Atlanta Gas Light

AMENDED INTEGRATED CAPACITY AND DELIVERY PLAN

2025-2034

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ATLANTA GAS LIGHT
AMENDED INTEGRATED CAPACITY AND DELIVERY PLAN 2025-2034
Docket No. 43820

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CHAPTER 1.EXECUTIVE SUMMARY

1.1 Summary of AGL's Integrated Capacity and Delivery Plan

Atlanta Gas Light Company ("AGL" or the "Company") seeks approval from the Georgia Public Service Commission (the "Commission" or "GPSC") of its Amended 2025-2034 Integrated Capacity and Delivery Plan ("i-CDP" or the "Plan"). Specifically, as summarized below and detailed in the following Chapters, the Company requests approval of its forecast, infrastructure delivery plan, completion costs for the Valdosta LNG facility, Plan related Operations and Maintenance ("O&M") expenses, best practices plans and programs, and the SRR revenue requirements, rates, and tariff. In addition, AGL requests elimination of the GRAM capital budget categories known as Safety and Compliance and Other in favor of a single GRAM capital budget category.

As directed in this Commission's Orders establishing the i-CDP process,[1] this Plan provides a ten-year outlook of the interstate and intrastate capacity and delivery assets and initiatives necessary to meet Georgians' needs in the communities served by the Company. The Plan sets forth the parameters for capital budgets and related O&M during the planning period. The forecasts for the initial three-year period are more detailed then, the forecasts for the subsequent seven-year period.[2] While this Plan continues the programs and initiatives that were initially identified in AGL's first plan approved in 2021, the costs associated with those programs and initiatives have increased, in some cases substantially due to a combination of factors. Additionally, as discussed in Chapters 4, 5, 6, and 7 of this Plan, certain additional priorities have been identified. Consequently, this Plan presents capital and related O&M expenditures higher than those projected in the Company's first plan for 2022-2031 (the "2022 i-CDP"), reflecting both the growth within AGL's service area and a complex variety of challenging external forces, including increases in personnel, materials, and regulatory cost to operate the utility. Approval of this Plan is critical to the Company's ability to meet the needs of its customers and to support the continued economic growth and expansion of Georgia's economy, while striking a reasonable balance between the cost impacts of these factors and impacts to customers. Specific rate adjustments will continue to be reviewed and established in traditional and alternative ratemaking processes (such as the Georgia Rate Adjustment Mechanism annual filings). Likewise, AGL will continue to make specific adjustments to the array of interstate and out-of-state storage assets

[1] See the discussion in Section 1.2 *infra*.
[2] *Id*.

reviewed and established in triannual Capacity Supply Plan filings. This Plan is the opportunity for the Commission to approve a roadmap of future operations to meet customers' needs for the next planning period.[3]

AGL is Georgia's oldest corporation and the largest natural gas utility in the southeast, serving approximately 1.7 million customers. AGL is an industry leader for gas utility operations, economic growth, and environmental stewardship. The state of Georgia has been named the number one state to do business for ten straight years.[4] Natural gas continues to be a low-cost, environmentally friendly contributor to this growth, whether heating homes and businesses or fueling larger commercial and industrial activities, which is not surprising given that Georgia is a destination of choice. Economic development activity in Georgia is at an all-time high, with AGL responding to over 200 economic development requests for information in the past two years that included over 500 individual site locations within Georgia. In the past two years Hyundai Motor Group (Chatham County), LanzaJet (Treutlen County), Meissner Corporation (Athens/Clarke County), and Walmart (Lowndes County) are examples of business entities that have chosen to launch new operations in Georgia, adding more than 5,000 jobs to the local communities. AGL, in partnership with this Commission, has supported this growth trend by investing over $1 billion for new and improved infrastructure through the Pipeline Replacement Program ("PRP"), Strategic Infrastructure Development and Enhancement ("STRIDE") program, integrated Vintage Plastic Replacement program ("VPR"), New Business capital, System Reinforcement, and Economic Development Tariff programs to support new and expanding businesses in Georgia since deregulation of the natural gas market in Georgia in 1997. The Company has experienced customer expansion of 7.2% over the past ten years, with a customer growth of approximately 1% in last year alone. These economic development inquiries and customer growth trends are expected to continue into the future.

[3] *See* Docket No. 42315, Order Adopting Stipulation at 2 (February 23, 2021) (The i-CDP will provide the Commission and other parties the Company's view of what it needs for the system to reliably meet its customers' needs and to ensure that interstate, intrastate and distribution assets align.")

[4] On October 3, 2023, Governor Brian P. Kemp in conjunction with the Georgia Department of Economic Development announced that for 10 straight years, the people who help businesses choose where to make long-term investments have repeatedly said Georgia is the best state in the nation for opportunity. *Area Development*'s 2023 Top States for Doing Business rankings are based on scores from approximately 50 leading site consulting firms from across the U.S. in 14 categories. Georgia placed in the top 10 for all 14 categories, earning the No. 1 spot in seven classifications and claiming the overall No. 1 ranking. The Top States for Doing Business Survey is the 14th in the annual series.

Complicating the Company's ability to meet these many needs thus far during the execution of the first approved i-CDP has been unprecedented inflationary pressure, increased costs of capital, tight labor and construction materials markets, supply chain disruptions, and general unease with future federal regulatory direction. AGL understands the economic challenges of today's market and the resulting effects on customers. Rising to these challenges, AGL believes this Plan enables the Company to safely and reliably serve existing and future customers while minimizing the financial effects on customers.

Approval of this Plan will allow AGL to comply with existing and new state and federal pipeline safety regulations, improve the operation of its system, enhance safety and reliability, meet environmental responsibilities and goals, provide for future growth, and provide superior customer service. Based upon the various parameters detailed in the Plan, AGL projects an increase for typical residential customers of approximately $3.13 per month in each of the first three years of the Plan.

1.2 Background and Purpose of AGL's Integrated Capacity and Delivery Plan

In AGL's 2019 Rate Case, the Commission found "that the development of a Long-Range Planning Tool will assist in the integration of the Company's Capacity Supply Plan with an infrastructure delivery apparatus."[5] Critical to this planning process was the development of "parameters" for capital budgets (including related O&M spending) associated with multi-year outlooks.[6] Prior to the 2019 Rate Case, AGL relied on shorter-range planning periods to guide utility operations, usually presented as three-to-five-year outlooks included within filings that approved one-to-three-year regulatory authorizations. In today's environment, these shorter-term planning schedules have become untenable due to the advent of increased pipeline safety regulations requiring multi-year investments, longer interstate pipeline expansion project schedules that now typically take seven to ten years to complete, longer large-scope intrastate pipeline project schedules that typically span multiple years, and general cost increases, among other things. The GPSC Staff ("Staff") and AGL entered into a stipulation to establish the required long-range comprehensive planning process that would address both AGL's intrastate and interstate capacity assets. The Commission approved a revised version of this stipulation (the "Stipulation") and its required parameters in its February 23, 2021, Order in Docket No. 42315 ("i-CDP Order"). The i-CDP Order requires the filing of an i-CDP at least every three years. The i-

[5] Docket No. 42315, Short Order, at 5 (December 31, 2019) and Final Order, at 27 (February 14, 2020).
[6] *Id*.

CDP is AGL's ten-year plan to serve the natural gas needs of AGL's customers in a safe, reliable, affordable and clean manner. The Plan represents a comprehensive process for the Commission to review the Company's proposed projects and programs, including capital and certain related O&M spending requirements, in advance of the Company's related ratemaking proceedings such as the annual Georgia Rate Adjustment Mechanism ("GRAM"). Section 3 of the Stipulation between the Staff and AGL includes a listing of Minimum Filing Requirements ("MFRs") for both the System Reinforcement Rider ("SRR")[7] and the GRAM capital projects.[8] The information included within this Plan document and the accompanying pre-filed testimony and MFRs filed herewith more than satisfy the agreed-to minimum filing requirements. AGL's first plan was filed on April 28, 2021, and a stipulation and addendum to the stipulation were approved by the Commission on November 18, 2021.[9]

This filing includes a thorough description of the key drivers and benefits of the Plan; demonstrates the Company's robust planning process; serves as an informative resource to Commissioners, Staff and other parties for what is occurring generally within the natural gas industry and specifically with AGL and along with the supporting testimony and MFRs provides the evidentiary basis to support the Commission's approval for each component of the Plan. This filing also includes a request for the Commission's approval of the Plan and the associated parameters for capital budgets; and includes a request for approval of a rate amount for the SRR.[10] The Plan refreshes the data for the remaining years of the currently approved Capacity Supply Plan ("CSP") (Docket No. 44319) and updates a ten-year forecast of customer demand.[11]

The i-CDP provides a single, comprehensive planning and review process in which the parameters for subsequent CSPs, GRAMs, and SRRs can be established. The comprehensive

[7] *See* Stipulation at 7-8, § 3(B) ("Minimum i-CDP filing Requirements for Capital Projects that Improve Pressure or Provide System Reinforcement and that are to be Included within the SRR.").
[8] *See* Stipulation at 9, § 3(B) ("Minimum i-CDP filing Requirements for Capital Projects to be Included for Consideration within Subsequent Annual GRAM Filings.").
[9] Docket No. 43820, Order Adopting Stipulation and Addendum to Stipulation (November 18, 2021).
[10] The SRR is a ratemaking mechanism described in the i-CDP Order for the purpose of recovering costs of specific, unique projects and programs in the Plan.
[11] AGL's CSPs shall continue to be the dockets that: specify the range of the requirements to be supplied by interstate capacity assets; describe the array of interstate capacity assets selected by the electing distribution company to meet such requirements; describe the criteria of the electing distribution company (the "EDC") for entering into contracts under such array of interstate capacity assets from time to time to meet such requirements; and specify the portion of the interstate capacity assets which must be retained and utilized by the electing distribution company in order to manage and operate its system. An "updated forecast" does not necessarily indicate that a CSP Amendment is necessary or appropriate. If a CSP Amendment were to be required, it would be proposed within the existing CSP docket, not the i-CDP docket.



planning process of the i-CDP is in addition to processes for CSPs as required by Georgia statute and Commission approved MFRs and GRAMs as required by Commission Orders and approved Tariffs currently in effect. The i-CDP does not replace the CSP or GRAM processes, but rather ensures consistency and continuity for the forecasts, assumptions, selected options, and other planning parameters that are currently presented and approved within the independent CSP and GRAM processes.

1.3 Current Key Drivers, Significant Events, Government Decisions, and Market Conditions

The Plan identifies the investments, infrastructure, and resources that will be required in future years to meet the projected needs of AGL's customers and the communities we serve for a safe, reliable, affordable, and clean natural gas delivery system that will also facilitate the continued economic growth of Georgia for the benefit of all customers and residents of Georgia.

The most significant recent event affecting the Company and society at-large during the period since the first i-CDP was approved has been the COVID-19 pandemic and the inflation, interest rate, supply chain, and related challenges that followed. The effect on the economy has been significant. The initial i-CDP did not contemplate the effects of the pandemic on inflation, interest rates, labor availability, material costs, supply chain delays, and other unforeseen consequences. In its prior i-CDP, AGL assumed pre-COVID inflation rate growth, stable interest rates, and, not unlike other critical service providers, did not foresee the degree of impact to labor and material costs and the effects on the supply chain. Additionally, the economic success of the state has resulted in an increase in Department of Transportation (“DOT”) projects that AGL must incur costs to facilitate, which have outpaced the capital expense levels contemplated in the initial i-CDP. Budgeting for DOT-related projects is particularly difficult to manage because DOT relocation projects (as well as safety mandates required by governmental authorities discussed below and in Chapters 5 and 6) require significant capital expenditures without incremental revenues to offset the expenses.

While the pandemic has slowed customer growth in some areas of the AGL system, overall system-wide customer growth has remained constant, and AGL forecasts continued customer growth in Georgia due to the business-friendly environment. As a result, the New Business capital budget category outpaces the capital expense level contemplated in the initial i-CDP.



The lingering effects of the pandemic continue to adversely impact many of the assumptions underlying AGL's capital budget forecasts in the initial i-CDP. The resulting operational requirements imposed on the utility have been greater and costs have been higher. AGL has honored its commitments to the Commission and its customers to cap rate increases at 6% through the first three years of the initial i-CDP. But AGL had to make operational adjustments to manage unforeseen expenses that resulted in AGL delaying some projects or reducing the amount of activity in critical programs such as DIMP. AGL made the necessary capital investments in those budget categories over which it has no control, such as certain compliance requirements, New Business, and DOT relocations. Balancing these various competing requirements in the face of continuing strong economic growth has been challenging but also successful. While new customers or increased customer needs continue to play a significant role in the Plan, the need for many of the proposed projects and budgets in this i-CDP are independent of changes in future growth.

1.3.1 Aging Pipelines

The replacement of aging pipelines represents one very significant driver of the proposed Plan. As detailed further in section 5.11, AGL's system has thousands of miles of pipe, that need to be replaced to mitigate risks to safety and reliability, some of which have been in service far longer than their intended 60-or 70-year service life. Under this Commission's vision and leadership, AGL replaced its cast iron and bare steel pipes under previous pipeline replacement programs ("PRP"). Some of the remaining pipes that must be addressed are older coated steel that were not included in the PRP program or older resins of plastic that were not addressed in the VPR program discussed further below. Figure 1.1 and Figure 1.2 below show current miles of main in service that fit in the various date categories.

Figure 1.1: Mileage of Aging Pipelines

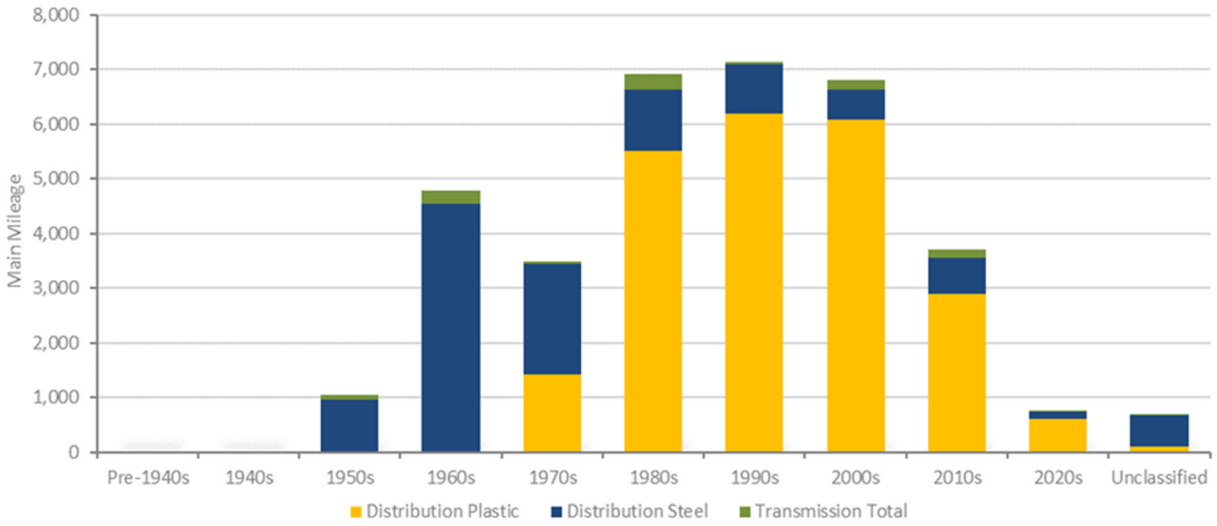


Figure 1.2: Mileage of Aging Pipelines

Facility Type (miles)	Steel Unknown Install Date	Vintage Steel Pre - 1960	Mid-Vintage Steel 1960 - 1970	Modern Steel 1970 - 2022
Main	576.9	1,043.4	4,788.0	6,077.4
	Plastic Unknown Install Date	**Early Vintage Plastic Pre - 1974**	**Mid-Vintage Plastic 1974 - 1983**	**Modern Plastic 1984 - 2022**
Main	118.0	11.20	2,571.9	20,113.8

In partnership with this Commission, AGL undertook the PRP beginning in 1998, which was a 15-year program whereby AGL replaced all known bare steel and cast iron pipe ("BSCI") within its system. AGL recovered these capital expenditures associated with the PRP through a rider. AGL prioritized BSCI replacement in the PRP because these materials were older, at higher risk of failure and had a higher leak rate than pipes made of more modern materials. Upon completion of the program in 2013, AGL had invested over $1 billion and replaced in excess of 2,700 miles of bare steel and cast iron pipe. Also, in partnership with this Commission, AGL undertook the VPR program beginning in 2013, which was a four-year program whereby AGL replaced some vintage plastic pipe present in its system. AGL defined "vintage plastic" for purpose of this program as pipes made of plastic resins manufactured in and prior to 1984, with capital expenditures associated with the VPR recovered through the same rider. Pipes made of the resins identified in the Order Adopting Stipulation establishing the VPR program demonstrated a high leakage rate, presenting higher risk of failure. AGL completed the VPR program in 2017, having invested over $250 million and replacing in excess of 750 miles of pre-1984 plastic pipe prone to leakage.

Certain remaining vintage plastic pipe materials in AGL's system demonstrate a higher leakage rate than those made of more modern materials. AGL's DIMP program has identified many of these segments as having a risk profile that necessitates replacement.

1.3.2 Federal Pipeline Safety Mandates

The ever-changing regulatory landscape further complicates the status of certain vintage plastic pipes in AGL's system as changing federal pipeline safety and compliance regulatory initiatives continue to significantly influence this Plan and future i-CDPs. For example, in October 2019, the federal government released its Pipeline and Hazardous Materials Safety Administration ("PHMSA") rule requiring Operators to reconfirm the Maximum Allowable Operating Pressures ("MAOPs") of its transmission pipelines. As noted in AGL's 2019 Rate Case and the initial i-CDP filing, AGL estimated the initial cost of this mandated 15-year program at more than $700 million. In 2022, PHMSA released an additional part of this rule, known as RIN-2, which expands the definition of a Transmission main, which potentially expands AGL's transmission mileage by up to more than 40 percent. Compliance with both rules, plus inflationary pressures on compliance with the initial rule, will likely result in full program costs to the Company of over $1 billion. Additional proposed federal and state requirements are discussed in Chapter 5.

1.3.3 Environmental Stewardship

AGL proudly supports the communities it serves and is committed to preserving and protecting the environment. In addition to complying with applicable environmental regulations and reducing the Company's impact on the environment through stewardship, AGL recognizes that an increasing focus on climate by customers, policy makers, and other stakeholders requires that that the Company continue to seek new opportunities to reduce greenhouse gas emissions within AGL's operations and to support customers in addressing their sustainability goals through the use of natural gas. Indeed, some economic development opportunities are foreclosed if the potential sites do not offer established criteria for corporate responsibility. Natural gas is cleaner, safer, and easier to store than other fossil fuels. Nonetheless, to continue to provide the fuel of choice, the natural gas industry must demonstrate its commitment to ensuring that natural gas production, transmission, storage, distribution, and consumption is as sustainable as possible. Specific information regarding AGL's efforts on greenhouse gas emissions reduction, sustainability, and support of renewable energy options are further described in Chapter 8.



1.4 Comparison of 2022-2031 i-CDP and 2025-2034 i-CDP

As previously mentioned, the current i-CDP did not contemplate certain unforeseen economic and market-based challenges that have emerged since approval of the initial i-CDP. Still, AGL made a commitment to the Commission and to customers to keep rate increases at or below 6% for the first three-year period and has kept that commitment. In order to keep customer rates within AGL's self-imposed 6% cap, AGL successfully managed its capital expenditures by reprioritizing programs and projects and reallocating resources to minimize rate impacts to customers. As a result, many critical programs and projects were delayed or foregone. These management decisions represent a necessary but significant departure from the original plan. Although inflation, materials costs, and labor rates have eased somewhat, AGL has assumed in this Plan filing that these economic factors will have an effect on capital detailed in the first three years of this Plan filing and beyond.

As will be discussed further in Chapter 5, AGL reduced overall capital expenditures in the GRAM – Safety and Compliance category, which includes the DIMP, TIMP, and corrosion sub-categories among others. In total, AGL reduced capital expenditures within this category by approximately $15 million. AGL prioritizes the safety, reliability, and resiliency of its system and leans on its utility expertise to manage reductions in these sub-categories. AGL will continue to prioritize these critical items and has included some proposed capital in this Plan filing to address some of these reductions.

As discussed further in Chapter 5, AGL reduced overall capital expenditures in the GRAM – Other category, which includes the Facilities, Fleet, IT, Renewals, Regulator Stations, and Operations sub-categories among others. In total, AGL reduced capital expenditures within this category by approximately $48 million. AGL has included some proposed capital in this Plan filing to address some of these reductions.

The Commission's Orders establishing the i-CDP process do not allow AGL to reallocate capital across the GRAM – Safety and Compliance and GRAM – Other budget categories without seeking an amendment to the current i-CDP. This provision limits AGL's ability to manage capital when unforeseen circumstances exist, such as the fallout from the pandemic, which limits AGL's ability to promptly address higher-risk programs or projects without a time-consuming amendment



process. AGL believes it important to remove this prohibition from the Plan governance so that AGL can carefully and efficiently manage costs from the perspective of system risk.

Nonetheless, in the midst of unforeseen and challenging circumstances, increasing governmental regulations, and dynamic market conditions, the Company has created a Plan that addresses customer needs and requirements in a best cost manner and seeks to ensure that lack of availability of safe and reliable natural gas service does not stifle the economic progress of Georgia, while keeping rates competitive and affordable.

1.5 System Reinforcement Rider ("SRR")

The i-CDP Order provides that AGL may propose for recovery through the SRR the capital costs of Commission-approved property additions and improvements (collectively "SRR-funded assets") associated with large pressure improvement and SRR projects. Projects that fall into this category will not be included in the calculations for the Annual GRAM Filing. Based on the total cost of the SRR assets detailed in Chapter 5, the revenue requirements for the SRR are shown in MFR-SRR-4.

AGL calculated the proposed SRR charge consistent with the methodologies used and approved in the Company's 2022 i-CDP proceeding. The proposed SRR charge for each rate class is as follows: R-1, G-10, AG-1 and S-51: $15.40 per customer annually ($1.29 per month) G-11: $46.44 per customer annually ($3.87 per month); and G-12: $387.00 per customer annually ($32.25 per month).

The Company includes a proposed SRR tariff sheet presented in Attachment A. As described in the i-CDP Order, the SRR charge will "reset" as new SRR projects are approved in new i-CDP Orders.

1.6 Request for Approval

The 2025 i-CDP sets forth a comprehensive plan that complies with the Commission's Order and shows the Company's Plan to continue to provide customers with safe, reliable, affordable, and clean natural gas service to meet the demands of its customers and the state of Georgia as

its population and economy continue to grow. As such, the Company seeks approval of the 2025 i-CDP and associated Action Plan contained in Chapter 9, including the following:

1. The forecast, as presented in Chapter 4;
2. The infrastructure delivery plan, as presented in Chapter 5, and associated parameters for capital budgets that allows for flexibility in managing capital expenditures in these challenging economic times, including the total planned capital expenditures estimated for the first three years of the Plan as shown in Figure 1.3 below;

Figure 1.3: Total Capital Expenditures ($ millions)

AGL Proposed Capital Budget ($ millions) (Includes Overheads and AFUDC)	Proposed									
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
	745.6	740.0	754.0	937.0	988.5	895.4	914.5	879.7	890.9	912.8

3. Completion of a storage/vaporization-only satellite LNG facility in Valdosta further discussed in Chapter 4;
4. The programs and action plans requiring the related O&M expenditures as described below in Figure 1.4;

Figure 1.4: Total Related O&M Expenditures ($ millions)

Estimated Incremental O&M Associated with Proposed Capital Projects/Programs ($ thousands)										
Item	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
O&M Related to Proposed Capital Projects	2,000.0	2,012.0	2,624.2	2,648.7	2,673.7	2,699.2	2,725.2	2,751.7	2,778.7	2,806.3

5. The programs and action plans for best practices described in Chapter 6;
6. The SRR revenue requirements as presented in MFR-SRR-4;
7. The monthly SRR charge of $1.29 per month for a typical residential customer;
8. The SRR tariff sheet and billing rate, as presented in Attachment A;
9. Eliminate the GRAM – Safety and Compliance and GRAM – Other capital budget categories in favor of a single GRAM capital budget category; and

10. Recovery of prudently incurred Universal Service Fund ("USF") actual project costs that may exceed estimates approved for USF projects through the Economic Development Tariff ("ECON-1") rider as discussed in Chapter 5.



