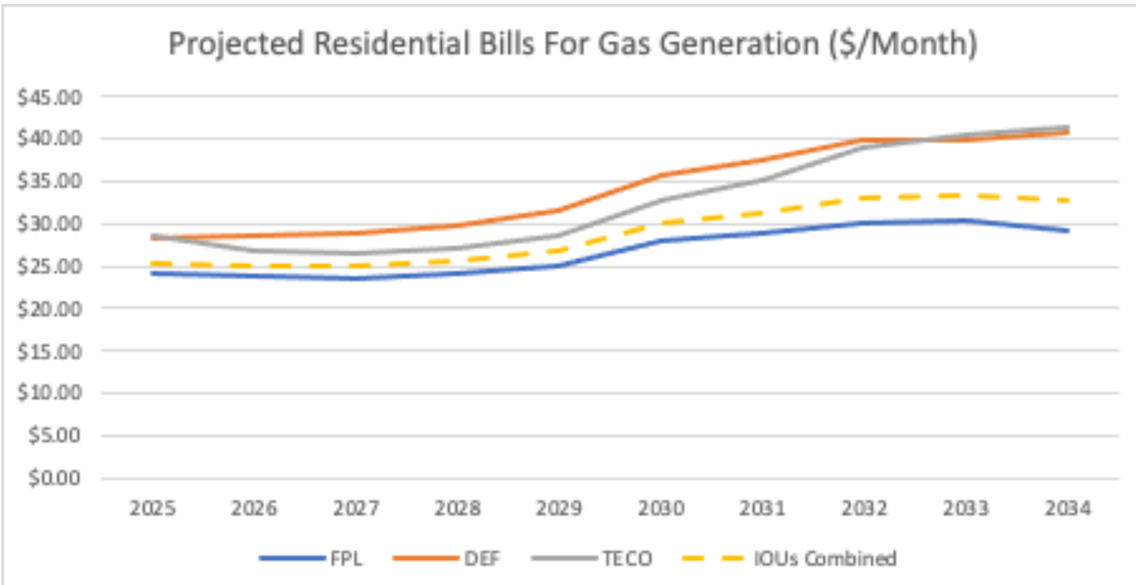
[22] All monetary values are stated in 2024 dollars consistent with how natural gas prices are stated in the 2025 AEO.

[23] This calculation uses the average cost of natural gas generation unadjusted for the tiered structure of the residential fuel charge. This reflects the fact that a customer with average usage of 1,000 kWh per month will have portion of their usage priced at the higher rate that applies to monthly usage greater than 1,000 kWh.

[24] The natural gas generation rate is not equivalent to a utility's fuel rate because natural gas does not make up 100% of a utility's energy mix. Pro-rating the natural gas generation rate by the percentage of generation sourced from natural gas approximates the portion of the fuel rate that is attributable to natural gas generation.

As illustrated in Figure 10, despite projected declines in reliance on natural gas generation over time based on the 2025 Ten-Year Site Plans, the trajectory of costs to customers is largely flat over time because lower amounts of natural gas generation and progressive heat rate improvements are offset by higher prices. Not surprisingly, FPL's lower reliance on natural gas generation at present and, as projected in the future, produces the lowest residential monthly bill. The High Price scenario changes the picture considerably. Figure 11 presents the same information as Figure 10, but uses the High Price natural gas price scenario.

Figure 11: Future Residential Bill Impacts (High Price - Ten-Year Site Plan Scenario)



In Figure 11, high natural gas prices, especially in the further future years (starting in roughly 2028) overshadow the moderate declines in natural gas reliance and modest efficiency improvements in the natural gas generation fleet. Furthermore, even though the upward trend only becomes more pronounced after 2028, costs in the High Price scenario are on average roughly $5/month (25%) higher in 2025 to start with compared to the Base Case scenario.

Relative to the Base Case natural gas price scenario, the monthly bill increases indicated by the High Price scenario under the IOUs' forecasted natural gas generation penetration are as follows:

- FPL: $4.72/month in 2025, increasing to a maximum of $12.53/month in 2032, with slight declines through 2034 and an average of $8.74/month.
- DEF: $5.58/month in 2025, increasing to a maximum of $16.55/month in 2032, and flattening during 2033 and 2034 with an average of $11.28/month.
- TECO: $5.61/month in 2025, increasing to a maximum of $16.68/month in 2034, with an average of $10.84/month.