CHAPTER 2.COMPANY AND NATURAL GAS SYSTEM OVERVIEW

2.1 Company Information

AGL delivers safe, reliable, affordable, and clean natural gas to approximately 1.7 million customers in Georgia. AGL has been in continuous operation as a natural gas LDC since 1855 and is the largest LDC in the southeast United States. The Company has been a trustworthy source of energy and a constant partner to the communities it serves. In 2016, AGL became a part of Southern Company. Listed below are additional facts and statistics about the Company:

- Largest natural gas LDC service territory – 26,650 sq. miles
- 98 Georgia counties and 243 municipalities served
- 25 service locations
- 34,000 miles of distribution and transmission pipeline mains
- 1,000 miles of transmission pipeline
- 4,400 regulator stations
- 3 Liquefied Natural Gas (LNG) facilities – Cherokee, Riverdale, Macon
- 17 Compressed Natural Gas (CNG) stations
- 6.1 Bcf storage capacity
- 983 employees
- 17 certified natural gas marketers served in Georgia's unique competitive customer choice model
- First natural gas utility in nation to complete the replacement of all bare steel/cast iron pipe in its system (2,712 miles)
- Among the first natural gas utilities to begin to address the replacement of early vintage plastic pipe in its system (756 miles replaced in the first phase)
- AGL serves more than 1.7 million customers in Georgia
- AGL delivered approximately 145,100 million cubic feet of annual firm load in 2020
- Three Non-geologic gas sources for customers



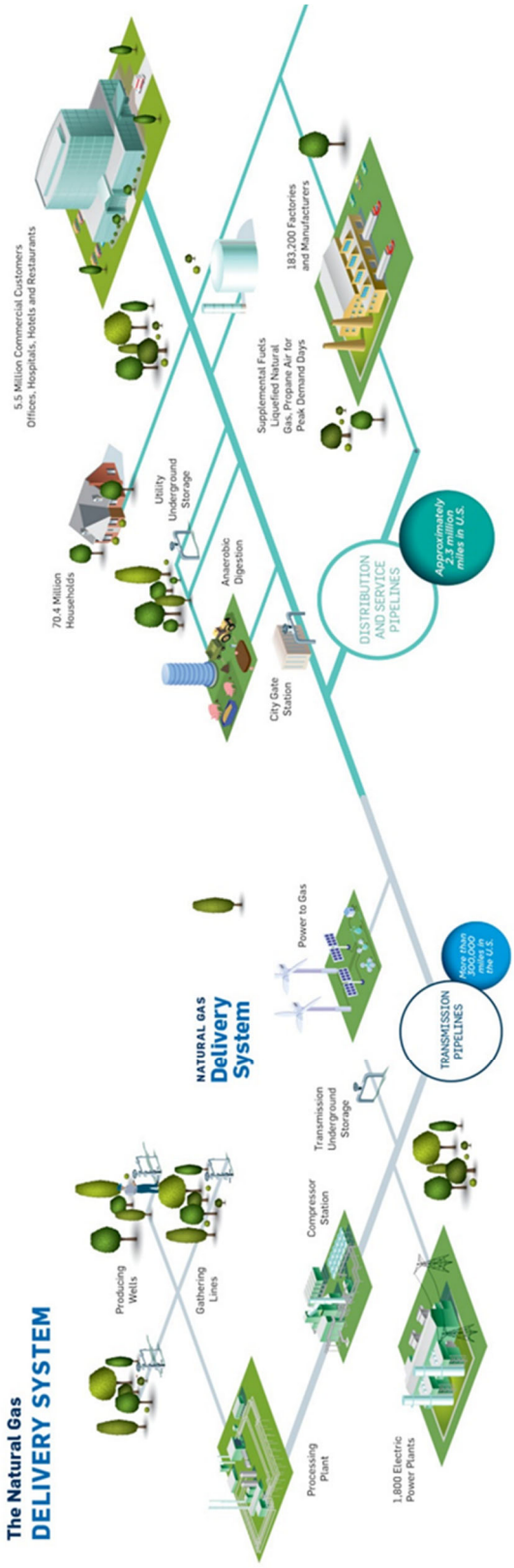
2.2 Natural Gas System

Since 1998, AGL has operated under Georgia's Natural Gas Competition and Deregulation Act. Multiple Commission-certificated natural gas Marketers compete for customers and sell natural gas directly to customers while AGL distributes the natural gas to those customers. Marketers' responsibilities include: processing customer service requests with AGL; billing customers for natural gas service (including the AGL base charges); buying natural gas to sell to residential and commercial customers throughout Georgia; and assisting customers with questions about billing, programs, and services. AGL's responsibilities include: performing service requests (turn customer's gas service on or off as requested by Marketers); meter reading; responding to gas emergencies; forecasting firm customers' loads; contracting for interstate assets to serve end-use customers; allocating the array of interstate assets to Marketers based on their firm customers' needs; and building and maintaining the intrastate natural gas pipeline and distribution system.

An illustration of the natural gas delivery system is shown in Figure 2.1 on the following page.



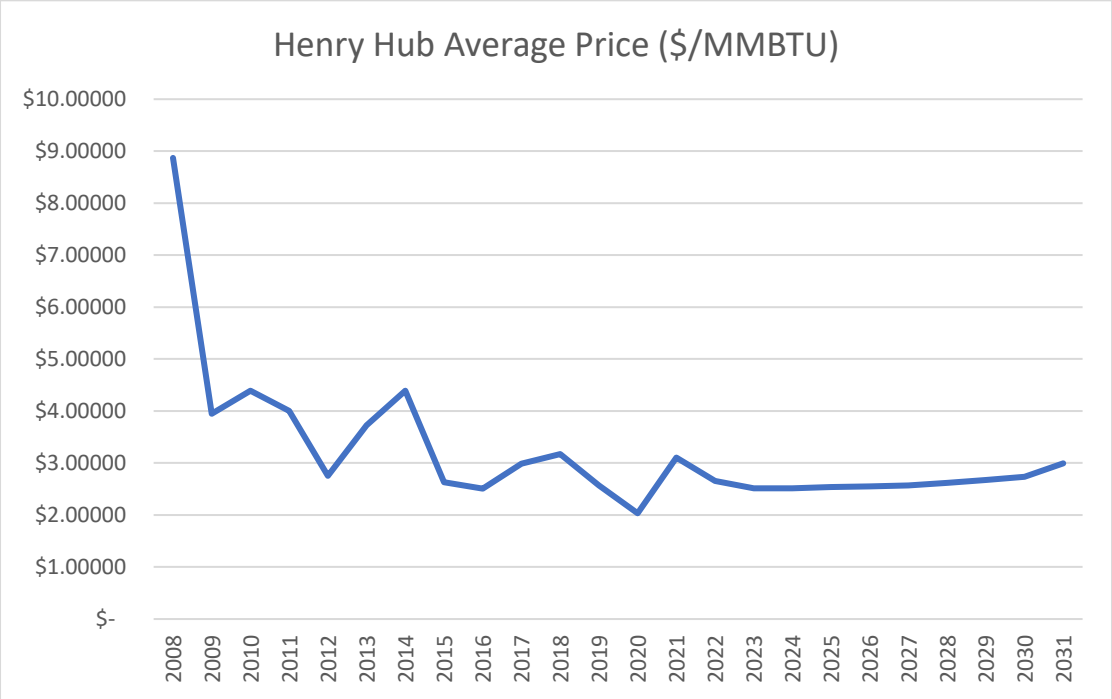
Figure 2.1: Natural Gas Delivery System



AGL contracts for capacity on interstate pipelines on behalf of the end-use customers in Georgia. AGL receives gas supply from interstate pipelines, storage facilities or its own LNG facilities and distributes the gas to residential, commercial, and industrial customers throughout the state of Georgia. AGL delivers the gas to customers through a system of high-pressure transmission pipelines and high/medium/standard-pressure distribution mains. A typical residential service is delivered at less than 1 pound per square inch ("psi"). AGL operates its complex delivery system to meet customers' needs in a safe, reliable, affordable, and clean manner. AGL also establishes sound and effective long-range plans to add and maintain firm gas supply resources to accommodate growth in demand and to ensure the ongoing successful delivery of natural gas to customers.

Fortunately, natural gas customers have enjoyed the benefit of low natural gas prices for several years and are expected to experience continued low prices for the foreseeable future (see Figure 2.2 below). The United States has been the world's top producer of natural gas since 2009. Natural gas commodity prices remain relatively low because of the abundance of supply, including natural gas from shale resources, in addition to continued natural gas supply from more traditional onshore and offshore sources within the nation.

Figure 2.2: Annual Average Prices



Source: S&P Global Market Intelligence (reflects historical prices through February 2021, and projected prices starting March 2021)

CHAPTER 3.NATURAL GAS DEMAND AND FORECAST

3.1 Overview

AGL's Plan includes and relies on projections of the Company's forecasted firm Design Day load requirements. The Company uses its forecasted Design Day load to ensure that the Company has secured appropriate levels of capacity to deliver firm gas supply resources to meet the projected existing and future needs of AGL's firm customers. AGL includes the ten-year projected Design Day load requirement in Trade Secret Attachment B.

AGL's system is divided into nine discrete geographic pools or areas across the state. The construct has been a part of the AGL retail choice program since its inception. In its simplest sense, the pools are defined by the firm delivery entitlements of AGL's firm capacity contracts on the interstate pipelines. Most of these nine pools or areas have a level of firm demand and a corresponding amount of firm gas supply capability to satisfy the requirements on a standalone basis. A few of the pools have a very limited amount of interplay between them, allowing a pool to share firm gas supply capability or capacity with another pool. The development of a gas supply portfolio having an appropriate amount of gas supply capability or capacity in aggregate while also balancing the discrete needs of the individual pools is essential. No two pools are exactly alike and the mix of customers in each makes their firm demand characteristics dynamic over time. As an example, the gas supply capability for the Valdosta area of the system cannot support meeting load in the largest load center, the Atlanta pool, because the pipelines that serve Valdosta do not run through Atlanta. However, Augusta and Savannah gas supply capabilities may help support the Atlanta pool on a particular day because the gas in the delivering interstate pipeline "flows by" Atlanta on its way to these two East Georgia pools. Discrete and interrelated pool dynamic details such as those identified above are fundamental to developing a comprehensive capacity supply plan for the AGL system.

3.2 Forecast Assumptions and Methods

Demand Forecasting Methodology:

Business Forecast System, Inc.'s regression analysis tool, Forecast Pro XE, produces a set of equations that describe firm customer usage in relationship to outside temperature. Historical daily heating degree days ("HDDs"), wind speed, usage per billing unit, holiday, day of week flags or variables, the 7-day rolling average temperature, a year trend variable, an indicator for the



winter in which the datapoint falls, and the bend point data or a point along a span of HDD values where firm customer consumption characteristics changes are all entered into Forecast Pro.

Historical billing units, daily firm usage, and historical HDDs are gathered separately for each of the nine pools. For each day, a use per billing unit is calculated. A use per billing unit is calculated by dividing a historical day's firm natural gas usage by the billing units on the system for that month. This calculation measures the level of billing units on a monthly basis and uses the appropriate month's value. AGL performs this daily level calculation is done across each of the nine geographic pools. For each day, bend points at 5 HDD increments (10, 15, 20, 25, 30, 35, and 40 HDDs) are then calculated. Bend points act as spline points in a linear regression. The input bend points for a historical day can be calculated by subtracting the bend point variable from the day's historical HDDs. For example, on a day where there were 16 HDDs, the bend 10 input variable for that day would be 6 (16 HDDs minus 10). The bend 15 variable for that day would be 1 (16 HDDs minus 15). All other bend point variables are set to zero as their resulting calculation would result in a negative value. Bend points help capture potential changes in customer consumption behavior as temperatures get colder and resultant HDD levels increase. A simple example of customer behavior change in the Fall would be as those evenings get colder and daytime highs do not reach as warm as the customer may like, there is a point at which the customer decides to turn on their heat to be more comfortable.

Design Day Forecast:

For most pools, the typical dataset used for Design Day forecasting includes the core winter months (December - February) for the most recent 5-year period. The results of this baseline analysis are always evaluated for proper fit and trending to ensure that they are relevant and effective at projecting the possible level of gas consumption by firm customers under certain design weather conditions.

Projecting billing units represents another key component to the forecast. As described above, AGL calculates the use per billing unit value from historical observations which are then used in the regressions. Therefore, the Design Day forecast requires a forecast of billing units coupled with the pool's design temperature criteria which correlates to an HDD value. With those basic building blocks, the coefficients of the regression analysis can be used to calculate a meaningful portion of the forecasted Design Day.



The next component of AGL's Design Day load forecast is a load value for expected new large firm commercial or industrial customers. AGL develops this information by looking to its sales and marketing group. The new large load component attempts to capture new firm loads being added to the AGL system that would not be otherwise adequately reflected in the analysis driven solely from historical load relative to historical billing units and daily weather observations.

AGL compiles this identified new load for each geographic pool and adds to the pool's regression results to produce a base Design Day load forecast. The projected load on a Design Day captures shifts in use per billing unit in the historical period. Billing unit forecasts themselves incorporate customer attrition and growth in general terms. Including appropriate future load components allows the Company to design its supply portfolio to accommodate the future firm customers whose needs are larger than an average customer.



CHAPTER 4.CAPACITY SUPPLY PLAN

4.1 The Relationship Between i-CDPs and CSPs

AGL must file a CSP at least every three years to designate the array of available interstate capacity assets to make gas available on its system for firm distribution service to retail customers.[12] The Commission approved the Company's current CSP for the period of 2022-2025 in Docket No. 44319. This i-CDP filing does not change the approved 2022-2025 CSP. Rather, as part of the i-CDP ten-year planning process, this Plan identifies potential CSP impacts beyond 2025 that may be a part of future CSP filings, including new LNG vaporization and liquefaction facilities and a reassessment of the Company's Reserve Margin.

By design, the planning and forecasting criteria for both i-CDPs and CSPs are consistent and complementary. The i-CDP shares a road map of the Company's capacity needs, available market-based or Company-built options, their general availability, and possible timelines for potential projects. Neither the CSP nor the GRAM provide this opportunity to share with the Commission the long-lead forecast that is included in this Plan filing. The i-CDP will provide the Commission with greater details of the Company's long-term resource planning process that the 2025-2028 CSP will further support.

AGL's Liquified Natural Gas ("LNG") peaking facilities provide a cost-effective gas supply to customers on days when the interstate pipelines are constrained. Although the 2022-2025 CSP includes improved and expanded LNG facilities, given AGL's ever growing demand, the longer-term outlook indicates that additional vaporization-only peak shaving facilities will be needed in the Valdosta pool in addition to additional liquefaction improvements in Riverdale. Increased LNG resources and continued firm load growth and projected growth of the customer base in AGL's service area suggest that a reevaluation of AGL's Reserve Margin as well as the elimination of the restrictive provisions around the Elba Island FT capacity may also be appropriate.

4.2 Summary of CSP Requirements

The CSP process is set forth in O.C.G.A. § 46-4-155 and Commission Rule 515-7-11-.04.

The CSP establishes the appropriate level of firm gas supply services that the Company contracts for on the Federal Energy Regulatory Commission ("FERC") regulated interstate pipelines, as well as on-system gas supply capabilities, which combined serve the utility's firm customers in the

[12] O.C.G.A. § 46-4-155(e)(3).



state of Georgia. Firm gas supply services are made up of Firm Transportation ("FT") capacity on the interstate pipelines and out-of-state storage services. With respect to FT, AGL relies on Southern Natural Gas Pipeline ("SNG") and Transcontinental Gas Pipe Line Company ("Transco"). For purposes of this filing, the Company relies on the approved 2022-2025 CSP, which included the approved array of interstate capacity assets for the heating seasons of 2022-2023, 2023-2024, and 2024-2025.

For informational purposes, AGL includes the Array of Interstate Assets from the 2022 CSP in Trade Secret Attachment C. The Company has provided ten-year projections of its Design Day[13] supply requirements in Trade Secret Attachment B. The Range of Requirements is provided in Trade Secret Attachment D.

The assets approved to meet the Range of Requirements fall into several categories. Capacity Release includes all the gas supply resources that the Company releases to the Certificated Marketers to use in meeting firm customer load. Firm and Interruptible Nominated Sales Service ("FINSS") and Marketer Accessible Retained Storage ("MARS") are tariff-based sales services made up of additional gas supply resources contracted for on the interstate pipelines. Drop Short Firm Transportation is an operational flexibility mechanism that exists in the Atlanta pool based on its geographic location, where FT capacity that is pathed on the interstate pipelines for Augusta and Savannah can be used to "drop" gas off at the Atlanta pool on a Design Day.

LNG peaking service is another asset made up of on-system LNG resources (Cherokee, Riverdale, and Macon) and serves to reduce the amount of FT necessary to meet firm load on a Design Day. Additionally, Bundled Pipeline Peaking Service ("BPPSS") comprises interstate pipeline based peaking supplies. All of the assets in these two categories are short durational supplies – available for 5 days or less in most cases. As the AGL CSP indicates, there is a planned bundled peaking or city-gate delivered gas supply component included in the BPPSS service.

With respect to storage capacity, as shown in the figures below, once a storage resource hits a storage threshold, its deliverability is reduced in subsequent days. Once a storage or LNG asset has depleted its inventory, its deliverability is reduced to zero in subsequent days on the chart.

[13] A "Design Day" is a 24-hour period of demand which is used as a basis for planning gas capacity requirements. For AGL, a Design Day is a day when the average temperature in the metro Atlanta area is just 10 degrees Fahrenheit.



Figure 4.1: Load versus Available Capacity 2025-2026 Winter

Maximum Inventory			1,000,000	Dth	
Maximum Daily Withdrawal			100,000	Dth/d	
Deliverability Decreases					
% of Max Inventory		% of Max Withdrawal	Effective Max Withdrawal		Inventory Threshold
100		100	100,000		1,000,000
80		90	90,000		800,000
70		80	80,000		700,000
40		70	70,000		400,000
10		0	-		100,000

Because of the importance of LNG to AGL and its customers, the next sections address both LNG current capacity and expansion projects within the 2022-2025 CSP, as well as projected future LNG projects expected to be included in the next CSP cycle filing.

4.3 Present and Approved LNG on AGL's Intrastate System

The Company's LNG resources are a critical component of the Company's ability to supply gas to its customers on days with high gas needs because the natural gas pipelines serving AGL do not have the capacity to deliver the amount of gas needed on cold days with high demand. AGL's projections show that as much as 35% of the Company's forecasted Design Day firm load requirement will come from LNG supplies; that figure grows to 41% over the next 10 years. If any one or more of the Company's three LNG plants fail, supplemental delivery of a comparable amount of natural gas by SNG and/or Transco would not be physically possible without significant time (measured in multiple years) and expense (measured in hundreds of millions of dollars). As such, the Company continues to explore new LNG facilities, whether reserve margin levels should be modified, and any opportunities for incremental interstate FT-based gas supply resources.

AGL has developed, maintained, and utilized a meaningful amount of on-system LNG resources. Currently, these existing LNG facilities can provide up to 940,000 Dth/day of gas to serve firm demand on a Design Day. Because of the physical constrains around the volume of LNG needing to be stored, in most cases the LNG plants can only provide this peak level of gas supply or send-out for 5 days or less. AGL's previously approved LNG projects will increase the capability of its LNG assets to address not only the increasing firm Design Day load requirements, but also to



meet near-term customer needs in a long cold winter. AGL outlines the overall need for incremental LNG supply in Trade Secret Attachment D. That attachment illustrates the projected Design Day system load growth and how that growth in forecasted firm load can be best met with added LNG capabilities, while supplementing with a reasonable amount of bundled peaking. AGL's past CSP filings spoke to the need to limit the Company's overall reliance on bundled peaking services in a capacity constrained marketplace because, among other reasons, this resource is dependent on third-party agreements to deliver gas when AGL's firm customers need it. Company-owned peaking assets and FT that the Company directly contracts carry much less risk than those dependent on third parties.

The Cherokee LNG expansion project authorized in the current i-CDP will double the storage and send-out capability of Cherokee. The Company planned to implement this project in several phases: adding a second tank, replacing the existing liquefaction train, adding the additional vaporization capacity, and adding intrastate pipeline facilities necessary to carry the additional send-out to customers during peaking operations. As of the date of this filing, the second tank is operational, and liquefaction train replacement is underway. The pipeline projects necessary to complete the Cherokee LNG expansion project are noted as the Cumming to Hall SRR project and the Cumming to Commerce SRR project, both of which are included in the SRR project list detailed in this Plan. The Cumming to Hall SRR project is scheduled to be complete in 2025, and the Cumming to Commerce project is scheduled to be complete in 2028. At that time, the full 800,000 Dth/day of Cherokee send-out capacity will be available to the AGL system, specifically to the Atlanta pool.

Although the Cherokee LNG expansion project will make a significant contribution to the Company's ability to continue to provide service on peak days, AGL needs to add additional incremental LNG facilities to keep up with customer growth and demand.

4.4 The Need for Additional On-system Peaking Capabilities

4.4.1 Valdosta

AGL projects a need to construct a satellite storage/vaporization-only LNG facility in Valdosta in years 2025-2027 of this Plan, at an estimated capital cost of approximately $51 million, to meet current and new customer needs. Because of the immediacy of the need, and the long-lead time needed to construct the facility, AGL will transport LNG by truck for the immediate next few heating seasons. The multi-year planning and the development process proposed here is similar to what



AGL followed for the Cherokee LNG expansion project, which was projected to begin service beyond the 3-year period included in the 2022-2025 CSP. Continuing market growth has largely consumed available design Reserve Margin in the Valdosta pool and adding peaking facilities is the most cost-effective solution to meet the forecasted growth in firm customer load.

The need for incremental peaking capacity in the Valdosta area is driven by three new customer projects. For many years, a large agricultural and food provider has been an interruptible natural gas customer in the Valdosta area. In early 2023, that customer requested to convert to firm service. Additionally, a second existing firm customer has expressed its intent to double its production capability in the area, which has not yet been publicly announced. Finally, on October 11, 2023, Wal-Mart announced the construction of a large dairy processing facility in Valdosta. The combined new firm load of just these three customers, when added to existing customer load as forecasted into the future, shows a need to start now the process to develop the necessary incremental peaking supply capability.

AGL has discussed the challenges related to converting interruptible customers to firm customers in several of its past CSP filings. One of the major challenges that comes from these customer conversions is that the customer is already connected to and consuming natural gas. When such customers elect to convert to firm service, AGL needs to respond with an approval coupled with any appropriate pressure improvement projects necessary to maintain the operational status quo as the customer begins its new firm service. Such a change would also be conditioned on there being sufficiently available gas supply capability in the pool to support the converted customer, in addition to the already existing firm customer base.

Back in 2009, AGL proactively subscribed to added gas supply capability in the Valdosta Pool after retiring the old propane-air facility. Had the Company not done so, these new loads may not have been possible, and the economic benefits of new jobs and regional growth may have not materialized. But this pipeline capacity alone is insufficient to meet the growing peak demand. AGL plans to meet the incremental, short durational peaking supply need in the Valdosta pool with portable LNG capability while the construction of a more permanent and scalable storage and vaporization-only LNG facility. Chapter 5 discusses that project in greater detail. Notably, these three incremental firm loads arose in less than one year. Having a proactive ability to accept new load when the opportunities present themselves is possible only when the aggregate gas supply capability of the system is appropriately sized for growth and development. Although AGL can presently serve the new load from these new customers during normal operating conditions,



the Company still needs to serve them on a Design Day, which is the basis for the planned projects described above.

4.4.2 Riverdale

Riverdale LNG has been in service since 1972 and utilizes a turbo-expansion liquefaction system that is far beyond its designed useful life. This process requires a great deal of natural gas volume and pressure to liquefy natural gas for storage and subsequent peaking use. The process requires 100 million cubic feet of inflow to liquefy 10 million cubic feet, and the remaining 90 million cubic feet must be taken into the Atlanta distribution system, often during the summer months when natural gas usage is low. Additionally, the process relies on significant pressure differential, with inflow coming into the plant at as much as 1,200 psi and discharging from the Riverdale facility at around 200 psi. This large differential is necessary because the turbo expander liquefaction process relies upon significant and controlled pressure drops to provide the necessary cooling to produce cryogenic temperatures required to cool the vapor form of natural gas to convert to the liquid form. The turbo expanders are 1972 vintage, much beyond their designed useful life, and a failure of one expander could make Riverdale unable to liquefy. Certain parts for the expanders are available, but other replacement parts take much longer to acquire. Replacement parts may require the assistance of overseas companies that make customized components or refurbish damaged parts, which further lengthens the construction timeline.

Further, the system requires careful gas operations management of the Atlanta distribution system because of the lower-than-normal pressure on the discharge side of the liquefaction process that then enters the distribution system. If pressure on the Atlanta distribution system becomes too high, Riverdale cannot liquefy.

AGL has included $50 million in capital in years 2025-2027 to replace the outdated turbo expander liquefaction system at Riverdale with a modern and more reliable refrigerant loop system similar to those used at Cherokee and Macon LNG. This critical plant update will eliminate the risk of expander failure and mitigate the summertime low pressure operating risks.

4.5 Reserve Margin

The Company includes a level of gas supply capability or capacity to deliver an amount of gas supply that is above the projected firm load requirements for a projected Design Day. This Reserve Margin is an amount of deliverable supply resource that is included in the Supply Requirements, a term used throughout a CSP, to ensure that adequate capacity exists to “absorb”



supply/capacity disruptions or higher-than-forecasted firm demand with minimal disruption to the firm market. Reserve Margin is the buffer that is put in place to absorb the inaccuracies that are inherent in any forecast.

AGL's current Reserve Margin came from a decades-old regulatory review. It is from a different era of the natural gas industry and a time when the interstate pipeline market was fundamentally different from today's. Years ago, pipelines had fallow capability that they could sell to a shipper. Today, the interstate pipelines that serve AGL are fully subscribed. Incremental FT service is only created through a pipeline expansion project. The long lead time and uncertainty of these incremental service projects has been discussed at length in the Company's CSP filings. What may have been a marginally adequate perspective on Reserve Margin 20 years ago is not appropriate today. AGL will present in its next CSP further details and a recalibrated point of view on the level of capacity that is appropriate for service to meet the needs of today's customers while underpinning a robust need for energy infrastructure across the State to support its growing economy.

The Company's firm load forecast for Design Day relies on forecasts of components that form the basis for the projection of firm customer demand, so it is important to enumerate these elements. Potential inaccuracies in a forecast are unavoidable and usually the result of discrepancies in one or more assumptions relied on in the projection, including billing unit error, weather forecast error, and customer consumption error.

4.5.1 Billing Unit Error

Billing unit count looks at the number of individual discrete billing units that must be served and has the potential to be a large factor in forecast error. The forecasted firm demand relies upon a projection of the number of billing units that AGL expects to be on the distribution system at a future point in time. Billing units can be closely associated with a premise rather than a customer, a single premise may serve multiple actual customers, or a customer may actually have multiple billing units. The difference is easier to understand with an example. A residential house is a single billing unit that serves the members of the family residing in the premise. Alternatively, a customer could be a chain retailer. The franchise owner could have multiple locations. The customer, the chain retailer, is a single entity. The stores they operate are individual locations of consumption or billing units.



The forecasted level of billing units active on the system for a future month will likely be different from what is actually experienced. For this application, a forecast that turns out to be low is actually more problematic than one that is too high because that means that existing supply the Company counted on to meet demand may be inadequate. The number of billing units or consuming locations projected to require firm natural gas service sets the foundation of the firm load projections as the Company develops them. Typical system-wide billing unit growth has averaged about 0.9% in year-over-year growth in the recent past. Some years have more growth and some have less. Figure 4.2 shown below reflects the longer term trend or history on the number of billing units on the AGL system. The billing units on the AGL system ebb and flow as customers activate and deactivate their service year after year. The second graphic shared below, Figure 4.3, highlights the near-term year-over-year change in actual billing units.

Figure 4.2*: History of Billing Units on AGL System*

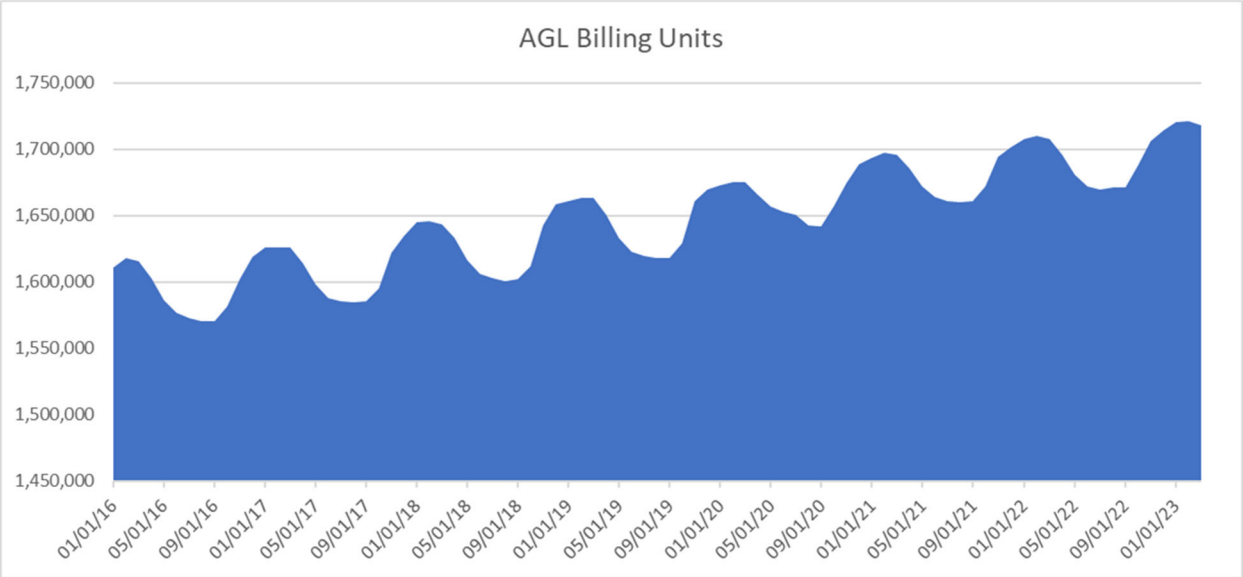


Figure 4.3*: Near-Term Year-Over-Year Change in Actual Billing Units*

Thousands of billings units

Date	ATL	AUG	BRU	MAC	ROM	SAV	SNG	TR	VAL	Total	YOY Growth
2/1/2017	1,327.0	69.5	21.7	48.4	27.9	45.6	40.0	39.0	7.1	1,626.3	0.5%
2/1/2018	1,346.2	70.1	21.4	48.0	28.0	45.7	39.6	39.4	7.0	1,645.5	1.2%
2/1/2019	1,365.4	70.1	21.4	47.5	28.0	45.7	38.4	39.7	6.9	1,663.1	1.1%
2/1/2020	1,378.6	70.1	21.2	46.7	27.9	45.4	38.9	39.9	6.7	1,675.5	0.7%
2/1/2021	1,399.4	70.9	21.3	46.9	28.0	45.7	38.6	40.0	6.7	1,697.5	1.3%
2/1/2022	1,412.8	71.3	21.3	46.2	27.8	45.8	38.4	40.1	6.5	1,710.3	0.7%
2/1/2023	1,425.1	71.2	21.3	45.5	27.5	45.5	38.4	40.0	6.3	1,720.8	0.6%

Figure 4.3 illustrates that the year-to-year actual change in billing units is not linear and there are fluctuations in the amount of billing units from year-to-year. Accordingly, AGL uses the average year-to-year change, which is about 0.9%. The projected change in billing units, assuming that generalized growth trend, sets the majority of the forecasted firm load on the AGL system for the Design Day, as well as any given day of the year. In a year like 2021, where the actual growth rate was 1.3%, there were 0.4% more billing units (about 7,000 more billing units or premises) consuming natural gas than the general long-term trend would have suggested. That added billing unit level roughly equates to another 10,500 Dth/d of firm gas requirements.

The unexpected level of increase in billing units from 2020 to 2021 would not necessarily be included in the projections for firm load growth contained in a previous CSP because such filings rely on a 3-year projection. Consequently, if there are major differences from what was reasonably expected and what was experienced, the Company would have to meet the higher demand with the resources approved in the last CSP. Notably, these prior filings included a minimal Reserve Margin. There is currently little room for error to address forecast inaccuracies, especially if they are coupled with other unforeseen events. AGL stresses the need to increase the level of Reserve Margin because as the system grows, unplanned discrepancies may be larger as well, and AGL needs a Reserve Margin set at a level that mitigates the impact of insufficient supply from a variety of potential areas.

4.5.2 Weather Forecast Error

An error in the weather forecast can also lead to unforeseen variances in the Company's projection of resource needs. Weather is, of course, notoriously variable, and a weather forecast over a ten-year period will surely experience some deviation from the projection. Currently AGL plans for a 55 HDD for its Design Day load projections. An HDD is a measure of the number of degrees colder than a day has compared to a mean temperature of 65 degrees. A day with a mean temperature of 64 degrees is a 1 HDD day. Therefore, a 55 HDD day means that the day would have a mean temperature of just 10 degrees, which is the Design Day temperature. Said a different way, a portion of the day would potentially be colder than 10 degrees and a portion of the day could be warmer than 10 degrees but the average temperature, across 24 hours in a gas day, would be just 10 degrees. Of course, Georgia is not Minnesota, and Atlanta does not experience as many cold-related Design Days as Minneapolis. Importantly, however, AGL must plan for the peak demand of a Design Day in order to have sufficient resources available when they occur. Thus, customer firm load projections on a Design Day are one of the key metrics that



determine the gas supply capability of the system as a whole to provide reliable and safe natural gas service to meet customers' needs.

The Commission has relied on the Company's planning assumption for a Design Day using 55 HDD or an actual temperature of 10 degrees. Atlanta has had colder days and may in fact experience them this winter. This ties to the need to expand the Reserve Margin AGL uses in its planning. When AGL plans its system needs using a Design Day of 55 HDD, every day the temperature is colder than 10 degrees results in an inherent under-forecasting error in the projected Design Day. In each CSP, the Company attempts to identify the incremental firm load the system would experience if it realized a repeat of the coldest weather in recorded history. The table below, Figure 4.4 illustrates the historical coldest weather days in the Atlanta area.

Figure 4.4*:* Atlanta Historical Coldest Weather

GasDate	TempF	HDDs	WindMPH
1/20/1985	-0.6	65.6	18.8
1/10/1982	2.7	62.3	18.0
12/24/1983	6.3	58.7	18.8
12/12/1962	7.3	57.7	12.8
12/25/1983	9.2	55.8	11.7
1/30/1966	9.6	55.4	12.4
1/27/1986	10.2	54.8	14.8

In Docket No. 44319 on page 37 of the Pre-Filed Direct Testimony of Gregory Becker at lines 5 through 16, Mr. Becker summarizes the impact of experiencing a 65.6 HDD. The added cold weather, nearly 11 HDD colder than the adopted regulatory standard of 55 HDDs, would yield an added firm customer demand of up to 159,000 Dth/d of incremental customer consumption given the load parameters and metrics the Company filed and the Commission approved in the 2022-2025 CSP. As stated in the 2022-2025 CSP, if the Company is held to its current forecasted Design Day with only a 5% Reserve Margin there would not be adequate supply to meet customer needs of a 65.6 HDD day. At least 94,000 residential customers worth of demand would not be served based on estimates prepared in conjunction with the 2022-2025 CSP. To cover a repeat weather event like this, if it were to happen, and 8 of the 9 geographic pools were to experience record cold temperatures, the approved array would need a MINIMUM of 10.1% Reserve Margin just to have a chance to keep customers served, assuming there were no other system issues on such a brutally cold day. Mr. Becker explains on pages 38 through 41 of his testimony in the 2022-



2025 CSP that there is an inherent risk to allow the system to operate at such a minimal Reserve Margin.

4.5.3 Customer Consumption Error

The Company must also contend with changes in customer behavior in forecasting future demands on the system. Statistically, the Company uses regression analysis techniques, which attempt to mitigate forecast error by incorporating potential error into the forecast itself. For example, in December 2022, Georgia experienced a very cold weather event isolated in the northern portion of the state around the Christmas holiday. Notably, AGL set a throughput record that day, even though it was only a 51 HDD day for the metro Atlanta area. Said another way, even though the weather was not as cold as the 55 HDD planning standard, actual consumption approached expected Design Day levels. This difference is due to customer behavior -- It was a holiday weekend, schools and businesses were closed, municipalities scaled back gas usage as a result of the holiday and closures, countless families left town for holidays, and countless visitors flocked to Georgia for the holidays. With all these muting compounding factors, the company still realized record send-out. When the Company performed a post-event review using regression models, it reached a result very close to the actual firm consumption experienced. Figure 4.5 below highlights the accuracy of the Company's forecasting. When viewing the below figure, it is important to note that the vast majority of the system's firm load falls within the Atlanta pool. Also, the extreme cold temperatures did not extend much further south than the I-20 corridor for this event. Had the Company re-projected the December 23, 2022 load using its established regression forecasting tools the models would have estimated 2,214,402 Dth in total. That aggregate accuracy is important to recognize and the small variations seen in a few pools are being evaluated for performance improvement where possible.

Figure 4.6 below shows how much warmer the southern portion of the state stayed compared to that of the northern portion of the state. The 2,226,904 Dth of firm load was the largest part of the record throughput seen on that day. Forecasted Design Day for the heating season of 2022-2023 was 2,642,686 Dth at 55 HDD in Atlanta. The Design Day forecast does not anticipate any one of the load muting impacts listed of a Christmas holiday weekend, yet the Company was just a few hundred thousand Dth away from its design load in total.



Figure 4.5: Comparison of Forecast and Actuals for Heating Season 2022-2023

Load Dth

	Actual	Predicted	Over/(Under) Predicted
Atlanta	1,860,953	1,868,960	8,008
Augusta	67,766	89,674	21,909
Brunswick	30,710	32,034	1,323
Macon	54,104	51,342	-2,762
Rome	50,456	46,929	-3,527
Savannah	40,781	44,812	4,031
Ex-Atl SNG	24,331	23,679	-652
Ex-Atl TR	89,055	49,990	-39,065
Valdosta	8,748	6,982	-1,766
System Total	2,226,904	2,214,402	-12,501

UPBU

	Actual	Predicted	Over/(Under) Predicted
Atlanta	1.3110	1.3124	0.1%
Augusta	0.9573	1.2601	31.6%
Brunswick	1.4526	1.2953	-10.8%
Macon	1.1939	1.1167	-6.5%
Rome	1.8440	1.5381	-16.6%
Savannah	0.9022	0.9860	9.3%
Ex-Atl SNG	0.6347	0.6177	-2.7%
Ex-Atl TR	2.2350	1.2389	-44.6%
Valdosta	1.3881	1.0892	-21.5%
System Total	--	--	--

Figure 4.6: HDDs and Firm Load by Pool

	HDDs			Firm Load (dth)	
	1/29/2022	**12/23/2022**	Yr 3 CSP	1/29/2022	**12/23/2022**
Atlanta	34	51	55	1,359,721	1,860,953
Augusta	32	42	40	51,867	67,766
Brunswick	28	29	48	27,932	30,710
Macon	33	43	50	43,155	54,104
Rome	37	53	57	40,819	50,456
Savannah	31	34	50	40,163	40,781
Ex-Atl SNG	34	51	55	17,550	24,331
Ex-Atl TRA	35	50	55	60,186	89,055
Valdosta	32	33	45	9,896	8,748
Total	--	--	--	1,651,289	**2,226,904**

4.5.4 Issues with AGL's Current Margin Reserve

AGL's current Margin Reserve is insufficient and needs to be increased. AGL needs an aggregate supply capability that provides for robust economic development into the future and accommodates the forecasted load, including providing for the potential forecasting inaccuracies covered above. The Company needs the ability to participate in and continue to provide adequate energy infrastructure to emerging customers, large and small, who look at Georgia to do business. Without an appropriate recalibration of the framework used to review this key element of the energy solutions the Company can offer, there will be a finite and predictable end to the economic growth and system-wide benefits that come from new load being served. AGL asks the Commission to join it in this important process and allow the Company to adopt a firm load forecast that incorporates or covers the inherent and quantifiable known forecast error. Further, the Company and the Commission need to address the disparity between the HDD planning



criteria and the colder weather observations that have occurred and continue to occur, including in January of this year. Armed with this information, AGL and the Commission can develop an appropriate and flexible framework for adequate and relevant gas supply capability. The limitations of the current construct and long-dated myopic view on Reserve Margin will only serve to stifle opportunity going forward. In an environment where added interstate pipeline capacity is difficult to come by, it makes it all that much more important to move away from this historic and outdated view of minimal Reserve Margins.

New capacity projects approved by the FERC on the interstate pipeline projects serving the AGL system have been few and far between. New capacity is hard to come by, and the Company cannot rely on new capacity until construction is complete. Transco has one such project proposed that it expects to file in early 2024. It is called the Southeast Supply Enhancement Project. The pipeline held an open season for interested shippers in July 2023. AGL has been engaged with this pipeline to secure an amount of capacity in that proposed project if it moves forward to approval by the various regulating agencies. SNG may be looking at an expansion project of their own in 2024, but commercial terms and other such provisions of their possible project are still pending. AGL will participate in that project as well if it moves forward.

Neither of these two expansions projects are guaranteed. Recently announced, fully subscribed and supported expansion projects like Penn-East pipeline in the Northeast and Atlantic Coast Pipeline in the mid-Atlantic region were delayed by the regulatory review process for so long that they became economically unsustainable and were ultimately cancelled. The Mountain Valley Pipeline project is finally moving toward completion, only after special provisions were included in the Fiscal Responsibility Act of 2023 and its provisions were upheld by the United States Supreme Court. The project was initiated on October 23, 2015, with its formal application to the FERC. More than 8 years later the project is still under construction with a 2024 in-service date expected. There is little reason to expect these new projects will face a clearer path.

When pipeline projects are available for shippers such as AGL to participate in and gain greater gas supply capability to support the continued economic growth and related jobs and other overall societal benefits, it makes sense to acquire amounts of capacity at a level that is projected to be needed as well as an added amount to cover unforeseen disruptions. But the Company and the Commission must be aware in their planning process that not all pipeline projects will become operational assets.



Another aspect to consider regarding the acquisition of pipeline capacity is that new capacity is not incremental, but rather "lumpy." The nature of the industry requires pipelines to expand in large chunks, adding large amounts of capacity at one time, only after an expansion project is complete. As a result, the Company must move quickly to secure capacity when a new expansion project is announced, not only for its existing needs, but also in anticipation of future needs as the Company cannot rely upon on the availability and timing of new capacity in the future.

Where new capacity is hard to come by, AGL must recognize the need to proactively subscribe to capacity in large blocks for several reasons: to support the overall project and help it gain completion, to meet the projected needs of customers, and to stay ahead of the growth curve as much as possible to avoid stalling growth and economic development. Businesses are seeking locations in the State because of robust infrastructure (roads, internet, and energy options), as well as strong options for a labor force. Without all of these variables, the State will be less likely to win competition for potential customers. Valdosta and the recently announced Wal-Mart project is a great recent example.

To mitigate the possibility that expected pipeline projects will not manifest, or other unforeseen disruptions in available gas supply resources, AGL relies on LNG as a gas supply resource when planning for peak cold days. In fact, with the added capability of the expansion of AGL's Cherokee LNG facility, a full 1.34 Bcf of daily gas supply capability for the AGL system will be available from its 3 on-system LNG facilities; 400,000 from Riverdale LNG, 140,000 from Macon LNG and up to 800,000 from Cherokee LNG upon its full completion and other system improvements that are pending.

AGL's current Reserve Margin at 5% of its forecasted Design Day is only about 130,000 Dth/d of gas supply capability spread across the entire state of Georgia. It is inadequate to fully meet system needs. In a situation where, for example, Macon LNG were to become disabled, regional supply capability supporting Macon and the Atlanta Pools could not be offset by the system level of Reserve Margin. The gas supply capability across the state of Georgia would be leveraged to its greatest extent possible but service would be lost to some extent.

Because of these and other potential issues, AGL, and indeed the industry in general, prefer a standard of Reserve Margin that focuses on a single contingency failure when it is just 10 degrees or colder outside and the potential impact is even greater. To put the need for a more robust Reserve Margin in context, AGL's Riverdale pipeline infrastructure receives flowing gas from four



main sources: pipeline delivery from SNG; pipeline delivery from Transco; LNG send-out from Riverdale; and South Thomaston delivery of gas off the of SNG pipeline. If a disruption of the SNG feed into the Riverdale portion of AGL's system were to occur, there would be a loss of up to 260,000 Mcf of flowing capacity. That is at least 10% of AGL's projected system firm gas supply need on a Design Day. Depending on the nature of the disruption, this same situation could impact send-out from the LNG Plant, delivery from Transco into that same part of the AGL system, or both. If the entire Riverdale complex has to go offline to make emergency repairs, that would total about 18% of AGL's gas supply capability feeding into the Atlanta pool, which supports the largest population center in the state.

The upstream end of the interstate pipeline is also susceptible to interruptions. Wellhead freeze-offs happen when extremely cold weather settles in on the upstream side of the pipeline, which is part of the cause for the disastrous effects from the winter storm in Texas with winter storm Uri. Accounts of winter storm Uri from February of 2021 show documented instances where infrastructure on the region's interstate and intrastate pipelines failed to perform due to exposure to durational record cold weather. Those isolated failures had a cumulative effect as the storm settled in. Loss of flowing gas supply meant power plants couldn't run at full capacity. Pipeline compression driven by electricity began having outages which further impeded delivery of natural gas for power generation. This created a near catastrophic downward spiral that only stopped when enough load was shed from the system due to power outages and loss of service to customers.

AGL will continue to evaluate its Reserve Margin position, including available capacity options and the impact of possible outages. The 2025-2028 CSP will recommend a higher Reserve Margin for the system to ensure the safe, reliable service that AGL customers expect that also preserves an ability to support and encourage further economic growth and development.

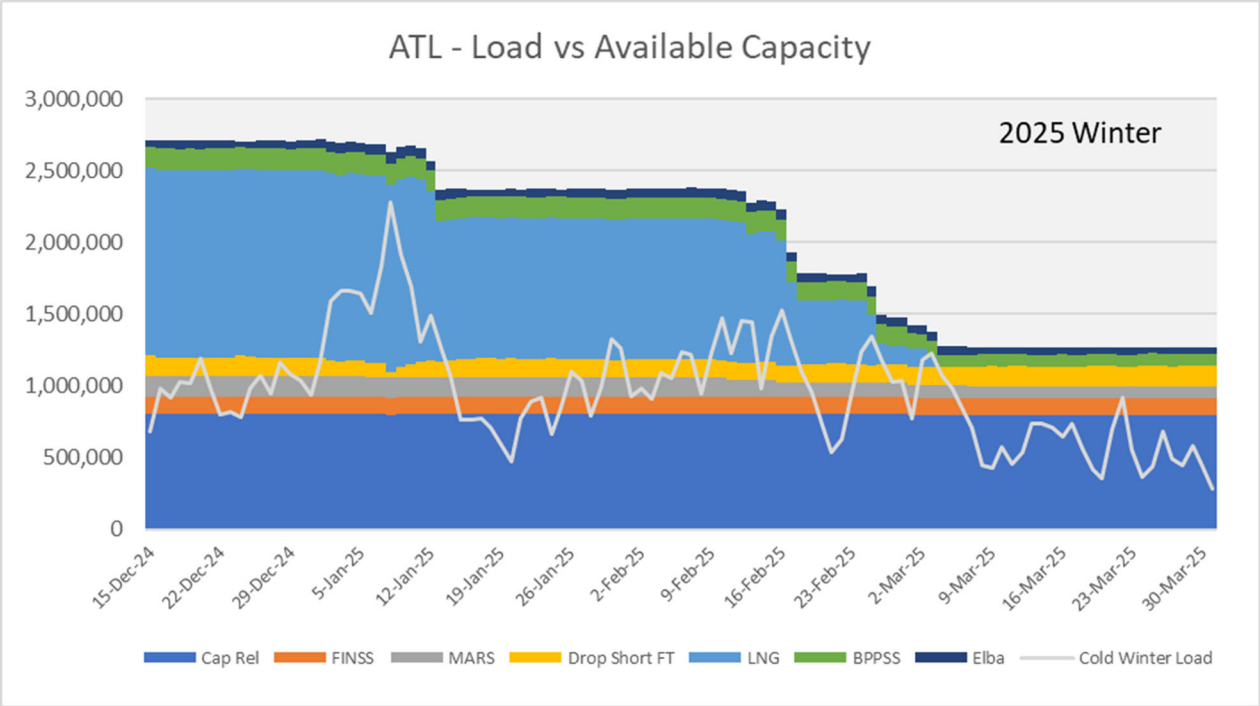
4.6 Future Considerations and Action Plan

In Figure 4.7 shown below, the Company projects out to the heating season of 2024-25 using the same forecasting approach to calculate firm load. By this time, the Cherokee LNG facility will have full access to all of its existing 520,000 Dth/day of vaporization capability because the liquefaction capability of the plant is projected to be doubled in the previous year. Without the added liquefaction capability, the added send-out capability would shorten the durational availability of natural gas from the LNG Plant from approximately 5 days to approximately 3 days. To satisfy the projected load, the LNG plant would need to run at nearly 100% of its equipment's



rated capacity. Although that is an acceptable plan, it is risky. Failure of any one component of the vaporization process could meaningfully reduce the amount of gas supply available from the plant. Additional gas supply capability of that magnitude would be nearly impossible to replace or replicate with additive supply being delivered from the interstate pipeline system. Because of this great risk, the Company will include this dynamic as it re-evaluates the Reserve Margin needs of the geographic pool groups, as well as the system as a whole.

Figure 4.7: Load versus Available Capacity 2024-2025 Winter



Moreover, the firm load expectations in 2027-28 will exceed the durational capabilities of the upgraded LNG facility. There are several ways to approach this projected shortfall. The heart of it is to introduce further durational gas supply capabilities to the AGL system. One simple alternative would be to eliminate the restrictive provisions around the FT capacity that AGL contracts for with firm receipts at Elba Island. Additional reductions of the limits placed on the Transco capacity originating at Station 210 may also help. Currently the utility is only allowed to call on FT capacity with receipt at Elba Island for 5 days in any heating season. Making that gas supply available, like any other FT on the system, would help reduce the number of days that peaking supplies like Cherokee LNG, would need to be partially or fully utilized. Further, the utility has begun searching for additive firm transportation capability to augment the gas supply

capabilities of the system. This set of circumstances was also mentioned in the Company's 2019-2022 CSP.

Given the limitations of the interstate pipeline system, the Company's location on those pipelines, and the continuing growth and demand for natural gas in AGL's service area, this analysis demonstrates that a re-evaluation of AGL's Reserve Margin is not only appropriate, but necessary to ensure the Company's ability to meet the needs of its firm customers on any day of the year. As a part of the next CSP process in 2025-2028, with the input of the relevant stakeholders, the Company will present its findings and recommendations to the Commission for any changes in its Reserve Margin and how to best meet any increased margin requirements.

4.7 Conclusion

The Commission's approval of the 2022-2025 CSP greatly benefited customers by enabling AGL to develop important new and upgraded LNG facilities at Cherokee. But the pace of growth for both new and existing customers, combined with the ongoing limitations in the pipelines serving Georgia, compel further key actions. Accordingly, for the next CSP proceeding that will be filed in 2025, AGL requests that this Commission agree with AGL's load forecast as presented in this filing and approve the following in the 2025-2028 CSP: allow AGL and other stakeholders to explore readily available incremental gas supply options like making Elba Island FT available to deliver supply to the AGL system consistent with other FT in the approved Array of Interstate Assets; allow AGL and other stakeholders to explore increasing the Reserve Margin; approve the upgrade to the liquefaction equipment at Riverdale LNG as further discussed in Chapter 5, and approve construction of a scalable storage / vaporization-only LNG facility in Valdosta further discussed in Chapter 5 of this Plan.



CHAPTER 5. INFRASTRUCTURE DELIVERY PLAN

5.1 Capital Challenges and Infrastructure Delivery Plan Summary

This second Plan continues and advances those projects and initiatives presented in the Company's 2022 i-CDP while identifying new and potential projects responsive to the demand of existing and new customers and increasingly more impactful regulations. Balancing customer safety and reliability with customer affordability has been especially exacerbated these last three years because of substantially increased labor and materials costs caused by rising interest rates and inflation, supply chain disruptions, and scarcities in the labor market, especially for skilled workers. None of these unforeseen challenges were reasonably anticipated when the 2022 i-CDP was prepared. These challenges and others, as outlined in detail in Section 5.2 of this document, have required AGL to adjust, reprioritize, and reorder certain other safety, compliance, system integrity, and growth initiatives to stay within the approved 2022 i-CDP and with each of the subsequent Annual GRAM Filings. The effect of this is the Company generally spent what was projected, but less was accomplished because the dollars did not go as far.

Going forward, the Company can and must complete the projects identified herein. But the timetable for some projects will be extended as AGL works to balance customer needs and regulations with responsibly managing customer rate impacts. In accomplishing these goals, there are multiple challenges and opportunities that must be addressed. Key among these are the following:

- **The Challenge of Largely Uncontrollable Project Scale, Scope, and Costs** – As Georgia's opportunities continue to grow, many of AGL's obligations have grown as well. Georgia is proud to have been named among the most favored places in the nation to do business. The ongoing initiatives authorized by this Commission have fundamentally sustained Georgia's economic growth and continued prosperity. Indeed, access to available, affordable energy is a key consideration for many who have decided to make Georgia their home. State law, federal regulation, and AGL's Commission-approved Tariff require AGL to incur certain expenses and make certain investments to meet the growing needs of its customer base. Work types such as New Business (Section 5.9), PT Meters (Section 5.20), and DOT relocations (Section 5.13) are largely driven by tariffs, right-of-way agreements, or other external factors, which make it very difficult for AGL to control the quantity, location, and type of this work. Additionally, DOT relocation cost increased by more than 50% in 2023 due to a combination of additional federal infrastructure funding,



pandemic related project quantity rebounds, a significant number of DOT state highway widenings, and just overall project cost increases. This increased level of DOT work is expected to continue based on ongoing and currently known projects and may even increase further based on recent statements from Governor Kemp and his 2024 legislative budget proposal for an additional $1.5 billion for the DOT to accelerate the agency's project pipeline for infrastructure investments.[14] The costs of these projects cannot be effectively forecasted, as the actual scale and scope of these projects are often not known until the middle of the fiscal year in which the projects arise.