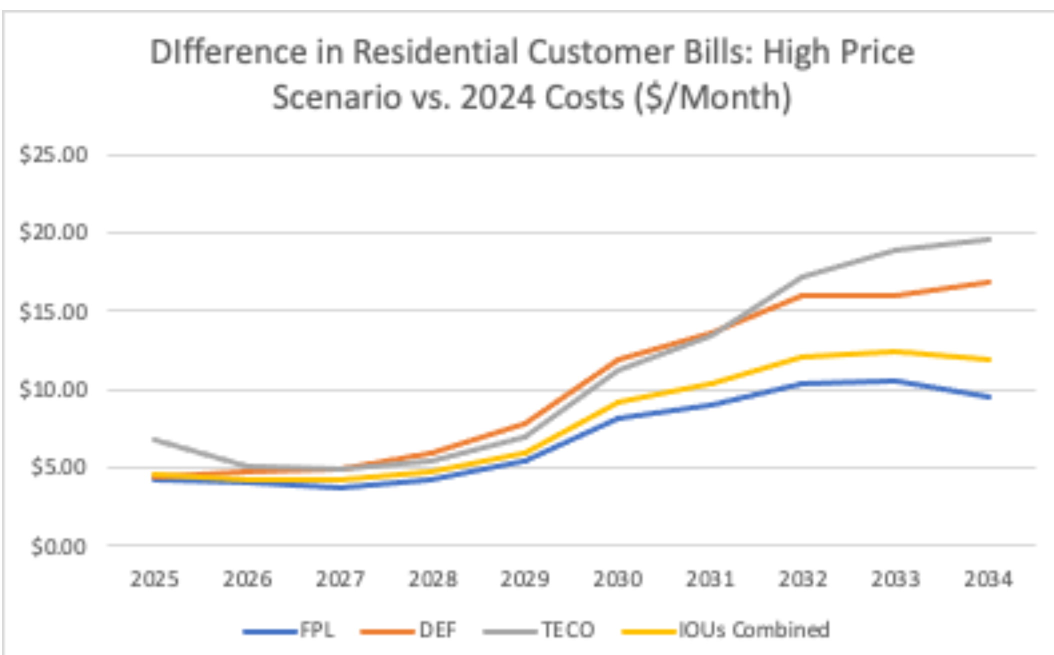
- IOUs Combined: $4.99/month in 2025, increasing to a maximum of $13.71/month in 2032, with slight declines through 2034 and an average of $9.47/month.

The IOUs Combined values related above are driven by FPL because FPL serves a disproportionately large amount of the total IOU load in Florida. The monthly bill impacts on a statewide basis are therefore just a somewhat diluted reflection of FPL/Gulf Power's relatively lower current and future reliance on natural gas generation as a portion of its resource mix.

On a broader level, the High Price scenario results in a roughly $21 billion increase in ratepayer costs from 2025-2034 relative to the Base Case scenario, approximately 50%. Of course, this total increase is not evenly distributed over time. The incremental total costs of the High Price scenario accelerate from approximately $1.05 billion in 2025 to a maximum of approximately $3.05 billion annually during 2032 - 2034. The flattening of the incremental cost curve associated with the High Price scenario from 2032 onward is attributable to a combination of gradual declines in reliance on natural gas in the utilities' generation mix projections and a flattening of the natural gas price differential between the Base Case and High Price gas price scenarios.

The cost impacts of the High Price natural gas price scenario can also be viewed from an alternative vantage point, the difference in costs compared to actual 2024 costs. This perspective, which could be viewed as a comparison to "current costs" (the most recent full calendar year), is shown in Figure 12 below.

Figure 12: High Price Scenario Impacts on Residential Customer Bills



The residential bill impacts of high natural gas prices shown in Figure 12 are fairly similar in magnitude and overall shape to the impacts of the High Price scenario as compared to the Base Case natural gas price scenario. This is because the Base Case scenario has a fairly flat price curve and actual 2024 prices were similar to the Base Case average. However, certain differences are apparent. Relative to a comparison to the Base Case scenario, a comparison using 2024 as a flat "base" produces: (i) lower incremental cost impacts for FPL and DEF on average and nearly all years, and (ii) a mixed result for TECO, with lower incremental cost impacts in most years, but significantly higher impacts from 2032 to 2034. The difference for TECO is caused by TECO's relatively lower 2024 natural gas costs and its flat, rather than downward, trajectory of natural gas reliance from 2031 onward.