- **The Challenge of Meeting Customers' Increasing Design Day Requirements –** As provided for in the 2022 i-CDP, AGL has worked to install a large LNG plant expansion at the Cherokee LNG facility and continues to invest in multiple large System Reinforcement projects to address existing and pending system supply challenges. While the Cherokee LNG plant expansion is still on track to be completed in 2025, the need for a new satellite LNG facility has arisen in the Valdosta area to support new growth and customer load conversions (Section 5.7). Cost increases have required System Reinforcement project adjustments to stay within the rate impact commitments made during the hearings on the initial i-CDP. Proposed System Reinforcement plans detailed in this Plan reflect the need to accelerate these delayed projects at higher-than-initially-estimated costs to help maintain system supply and operating pressures on the coldest days of the year. Past investments in capacity and infrastructure have created opportunities to add new customers, including some large demand customers, but meeting those needs on Design Days can be problematic.

- **The Challenge of New Pipeline Regulations –** AGL must increase initiatives to comply with new regulations, and that increased work is the cause of capital budget increases in the TIMP-Digs (Transmission Integrity Management Program) (Sections 5.19 and 5.20), AC Mitigation (Section 5.21), and Renew-Remote-Controlled Valves (Section 5.15) budget lines in excess of $100 million over the next 10 years to comply with these new regulations. It should be noted though that as of the filing date for this i-CDP, there are multiple proposed PHMSA regulations and a potential proposed Notice of Proposed Rulemaking ("NOPR") by the GPSC Facilities Protection Staff, the **impacts of which are**

[14] *Gov. Kemp Lays Out Priorities for 2024 Session at Georgia Chamber's Annual Eggs and Issues Legislative Event*, available at, https://gov.georgia.gov/press-releases/2024-01-10/gov-kemp-lays-out-priorities-2024-session-georgia-chambers-annual-eggs (last viewed 1-24-2024).



not included in this Plan due to uncertainties as to the final requirements. As currently drafted, any of these proposed rules has a potential to require an update to AGL's proposed plans and significant increases of costs to comply. Continuing customer growth provides some opportunities for spreading out these costs, but the ultimate customer rate impacts will likely be significant if the new rules require new projects or other new investments.

- **The Challenge of the Highest Risk Pipes –** As outlined in AGL's 2019 case and the 2022 i-CDP, AGL needs to replace at a significantly faster pace its aging pre-1960 steel and mid-vintage (1974-1983) plastic pipelines, which have been identified as its highest leak rate pipes (section 5.11). The start of the proposed growth of DIMP-driven pipeline replacements has been delayed until 2028 to mitigate impacts to customers' distribution rates. Nonetheless, replacing these aging facilities will need to be accelerated in the coming years, with potential additional mandates being included within proposed and anticipated environmental and safety rules. Updates and modern materials provide opportunities both for system reliability and lesser environmental impacts.
- **The Challenge of Technology –** As outlined in Section 5.21 of this document, AGL has a significant number of aging Encoder Receiver Transmitters ("ERT") units that must be replaced to maintain current meter reading capabilities. AGL proposes to significantly increase these replacements in the outer years of the Plan. Improved technology within the system provides potential opportunities for reduced labor costs, better management of demand, and more accurate and timely reporting.

The items listed above, as well as many more as outlined within this chapter, will require AGL to significantly increase its capital investments over the coming years to maintain safety, regulatory compliance, system reliability, and support continued economic development. While the number and scope of projects must increase in the coming years, in this Plan the Company has attempted to balance the timing such projects, where possible, against maintaining affordability for AGL's customers.

5.2 Key Challenges and Regulations Affecting Existing and Proposed Plans

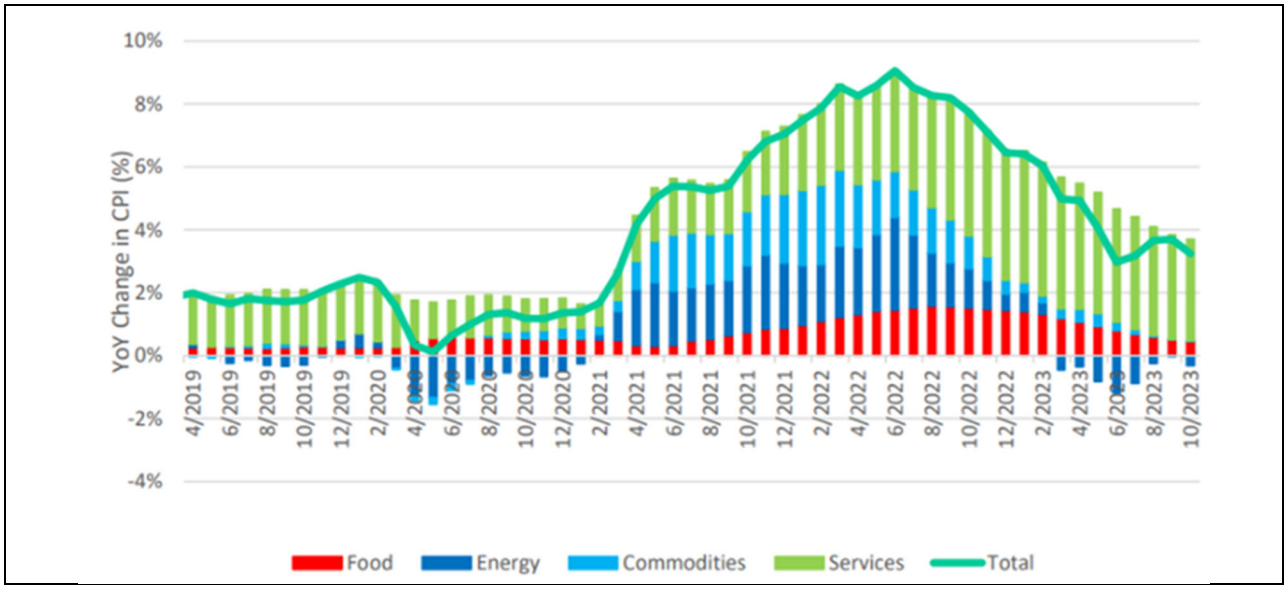
As stated in section 5.1, there are multiple challenges facing AGL as it maintains safe and reliable service to its customers while supporting growth, implementing industry best practices, replacing aging facilities, complying with current and new regulatory requirements, and increasing



environmental stewardship measures. In assessing where, when, and how the Company should make necessary system investments, the Company must also balance customer costs, so the services remain affordable and supportive of continued economic growth in Georgia. This section further outlines these challenges, along with others, in significant additional detail for clarity and support of the proposed Plan and the necessary capital investment and related expense levels. These challenges include, but are not limited to, the following:

- General price increases continue to adversely impact project costs. While general inflation itself has driven up AGL's costs across the board (see Figure 5.1 based on Bureau of Labor Statistics data), price increases for the types of materials and labor that are specific to AGL's operations far exceed general inflation rates. Labor shortages are especially impactful where skilled labor is necessary both for AGL and its subcontractors, causing delays and unanticipated cost increases Moreover, interest rate increases implemented by the Federal Reserve to combat general inflation also significantly affect AGL's costs for borrowing funds to invest in capital projects. While recent inflation trends have been downward, the cumulative effect of higher costs when combined with continuing labor and materials shortages results in the cost floor being substantially higher, meaning the dollars do not go as far.

Figure 5.1: Inflation Tracker



- Significant growth in residential, commercial, and industrial usage of natural gas, especially from new customers, continues to require large investments in peaking and infrastructure, especially to meet Design Day requirements.

- Supporting this growth also requires moving gas from the supply pipelines and facilities to AGL's customers. Current projects are addressed within the current i-CDP through the SRR.

- Replacing aging facilities continues to be a major focus of the Company as AGL works to maintain a safe and reliable system while reducing methane emissions from these older facilities. Bare steel and cast-iron replacements as well as replacements of early vintage plastics was previously completed under separate rider programs. With the foresight and support of the Commission for these programs, AGL has been a leader within the industry in replacing these higher-risk facilities. But the need for large scale infrastructure replacement programs continues for aging facilities made from materials other than bare steel and cast-iron in AGL's system. Based on current AGL DIMP findings (see section 5.11) and previously released regulations and guidance from PHMSA, the need to stop methane leaks from pipelines and pipeline facilities due to other vintage materials must be addressed. An advisory bulletin[15] released June 7, 2021, states "*In addition to addressing intentional and unintentional emissions, the advisory also specifies that operator plans are required to address the replacement or remediation of pipelines made from cast iron, bare steel, certain vintage plastic, or other legacy materials that are known to cause a disproportionately large share of incidents involving methane leaks.*" It should also be noted that additional vintage pipeline replacement mandates are currently proposed in the PHMSA leak detection and repair rule as outlined immediately below.

- New regulatory requirements continue to drive significant infrastructure investments, as well as O&M expenses, *including*:

    - MAOP Reconfirmation – The PHMSA rule that went into effect in July 2020 requires Operators to reconfirm the MAOP of their transmission pipelines. This requirement was originally estimated in late 2019 to early 2020 at a total cost for AGL exceeding

[15] PHMSA Advisory Bulletin concerning the need to address methane leaks from pipelines and pipeline facilities is available at the following link: https://www.phmsa.dot.gov/news/phmsa-advisory-bulletin-pipeline-industry-must-take-actions-address-methane-leaks-pipelines

$700 million over a 15-year period. These projected costs have increased significantly due to cost increases and other challenges as well as an increased portion of AGL's system that must comply with the rule (described as RIN-2 below).

- RIN-2 – PHMSA released a final rule titled "Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments," in August 2022 which is commonly referred to as "RIN-2." One of the many changes in this rule includes a significant change in the definition of a "transmission line." The total impacts of this definitional change, however, are still unclear since the language within the new definition can be interpreted multiple ways. Industry informed PHMSA of this ambiguity following the issuance of the rule and PHMSA committed to industry in the fall of 2022 that they would clarify the definition with a series of Frequently Asked Questions ("FAQs"). It is now early 2024 and PHMSA still has not issued those FAQs to remove the ambiguity. Depending on how PHMSA resolves the ambiguities, the Company could be required to do hundreds of very costly investigatory digs to validate pipeline material characteristics on existing pipelines within the AGL system should they be reclassified as "transmission." These digs would validate material type, grade of material, size, wall thickness and weld seams. Based on these validations, several hundreds of AGL's existing "distribution lines" may be reclassified as "transmission lines" for purposes of this rule. If that occurs, the reclassification will greatly expand the scope of the required response to this regulatory mandate as well as the ongoing costs to monitor and maintain these pipelines and install Remote-Controlled Valves ("RCVs") per AGL's TIMP program and current PHMSA requirements. These validation digs will require significant investments just to determine or confirm the actual characteristics and ultimately the quantity of the pipe in question. Once the quantity and location of the pipeline segments that will may qualify as "transmission" are confirmed following the investigatory digs, AGL will then be required to:

    - Determine if any of this newly determined transmission pipe has created even more reclassified transmission segments from the ambiguous definition language associated with "connected series of pipelines" under the rule. This alone has the potential to add tens or even hundreds of additional transmission miles to the program.



- Once all of the new transmission miles are quantified, AGL must then also add these pipelines to its MAOP reconfirmation program as outlined above. As of now, PHMSA has neither provided a clear definition nor an extension of the original 15-year MAOP reconfirmation mandate to account for these newly identified pipeline segments. If the scope of the PHMSA rule were to be expanded without a compliance deadline extension, AGL would need to accelerate its compliance program at additional cost to accommodate the substantial scope expansion.

  - PHMSA Valve Installation and Minimum Rupture Detection Standards ("RMV rule") – This final rule was released in 2022 with a full implementation deadline of April 10, 2023. The rule requires RCV or automatic shut-off valve ("ASV") installations on most new and "Entirely Replaced" (as defined in CFR 192.3) 6-inch and larger transmission lines. The proposed rule also addresses rupture detection and response standards and has a requirement to evaluate existing transmission line valves in High Consequence Areas ("HCAs") for retrofitting with remote controls or replacement to enhance the safety of these pipelines (see section 5.15 for additional details).

- Along with the known (and partially known) requirements listed above, there are multiple proposed rules that are not funded in this Plan because the final requirements and timing are not yet known. These proposed requirements could potentially increase the scope of compliance initiatives and associated funding requirements significantly. These additional proposed rules include, but are not limited to:

  - GA PSC Docket No. 43465 – Notice of Proposed Rulemaking – Consideration of Rules Addressing the Safe Installation and Operation of Natural Gas Transmission and Distribution Systems – This draft NOPR includes potentially significant new requirements in multiple areas including construction reporting, ongoing review of inactive service lines and stubs, abandonment of inactive service lines and stubs that no longer have a prospect for future use, valve placement program development and implementation, and the regulator station inlet valve 25-foot distance requirements. While the actual impacts of these new requirements cannot be determined until a proposed rule is issued by the Commission, many of the proposed items issued in the initial draft rulemaking would require significant incremental investment, and compliance requirements for many of these items exceed the requirements of federal pipeline safety regulations. An evaluation of the financial impact to comply with this



new proposed Georgia-only rule indicates an estimated cost ranging from $25 million per year or $250 million for a ten-year period, to $70 million per year or $700 million for a ten-year period, depending on the final version of the NOPR. The cost of the NOPR is unknown at this time as the proposed rule has not yet been promulgated. Initial estimates of the potential impacts (capital and O&M) have been shared with the Commission's Facilities Protection Staff. Moreover, natural gas operators within Georgia have suggested adjustments to the proposed new requirements to lessen the financial impacts of the proposed rules while continuing to address many of the draft Rule's areas of focus. At the time of this filing, the status of this draft NOPR remains uncertain.

- Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2020 ("PIPES Act of 2020") – This federal law became effective on December 27, 2020, and includes the necessary reauthorizations for PHMSA but also includes multiple requirements for PHMSA to propose new rulemakings related to the reduction of methane emissions and the concerns that emerged following the Merrimack Valley, MA incident in 2018. The PIPES Act of 2020 includes an array of Congressional mandates to PHMSA including DIMP and emergency response plan enhancements, implementation of Pipeline Safety Management Systems ("PSMS"), requirements around idled pipe, new regulator station requirements, RCV requirements for transmission lines as noted above, and multiple mandates related to reducing methane releases. This Congressional mandate to PHMSA has resulted in two major proposed rules being released recently with potentially dramatic impacts to compliance initiatives within this Plan (as well as the associated capital budget parameters and related O&M requirements), should proposed rules be adopted as currently written:

    - PHMSA Pipeline Safety: Gas Pipeline Leak Detection and Repair (Docket # PHMSA-2021-0039, May 2023) – This proposed rule[16] includes amendments to reduce methane emissions from new and existing gas transmission pipelines, distribution pipelines, and liquefied natural gas facilities. Among the proposed amendments for Part 192-regulated gas pipelines are more frequent leakage

[16] The PHMSA Gas Pipeline Leak Detection and Repair proposed rule was released in May 2023 and subsequently published to the Federal Register on June 2023 at the following link: https://www.federalregister.gov/documents/2023/06/30/2023-13900/pipeline-safety-gas-pipeline-leak-detection-and-repair



survey and patrolling requirements; performance standards for advanced leak detection programs; leak grading and repair criteria with mandatory repair timelines; requirements for mitigation of emissions from blowdowns; pressure relief device design, configuration, and other maintenance requirements; and clarified requirements for investigating failures. This rule proposes expanded reporting requirements for operators of all gas pipeline facilities within the United States DOT's jurisdiction, including liquefied natural gas facilities.

The actual impacts of these new requirements cannot be determined until a final rule is published, but many of these proposed items, if adopted as initially proposed, would require significantly more robust compliance work (along with higher investments and expenses in these areas) to achieve compliance. AGL's specific current compliance and safety standards that would not meet the newly proposed federal requirements in the NOPR are: Defining all Leaks as Hazardous/Repairing all Grade 3 Leaks; Pressure Relief Limiting Design and Relief Maintenance; Developing an Advanced Leak Detection Program ("ALDP"); Need for Additional Advanced Leak Detection Mobile Equipment and Advanced Leak Detection Handheld Equipment; Accelerated Transmission Leak Survey and Monthly ROW Inspections; Accelerated Distribution Leak Survey; LNG Leak Survey; Accelerated Grade 2 and Grade 3 Leak Re-evaluations; IT Costs (Leak Survey, Asset & Work Management Systems); Performing Extreme Weather Leak Surveys; Investigating Known Leaks After Environmental Changes; Minimizing Emissions on Transmission Line Blowdowns; Pressure Relief Device Maintenance; and Additional Personnel (Engineers and Analysts). Initial evaluation of meeting the requirements of this proposed rule estimate initial capital costs of $10.68 million plus another $3.35 million annually thereafter. Estimates of the O&M impacts associated with the proposed rule are an additional $39.12 million up front and annual costs of $28.96 million each year thereafter. This rule could be finalized by PHMSA as early as late summer 2024.

- PHMSA Safety of Gas Distribution Pipelines and Other Pipeline Safety Initiatives (Docket No. PHMSA-2021-0046, August 2023) – This proposed rule[17] would revise

[17] The PHMSA Safety of Gas Distribution Pipelines and Other Pipeline Safety Initiatives proposed rule was published to the Federal Register on 9/7/2023 at the following link:



the pipeline safety regulations to require operators of gas distribution pipelines to update their DIMP, emergency response plans, operations and maintenance manuals, and other safety practices. These proposals implement provisions of the Leonel Rondon Pipeline Safety Act—part of the PIPES Act of 2020—and a National Transportation Safety Board ("NTSB") recommendation directed toward preventing catastrophic incidents resulting from over-pressurization of low-pressure gas distribution systems similar to that which occurred on a gas distribution pipeline system in Merrimack Valley in 2018. Further, PHMSA proposes other pipeline safety initiatives for all Part 192-regulated pipelines, such as updating emergency response plans and inspection requirements. Based on the existing proposed rule, many of the proposed items could require significantly more robust compliance work (along with higher investment and expenses) in these areas to meet compliance requirements. Initial evaluation of meeting the requirements of this proposed rule indicate that the initial capital costs would be $135 million with annual capital costs of more than $100,000 and annual O&M costs thereafter of $6.5 million. This rule could be finalized by PHMSA as early as winter 2025.

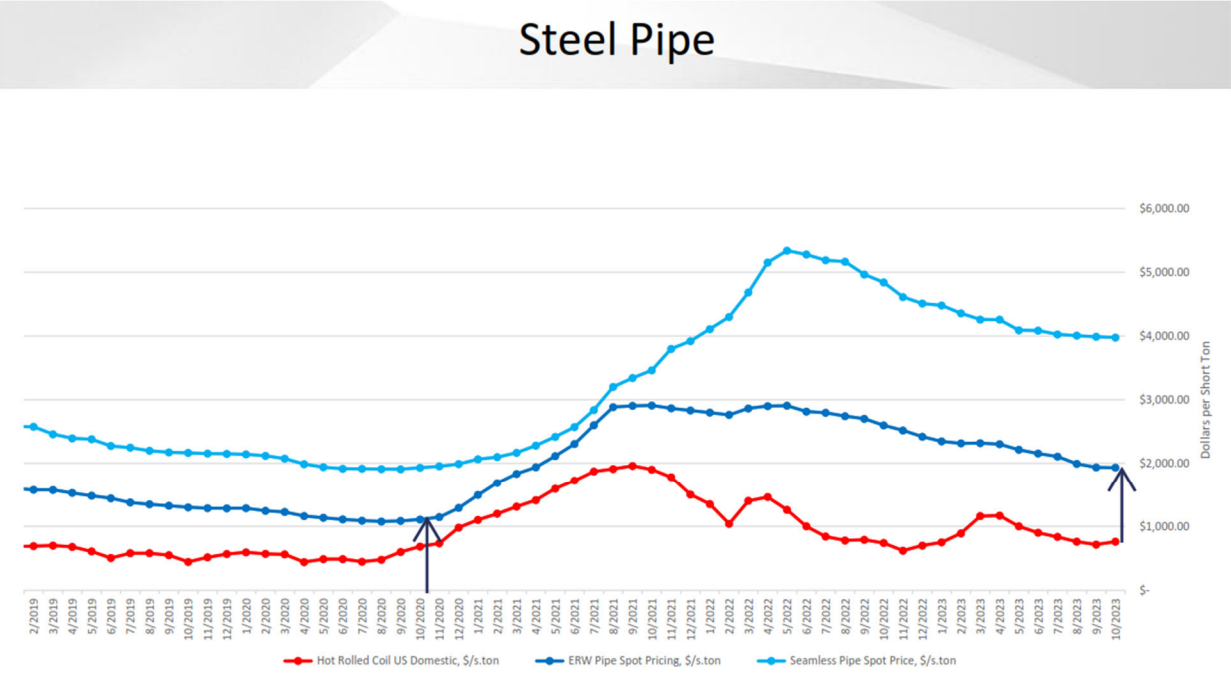
- Changes in key gas pipeline and related construction material prices can have a significant impact on project costs. In the current environment, it is very difficult to predict changes in these material prices over a 10-year or even a 3-year period. A current example is the significant increase in the cost of Electric Resistance Welded ("ERW") steel pipe.[18] As shown below in Figure 5.2 in the dark blue trend line, ERW steel pipe prices increased from just over $1,000 per ton in late 2020, when the existing 2022 i-CDP was being created, to almost $3,000 per ton through early 2022. Since that time, ERW pipe costs have subsided some, but they are still approximately $2,000 per ton as of October 2023. Even with this slow price reduction, steel pipe is now double the cost that it was in late 2020 when the initial i-CDP approved in 2021 was being developed, resulting in a significant and mostly uncontrollable impact on the costs for many of AGL's larger and higher-pressure pipeline projects.

https://www.federalregister.gov/documents/2023/09/07/2023-18585/pipeline-safety-safety-of-gas-distribution-pipelines-and-other-pipeline-safety-initiatives

[18] ERW steel pipe is the standard for 2" through 16" new or replaced steel pipelines within the AGL system so it is a good representation of the cost increases AGL has seen on steel pipe in recent years.



Figure 5.2: Price of ERW Steel Pipe per Short Ton



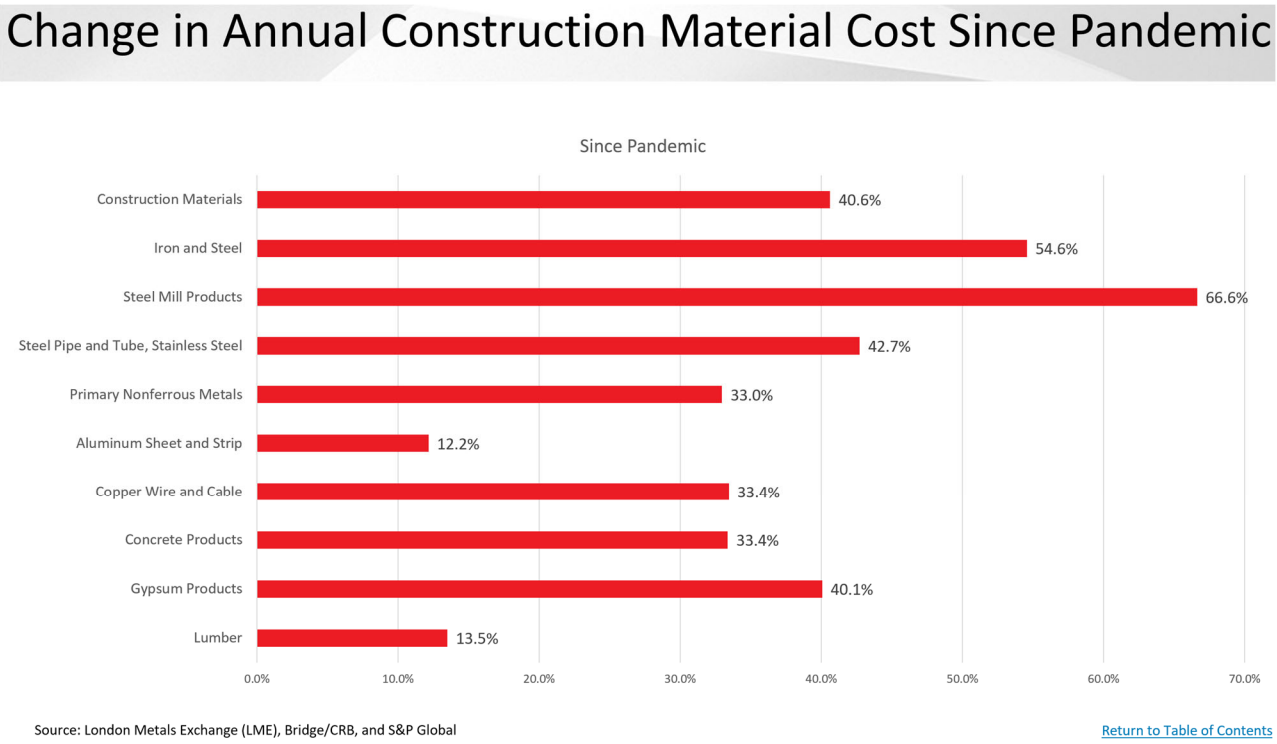
Source: MRC Global

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For context as to the potential impact of a $1,000 per ton increase on a large steel project, the current “Cumming to Hall” System Reinforcement project includes 27.8 miles of 16” 0.375” ERW steel pipe which weighs 62.64 lbs. per ft. This would equate to an approximate increase in base pipe costs of $4.6 million for this project alone.

This cost impact is mirrored across almost all materials categories associated with gas facility construction as evidenced by the Figure 5.3 graphic below which shows the percent change in costs for many of these items since the start of the pandemic.

Figure 5.3: Change in Annual Construction Material Cost Since Pandemic

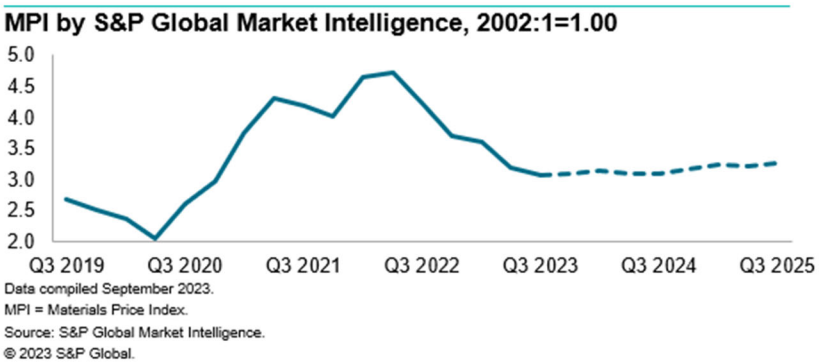


Source: London Metals Exchange (LME), Bridge/CRB, and S&P Global

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While the Materials Price Index ("MPI") by S&P Global Market Intelligence clearly indicates that the spike of 2021–22 is over, the table in Figure 5.4 below indicates that prices are starting to level out and have generally established a higher price floor. This analysis supports AGL's expectation that overall material costs will remain elevated well into the next i-CDP period and therefore must be considered as the Commission considers capital budget parameters.

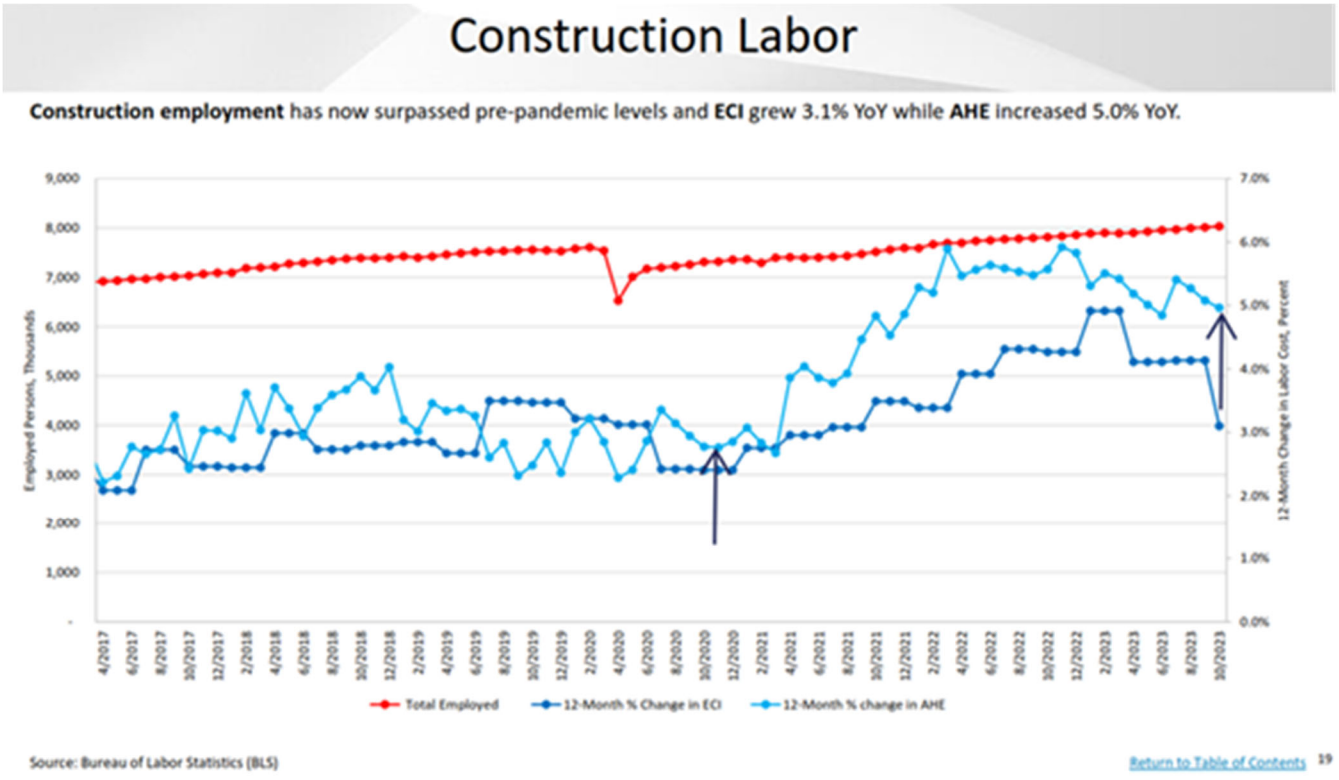
Figure 5.4: MPI



- Tight Labor Markets – As shown by the red trend line in Figure 5.5 below, construction labor employment levels have just now returned to pre-pandemic levels. This multi-year

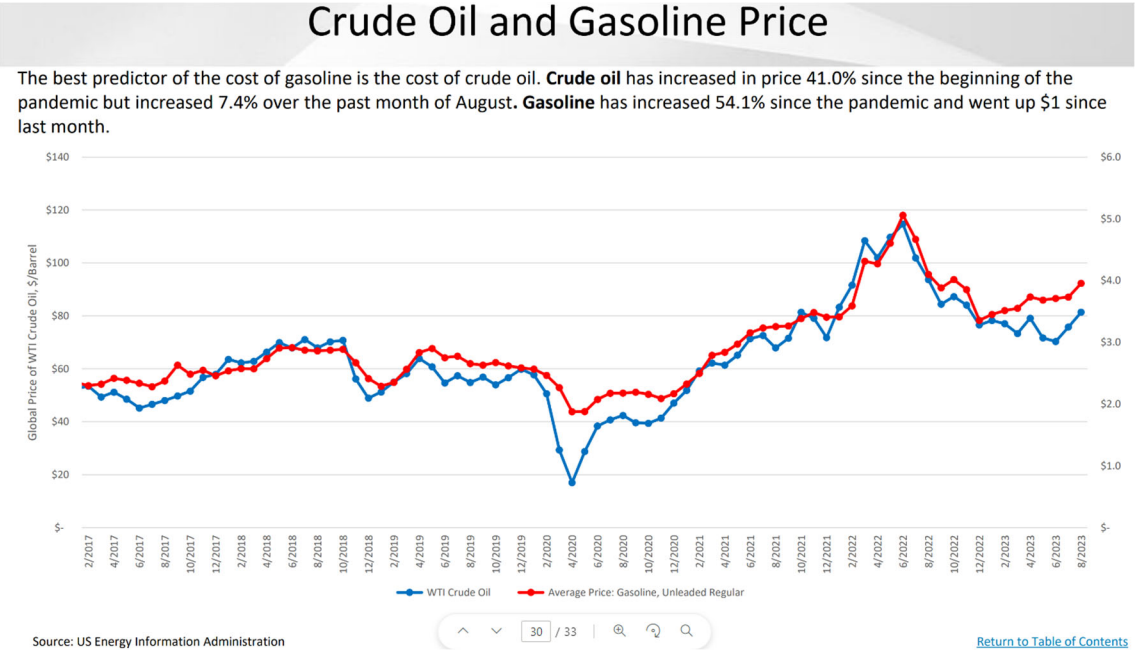
shortage of pipeline contractors, inspectors, and others involved in the installation of AGL's facilities has led to a step change in construction labor costs, which in turn has and will continue to increase project costs. As can be seen in the chart below, the 12-month percentage changes in Average Hourly Earnings (light blue trend line) have spiked since late 2020 and currently are still holding around 5.0% vs. approximately 2.8% at the time of drafting the 2022 i-CDP.

Figure 5.5: Construction Labor



- Fuel Costs – All aspects of natural gas pipeline work, from vehicles and equipment to the asphalt necessary to repair road cuts, are affected by oil and related fuel costs and these costs have risen sharply over the past few years as shown in Figure 5.6 below:

Figure 5.6: Crude Oil and Gasoline Price



- Implementation of Best Practices – AGL continually reviews and implements best practices across its system to increase safety, reliability, and customer service. While many of these best practices require additional infrastructure investment, the corresponding risk reductions and increases in safety and customer service have been deemed by the Company to be worthy investments. Current examples include:
    - Ongoing programs within the current i-CDP to reduce the likelihood of an over pressurization event based off best practices identified in the wake of the Merrimack Valley incident including:
        - The “Partition Valve” program as outlined in Section 5.15 of this document which is designed to mitigate existing single valve separation points between two different pressure systems.
        - Multiple regulator station safety enhancement programs as outlined in Section 5.16 of this document.
    - Continuing to strengthen the creation of “Flow Interruption Plans” to increase safety when tying into, relocating, retiring, or otherwise physically changing the flow of gas in the system. Also integrating emission reduction measures and reporting into these

plans to enhance reporting needed to help meet proposed emission reduction requirements.

- Environmental Stewardship Measures – AGL continues to look for innovative ways to reduce its environmental footprint. In addition to the opportunities identified in Chapter 8 of this document, other operational efforts are being tested and implemented. One example is the growth of portable gas compression options to reduce the impacts of gas releases during blowdown activities to help meet Company net-zero emission goals and are consistent with PHMSA proposed rules.

Each of the challenges, programs, and best practice implementations listed above, as well as continued high cost increases and interest rates, have and will continue to significantly affect AGL's capital investment requirements.

5.3 Summary of Existing and Proposed Projects and Action Plans

As outlined in the "Pre-Filed Direct Testimony of Steve Murphy, Jennifer Rose, Donald Carter, and Bradley J Beckman on Behalf of Atlanta Gas Light Company" in the 2019 rate case filing, also known as the "Engineering Panel" testimony, and repeated within the currently effective 2022 i-CDP, AGL proposed multiple projects and programs to help ensure a safe and reliable system while supporting the continued growth and minimizing where possible the impacts to customer rates. These submissions included fifteen safety programs plus support for customer growth and other required work.

The safety programs as previously submitted, with updates inclusive of new and emerging regulations, are as follows:

1. Reconfirming MAOP - Verifying whether AGL can continue to operate its transmission pipelines at their current MAOPs. This PHMSA mandated program began in July 2020 and ends July 2035. Update: This program is not only challenged by inflationary costs but also will have to expand significantly to meet the new PHMSA definition in the RIN-2 rule released in 2022.

2. Modifying Pipelines for Smart Pigs - Modifying AGL's transmission pipelines to allow internal inspection tools, commonly known as "smart pigs," to collect pipeline integrity data and to identify parts of pipelines that pose risks. This work will continue on selected pipelines that have been identified as candidates for retrofit but no ending date has been



identified for this initiative. Update: While AGL continues to invest in this significant safety and pipeline integrity initiative, investment levels continue to be challenged by rising costs and competing priorities.

3. Preventing Alternating Current ("A/C") Hazards - Installing protective systems on existing transmission pipelines to prevent accelerated corrosion. Update: While this program has also been challenged by rising costs and competing priorities, the RIN-2 rule released in 2022 now mandates AC Mitigation efforts as outlined in CFR 192.473(c) and will likely require increased investment in this area based on results from required pipeline interference surveys.

4. Installing RCVs - Expanding the use of RCVs on AGL's existing transmission pipelines to enable faster responses to unsafe conditions. AGL has not determined a timeline for this work since there are many unknowns as to what the PHMSA NOPR will require as well as what guidance will be provided by the PIPES Act of 2020. It should be noted that new and fully replaced transmission pipelines include strategically placed valves that include remote controls or remote-control capabilities. Update: This work is now mandated by the PHMSA RMV rule, as outlined previously in this section, and will require significant additional investment as outlined in section 5.15 of this document.

5. Replacing Higher Risk Pipelines - Prioritizing system replacement based on DIMP risk analyses. There is no end date for the DIMP requirements. Update: AGL continues to replace its highest risk pipelines based on DIMP program analyses but will require accelerated replacement of these pipelines in the coming years to avoid obsolescence issues with potentially additional mandates coming through proposed environmental and safety rules from PHMSA.

6. Remediating POSI-HOLD Couplings - Replacing or repairing POSI-HOLD couplings near end caps on systems operating at elevated pressures. AGL had committed to a completion date of 7/1/2022. Update: This program was completed as planned and committed to by AGL.

7. Remediating Cased Crossings - Verifying electrical isolation of pipelines at cased crossings and remediating any identified isolation failures. The GPSC casing program began July 2018 and was originally projected to end July 2025. Update: This program continues and AGL is currently on track to meet its commitment to the PSC Facilities



Protection Staff with 677 of the 711 reported casings remediated. Additionally, while working to complete this 7-year program, an additional 589 casings have been identified of which 143 have also already been remediated to date.

8. Evaluating Regulator Stations – Reviewing existing regulator station designs and making necessary changes to stations to help prevent over pressurization of AGL's system. This program, called Regulator Station Review Program ("RSRP"), was originally scheduled to be completed in 2023. Update: This program was slowed significantly due to cost increases and pressures from competing priorities with a current proposed completion in 2028.

9. Retiring Inactive Services - Reducing the risk of excavation damage to inactive service lines that have little or no potential for providing service in the future. AGL is currently addressing the highest risks, such as instances where a structure is going to be demolished. Other abandonments often occur in conjunction with main retirements or replacements performed in the same general area so as to take advantage of cost savings associated with mobilizing field resources on a project. This initiative may be affected by the GPSC NOPR in Docket No. 43465. Once the NOPR is finalized, the Company will re-evaluate its approach to retiring inactive services. Update: AGL continues to address higher risk inactive services, with some work reductions due to cost increases and competing priorities and continues to await the final requirements from the NOPR before making additional adjustments to its program.

The following programs have significant O&M cost impact, the cost of which will continue to be addressed in the Annual GRAM Filings:

1. Replacing Celcon Caps on Service Tees - Identifying and replacing Celcon caps on higher risk service tees installed between 1984 and 1995 to avoid leaks and potential service disruptions.

2. Inspecting Sewer Systems for Potential Cross-bores - Identifying natural gas pipelines within sewer systems using a robotic camera and relocating AGL's pipe to eliminate unintended damage during sewer clearing.

3. Reducing Third Party Excavation Damages - Implementing a watch and protect program focused on AGL's critical pipelines.



4. Improving Data Quality and Accessibility - Converting older paper pipeline records into electronic formats, validating the records, and making those records readily available to field personnel.

5. Expanding Quality Assurance - Enhancing existing quality assurance evaluations at AGL to include operations and maintenance work.

6. Applying PSMS - Implementing PSMS at AGL.

Along with the safety and reliability programs listed above, the Engineering Panel also included additional ongoing programs to address growth and other required work. These programs included:

- System Reliability Projects – These are generally large-scale new pipelines to get the gas supplies from the supply points to the areas of the state where there is the most growth. Going forward, these projects will be considered, and Commission-approved projects will be funded by the SRR charge as a ratemaking process within each i-CDP. Update: While the highest priority System Reinforcement projects have not changed, the labor, materials, and other cost pressures on these large projects have required the slowing of the work plans to allow for critical SRR projects associated with the Cherokee LNG expansion and the highest risk of customer loss to be completed first.

- LNG Facility Upgrades Other than the Cherokee Expansion Project – AGL relies heavily on three LNG plants strategically located across the state to provide peak gas on the coldest days of the year. These plants all have significant age and require some large capital improvements to maintain reliability and operability when called upon. This is an ongoing initiative,[19] nonetheless, AGL is accelerating investments in this area for a few years to address some key issues as outlined in section 5.6. Update: Key reliability and obsolescence projects continue at these plants to help ensure adequate capacity on the coldest days of the year.

[19] The need to maintain and replace LNG equipment as the equipment the end of its expected useful life is incremental to, and independent of, the proposed new LNG tank and related facilities to expand the Cherokee LNG plant capabilities discussed in section 4.3 of this Plan.



- DOT Relocation Work[20] – AGL is required to relocate Company facilities located in road rights-of-way when the state, county, or municipal entity makes significant changes to their roadways (e.g., road widenings, intersection improvements, etc.). This is an ongoing requirement. Update: The pace and cost of DOT driven relocations has significantly increased driven in part by the release of multiple large scale state route widening projects as outlined in section 5.13.

- New Business – This is ongoing work, required by the Tariff, to serve new customers and to accommodate changes in loads for existing customers. Update: While actual customer growth has slowed somewhat due to cost increases and interest rate pressures on the housing market, the strong economic development in Georgia along with a shortage of available housing has kept the residential market reasonably strong. This resilient market, coupled with significant labor and material cost pressures on the work, has resulted in significantly higher New Business costs.

- Economic Development Projects – Projects specifically designed to provide natural gas access to unserved and underserved areas of the state, support economic growth, and serve large-scale developments and industries. This ongoing work is generally done through the Universal Service Fund (USF) program or the Econ-1 program with all projects approved by the Commission within the framework of those funding mechanisms. Update: These programs continue as projects are approved by the Commission and now include an increased Econ-1 tariff annual cap.

In addition to the programs and initiatives outlined above, AGL must continue making investments to support and maintain its system and daily operations. This includes but is not limited to: vehicle and equipment purchases (Fleet); building maintenance, repairs, and replacements necessary to support operations (Facilities); and expenses and investments necessary to control corrosion of the Company's steel pipelines (Corrosion).

As can be seen in the provided updates to many of the above programs formalized in the 2019 rate case and the 2022 i-CDP filing, the addition of new mandates as well as challenging economic conditions have required AGL to reprioritize and reallocate resources throughout the

[20] The term "DOT Relocation" is used generically to refer to relocations of the Company's facilities in public rights-of-way and is inclusive of the relocations performed because of public work done by or on behalf of any local, state or federal authority.



first years of the i-CDP program to remain compliant and address the system's highest risks, while remaining within the rate impact limits committed to by the Company during the initial i-CDP hearings. Additionally, using the i-CDP program opportunity (and responsibility) to make investment level adjustments within the same category (GRAM-Safety & Compliance, GRAM-Other, SRR, or Cherokee LNG) further shaped the Plan reprioritizations resulting in differences from AGL's original plans in the 2022 i-CDP as outlined in the Figure 5.7 tables below. For clarity, the green tables below represent the following by column:

- Item – Applicable budget lines shown within the larger i-CDP budget categories
- As Filed – 3-Year average proposed annual investment per budget line in the 2022 i-CDP filing from 2022-2024
- Actuals/Projected – 3-year average of actual 2022 and 2023 plus budgeted 2024 investments
- Chapter 5 Section Providing Additional Details – Location within chapter 5 or other chapters as noted where additional and supporting details can be found for each item
- Initial Plans, Updates, and Resulting Requirements Summary – Provides:
    - Initial Plan - 2022-2024 i-CDP as initially filed and expected results
    - Updated Plan - Actuals from 2022 & 2023 plus budgeted plan for 2024 and expected impacts of any plan adjustments
    - Resulting Requirements - What is needed within the proposed plan to offset these challenges and address new requirements while maintaining a safe, compliant, and reliable system.
    - Avg Annual Proposed Adjustments - Investment levels necessary to mitigate inflationary and other cost pressures, comply with expanded regulations, and catch up key delayed compliance and safety programs as compared to 2022-2024 As Filed investment levels.
- Average Annual Proposed Adjustments vs. 2022-2024 As Filed –



- 2025-2027 – Proposed adjustment to the annual investment rate for each budget line. Compares the average per year rate for 2022-2024 as filed in the 2022 i-CDP against the proposed average 2025-2027 investment rate (e.g., A 1.0 figure in this column signifies that the proposed average 2025-2027 investment for this budget line is $1 million per year higher than the average proposed for 2022-2024 in the original 2022 i-CDP filing).

- 2028-2034 – Proposed adjustment to the annual investment rate for each budget line. Compares the average per year rate for 2022-2024 as filed in the 2022 i-CDP against the proposed average 2028-2034 investment rate.



Figure 5.7: 2022-2024 i-CDP Filing vs. Actuals/Plan

2022-2024 i-CDP Filing vs. Actuals/Plan (NOTE: Totals do not include Overheads and AFUDC)							
Item	**2022-2024 i-CDP (avg. annual investment in $ millions)**			**Chapter 5 Section Providing Add'l Details**	**Initial Plans, Updates, and Resulting Requirements Summary**	**Avg Annual Proposed Adjustment vs. 2022-2024 As Filed Investment Levels**	
	As Filed	**Actuals / Projected**	**Change in Plans**			**2025-2027**	**2028-2034**
GRAM - Safety & Compliance							
Distribution Integrity Management Program (DIMP)	**21.9**	**13.5**	**(8.4)**	5.12	**Initial Plan**-Replace highest risk pipes per the DIMP program. At est. avg. of $1.1MM/mi, expect ~20 miles/yr. **Updated Plan**-Results in ~12 mi/yr (~39% reduction). Per section 5.12, AGL's current rate of pipeline replacements is already inadequate. At 10 mi/yr, replacement of pre-1960 pipelines will take until 2188 at an asset age of 229 years and pre-1970 pipelines will take until 2642 with an asset age of 673 years. The current reductions just further exacerbate the issue. **Resulting Requirements**-While it is clear that a significant increase in vintage pipeline replacement investments is necessary, AGL is initially proposing a return to ~20 miles per year for 2025-2027 to allow for other projects related to compliance and system stability to be completed. Beyond the first three years, AGL anticipates the need to increase these replacements to manage the pace at which these aging pipelines are removed from the system. This rate of DIMP replacement growth will bring DIMP budgets up to $75 million per year, as outlined in the 2019 Rate Case and 2022 i-CDP filings. (see additional DIMP-Vintage Pipelines line for proposed additional investments)	(1.9)	3.1
DOT Projects	**30.6**	**43.6**	**12.9**	5.14	**Initial Plan**-Average annual DOT relocation costs were ~$30MM when the 2022-2024 i-CDP was being developed. NOTE: DOT work is largely uncontrollable spend based on AGL's requirement to relocate its facilities when located within state, county, and municipal rights-of-way. Project quantities, locations, etc. are controlled by the various DOT entities. **Updated Plan**-Revised plan to cover actual/expected run rate of nearly $44MM/yr driven by significant project quantity and cost increases (nearly $40MM in additional mandatory and uncontrollable investment). **Resulting Requirements**-Known current and outstanding projects, increased costs, and additional proposed infrastructure investments will require maintaining this increased level of investment for the foreseeable future.	12.3	13.4



2022-2024 i-CDP Filing vs. Actuals/Plan (NOTE: Totals do not include Overheads and AFUDC)							
Item	**2022-2024 i-CDP (avg. annual investment in $ millions)**			**Chapter 5 Section Providing Add'l Details**	**Initial Plans, Updates, and Resulting Requirements Summary**	**Avg Annual Proposed Adjustment vs. 2022-2024 As Filed Investment Levels**	
	As Filed	**Actuals / Projected**	**Change in Plans**			**2025-2027**	**2028-2034**
GRAM - Safety & Compliance							
AC Mitigation	**6.0**	**3.6**	**(2.4)**	5.22	**Initial Plan**-Complete 5 zinc ribbon install projects and start 2 more **Updated Plan**-~41% budget reduction to offset increased DOT and other GRAM-Safety & Compliance category increases. Budget reductions plus cost increases resulted in only 1 of the 5 being completed with another to be ~88% complete by the end of 2024 (~86,000 linear ft of zinc ribbon installed in total). The three other planned projects (~34,000 linear ft of zinc ribbon) plus the design/start for two more were all delayed to 2025 and beyond. **Resulting Requirements**-New PHMSA requirements in CFR 192.473(c) now require interference assessments with any currents exceeding 100 amps per meter squared AC to be remediated. Proposing investment levels of $9-$12 million annually to comply with the new requirements.	4.6	5.4
Shorted Casings	**4.8**	**3.5**	**(1.4)**	5.22	**Initial Plan**-Ongoing 7-year commitment to remediate 711 known casings at just under $5MM/yr to maintain progress to meet the 2025 completion commitment **Updated Plan**-Currently at 677 of the original 711 with remaining funding to complete the original commitment **Resulting Requirements**-Significant number of additional casings identified during the first 5 years of the program. Proposing continued investment at ~$5MM/yr to complete the commitment then slowing to $3MM/yr to address additional casings identified.	(0.5)	(1.8)
TIMP-Dig Program	**62.0**	**67.6**	**5.6**	5.19-5.20	**Initial Plan**-Large TIMP driven pipeline replacement project (Buford Hwy) plus an ongoing ~$700MM 15-year PHMSA mandate to assess and remediate all transmission lines to confirm MAOP. Also includes funding for required periodic assessments of transmission pipelines per CFR 192. **Updated Plan**-Complete Buford Hwy and continue 15-year program but at significantly higher actual/estimated costs which requires some slowing of the 15-year plan. **Resulting Requirements**-Further refinement of the program scope through 2035 including adjustments in work type between hydrotest, investigation, and replacement and the addition of potential RIN-2 transmission mileage to the program now have estimates at $1.2 billion resulting in a significant annual required increase in investment just to comply with the existing and newly implemented PHMSA rules.	52.1	108.0

2022-2024 i-CDP Filing vs. Actuals/Plan (NOTE: Totals do not include Overheads and AFUDC)							
Item	**2022-2024 i-CDP (avg. annual investment in $ millions)**			**Chapter 5 Section Providing Add'l Details**	**Initial Plans, Updates, and Resulting Requirements Summary**	**Avg Annual Proposed Adjustment vs. 2022-2024 As Filed Investment Levels**	
	As Filed	**Actuals / Projected**	**Change in Plans**			**2025-2027**	**2028-2034**
GRAM - Safety & Compliance							
TIMP-ILI Retrofits	**15.4**	**10.4**	**(4.9)**	5.20	**Initial Plan**-Retrofit 3 major transmission lines for preferred inline inspection plus some additional projects not scoped at the time of the initial i-CDP filing. **Updated Plan**-Budget was reduced by ~33% to help offset DOT and other cost increases within the GRAM-Safety & Compliance category. Initial 2022-2024 plan was to complete two projects and part of a much larger third making an estimated 54 miles of transmission pipeline piggable. After budget reductions and cost increases, the large project (Mars Hill to Johnson Ferry) had to be completely pushed beyond 2024. **Resulting Requirements**-While ILI Retrofits allow for the assessment of AGL transmission pipelines by superior methods with quantifiable safety benefits as outlined in previous and current testimony, there is not a firm mandate in code which allowed for the current plan reductions as well as the very limited $2MM/yr proposed in 2025-2027 to help offset DOT and MAOP validation program increases within GRAM-Safety & Compliance. AGL does propose a return to planned investment levels in 2028 to resume work on this key safety program.	(13.4)	(1.1)
TIMP-Other	**4.4**	**0.7**	**(3.7)**	5.20	**Initial Plan**-Estimated investment levels were based off of run rate costs for TIMP Digs made necessary by other work outside of the MAOP validations and other planned TIMP work. **Updated Plan**-Reduction primarily by incorporating this work as required into other TIMP work and delaying initial TSA driven facility security work. **Resulting Requirements**-Proposed plans include continuing this work plus the addition of TSA driven facility/station safety initiatives	(1.9)	1.9
Corrosion	**6.5**	**4.8**	**(1.7)**	5.22	**Initial Plan**-Primarily to address system corrosion issues and comply with cathodic protection mandates. **Updated Plan**-Small work slowdown to help offset DOT and other GRAM-Safety & Compliance increases **Resulting Requirements**-Proposing ~$7.5MM/yr going forward due to increased costs	0.8	1.3
Posi-Hold Remediations	**1.7**	**1.5**	**(0.1)**	**N/A**	5-year safety program completed as committed in 2022	**(1.7)**	**(1.7)**