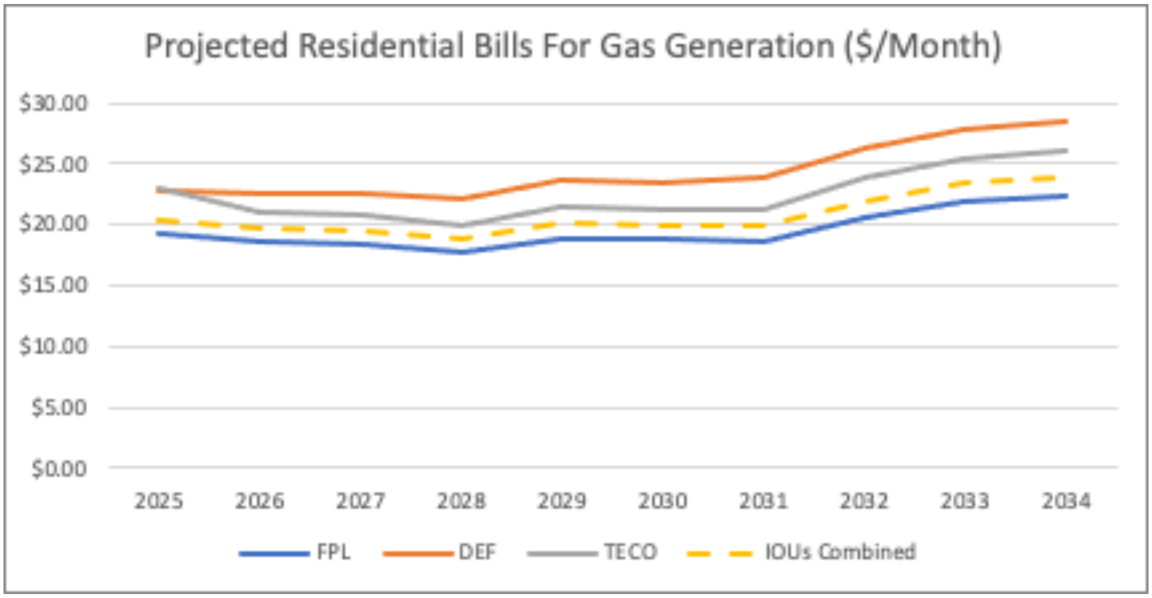
4.3 Natural Gas Price Impacts on Customers (High Gas Reliance Scenario)

In the High Gas Reliance Scenario, we evaluated how costs and rate impacts would differ if the general downward trajectory of natural gas reliance presented is slower over time. In this scenario, the projected amounts of natural gas generation for each utility were shifted higher starting in 2028 by applying a 50% adjustment to the YOY differences in projected natural gas generation (MWh). For instance, if a utility projected a reduction of 100 MWh in gas generation from one year to the next, that amount was reduced to 50 MWh, and if a utility projected an increase in gas generation of 100 MWh, that amount was increased to 150 MWh.[25] Calendar year 2028 was selected as the start year for this adjustment in order to reflect the fact that the near-term resource mix is largely a product of decisions that have already been made and generation projects (e.g., new natural gas and/or solar facilities) that are already underway.

Figure 13 shows the results of this alternative natural gas reliance scenario in terms of the monthly cost of natural gas generation to a residential customer that uses 1,000 kWh/month using the Base Case natural gas price projection. Figure 13 is the equivalent of Figure 10 but with the higher natural gas reliance assumption described above.

[25] Overall natural gas reliance still declines under this scenario for all utilities, just in lesser amounts than those projected in the 2025 Ten-Year Site Plans. In reality, changes in natural gas reliance may be lumpier in character than the smooth character shown by either the Ten-Year Site Plans or the High Gas Reliance Scenario.

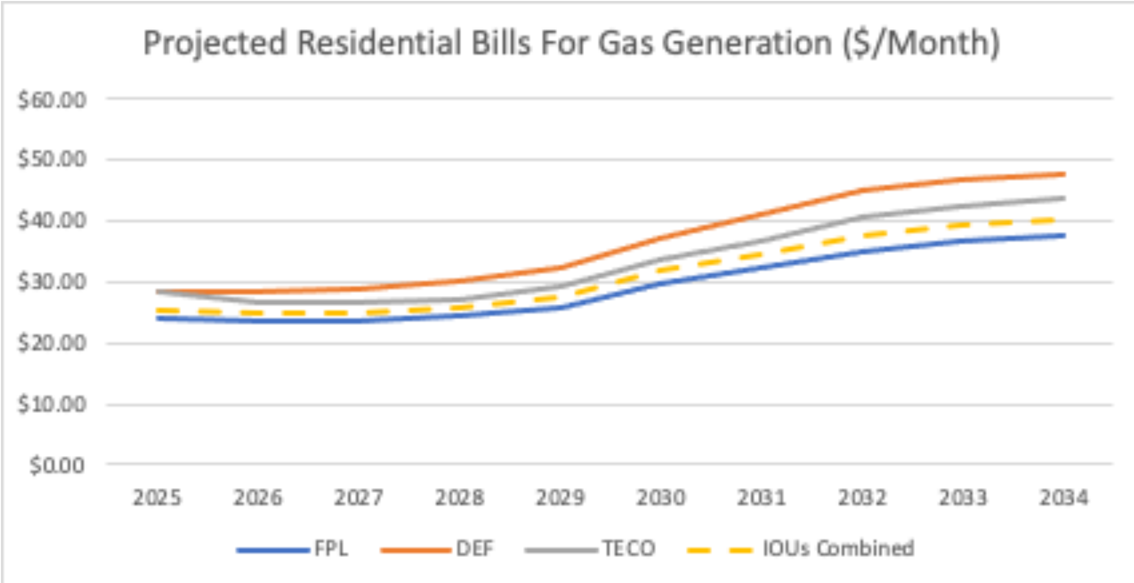
Figure 13: Future Residential Bill Impacts (Base Case - High Gas Reliance Scenario)



In contrast to Figure 10, Figure 13 shows an upward trend in monthly costs for a typical residential customer, as the smaller reduction in natural gas reliance offsets less of the upward cost pressure produced by higher natural gas prices. In 2034, the monthly cost of natural gas generation under the High Gas Reliance Scenario is $4.84 higher for FPL, $4.24 higher for DEF, and $1.50 higher for TECO, with a weighted statewide average of $4.32. FPL shows the largest difference primarily because its 2025 Ten-Year Site Plan plotted the most aggressive reduction in natural gas generation from 2027 onward. Conversely, TECO's plan was the least aggressive, so the effect of the natural gas generation adjustment was lower. In fact, the adjustment method results in DEF and TECO switching places in terms of relative reliance on natural gas in 2034. This result may seem counterintuitive, but it makes sense from the standpoint that DEF's (and FPL's) projections require greater change from the status quo than TECO's. Therefore, there is greater downside risk for FPL and DEF customers should those changes proceed at a slower rate.

Applying the High Price natural gas scenario and the High Gas Reliance scenario together results in higher cost increase than either alone, as shown in Figure 14.

Figure 14: Future Residential Bill Impacts (High Price - High Gas Reliance Scenario)



For the reasons discussed above, the effects are more pronounced for FPL and DEF than TECO. The statewide incremental costs of the High Price and High Gas Reliance scenarios together relative to the Base Case scenarios rise to $3.85 billion in 2034, and total $23.6 billion for 2025-2034. This amounts to an increase of roughly $0.8 billion in 2034 and $2.6 billion over the entire 2025-2034 period as compared to the High Price scenario and 2025 Ten-Year Site Plan natural gas reliance scenario.

Relative to the Base Case natural gas price and natural gas reliance scenarios, the monthly bill increases indicated by the High Price and High Gas Reliance scenarios together are as follows:

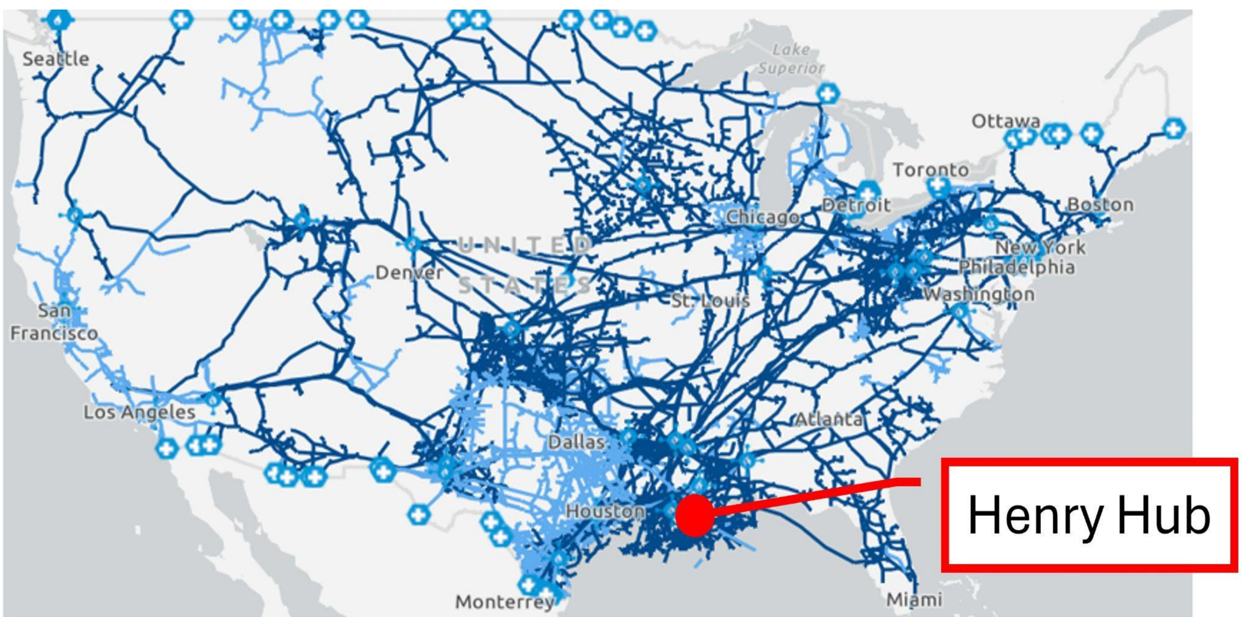
- FPL: A maximum of $18.41/month in 2034, with an average of $11.34/month.
- DEF: A maximum of $23.55/month in 2034, with an average of $13.77/month.
- TECO: A maximum of $19.20/month in 2034, with an average of $11.80/month.
- IOUs Combined: A maximum of $20.51/month in 2034, with an average of $11.86/month.