2022-2024 i-CDP Filing vs. Actuals/Plan (NOTE: Totals do not include Overheads and AFUDC)							
Item	**2022-2024 i-CDP (avg. annual investment in $ millions)**			**Chapter 5 Section Providing Add'l Details**	**Initial Plans, Updates, and Resulting Requirements Summary**	**Avg Annual Proposed Adjustment vs. 2022-2024 As Filed Investment Levels**	
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GRAM - Other							
NB-Core New Business	**87.6**	**104.5**	**16.9**	5.10	**Initial Plan**-Based on 2021 new customer addition costs and projected meters. **Updated Plan**-~$17MM increase per year due to significant material, labor, supply chain, and other inflationary cost increases. **Resulting Requirements**-Work is Rule 7 & 8 driven with limited ability to control quantities and costs resulting in required reductions primarily in Facilities and Regulator Stations.	30.5	37.3
Facilities	**15.5**	**4.1**	**(11.5)**	5.23	**Initial Plan**-Complete the Clayton office rebuild and surrounding support buildings, the Gwinnett office purchase/rebuild, 67% of the Marietta office consolidation and rebuild, 78% of the Savannah rebuild, expansion, and hurricane hardening, and the Vidalia office remodel. **Updated Plan**-Reduced to ~$4MM/yr primarily to complete the already ongoing Clayton office work. Everything else pushed to future years requiring lease extensions and stranded investments in land/facility purchases for Savannah and Gwinnett until the projects can be completed (now planned for 2025 & 2026 respectively) **Resulting Requirements**-Significant budget reductions have pushed office rebuilds/replacements/expansions for multiple years resulting in extended and generally higher lease costs, stranded property costs at Savannah and Gwinnett, and likely much higher overall future construction costs for these facilities while continuing the risks in Savannah of the primary response office not being built for extreme weather such as hurricanes. Proposed 2025-2027 budgets remain at ~$13MM/yr to balance building needs with already significant anticipated rate impacts with substantial increases proposed for 2028 and beyond to begin catching up these key facility replacements.	(2.2)	14.5
Fleet	**12.1**	**11.3**	**(0.8)**	5.24	**Initial Plan**-~$12MM/yr for vehicles and equipment to support operations **Updated Plan**-While actual investment reductions are limited, new vehicle purchases were substantially reduced due to increased vehicle costs resulting in O&M increases for maintaining vehicles and equipment beyond their optimal lifespans. **Resulting Requirements**-Increasing investments by $1.5-$3MM/yr in 2025-2027 to cover	2.0	6.5

2022-2024 i-CDP Filing vs. Actuals/Plan (NOTE: Totals do not include Overheads and AFUDC)							
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GRAM - Other							
					increases in vehicle costs with additional significant increases from 2028-2034 to catch up on multiple years of delayed purchases.		
IT Totals (Includes Allocations from AGSC)	**28.6**	**18.7**	**(9.8)**	5.25	**Initial Plan**-Direct IT charges such as computers and AGL specific systems like GCMA as well as allocated costs for shared financial, work management, and other systems. NOTE: Includes $16MM/yr allocation of shared systems from AGSC as shown in the original 2022-2024 i-CDP filing. **Updated Plan**-Reduction primarily related full financial system conversion related work slowdowns and overall cost allocations. **Resulting Requirements**-Proposed increases of $3-$6MM/yr for finishing ongoing EAM and other programs plus additional system investments as outlined in section 5.25.	3.6	4.2
Measurement	**2.2**	**1.6**	**(0.7)**	5.13	**Initial Plan**-SCADA and other large meter costs plus programs focused on remote monitoring of odorization at key locations and obsolete pressure recorder (ERX) replacement programs. **Updated Plan**-Reductions primarily in timing of remote odorization monitoring and ERX replacement programs. **Resulting Requirements**-Delays in ERX replacements require a ramp up of $1-$2MM annually to catch up and complete the replacement program by 2030 to maintain code required operability and to address required technology upgrades. Proposed budgets also include $3MM total over 5-years to install remote odorization detection units at ~35 locations where AGL receives odorized gas from suppliers. This program was deemed a critical risk by AGL after multiple instances of supplier system issues have led to inadequately odorized gas being introduced into AGL's system. Finally, a program to expand the number of ERX's in the AGL system is proposed to begin in 2028 to provide better visibility into system pressure issues and to allow AGL to plan for and react to system pressure issues before they become major outages.	0.7	1.8

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STRAT-Strategic (CNG Stations)	**0.5**	**0.3**	**(0.2)**	5.10	**Initial Plan**-Plan primarily related to CNG station installs and relocations at proposed facility replacements. **Updated Plan**-Delays in AGL facility replacements have delayed the need for these CNG stations for fueling Company CNG vehicles. **Resulting Requirements**-Adjusted funding to align with updated facility replacement schedules plus a placeholder in the outer years for other stations as needed.	0.8	0.5
PT Meters	**7.7**	**8.4**	**0.7**	5.21	**Initial Plan**-Tariff required periodic testing and replacement of meter sets plus the addition of residential meter set assemblies with bypasses (MSA-B) to allow for maintaining customer gas service during maintenance activities. **Updated Plan**-Minor adjustments primarily due to labor and material cost increases. **Resulting Requirements**-Maintaining run rate meter testing and replacement programs with additional funding to expand the ongoing MSA-B program.	3.9	7.0
RENEW-General Renewals	**5.4**	**10.8**	**5.4**	5.16	**Initial Plan**-Replacement and remediation of pipeline issues identified in the field such as leaks, damages, extensive corrosion, partition valve remediation, etc. **Updated Plan**-Plan essentially doubled due to the need to replace three aging and unrepairable transmission line valves with grade 2 leaks (repair required within 15 months) plus a large pipeline relocation in Savannah related to the port expansion. Slowed the partition valve remediation program to help offset the other cost increases resulting in an estimated 27 of the 55 planned valve remediations to be completed by the end of 2024 (~50% reduction). This not only pushed out the planned completion of this identified risk remediation program by another year but it also required $200K/yr budget increases in 2025 and 2026 to avoid pushing the completion out a second year (see Risk Remediation Items table below for additional details). **Resulting Requirements**-Maintaining normal renewal run rates with some escalation for cost increases and to complete the partition valve program by 2028. Also included $9MM total over 2025-2026 to address two large odorant fade driven renewal projects required to maintain safe and compliant operation of these isolated systems.	5.1	1.5

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RENEW-Remote-Controlled Valves	**1.8**	**0.2**	**(1.6)**	5.16	**Initial Plan**-To begin a ramp up of remote-controlled valves on transmission lines. **Updated Plan**-89% reduction in plan to help offset New Business and other GRAM-Other cost increases since there was not a clear mandate for installation until the 4/10/23 implementation of the new Rupture Mitigation Valve (RMV) rule. **Resulting Requirements**-Ramp up of $3-$4MM/yr in 2025-2027 to complete RMV rule mandated TIMP assessments with a further increase to $10MM/yr thereafter to begin a multi-year RMV installation program based on the new RMV rule guidelines.	1.9	8.2
RENEW-Emergency Districts	**0.8**	**0.2**	**(0.7)**	5.16	**Initial Plan**-To maintain emergency districts per past commitment to the Commission with a small increase to begin creating key facility districts around places like Mercedes-Benz stadium and State Farm Arena. **Updated Plan**-Reductions to help offset overages in other GRAM-Other items by delaying key facility district improvements and temporarily slowing normal district valve cut in work. **Resulting Requirements**-Proposing a return to the $0.5MM/yr run rate to maintain district commitments and slowly make key facility and other improvements.	(0.3)	(0.3)
RENEW-Exposed Mains	**1.0**	**0.3**	**(0.7)**	5.16	**Initial Plan**-To address unintentional main exposures due to storms, erosion, etc. **Updated Plan**-Significant slowdown to cover increases in other GRAM-Other budget categories causing a backlog of work. **Resulting Requirements-**Intentional work slowdowns coupled with an increased focus on exposed facilities by AGL led to the identification of a significant number of additional exposed facilities through combining information from Corrosion, Right-of Way, DIMP, and other data sources. This increased backlog of approximately 286 identified locations needing evaluation and remediation has resulted in the need for expanding the exposed mains remediation program to $5MM/yr to adequately address the expanded number of known issues that must be addressed for safety and compliance.	4.0	4.0
OPS-Bollard Projects	**1.9**	**1.0**	**(0.9)**	5.21	**Initial Plan**-To maintain bollard installation commitments, replace aging ERTs, and replace individual damaged or leaking services as necessary. **Updated Plan**-All programs intentionally slowed to offset other Operations capital overages in PT Meters as well as other GRAM-Other category budget pressures. Impacts are limited due	(0.8)	(1.0)

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OPS-ERT / AMR Projects	**1.5**	**0.7**	**(0.9)**	5.21	to natural slowing of bollard installation requirements. **Resulting Requirements**-Primarily maintaining run rates for this must do work with a significant increase beginning in 2029 to begin addressing expected end of life issues for approximately one million ERTs.	1.1	16.1
OPS-Blanket Service Renewal Projects	**1.0**	**0.7**	**(0.3)**	5.21		(0.1)	(0.1)
REG STN-Regulator Station Projects	**27.2**	**19.6**	**(7.6)**	5.17	**Initial Plan**-To replace aging facilities, address multiple risk assessment identified safety issues resulting from lessons learned from the Merrimack Valley incident and resulting Federal and State guidance, and address station inlet valve availability at a distance to more easily allow for operation in an emergency (also a PSC Facilities Protection NOPR key item). **Updated Plan**-Reductions of ~$7.6MM/yr necessary to offset New Business increases within the GRAM-Other category. Primary result is the slowing of multiple key station risk programs as well as the slowing of aging facility replacements, each of which increases the risks of station failures resulting in customer outages, significant gas releases, and the potential for system over pressurizations (see Risk Remediation Items table below for program impact details). **Resulting Requirements**-Multiple years of significant budget reductions to stay within GRAM-Other budget commitments as well as an already significant obsolescence backlog around the nearly 4,700 stations in GA are driving the need to significantly increase station and related facility investments to finish these critical risk programs and begin addressing station obsolescence issues in a timely manner.	7.2	11.9

Risk Remediation Items																		
	Partition Valves			Strainers			Tap Station OPP			Kerotest Valves			Emergency Districts			Fire Valves		
	Planned	*Completed*	*Projected Completion Year*	*Planned*	*Completed*	*Projected Completion Year*	*Planned*	*Completed*	*Projected Completion Year*	*Planned*	*Completed*	*Projected Completion Year*	*Planned*	*Completed*	*Projected Completion Year*	*Planned*	*Completed*	*Projected Completion Year*
2022	17	17	2026	21	22	2030	2	2	2024	290	290	2029	86	86	2024	154	195	2024*
2023	19	10	2027	38	14	2030	4	3	2026	290	115	2030	86	96	2024	154	97	2035
2024	19	*0*	*2027*	37	*0*	*2030*	4	*3*	*2026*	290	*110*	*2031*	86	*86*	*2024*	153	*70*	*2035*
TOTAL	55	*27*		96	*36*		10	*8*		870	*515*		258	*268*		461	*362*	
Program Summary	Due to budget reductions and project cost increases, program duration extended by 1-year to 2027 @ $1.54MM annual budget. Also increased annual budget for 2025 & 2026 by approx. $200K.			Program duration to remain the same. Station's without strainers volume reduced from original estimate (320 to 228) through RSRP program and targeted annual field investigations offsetting effects from budget reductions.			Program duration extended by 2-years due to a combination of budget cuts plus the addition of 2 stations from original estimates. Budget reductions and increased costs forced a 1-year extension @ $2MM budget & 2 additional stations account for the 2nd year @ $2MM budget.			Due to budget reductions and increased project costs, program duration extended by 2-years. 2025-2031 Annual budgets reduced by approx. $1.12MM with 2-year extension.			No expected impacts to the baseline program due to budget budget reductions but have had to delay additional program to create special districts around key high risk areas/facilities.			Accessible inlet and outlet valve (as needed) at 25 ft+ program duration unchanged. 2025-2035 Annual budget increased by ~$102K/yr to account for cuts. **In 2022, we adjusted the program based on signficant increase in estimated stations without accessible inlet valve at 25+ ft based on targeted field investigations and initial RSRP program results.*		
Note: yellow cells are showing estimated completions for 2024 & 2022-2024 estimated totals based on revised plan due to budget reductions and project cost increases																		

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REG STN-RSRP Program Projects	**3.0**	**1.7**	**(1.3)**	5.17	**Initial Plan**-Program was initially planned for completion in 2022 with multiple delays due to competing priorities and the need to offset other GRAM-Other category cost increases. **Updated Plan**-Continued slowing of the program required to offset New Business and other largely uncontrollable increases. **Resulting Requirements**-Updated plans now have the completion of this critical station safety initiative stemming from the Merrimack Valley incident now not being completed until 2028. These continued delays not only push off the completion of the detailed risk assessments of AGL's nearly 4,700 stations, they also have significantly increased overall program costs and have limited the ability to fully utilize the assessments to better prioritize station remediations and replacements.	0.0	(2.7)

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REMOV-Removals	**13.9**	**12.8**	**(1.1)**	5.18	**Initial Plan**-Retirements related to DOT, Renewal, Reg Station, and other categories **Updated Plan**-Minor reductions associated with work slowdowns. **Resulting Requirements**-Proposed investment increases in these areas will require full or potentially additional funding for associated retirements going forward.	0.7	1.1
REMOV-Removals (inactive services)	**2.1**	**0.3**	**(1.8)**	5.18	**Initial Plan**-To address highest risk inactive services (key safety initiative for AGL and a key item in the proposed PSC Facilities Protection NOPR). **Updated Plan**-The need to offset largely uncontrollable New Business increases within GRAM-Other along with the lower risk profile of these facilities related to items such as aging regulator stations has resulted in an almost complete stoppage of this program. **Resulting Requirements**-While there is the potential that the PSC Facilities Protection NOPR may mandate program increases in the future, AGL has proposed a return to the ~$2MM/yr run rate to continue addressing the riskiest of these facilities while focusing remaining available funding in other areas.	0.1	0.2
Tools (blankets, NB, Field, Con Ops)	**1.6**	**2.0**	**0.3**	5.21	**Initial Plan**-Tools required to maintain daily operations. **Updated Plan**-Small increase in the plan for the expansion of personal gas monitors and the tools necessary to use the new residential meter set assemblies with bypasses as outlined in the PT Meters section. **Resulting Requirements**-Proposed increase to ~$4MM/yr for full implementation of personal gas monitors, MSA-B related tooling, cross-compression equipment to limit methane emissions during certain activities, and a respirator replacement initiative required by the exit of Honeywell from the personal respirator market.	2.6	2.7
Rate Base Accruals	**0.0**	**(0.5)**	**(0.5)**	N/A	Unspecified yearend accruals not aligned yet with actual programs.		

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System Reinforcement Rider							
Pressure Improvement (PRIM) - SRR	**13.2**	**14.4**	**1.2**	5.15	**Initial Plan**-Shows $13.2MM/yr but removing the impacts of the large Piedmont project it is closer to an average of $8.6MM/yr PRIM investment budgets are based on run rate estimates since they are heavily dependent on the levels and location of growth. Required projects are determined primarily by PRIMs resulting from annual system pressure model analysis. Regardless of available budget, all projects showing <5 psig in the model must be done to help ensure system reliability and projects showing <10 psig should be done to help ensure proper operability of excess flow valves (safety device mandated by code to be installed on almost all single residential services and some commercial services for systems designed to operate at over 10 psig). Note; Projects with Normal Operating Pressures (NOP) that differ from 60 psig have different system minimums but similar challenges. **Updated Plan**-Removing the Piedmont project affects, revised plan averages ~$7MM/yr. Increased costs and reduced budgets limited 2023 actual PRIMs to <10 psig projects (table below) with only the ability to address <5 psig projects in 2024 to stay within SRR category approved totals and offset some overages in System Reinforcements. This limited investment is not only limiting the effectiveness of EFVs in these areas on the coldest days of the year but it can also lead to more required PRIMs when smaller loads are added. **Resulting Requirements**-Proposed 2025-2034 budgets return to ~$11MM/yr to be able to address estimated PRIMs for <10 psig plus some PRIMs for 10-15 psig model results. Starting in 2028, an additional $5MM/yr is added to begin addressing system issues between 15 psig and actual system pressure design minimums of 25 psig for a large part of the 60 psig system.	(2.5)	2.9

2023 Planned Pressure Improvements Based on Annual System Model Results (not including New Business PRIMs identified throughout the year)													
Project #	PRIM Name	Project Description	Status	LDC	Service Center	Priority	NOP	Minimum allowable	# Cust < min P	#Cust <5#	Min P Bef.	Min P After	Notes
23-12	Lester Mill Rd	Install 5000' x 4" PLS	Complete	AGLC	Clayton	1	60	15	75	65	0	38	Stn is too small and is only feed, model will not solve
23-8	W Stubbs Rd Station Outlet	Replace 35' of 2" and 4" with 6" MHP STL	Complete	AGLC	Clayton	2	60	15	750	50	3	15	
23-3	Old Alabama Rd @ CCOS station	Replace station with 2" prefab (min = 125#, Q = 175 mcfh)	Complete	AGLC	Cumming	3	Regulator Station Replacement. Current system model will not even solve without this work.						Stn is too small and is only feed, model will not solve
23-4	Perimeter Summit Pkwy	Install 5100' x 4" HP STL, 2" prefab @ 56#, and 400' x 6" PLS	Cancelled	AGLC	Peachtree	4	60	15	470	0	10	22	Alternate PRIM 22-3 completed in 2022 resolved the issue
23-7	Christian Circle	Install 600' x 4" PLS and replace 2500' x 2" PLS w/ 4" PLS	Complete	AGLC	Conyers	5	60	15	250	0	10	28	
23-2	McGinnis Ferry @ PIB Station	Replace all pipe downstream of regulators with 6" MHP STL	Complete	AGLC	Gwinnett	6	60	15	130	0	10	19	
23-1	Memorial Dr	Retire 600' x 1 1/4" STL and install 20' x 2" PLS	Complete	AGLC	Athens	7	25	10	0	0	10	21	
23-11	Hal Jones Rd	Replace 1350' x 2" PLS with 4" PLS	Complete	AGLC	Newnan	8	60	15	315	0	12	30	
23-9	S Fulton Pkwy	Install 25,000' x 6" HP STL, 1500' x 4" HP STL, reg stn, 50' x 6" PLS	Delayed	AGLC	Clayton	9	60	15	295	0	11	27	Projects delayed until 2024 or later
23-5	Athens Hwy	Opt 1 - Replace 1600' x 4" w/ 6" STL; Opt 2 - replace 6000' x 4" w/ 6"	Delayed	AGLC	Gwinnett	10	60	15	250	0	13	17/23	
23-10	Peach Dr	Install 1000' x 4" PLS	Delayed	AGLC	Clayton	11	60	15	60	0	14	24	
23-6	Brown Bridge Rd	Replace 4250' of 2" HP STL with 4" HP STL	Delayed	AGLC	Conyers	12	300	125	10	0	124		

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Gas Ops-Peaking (LNG, Propane, Compression)	**12.6**	**10.6**	**(2.0)**	5.7	**Initial Plan**-Required and prudent replacements at these aging facilities that represent 35% of the system capacity on a Design Day. **Updated Plan**-Reduction of ~$2MM/yr taken to help offset System Reinforcement overages and stay within approved SRR investment levels. Reductions resulted in pushing replacement projects for these 36, 47, and 52 year old plants out further and increasing operability risks when needed on the coldest days of the year to avoid large system outages. For example, the Riverdale Generator project was scheduled to be completed in 2023 in the 2022 i-CDP filing but delays now require an additional $2MM in 2025 to complete this critical end of life equipment replacement project. **Resulting Requirements**-Proposed investment levels for 2025-2027 are significantly increased due to the need to replace the Liquefaction system at the Riverdale plant as outlined in section 5.7.	20.8	1.2
SYS RE-Major Pipelines	**59.5**	**56.0**	**(3.4)**	5.11	**Initial Plan**-For the completion of System Reinforcement projects as outlined in section 5.11 and the Minimum Filing Requirements document to resolve current and projected major system pressure issues and to provide system capacity for the expanded Cherokee LNG plant send-out capabilities. **Updated Plan**-Only minor reductions in overall investments but projects have seen significant material, labor, and overall inflationary cost increases as well as additional transmission work requirements to ensure compliance with new MAOP validation, RMV, and other federal mandates. These cost pressures have resulted in the further delay of many of these key system pressure and supply projects. **Resulting Requirements**-Proposed 2025-2027 annual investments are nearly doubled and then increase further through 2029 to mitigate these cost increases and to return the plan to necessary levels to maintain system stability.	52.5	40.7
SYS RE-Cherokee LNG Expansion Pipelines	**0.0**	**2.1**	**2.1**				

System Reinforcement Revised Timeline Impact Summary				
Project	Description	2022 i-CDP Plan Target In Service	Current Plan Target In Service	Timeline Adjustment Implications and Increased Risks for Large Customer Losses and/or Costly and Limited Mobile LNG Vaporization Activations
Wade Green Rd Phase 2	4.3 miles x 12" steel	2023	2027	Currently requires LNG vaporizer mobilization on a design day to avoid customer outages. 4-year push not only requires continued mobilizations but also costs incurred to maintain injection locations (~$150K install and recurring land lease/purchase/maintenance costs).
Cumming to Hall County Pipeline	28.74 miles x 16" steel	2024	2025	Push requires an additional year of mobile LNG vaporizer mobilizations triggered nearly 10 degrees above a design day.
High Point Road to Villa Rica	7 miles x 12" steel	2024	2026	Projects are both needed for system supply and for pressure issues. Multi-year delays of these 3 connected projects further limits AGL's ability to get Transco gas into west GA, puts nearly 3,000 customers in jeopardy by 2033, and likely will require mobile LNG in future years to avoid customer losses before the projects are completed.
Villa Rica to Temple	5.4 miles x 12" steel	2024	2029	
Temple to Bremen	6.3 miles x 12" steel	2025	2031	
NW GA Line to Rome #1	3.4 miles x 16" steel	2025	2033	Currently shown 8 year push to allow for LNG expansion related and current customer loss projects to be completed since this project is specific to system supply needs. Latest system supply evaluations may require this project to be accelerated to help ensure supply stability in NW GA.
Cumming to McGinnis Ferry Road (Now Segment 1-Cumming to Commerce and Segment 2-Commerce to McGinnis)	Was 12.8 miles x 24" steel; Now 11.2 miles x 24" steel and 4.2 miles of 24" steel	2025	2028 2029	Segment 1 must be completed to provide system capacity to take the full send out of the Cherokee LNG expansion by current projected needs in 2028. Full project completion needed soon thereafter to avoid the loss of >50,000 customers on a design day as early as 2033. Current timeline includes substantial risk for the need for mobile LNG before 2029 to avoid customer losses.
Ball Ground to Ellijay (now Jasper to Ellijay)	31.7 miles x 12" steel	2028	2030	Current modeling shows the loss of >5,600 customers on a design day by 2033 but also shows that any substantial new load in this area could result in the immediate need for mobile LNG well before the currently proposed 2030 completion.
Camp Creek to Fulton Industrial Blvd	5 miles x 8" steel	2029	2030	Pressure model abilities limit the ability to clearly show any impact of this one year push.
Hall County Extension	11 miles x 12" steel	2030	2032	Current timeline for the need to connect the additional gas supply NW of Lake Lanier (Cumming to Hall project) to the supply feeding the NE side of the lake is not clear but multiple recent large industrial load requests totaling nearly 200mcfh coupled with already significant load growth in the area may require the acceleration of this project from the current 2032 date to avoid the inability to serve large business development growth in this area.
Peachtree Rd.	2.4 miles x 12" steel 0.75 miles x 12" plastic	2022	Project Completed	
McGinnis Ferry Rd	2.9 miles x 12" steel	2022	Project Completed	

O&M Best Practices Programs Status Updates

O&M Best Practices Programs Status Updates	
Best Practices Programs	**Status**
Replacing Celcon Caps on Service Tees	AGL remediated 698 caps in 2022 and 230 in 2023. Since the program began in 2016, we have remediated a total of 2,750 of the original estimated 7,000 caps to be remediated. There are no caps planned to be remediated in 2024 due to budget constraints further pushing out the completion of this safety initiative.
Inspecting Sewer Systems for Potential Cross-bores	Over the 2022 thru 2023 time span, AGL has completed over 29 inspections spanning 104 miles of pipeline for cross-bores using data-driven processes. The program has expanded because additional areas in the AGL system have been discovered to have cross-bores, necessitating an additional phase to the cross-bore program.
Reducing 3rd Party Excavations	Over the 2022 thru 2023 time span, AGL has expanded the use of its predictive analytics tool to identify areas of high-risk excavation to deploy intervention methods like Watch and Protect – we have conducted over 2639 interventions over this period. This effort in addition to others have supported a YOY reduction of 5% in damages. AGL has delayed the planned expansion of its Watch and Protect Program to 2024.
Improving Data Quality and Accessibility	AGL has continued on its data quality program commonly referred to as the SRV (Source Record Validation Project). To date, AGL has scanned and digitized over 10 million pages of records and is in the process of validating the data.
Expanding Quality Assurance	Initial Plan was to hire additional QA personnel, but none have been hired to date since full funding was not approved.
Applying PSMS	AGL has implemented RP 1173, developed a MOC process in compliance with PHMSA RIN-2, and will conduct an assessment of its PSMS in 2024.