Appendix A Natural Gas Pricing and Transmission Costs

The commodity portion of natural gas prices is fundamentally the same for all Florida electric utilities because they all have access to the same commodity markets. However, the full price that a given utility pays will differ due to: (i) their contracting practices (e.g., futures, forwards, options, etc.), and (ii)) the transmission and distribution costs associated with the natural gas infrastructure necessary to deliver the fuel to their electric generating facilities, a price factor largely dictated by location.

Natural gas prices in North America are based primarily on the Henry Hub price, which reflects the delivery of natural gas at the physical Henry Hub located in Louisiana.[26] The price for retail consumers of natural gas, including electric utilities, includes gas transmission costs charged by interstate pipeline companies as well as gas distribution costs charged by local distribution companies.

Figure A-1: U.S. Natural Gas Pipelines



eia Source: U.S. Energy Information Administration, U.S. Energy Atlas, January 29, 2024
Note: Light-blue lines are intrastate pipelines, dark-blue lines are interstate pipelines, and + are border crossings.

Florida receives natural gas from the following five interstate pipelines, as shown in Figure A-2.[27]

- Florida Gas Trans Co. - 3,235 MMcfd through Alabama;

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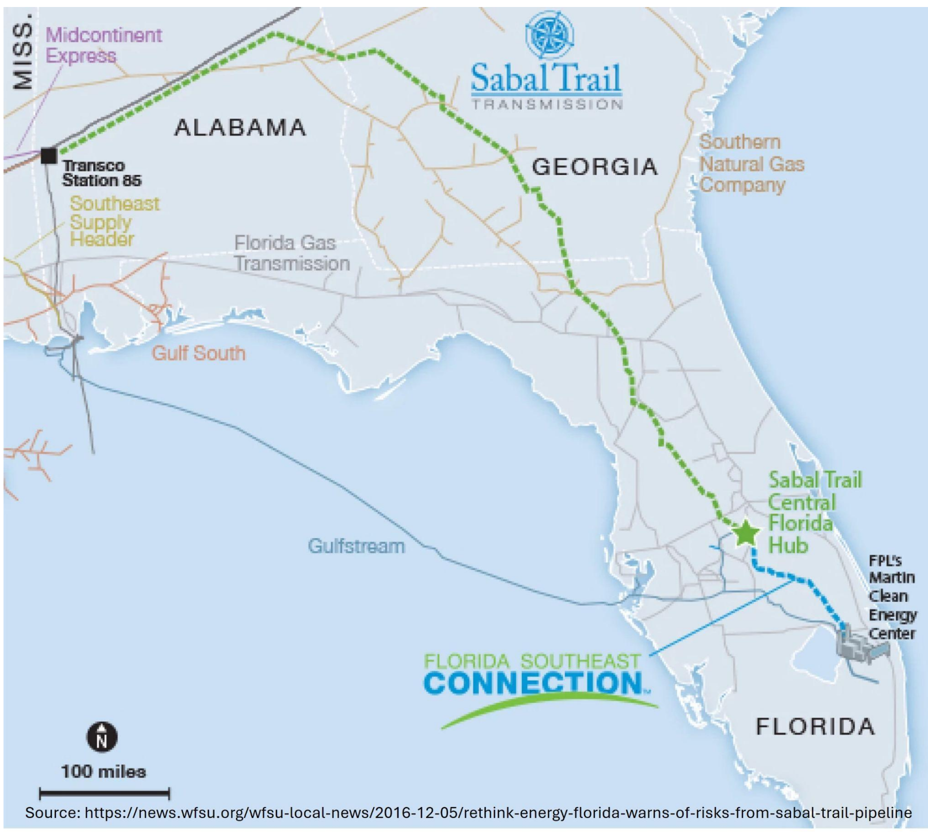
[26] The Henry Hub is a physical delivery point for natural gas located near Erath, Louisiana and is the official delivery point for settlement on the New York Mercantile Exchange (NYMEX). *See,* for example: https://www.investopedia.com/terms/h/henry_hub.asp and https://www.cmegroup.com/markets/energy/natural-gas/natural-gas.contractSpecs.html

[27] U.S. EIA. Natural Gas. https://www.eia.gov/naturalgas/data.cfm#pipelines

- Gulf South Pipeline Co. - 190 MMcfd through Alabama;
- Gulfstream Natural Gas System (via the Gulf of Mexico) - 1,435 MMcfd through the Gulf, but classified as through Alabama;
- Sabal Trail - 1,052 MMcfd through Georgia; and
- Southern Natural Gas Co. - 646 MMcfd through Georgia.

Each interstate pipeline has its own FERC-approved tariff and pipeline-specific natural gas transmission costs, which results in differences in delivered natural gas costs at the utility level depending on source of their supply. Those sources are in turn determined by the location of a utility's natural gas generation units in relation to pipelines. Figure A-2 shows the paths of individual gas transmission lines.

Figure A-2: Major Natural Gas Pipelines Serving Florida



Based on this map in relation to utility service territories, it is likely that FPL's Northwest division - formerly Gulf Power - receives natural gas from the Gulf South pipeline while FPL's Southern Florida generating facilities likely receive natural gas via the Sabal Trail and Florida Gas Transmission pipelines. TECO is likely served mostly or entirely by the Gulfstream pipeline, and DEF likely has a mix of natural gas supply from the Gulfstream and Florida Gas Transmission pipelines.

As discussed in the body of this report, EQ Research developed a delivered price differential between the utilities based on the difference between the natural gas prices reported in their monthly fuel reports and the U.S. EIA's reporting of historic annual natural gas prices for electric power generation in the South Atlantic region. This method for establishing utility-differentiated prices was selected in order to align with the use of the U.S. EIA's South Atlantic region natural gas price projections for estimating future natural gas generation costs. The result showed slight premiums over the EIA-reported prices for TECO and DEF, with TECO having the lowest average premium, and FPL having the largest.

One alternative to this approach that was also explored, but ultimately not selected, was basing the differential on the spread between the Henry Hub spot market price and the total delivered natural gas prices as reported by the utilities. This difference represents the interstate transmission costs of natural gas for each electric utility, as well as any variations that may exist between their purchasing practices. Table A-1 shows the results of this comparison from January 2017 to May 2025.

Table A-1: Actual Utility Natural Gas Prices vs. Henry Hub Prices ($/MMBtu)

Pricing Metric	FPL	DEF	TECO
Average Price Premium	$1.60	$1.49	$1.17
Median Price Premium	$1.49	$1.38	$1.06
Standard Deviation	$0.59	$0.62	$0.64

As shown in Table A-1, TECO has the lowest interstate transmission costs, while FPL has the highest. It seems likely that FPL's higher costs stem from its reliance on the Sabal Trail pipeline, which entered service in 2017 and increased its capacity in 2020. That timing coincided with increases in the difference between the Henry Hub price and Florida citygate natural gas prices. The results shown in Table A-1 are mostly consistent with the delivery premiums that were arrived at using a comparison to EIA South Atlantic prices, with the exception that the EIA price comparison placed DEF closer to TECO than FPL in terms of delivered costs. This is likely an artifact of the different time horizons used in each comparison.

Appendix B Additional Figures

Figure B-1 (YOY Variation in Residential Fuel Costs – Inflation Adjusted Variation)
Figure B-1 presents a variation on Figure 8 that shows dollar values adjusted to January 2025 real dollars. The source values for Figure B-1 were developed using monthly Consumer Price Index inflation adjustments applied to each utility's monthly fuel rate, which, as in Figure 8, was scaled to customer usage of 1,000 kWh during a given month. As shown in Figure 8, the yearly oscillations for FPL and Gulf Power have a generally narrower range and lower average annual variation for FPL and Gulf Power as compared to DEF and TECO regardless of whether costs are measured in terms of nominal or real dollars.