This 2025 i-CDP acknowledges the progress made in the ongoing initiatives, as well as the project and program delays that were implemented during the initial i-CDP years to accommodate the commitments made regarding minimizing rate impacts on end-use customers. Consequently, this new Plan reflects multiple relatively smaller efforts to "catch up" in areas where projects were or will be deferred during work reprioritizations within the 2022-2024 i-CDP years, as well as some additional key projects and programs outlined below:

- Valdosta Satellite LNG – AGL must development of a new supply source for the Valdosta area to provide adequate supply on the coldest days of the year as outlined in this Plan in Chapter 4 as well as Section 5.7 below.

- DIMP-Pipeline Replacements – As first mentioned in the Engineering Panel testimony in the 2019 Rate Case and repeated within the current 2022 i-CDP, as well as earlier in Chapter 5 of this document, the current pace at which additional at-risk pipeline is being replaced within the DIMP program is not adequate to address AGL's highest leak rate pipes in a timely manner. While expansion of these efforts is needed now, AGL is proposing them to start ramping up in 2028 due to already challenging near-term pressures on customer rates (see Section 5.11 for additional details).

- Automated Meter Reading System Upgrades –The "Operations-ERT/AMR Projects" budget line contains approximately $100 million in above-normal run-rate funds through 2034 to replace nearing-end-of-life 100G ERT units with current 500G units (the need for which was initially shared in the 2019 rate case and repeated in the 2022 i-CDP). For informational purposes, AGL has identified an additional $200 million in potential investment between 2028 and 2034 in the event the Commission wants AGL to expand these replacements to include Advanced Metering Infrastructure ("AMI"), which provides significant operational and technological benefits as outlined in section 5.21.

- RIN-2 Rule Required Additional Pipeline Assessments and Remediations – As outlined in Section 5.2 above, the RIN-2 rule is requiring the assessment of several hundred miles of existing distribution pipelines to determine if they meet the updated transmission definition and/or add additional mileage through being a part of a connected series of pipelines between two transmission lines. The full extent of the impacts of this new rule will not be known until PHMSA issues some rule clarifications in a pending set of FAQs and all of these pipelines are fully evaluated and then required MAOP validation efforts are



completed on any new transmission pipeline segments. AGL is planning to invest $3 million in both 2025 and 2026 to complete initial assessments of the pipelines plus $100 million from 2028-2034 to complete the mandated MAOP validation work, which may include retesting and, in many cases, replacements of these pipelines.

5.4 Proposed Three-Year Plan

The proposed three-year capital budget parameters for AGL are shown below in Figure 5.8 and includes the investment needed to address the items outlined within Chapter 5 of this document.

Figure 5.8: Proposed Three-Year Budget Parameters

AGL Proposed Capital Budget ($ millions) (Includes Overheads and AFUDC)	2022 (actuals)	2023 (actuals)	2024 (budgeted)	2025 (proposed)	2026 (proposed)	2027 (proposed)
	495.8	566.4	651.5	745.6	740.0	754.0

5.5 Proposed Ten-Year Plan

The parameters for the proposed ten-year capital budget for AGL is summarized below in Figure 5.9 and includes investment needed to address the items outlined within Chapter 5 of the document; these totals include overheads and AFUDC. The bill impacts for the Plan are summarized in Figure 5.10. The Capital Budget Parameters by year in Figure 5.11 provides the breakdown for individual projects or programs for each component of the Plan. The graphic in Figure 5.12 provides the proposed capital investment by program component by over time.

Figure 5.9: Proposed Ten-Year Budget Parameters

AGL Proposed Capital Budget Parameters ($ millions) (Includes Overheads and AFUDC)	Actuals		Bud	Proposed									
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
	495.8	566.4	651.5	745.6	740.0	754.0	937.0	988.5	895.4	914.5	879.7	890.9	912.8

Figure 5.10: Bill Impacts[21]

Figure 5.10.1: GRAM Impact with Traditional Rate Increase Implementation

Residential Bill Impacts	2025	2026	2027	
Annual Revenue Deficiency ($ millions)	$ 154	$ 38	$ 55	
Annual Impact	$ 76.32	$ 18.84	$ 27.36	
Monthly Impact	$ 6.36	$ 1.57	$ 2.28	
				3yr Average
Non-Gas Impact	15.7%	3.3%	4.7%	7.9%
Total Bill Impact-Includes Est Gas Costs	8.0%	1.8%	2.6%	4.1%

Figure 5.10.2: GRAM Impact with Levelized Revenue Requirement

Residential Bill Impacts	2025	2026	2027	
Annual Revenue Deficiency ($ millions)	$ 86	$ 86	$ 86	
Annual Impact	$ 42.84	$ 42.24	$ 41.88	
Monthly Impact	$ 3.57	$ 3.52	$ 3.49	
				3yr Average
Non-Gas Impact	8.8%	8.0%	7.3%	8.0%
Total Bill Impact-Includes Est Gas Costs	4.5%	4.2%	4.0%	4.2%

[21] The estimated revenue requirements and rate impacts provided in the table are based on numerous estimates and assumptions. These assumptions include capital spend an estimated cost based on known inflationary factors applicable to the specific cost, asset in service dates, growth in customers and revenues and growth in expenses based on known inflationary factors applicable to the specific cost. Additionally, the estimates assume the current federal and state income tax rates and applicable tax rules and regulations. When AGL files its annual GRAM filings for 2025-2027, the actual results will likely differ from the estimates provided in the figure.

The estimated revenue requirements and rate impacts include capital spending and estimated in service dates for projects that are eligible for recovery under GRAM and the SRR. The estimates do not include the capital spend associated with ECON-1 projects.

The information included in the three tables above is for illustrative purposes to inform the Commission that there are alternative means of implementing rates over the three year i-CDP period. AGL is not seeking or proposing a preferred method for rate recovery in this proceeding but is merely providing the required information as well as additional information required by the i-CDP MFRs.



Figure 5.10.3: GRAM Impact with Equal Annual Rate Increase Each Year

Residential Bill Impacts	2025	2026	2027	
Annual Revenue Deficiency ($ millions)	$ 85	$ 86	$ 87	
Annual Impact	$ 42.60	$ 42.60	$ 42.60	
Monthly Impact	$ 3.55	$ 3.55	$ 3.55	
				3yr Average
Non-Gas Impact	8.7%	8.0%	7.4%	8.1%
Total Bill Impact-Includes Est Gas Costs	4.4%	4.3%	4.1%	4.3%

A breakdown by budget line item and specific program is included below.

Figure 5.11: AGL Capital Budget Parameters

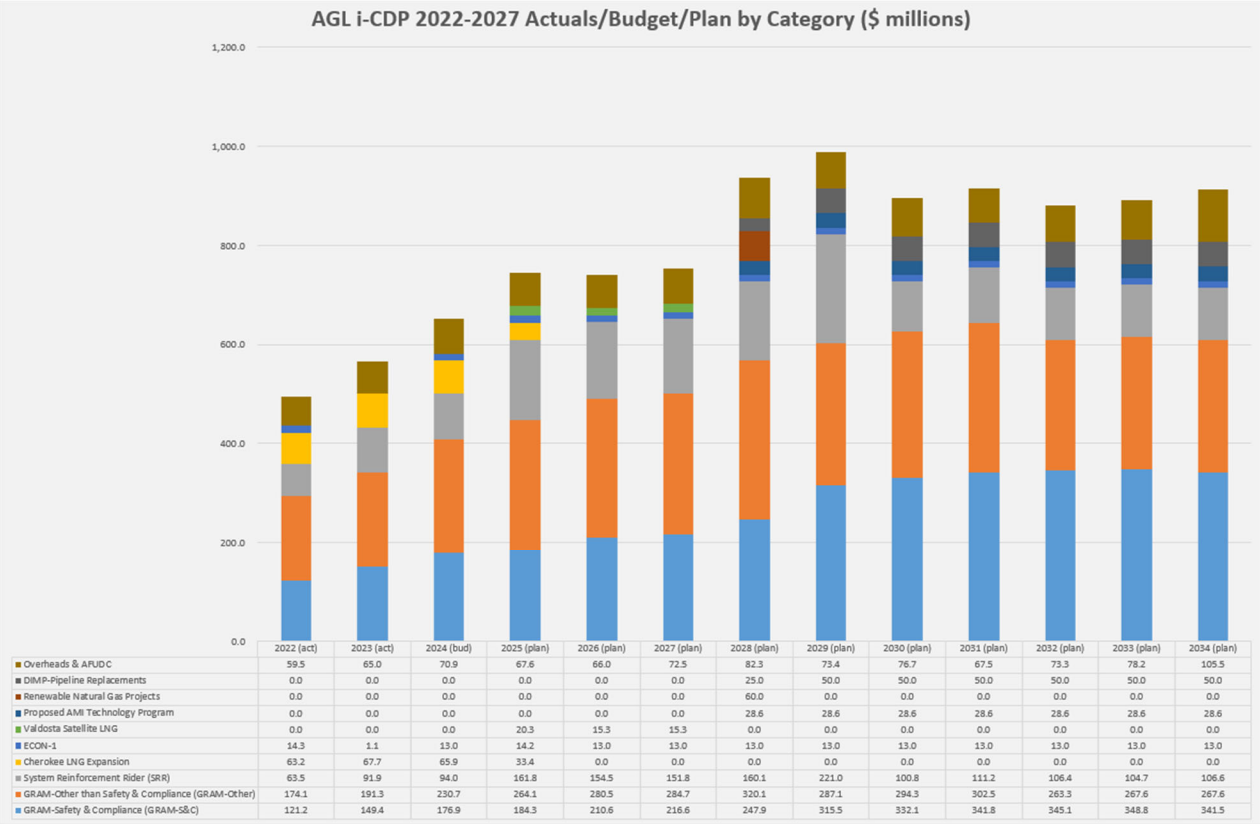
Capital Financial Summary Report (in $MM)										
AGLC - 2025-2034 Plan ($ millions)	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan	2032 Plan	2033 Plan	2034 Plan
AGLC Total (All Items)	**745.6**	**740.0**	**754.0**	**937.0**	**988.5**	**895.4**	**914.5**	**879.7**	**890.9**	**912.8**
AGLC Total (GRAM Only)	**490.5**	**535.7**	**547.3**	**615.7**	**650.5**	**672.9**	**689.2**	**653.3**	**662.1**	**675.4**
GRAM - Safety & Compliance (GRAM-S&C)	**202.7**	**228.4**	**235.0**	**267.2**	**285.1**	**301.4**	**309.9**	**313.9**	**319.2**	**324.6**
Distribution Integrity Management Program (DIMP)										
DIMP	20.0	20.0	20.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
Department of Transportation Driven Projects										
DOT Projects	44.3	43.2	41.3	41.5	42.3	43.2	44.0	44.9	45.8	46.7
AC Mitigation Projects										
AC Mitigation	10.6	12.1	9.1	9.1	11.1	11.1	12.1	12.1	12.1	12.1
Shorted Casing Remediation Program										
Shorted Casings	5.0	5.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Transmission Integrity Management Program (TIMP)										
TIMP-Dig Program	93.4	118.3	130.8	144.8	158.3	173.9	181.3	179.3	181.1	171.7
TIMP-ILI Retrofits	2.0	2.0	2.0	11.8	12.6	12.4	12.5	16.6	17.0	17.0
TIMP-Other	1.9	2.7	2.9	5.2	5.5	5.8	6.1	6.5	6.8	8.0
Corrosion Control Projects										
Corrosion Projects	7.1	7.4	7.5	7.6	7.7	7.7	7.7	7.7	8.0	8.0
Rate Base - GRAM-(S&C) Overheads & AFUDC										
RB-GRAM-(S&C) Overheads	12.4	14.4	14.9	15.5	15.5	15.5	15.5	15.5	15.5	15.5
RB-GRAM-(S&C) AFUDC	6.0	3.4	3.4	3.8	4.1	3.9	2.7	3.2	4.8	17.7
GRAM - Other than Safety & Compliance (GRAM-Other)	**287.8**	**307.3**	**312.3**	**348.5**	**365.4**	**371.5**	**379.3**	**339.5**	**342.9**	**350.8**
New Business - Core Work										
NB-Core New Business	113.7	119.7	121.1	122.1	123.0	124.0	125.0	126.0	127.0	127.0
New Business - Large Strategic Efforts										
NB-USF CNG PSC Funded	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NB-IP USF Rate Base	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
New Business - Overheads & AFUDC										
NB-NB Overheads	13.4	15.5	16.1	16.7	16.7	16.7	16.7	16.7	16.7	16.7
NB-NB AFUDC	1.8	1.9	2.0	2.0	2.0	1.3	1.0	0.6	0.1	5.6
Facilities Projects										
Facilities	9.0	15.3	15.6	32.2	37.3	38.6	24.0	25.0	26.0	27.0
Fleet Projects										
Fleet	13.5	14.1	14.8	16.7	17.4	18.1	18.8	19.6	20.3	19.3
IT Projects										
IT-IT (Base Business)	18.1	18.1	18.1	19.5	19.5	19.5	19.5	19.5	19.5	19.5
IT-IT (EAM)	5.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
IT-IT (ROOT)	4.3	6.2	6.2	5.9	5.9	5.9	5.9	5.9	5.9	5.9
IT-IT (DTS)	3.5	3.5	4.7	4.7	5.9	5.9	2.0	2.0	2.0	2.0
Gas Ops Projects										
Gas Ops-Measurement Ops (SCADA, Ctrls)	2.3	2.7	3.7	5.5	5.8	4.8	3.2	3.0	3.0	3.0
Strategic Projects										
STRAT-Strategic (Other)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
STRAT-Strategic (CNG Stations)	0.7	1.7	1.5	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Periodic Testing of Meters										
PT Meter	11.0	11.6	12.1	12.7	13.4	14.1	14.8	15.5	16.3	16.3
System Renewals (GRAM-Other)										
RENEW-General Renewals	11.9	12.0	7.7	7.7	6.5	6.6	6.7	6.8	6.9	6.9
RENEW-Remote-Controlled Valves	3.0	4.2	4.2	10.0	10.0	10.0	10.0	10.0	10.0	10.0
RENEW-Emergency Districts	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6
RENEW-Exposed Mains	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Operations Support Capital Work										
OPS-Bollard Projects	1.2	1.1	1.1	1.0	1.0	0.9	0.9	0.9	0.8	0.8
OPS-ERT / AMR Projects	2.4	2.3	3.2	3.2	14.0	18.4	44.7	14.2	14.3	14.3
OPS-Blanket Service Renewal Projects	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1.0	1.0	1.0
Pressure Regulating Facilities, Heaters, & Odorization										
REG STN-Regulator Station Projects	33.4	34.0	36.0	43.1	43.4	44.3	44.1	33.0	33.1	33.1
REG STN-RSRP Program Projects	3.0	3.0	3.0	2.0	0.0	0.0	0.0	0.0	0.0	0.0
Retirements (Removals)										
REMOV-Removals	14.5	14.5	14.5	14.5	15.0	15.0	15.0	15.1	15.2	15.2
REMOV-Removals (inactive services)	2.2	2.2	2.3	2.3	2.3	2.3	2.3	2.4	2.4	2.4
Capitalized Tool Purchases										
Tools (blankets, NB, Field, Con Ops)	4.2	4.0	4.5	5.5	5.4	4.7	4.3	3.1	3.5	3.5
Rate Base - Overheads & AFUDC										
RB-RB Overheads	6.8	7.9	8.2	8.5	8.5	8.5	8.5	8.5	8.5	8.5
RB-RB AFUDC	1.7	1.5	1.3	1.2	1.1	0.7	0.5	0.3	0.0	2.4



System Reinforcement Rider (SRR)	**179.1**	**172.6**	**173.7**	**189.1**	**244.9**	**129.4**	**132.2**	**133.3**	**135.8**	**143.9**
Pressure Improvements (SRR)										
Pressure Improvement (PRIM) - SRR	10.8	11.0	10.3	15.5	15.7	16.0	16.2	16.4	16.6	16.6
Gas Ops (SRR)										
Gas Ops-Peaking (LNG, Propane, Compression)	32.8	42.7	24.7	10.1	13.2	13.0	15.0	15.0	15.0	15.0
System Reinforcement - SRR Projects										
SYS RE-Major Pipelines	101.1	48.8	41.9	78.5	125.1	71.4	80.0	74.9	73.0	75.0
SYS RE-Cherokee LNG Expansion Pipelines	17.0	51.9	75.0	56.0	66.9	0.5	0.0	0.0	0.0	0.0
Rider - (SRR) Overheads & AFUDC										
RIDER-(SRR) Overheads	6.3	7.4	7.7	8.8	8.8	8.8	8.8	8.8	8.8	8.8
RIDER-(SRR) AFUDC	11.1	10.7	14.2	20.2	15.2	19.8	12.2	18.1	22.4	28.5
Cherokee LNG Expansion	**39.5**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Gas Ops (Cherokee LNG Expansion)										
Gas Ops-Cherokee LNG Expansion	33.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rate Base - (Cherokee) Overheads & AFUDC										
RB-(Cherokee) Overheads	4.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RB-(Cherokee) AFUDC	1.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ECON-1	**14.6**	**13.4**	**13.4**	**13.5**	**13.5**	**13.5**	**13.5**	**13.5**	**13.3**	**13.9**
ECON-1 Projects										
ECON-1	14.2	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0
Rider - (ECON-1) Overheads & AFUDC										
RIDER-(ECON-1) Overheads	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
RIDER-(ECON-1) AFUDC	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.0	0.6
Valdosta Satellite LNG	**21.9**	**18.3**	**19.5**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Gas Ops (Valdosta Satellite LNG)										
Gas Ops-Valdosta Satellite LNG	20.3	15.3	15.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rate Base - (Valdosta) Overheads & AFUDC										
RB-(Valdosta) Overheads	0.8	0.7	0.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RB-(Valdosta) AFUDC	0.8	2.3	3.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OPS-ERT / AMR Projects - Proposed AMI Technology Program	**0.0**	**0.0**	**0.0**	**29.1**	**29.1**	**29.1**	**29.1**	**29.1**	**29.1**	**29.1**
OPS-ERT / AMI Technology Program										
Ops-ERT - AMI Tech	0.0	0.0	0.0	28.6	28.6	28.6	28.6	28.6	28.6	28.6
Rate Base - (AMI) Overheads & AFUDC										
RB-(AMI) Overheads	0.0	0.0	0.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5
RB-(AMI) AFUDC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DIMP-Pipeline Replacements	**0.0**	**0.0**	**0.0**	**25.5**	**50.6**	**50.6**	**50.6**	**50.6**	**50.6**	**50.6**
DIMP - Pipeline Replacements										
DIMP-Replace	0.0	0.0	0.0	25.0	50.0	50.0	50.0	50.0	50.0	50.0
Rate Base - (DIMP-Replace) Overheads & AFUDC										
RB-(DIMP-Replace) Overheads	0.0	0.0	0.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5
RB-(DIMP-Replace) AFUDC	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1
Renewable Natural Gas Projects	**0.0**	**0.0**	**0.0**	**64.2**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Gas Ops (Renewable Natural Gas)										
Gas Ops-RNG	0.0	0.0	0.0	60.0	0.0	0.0	0.0	0.0	0.0	0.0
Rate Base - (RNG) Overheads & AFUDC										
RB-(RNG) Overheads	0.0	0.0	0.0	2.0	0.0	0.0	0.0	0.0	0.0	0.0
RB-(RNG) AFUDC	0.0	0.0	0.0	2.2	0.0	0.0	0.0	0.0	0.0	0.0



Figure 5.12: Proposed Capital Investment by Plan Component



	2022 (act)	2023 (act)	2024 (bud)	2025 (plan)	2026 (plan)	2027 (plan)	2028 (plan)	2029 (plan)	2030 (plan)	2031 (plan)	2032 (plan)	2033 (plan)	2034 (plan)
Overheads & AFUDC	59.5	65.0	70.9	67.6	66.0	72.5	82.3	73.4	76.7	67.5	73.3	78.2	105.5
DIMP-Pipeline Replacements	0.0	0.0	0.0	0.0	0.0	0.0	25.0	50.0	50.0	50.0	50.0	50.0	50.0
Renewable Natural Gas Projects	0.0	0.0	0.0	0.0	0.0	0.0	60.0	0.0	0.0	0.0	0.0	0.0	0.0
Proposed AMI Technology Program	0.0	0.0	0.0	0.0	0.0	0.0	28.6	28.6	28.6	28.6	28.6	28.6	28.6
Valdosta Satellite LNG	0.0	0.0	0.0	20.3	15.3	15.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ECON-1	14.3	1.1	13.0	14.2	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0
Cherokee LNG Expansion	63.2	67.7	65.9	33.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
System Reinforcement Rider (SRR)	63.5	91.9	94.0	161.8	154.5	151.8	160.1	221.0	100.8	111.2	106.4	104.7	106.6
GRAM-Other than Safety & Compliance (GRAM-Other)	174.1	191.3	230.7	264.1	280.5	284.7	320.1	287.1	294.3	302.5	263.3	267.6	267.6
GRAM-Safety & Compliance (GRAM-S&C)	121.2	149.4	176.9	184.3	210.6	216.6	247.9	315.5	332.1	341.8	345.1	348.8	341.5

5.6 Overview of Planning and Project Selection Process

Each year, the Company begins the detailed capital budgeting process for the following year, as well as a higher-level strategic planning exercise to update the ten-year capital budget. Generally, this process starts in April to meet the July 1st AGL filing requirement. To provide the most up-to-date and accurate budget for this filing, the 10-year capital budget includes adjustments for new and more recently identified work requirements through the end of 2023.

The budgeting process begins within the Engineering & Construction ("E&C") organization. E&C coordinates the development of the capital budget by consolidating project requests submitted by budget owners from all functional areas across the Company.

The Company uses a prioritization process which incorporates a risk-based evaluation to select capital projects. The first step in the prioritization and selection process begins with assigning a prioritization class and a criticality to each project request. The matrices in Figure 5.13, Capital Prioritization, and Figure 5.14, Project Criticality and Class, below are used to apply these prioritizations consistently focusing first on safety and compliance.

Figure 5.13: Matrix of Capital Prioritization

CAPITAL PRIORITIZATION				
CAPITAL PRIORITIZATION	Class	Prioritization		
		CRITICAL (1)	*SIGNIFICANT* (2)	*MODERATE* (3)
	Safety (A)	Documented incident *will require* a response involving capital funding in the plan year.	Identified risk to our personnel, the public or our property is high and *there is no* acceptable, cost effective alternative.	Identified risk to our personnel, the public or our property is high *but there is* an acceptable, cost effective alternative; or identified risk to personnel, the public or property is low.
	Regulatory (B)	A non-compliant regulatory or contractual condition exists in the current year but acceptable plans have been filed that *will require* capital funding to achieve compliance in the plan year.	A non-compliant policy condition will occur in the plan year or, the company's reputation will be at risk at a high level unless action is taken and *there is no* acceptable, cost effective alternative.	A non-compliant regulatory, contractual or policy condition will occur in the plan year *but there is* an acceptable, cost effective alternative; or, the company's reputation will be at risk at a low level unless action is taken.
	Reliability and Integrity (C)	A pipeline operations asset or service has failed and *will require* capital funding to meet operating needs in the plan year.	Required to meet BU strategy for growth or a pipeline operations asset that is likely to need replacement in the plan year (based on failure history) to meet operating needs and *there is no* acceptable, cost effective alternative.	Same as 2C *but there is* an acceptable, cost effective alternative; or, current operating rates do not require that this unit be maintained for immediate in-service readiness.
	Obsolescence and Upgrades (D)	Not Applicable.	Equipment which has reached end-of-life, no longer supported by any vendor *and* spare parts are no longer available. May generate spare parts for other locations.	Same as 2D*but there are* spare parts available from other locations.
	Productivity (E)	Carryover for projects currently in process based on prior year business cases.	Analysis of project economics indicates 10.9% or better ROE.	Analysis of project economics indicates less than 10.9% ROE.
	Business Projects & Programs (F)	Policy Committee approved company project for the plan year that will require resources, complete all deliverables and begin to accrue "value" in the plan year.	Policy Committee approved company project for the plan year that will require resources in the plan year and year two, completes some deliverables in the plan year and will begin to accrue "value" in year two.	Policy Committee approved strategic and multi-year programs that will require resources for more than two years, but does not begin to accrue "value" until year three.
	Contingency Funds (G)	Contingency funds for unspecified requirements.	Not Applicable.	Not Applicable.

Figure 5.14: Matrix of Project Criticality and Class

Class	Prioritization		
	CRITICAL (1)	SIGNIFICANT (2)	MODERATE (3)
Safety (A)	1A	2A	3A
Regulatory (B)	1B	2B	3B
Reliability and Integrity (C)	1C	2C	3C
Obsolescence and Upgrades (D)	1D	2D	3D
Productivity (E)	1E	2E	3E
Business Projects & Programs (F)	1F	2F	3F
Contingency Funds (G)	1G	2G	3G

Through a series of budget reviews, budget requests are refined using the prioritizations.

5.7 Peaking Projects – Existing LNG Facilities

I. Introduction:

The Company's LNG plants are critically important to meeting AGL's customers' needs. When AGL's customers use more natural gas than interstate gas pipelines can deliver, the LNG plants vaporize LNG and inject the gas into the distribution system to maintain system pressures and meet customers' needs on the coldest days of the year. AGL has three LNG plants: Cherokee, Riverdale, and Macon. Together they can provide approximately 35% of the gas consumed on a Design Day. See Figure 5.15.