Figure B-1: YOY Variation in Residential Fuel Costs (Inflation-Adjusted)

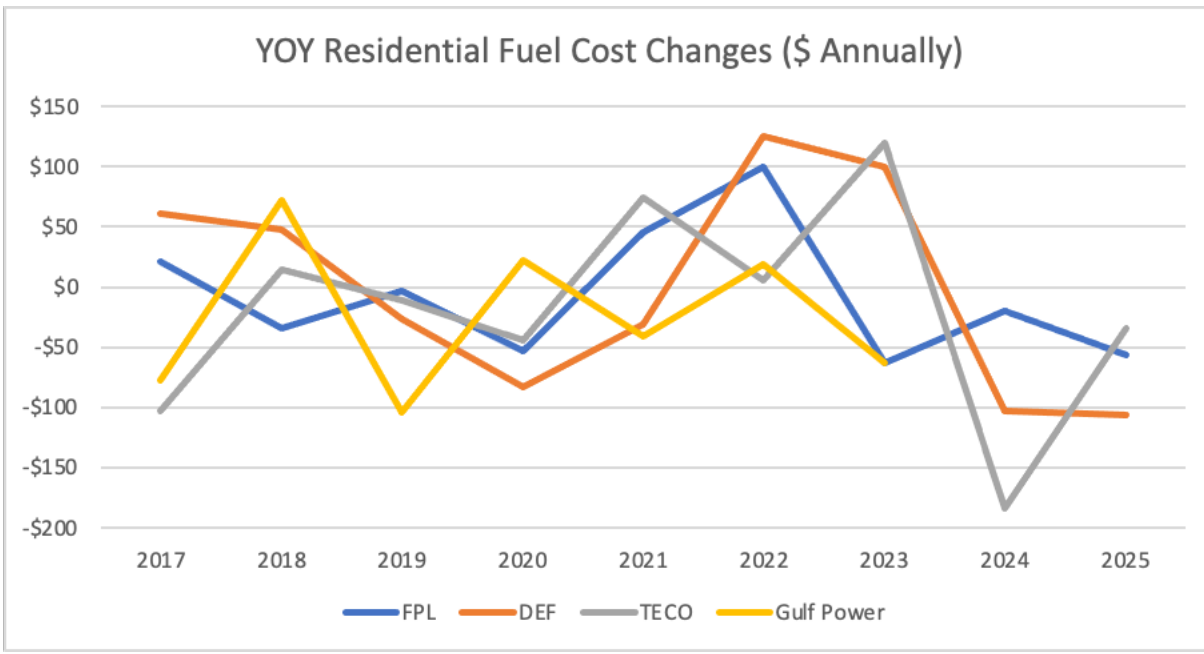


Figure B-2 (Base Case and High Price Percentage Difference)
Figure B-2 shows how the High Price natural gas price scenario affects customer bills as measured by the percentage increase above the Base Case natural gas price scenario, which is identical to the percentage difference between the natural gas price scenarios each year. The percentage increase is a common value across all utilities each year because the High Price scenario changes only the natural gas price input and leaves the remaining inputs unchanged.

Figure B-2: Residential Bill Impacts Under High Price Scenario

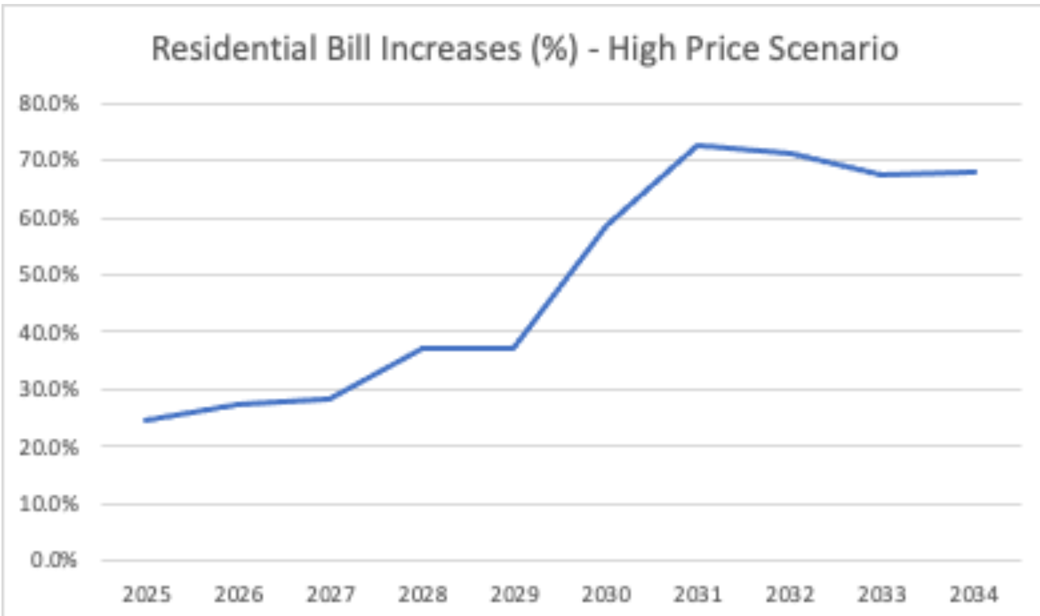


Figure B-3 (Base Case and High Price Cost Comparison – 2025 Ten-Year Site Plan Scenario)
Figure B-3 presents the same data shown in Figures 10 and 11 in a combined graphic. It provides a side-by-side comparison of the monthly costs of natural gas generation under the 2025 Ten-Year Site Plan natural gas reliance scenario for the Base Case and High Price natural gas price scenarios. The 2025 difference in costs is more obvious in Figure B-3 than it is in Figure 11, which shows the High Price scenario by itself.

Figure B-3: Comparison of Base Case & High Price Scenario (2025 Ten-Year Site Plans)

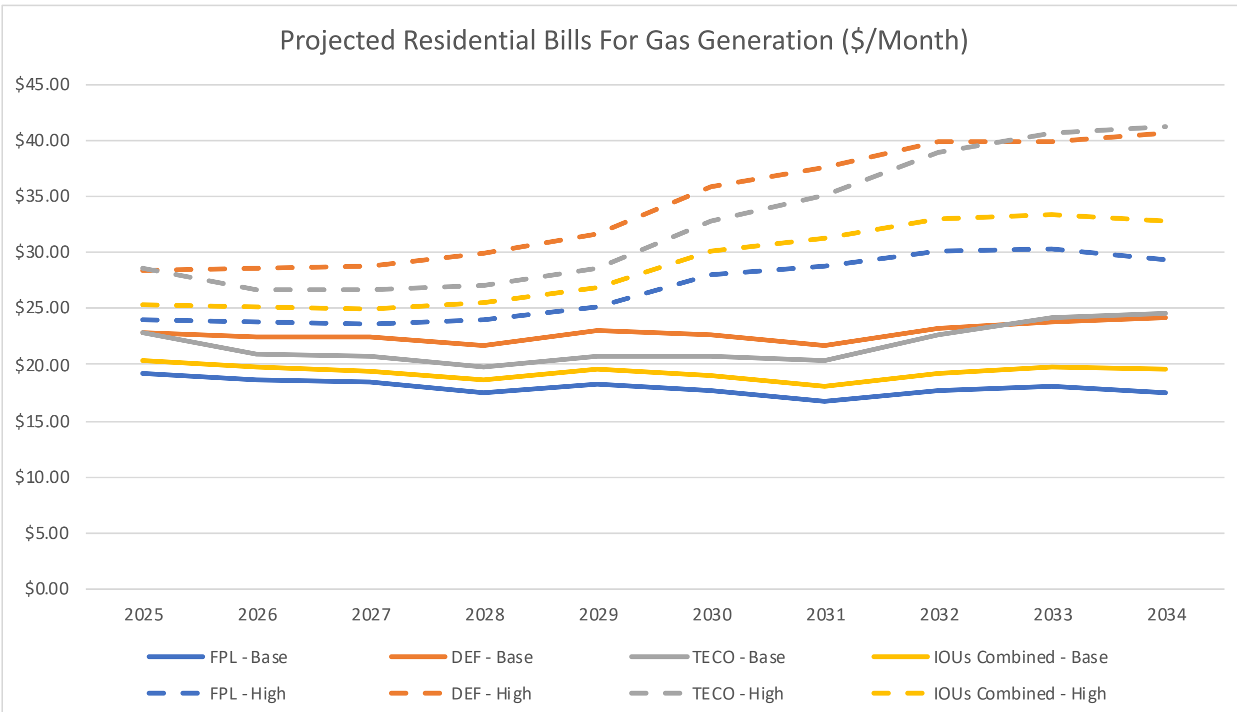


Figure B-4 (Base Case and High Price Cost Comparison – High Gas Reliance Scenario)
Figure B-4 presents the same data shown in Figures 13 and 14 in a combined graphic, providing the same side-by-side comparison shown in Figure B-2 but using the High Gas Reliance scenario rather than the 2025 Ten-Year Site Plan gas reliance scenario. The smoothness of the cost curves in Figure B-4 compared to Figure B-3 is a product of the smoother trajectory of natural gas reliance that results from the method of adjusting future gas reliance projections.

Figure B-4: Comparison of Base Case & High Price Scenario (High Gas Reliance)