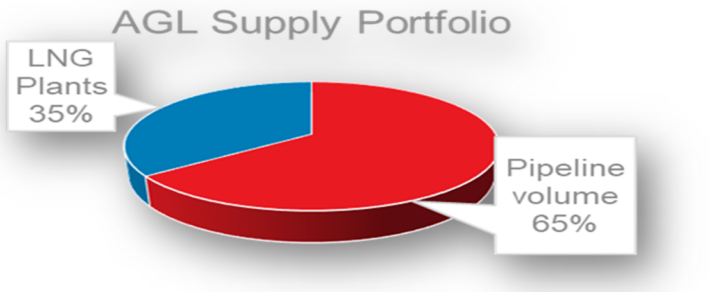


Figure 5.15: AGL Supply Portfolio on a Design Day

II. Present Drivers:

The Riverdale, Macon, and Cherokee plants were constructed in 1972, 1977, and 1988, respectively. They are beyond their expected service life of 25 years. Much of the equipment and materials in these plants have long lead times for replacement parts of several months, and sometimes more than a year, from order to installation. These long lead times make it imperative that AGL replace this equipment prior to failure. Failure to do so could result in the plant not being operable on peak gas demand days, thereby jeopardizing gas supply to thousands of AGL customers when they need it most. Also, in refurbishing the plants with modern equipment, improvements in safety, reliability, and performance are realized. In addition to expanding the capacity at the Cherokee facility, the Company proposed in the previous rate proceedings a proactive, multi-year approach to replacing and upgrading existing older equipment at the three plants. The Company continues to implement these improvements categorized as the following:

- Like-for-like replacement of end-of-life and obsolete equipment such as replacing a single pump or generator.

- Replacement of end-of-life and obsolete systems that may require bringing the system up to current codes and standards such as replacing fire protection systems, which now need to be brought up to the current National Fire Protection Association ("NFPA") 59A standards and other changes required by 49 CFR Part 193.

With the severe limitations on additional peaking supply from interstate pipelines and the increased reliance on LNG through the ongoing Cherokee LNG expansion, AGL has proposed a significant increase in investment in these facilities to help ensure that they continue to provide the necessary peaking supplies safely, economically, and reliably into the system on the coldest days of the year.

Funding Requirements:

While there are many smaller capital replacement items included within this Plan, below is a list of the major planned projects for each of these facilities through 2033. The Peaking Budget Parameters for the Existing LNG Facilities is presented in the table in Figure 5.16 at the end of this section.



Riverdale

The critical components at the Riverdale LNG plant planned for replacement include the liquefaction system, LNG send-out pumps, power generators, and boil-off compressors. Engineering for these projects began in 2023 and implementation is planned to continue into 2028.

- Riverdale LNG accounts for approximately half of AGL's peaking capacity on near Design Days. If Riverdale is not at full storage capacity at the beginning of a heating season, AGL's peaking capacity would be greatly reduced.

1. Liquefaction System

   AGL began exploring replacement options for the current Riverdale liquefaction system in 2023. The current open-loop expander liquefaction system is original to the plant and its age and parts obsolescence creates operational challenges and risks. These challenges include long lead times for replacement parts, increased maintenance of original equipment, and lack of efficiency due to the age of the equipment. Alternatives were identified for upgrading its existing 12.7 MMSCFD liquefaction system including replacing the exiting process in kind, a methane expansion compandor system, a nitrogen-based liquefaction system, and a Single Mixed Refrigerant ("SMR") system. The technology used will be finalized during the 1st quarter of 2024.

   - The replacement in kind option includes replacing the existing turboexpander liquefaction system components. This option may be less expensive than the other options, but the operational challenges discussed below and in Chapter 4 would remain.

   - Replace the open loop expander system with closed loop refrigerant technology, similar to Macon and Cherokee LNG. A full replacement of the existing open loop expander system with a new closed loop refrigerant technology would increase reliability and productivity and significantly reduce the tail-gas volume from the plant. This will eliminate the current capacity issues with the Atlanta distribution system and the difficulties in reconciling tail gas volumes with low customer usage. It will also mitigate any need for Riverdale or Cherokee to reduce the liquefaction



rate due to capacity restraints, ensuring all tanks can be refilled in a single liquefaction season.

2. LNG Send-out Pumps
    - Currently, there are nine natural gas engine driven LNG pumps that are utilized for send-out. If these LNG pumps are not operational, Riverdale cannot send-out gas into the system when needed. Due to parts obsolescence and reliability issues, the existing pumps will be replaced with four new electric motor driven LNG send-out pumps. Three will be required for full send-out and one will be redundant. The new pumps will reduce maintenance, have common spare parts, improve reliability during vaporization, and reduce emissions on site.

3. Generators
    - Two 4160V Turbine-driven generators are being installed to provide a new power source that can be used to provide electricity for multiple plant functions including the new motor-driven send-out pumps or tail-gas compressor, with utility power as a backup power source. This will provide the greatest reliability for this critical function of vaporization.

4. Boil-off Compressors
    - The boil-off gas compressors are original to the Riverdale facility and currently operate without redundancy. The new boil-off gas compressors will increase the system's reliability and help reduce liquefaction disruptions.

<u>Macon</u>

- The near-term major project at Macon includes the replacement of the generators. The current generators are nearing end of life, and these are critical for plant reliability. During peak send-out, the plant is unable to utilize the motor driven boil-off compressor and is fully dependent on the engine driven boil-off compressor.

- Other major projects at the Macon LNG plant in the ten-year plan include an additional LNG send-out pump and vaporizer and replacement of the pretreatment system and liquefaction system components. Currently, if one vaporizer failed this would impact fifty percent of the send-out capacity, and if an LNG pump failed, send-out would be reduced



by a third. The addition of a vaporizer and send-out pump will increase plant reliability when system demand is critical for customers. The pretreatment system is original to the plant and all associated piping and valves will be replaced. The liquefaction system upgrade includes the replacement of the cold box, compressor, and seal gas skid. The cold box replacement will increase liquefaction production and replace the current exchanger. Replacement of the liquefaction compressor and generators are needed to maintain system reliability. These items are not scheduled to go into service during the first three years of this Plan.

Figure 5.16: Peaking Budget Parameters – Existing LNG Facilities

Item	2022 i-CDP Filing				Current Actuals/Plan				2022-2024 Act/Plan vs. Filing	2025-2034 i-CDP Proposals ($ millions)									
	2022 (bud)	2023	2024	Filing Sub-Total	2022 (act)	2023 (act)	2024 (bud)	Current Sub-Total		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Peaking Projects - Existing LNG Facilities	4.2	16.3	17.3	**37.8**	4.2	8.6	18.9	**31.7**	**(6.0)**	32.8	42.7	24.7	10.1	13.2	13.0	15.0	15.0	15.0	15.0

5.8 Peaking Projects – LNG Expansion Projects

I. Introduction:

In its initial i-CDP filing (as well as in prior CSPs), AGL established that expanding the Cherokee LNG plant was appropriate to meet customers' needs. Fortunately for AGL and its customers, the designers of the Cherokee LNG plant had the foresight in 1988 to build the facility with the necessary land and footprint to allow for expansion. In accordance with approvals previously provided by the Commission, the Cherokee LNG expansion project was kicked off in 2020 and is currently scheduled to be complete in 2025. The multi-year project was contained in AGL's initial i-CDP filing. Nonetheless, this section provides an overview of the project, its brief history, current status, and plans for completion. More complete information concerning this significant capacity addition is available in the ongoing quarterly filing reports provided to the Commission, which AGL incorporates herein by reference.

Additionally, as outlined in Chapter 4 of this document, AGL now has a need to install a satellite LNG location in the Valdosta area to provide adequate gas supply to serve the growth in the region.

II. Present Drivers:

Cherokee LNG Expansion - The current plant has a single tank capable of storing two billion cubic feet (2 Bcf) of natural gas with a send-out capacity of 400,000 dekatherms per day. The



ongoing expansion adds a second 2 Bcf tank and the necessary facilities to add an additional 400,000 Dth per day of send-out capacity. The expansion includes the following:

- New 2 Bcf tank.
- New liquefaction train with pretreatment system.
- Additional send-out vaporization equipment.
- Expansion of power generation system to support additional equipment loads.

As noted in the quarterly reports referenced above, some supply chain disruptions have affected the Cherokee LNG expansion project, thus delaying the original projected in-service date. AGL is meeting incremental customer needs during the delay with supplemental citygate peaking services.

Valdosta Satellite LNG Project –

As outlined in Chapter 4, a satellite LNG facility is planned to meet the peaking needs of the Valdosta pool area. The facility will have ability to storage 300,000 gallons of LNG onsite and vaporize 311 MCF/H of LNG for delivery into AGL's distribution system. LNG stored onsite will be produced offsite and delivered to the facility by tankers. The full scope of the satellite facility will include the following:

- LNG bulk storage tanks.
- Send-out LNG pumps.
- Send-out vaporizer and water-glycol heaters.
- Storage tank boil-off gas recovery system.
- LNG truck unloading facilities.
- Interconnection with AGL distribution system.
- Gas metering and odorization.
- Fire and gas safety systems.
- Power and water utility feeds.
- Electric power generator.



Front-end engineering and design activities for the facility will begin in early 2025. Construction activities will begin in 2026 with a targeted in-service for the 2027-2028 heating season.

III. Funding Requirements:

Cherokee LNG - The project is currently estimated at approximately $249 million total (before overheads, AFUDC, and internal labor), approximately $33.4 million of which will be invested in 2025 to complete the project. See Figure 5.17, Cherokee LNG Budget Parameters, below. Based on updated system modeling, the ongoing Cumming to Hall LNG pipeline project must be completed by 2025 to address significant system pressure issues and in order to be able deliver the majority of the new Cherokee LNG into Hall County, and this project on track to do that. With respect to the Cumming to McGinnis Ferry Road pipeline project, there are two segments to this project. First, Segment #1: Cumming to Commerce, must be completed by 2028 to be able to provide the takeaway for the full Cherokee LNG capacity into the system to meet 2028 projected gas supply requirements on a Design Day. Completion of the Cumming-Hall and Cumming-Commerce pipelines will enable the expanded Cherokee LNG plant to send-out the full 800,000 Dth per day capacity. However, the second phase of the Cumming to McGinnis Ferry project, Segment #2: Commerce to McGinnis Ferry Road, must be completed by 2029 to maintain minimum system operating pressures under Design Day conditions for this area. These projects were included in the 2022 i-CDP filing and are currently being worked through the SRR (see Section 5.11 for project details and estimated costs).

Valdosta Satellite LNG Project -– While estimates are still being developed, current initial estimates of $50.9 million included below are based off of a similar project in a formerly owned Southern Company Gas utility with some adjustments plus an allocation for the necessary land purchase. See Figure 5.18, Valdosta Satellite LNG Budget Parameters, below.

Figure 5.17: Cherokee LNG Budget Parameters

Item	2022 i-CDP Filing				Current Actuals/Plan				2022-2024 Act/Plan vs. Filing	2025-2034 i-CDP Proposals ($ millions)									
	2022 (bud)	2023	2024	Filing Sub-Total	2022 (act)	2023 (act)	2024 (bud)	Current Sub-Total		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Gas Ops-Cherokee LNG Expansion	66.3	90.6	36.5	**193.4**	63.2	67.7	65.9	**196.8**	**3.4**	33.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Figure 5.18: Valdosta Satellite LNG Budget Parameters

Item	2022 i-CDP Filing				Current Actuals/Plan				2022-2024 Act/Plan vs. Filing	2025-2034 i-CDP Proposals ($ millions)									
	2022 (bud)	2023	2024	Filing Sub-Total	2022 (act)	2023 (act)	2024 (bud)	Current Sub-Total		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Gas Ops-Valdosta Satellite LNG	0.0	0.0	0.0	**0.0**	0.0	0.0	0.0	**0.0**	**0.0**	20.3	15.3	15.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0

5.9 *New Business*

I. Introduction:

AGL continues to support new customer growth and existing customer expansions through its New Business Tariff provisions. These investments support economic development and jobs across the state while providing clean, affordable natural gas to residential, commercial, and industrial customers.

II. Present Drivers:

The quantities and costs of this work have increased in recent years requiring significantly more capital investment. There are multiple significant cost drivers requiring additional spending for new mains and services.

First, AGL has seen very dramatic increases in labor and material costs due to pandemic and other cost increases and related supply chain disruptions. The first chart below in Figure 5.19 from Investing.com[22] shows the Dow Jones Construction & Materials 5-year Index through July 2023. As can be seen from the graphic, construction and materials costs have dramatically increased since the start of the pandemic and while they started to slow some in 2022, at the time of the creation of this testimony these costs were back near recent year highs.

Figure 5.19: Dow Jones Construction & Materials 5-year Index



[22] (https://www.investing.com/indices/dj-construction---materials)

Additionally, the same supply chain disruptions have caused inefficiencies in the construction process, such as return trips to finish installations and completing facility installations later in the construction process after driveways are poured and final restoration is in place. Figure 5.20 presents information on manufacturer lead times, lead time trends, lead time risk, and pricing trends for various materials.

Figure 5.20: Manufacturer Lead Times, Lead Trends, Lead Time Risk, and Pricing Trends

Material	Manufacturer Lead Time	Lead Time Trend	Lead Time Risk	Price Trend
PE Pipe, TUBING, <2"	Stock–6 wks (MD&HD)	▼	●	—
PE Pipe, MAIN, 2"	Stock–6 wks (MD&HD)	▼	●	—
PE Pipe, MAIN, 4+	Stock-6 wks (HD&MD)	▼	●	—
Meter Sets / Manifolds	50-60 wks	—	●	—
Meters	80-100 wks	▲	●	—
PE Fitting	16-26 wks	—	●	▲
Regulators (residential/commercial)	6-20 wks	▼	●	—
Anodes	20-26 wks	—	●	—
Tracer Wire	6-18 wks	—	●	▲
Risers	30-60 wks	—	●	—
Meter Valves	30-45 wks	—	●	—
EFVs	20-26 wks	—	●	—
PE Mechanical Fittings	16-52 wks	—	●	—
Valve Boxes	6-8 wks	—	●	—

Finally, AGL has seen significant new meter additions over the past decade as represented in the table in Figure 5.21 below. While the rate of growth has recently slowed, economic factors, the shortage of available housing, coupled with Georgia's business friendly environment, is expected to stabilize and return growth rates to pre-pandemic rates, albeit at higher costs.



Figure 5.21: New Meters

Actual New Meters											
2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	
8311	11676	14182	16036	17891	17740	19690	18539	17076	18102	18338	
Projected New Meters											
2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
14912	14729	15625	15849	16075	16224	16375	16528	16682	16837	16994	17512

The combination of these significant cost drivers as well as others as outlined in Section 5.1, plus consistent growth as shown above, has and will continue to result in large New Business investments under Rules 7 and 8 of the Company's tariff.

III. Funding Requirements:

The table in Figure 5.22 below contains current estimates for serving anticipated new residential and commercial customers based on current meter and cost projections which are significantly higher than estimates in the 2022 i-CDP filing. Note: While new meter projections are expected to stabilize and then rise, cost increases will likely still be a challenge in the coming years, AGL's expects that supply chain challenges will continue to slowly subsiding and new business costs will flatten during the term of the i-CDP.

Figure 5.22: New Business Budget Parameters

Item	2022 i-CDP Filing				Current Actuals/Plan				2022-2024 Act/Plan vs. Filing	2025-2034 i-CDP Proposals ($ millions)									
	2022 (bud)	2023	2024	Filing Sub-Total	2022 (act)	2023 (act)	2024 (bud)	Current Sub-Total		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
New Business	86.0	87.3	89.5	**262.8**	95.2	105.4	112.8	**313.4**	**50.6**	113.7	119.7	121.1	122.1	123.0	124.0	125.0	126.0	127.0	127.0

5.10 Strategic Delivery Projects

I. Introduction:

AGL and its customers have benefitted from the economic development activity that has been occurring in Georgia. Most of these economic development projects desire natural gas service. AGL, in partnership with this Commission, has contributed to this economic development success by undertaking several Strategic Delivery Projects to serve customers that have chosen Georgia as their desired location to launch or expand business operations bringing thousands of jobs to the state. SRR, together with ECON-1, SEED, and USF projects, continue to be key components to bringing natural gas service to unserved and under-served areas. This Commission is a leader in economic development, recognizing the benefit of providing necessary energy resources to unserved and under-served communities and to economic development projects that are of vital



importance to local communities. In addition to distribution system expansions, AGL makes strategic investments in Compressed Natural Gas fueling ("CNG") stations. These stations range from AGL fueling stations serving Company CNG vehicles to fueling stations serving key commercial and transportation customers.

II. Present Drivers

Strategic Pipeline Projects

AGL wants to serve all customers that seek natural gas service and has an obligation to do so if service can be provided under the terms of its Commission-approved Tariff. Sometimes the estimated costs to extend service to a new customer exceed the allowable investment based on revenues that AGL expects to collect from a customer. To enable communities to attract industry in support of economic development and job growth, AGL has access to the Universal Service Fund ("USF") and the Economic Development Tariff ("ECON-1") to construct natural gas infrastructure projects to serve areas that cannot be served without substantial contributions in aid of construction, based on typical line extension provisions (Rules 7 and 8 of the Company's Tariff). Since 2015, AGL has constructed more than $150 million in Commission-authorized natural gas infrastructure, throughout the Company's service area. Many more USF and ECON-1 projects approved by the Commission are currently in progress.

Strategic CNG Projects

AGL also strategically expands access to natural gas as a fuel for vehicles through CNG facility installations. For example, AGL completed the Chesapeake Utilities Corporation Port Fueling Center in Savannah in 2022. The Port Fueling Center CNG Station now provides natural gas fueling options for trucks moving cargo in and out of the port, yard tractors, and other equipment both on-port and in surrounding logistics centers, and for CNG trailers for mobile fuel and virtual pipeline solutions. Within the 2025 i-CDP, AGL plans to install CNG stations for Company vehicle refueling as a part of proposed regional business center replacements in Gwinnett and Marietta and to relocate an existing station as a part of the proposed Savannah office work.

III. Funding Requirements:

Strategic Pipeline Projects

Projects approved under USF or ECON-1 treatment are done at the discretion of the Commission and would not be done if not for the existence of the USF or ECON-1. As such, AGL does not



plan for USF projects in its capital budget. ECON-1 project capital expenditures are recovered through a rider that is updated annually in October for rates to become effective the following January to capture capital costs for completed projects that are in service or expected to be in service prior to the January rate-effective period.

AGL requests that the Commission continue its emphasis on economic development by continuing to approve USF and ECON-1 projects to provide vital natural gas infrastructure for job creators and unserved and under-served areas.

Strategic CNG Projects

AGL needs to install CNG stations at the Marietta and Gwinnett regional offices and to relocate the existing Savannah regional office station. AGL estimates $1 million per year for CNG stations starting in 2028 for future unplanned projects which is consistent with the 2022 i-CDP plan. The table in Figure 5.23 reflects the Strategic CNG Stations Budget Parameters, and the table in Figure 5.24 is the Econ-1 Estimated Budget.

Figure 5.23: Strategic CNG Stations Budget Parameters

Item	2022 i-CDP Filing				Current Actuals/Plan				2022-2024 Act/Plan vs. Filing	2025-2034 i-CDP Proposals ($ millions)									
	2022 (bud)	2023	2024	Filing Sub-Total	2022 (act)	2023 (act)	2024 (bud)	Current Sub-Total		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Strategic-CNG Stations	0.1	0.0	1.5	**1.6**	0.9	0.0	0.0	**0.9**	**(0.7)**	0.7	1.7	1.5	1.0	1.0	1.0	1.0	1.0	1.0	1.0

Figure 5.24: Econ-1 Estimated Budget Parameters

Item	2022 i-CDP Filing				Current Actuals/Plan				2022-2024 Act/Plan vs. Filing	2025-2034 i-CDP Proposals ($ millions)									
	2022 (bud)	2023	2024	Filing Sub-Total	2022 (act)	2023 (act)	2024 (bud)	Current Sub-Total		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Econ-1	0.0	0.0	0.0	**0.0**	14.3	1.1	13.0	**28.4**	**28.4**	14.2	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0

5.11 System Reinforcement

I. Introduction:

Because of continuing customer growth and the expansion of metropolitan areas in Georgia, there is an ongoing need for system reinforcement to bring natural gas from interstate supply points to the customers' locations. Historically, the Commission has shown great foresight on system reliability and customer growth by approving the STRIDE program, particularly the i-SRP part of STRIDE since 2010. Under the STRIDE program, AGL completed system reliability projects in Coweta, Fulton, Cobb, Gwinnett, Cherokee, Forsyth, and Paulding counties to bolster the system during extremely cold weather. As outlined and approved in the 2022 i-CDP, these types of projects are now being completed under the System Reinforcement Rider with the McGinnis Ferry



Rd project completed plus the first phase of the Cumming to Hall project installed with full project completion expected in 2025. Additionally, initial corridor studies and other engineering work has been performed for High Point to Villa Rica, Cumming to McGinnis Ferry, and multiple other projects as outlined in the MFR document. Finally, the Peachtree Rd project, as outlined in the 2022 i-CDP to shore up pressures in a large section of north Atlanta on the coldest days of the year, was also completed under the Pressure Improvement budget line since it was started before the approval of the System Reinforcement Rider.

II. Present Drivers:

As outlined in the 2022 i-CDP, AGL's System Planning Group analyzes flow and pressure data to ensure reliable service to customers. Using simulations based on historical and projected growth, AGL can anticipate where outages or low pressures are likely to occur. The models are flexible and can allow multiple growth projection, load migration, and extreme weather condition scenarios. The models are used to determine the areas that need additional capacity. While the updated system growth budgets presented within the 2025 i-CDP has shown very little change from the 2022 i-CDP, there were large changes from the work as initially planned compared to the work accomplished in the initial three years of the initial i-CDP. Significantly fewer System Reinforcement projects were undertaken during recent years to offset the large labor and material cost increases seen on SRR projects. The table in Figure 5.25 below shows the proposed projects and in-service dates as initially proposed in the 2022 i-CDP as well as updated plans within the 2025 i-CDP.



Figure 5.25: 2022 I-CDP Proposed System Reinforcement Projects & 2025 I-CDP Updates

2022 i-CDP Proposed System Reinforcement Projects				2025 i-CDP Updates	
	Project	Description	Target In Service	Updated Target In Service	Notes
1	Peachtree Rd.	2.4 miles x 12" steel 0.75 miles x 12" plastic	2022	Completed	Completed under the Pressure Improvement budget line
2	McGinnis Ferry Rd	2.9 miles x 12" steel	2022	Completed	Completed
3	Wade Green Rd Phase 2	4.3 miles x 12" steel	2023	2027	New in service date contingent on funding approval
4	Cumming to Hall County Pipeline	28.74 miles x 16" steel	2024	2025	First phase completed in 2023. Remainder to be completed by 2025.
5	High Point Road to Villa Rica	7 miles x 12" steel	2024	2026	New in service date contingent on funding approval
6	Villa Rica to Temple	5.4 miles x 12" steel	2024	2029	New in service date contingent on funding approval
7	Temple to Bremen	6.3 miles x 12" steel	2025	2031	New in service date contingent on funding approval
8	NW GA Line to Rome #1	3.4 miles x 16" steel	2025	2033	New in service date contingent on funding approval
9	Cumming to McGinnis Ferry Road	12.8 miles x 24" steel	2025	2028 2029	Split into two projects (Cumming to Commerce and Commerce to McGinnis)
10	Ball Ground to Ellijay	31.7 miles x 12" steel	2028	2030	Cut down to 20 miles of 16" steel now extending from Ball Ground to Ellijay
11	Camp Creek to Fulton Industrial Blvd	5 miles x 8" steel	2029	2030	New in service date contingent on funding approval
12	Hall County Extension	11 miles x 12" steel	2030	2032	New in service date contingent on funding approval

As can be seen in the Figure 5.25 table above, there were six projects planned for completion within the initial SRR period of 2022-2024. While the Peachtree Rd and McGinnis Ferry projects were completed along with the first phase of Cumming to Hall, the remainder of the projects have been pushed out to future years with even some of those updated completion schedules being contingent on a significant increase in proposed System Reinforcement funding.

III. Funding Requirements:



As shown in the Figure 5.25 table above, AGL has determined that the 2022 i-CDP Plan system reinforcement projects are still necessary in multiple greater Metro Atlanta counties to maintain reliable system performance in instances of extreme cold weather and to provide supply alternatives and stability in the west and northwest Georgia regions.[23] The delays in

[23] The details for these system reinforcement projects, including the counties where the projects are located, are available in the Company's Supplemental Minimum Filing Requirements for this i-CDP.

projected completion dates for these projects due to project cost increases continue to stress the system and require the deployment of mobile LNG vaporizers and other efforts on the coldest days of the year to avoid significant customer losses in the Dahlonega and Woodstock areas. The accelerated funding requests for these projects in the 2025 i-CDP filing are needed to complete the Cumming to Hall and Cumming to Commerce projects required to take the additional gas supplied by the Cherokee LNG Expansion into the system as well as to catch up some of these delayed projects and reduce the need for higher risk and costly emergency pressure support measures such as mobile LNG vaporization. The System Reinforcement Budget Parameters is detailed in the table in Figure 5.26.

Figure 5.26: System Reinforcement Budget Parameters

Item	2022 i-CDP Filing				Current Actuals/Plan				2022-2024 Act/Plan vs. Filing	2025-2034 i-CDP Proposals ($ millions)									
	2022 (bud)	2023	2024	Filing Sub-Total	2022 (act)	2023 (act)	2024 (bud)	Current Sub-Total		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
SYS RE-Major Pipelines	39.3	69.0	70.1	**178.4**	34.8	70.2	63.1	**168.1**	**(10.3)**	101.1	48.8	41.9	78.5	125.1	71.4	80.0	74.9	73.0	75.0
SYS RE-Cherokee LNG Expansion Pipelines	0.0	0.0	0.0	**0.0**	0.0	0.8	5.6	**6.4**	**6.4**	17.0	51.9	75.0	56.0	66.9	0.5	0.0	0.0	0.0	0.0

5.12 DIMP Projects

I. Introduction:

The objective of the DIMP is to comprehensively assess and address the integrity of the distribution system. As part of the DIMP, the Company identifies threats to its distribution system, determines the relative risk of each of the identified threats, and develops actions to mitigate those risks. AGL quantifies and ranks these risks through a combination of data analysis and subject matter expert workshops. The results of these assessments have determined that older steel (pre-1960) and mid-vintage plastic (1974-1983) pipelines pose an elevated risk to the distribution system in comparison to other pipelines in the system and should begin to be renewed. This assessment is further supported by multiple statements in a recently proposed Distribution rule (Docket No. PHMSA-2021-0046) from the PHMSA as well as references to the PIPES Act of 2020 passed by Congress. A few examples of the findings are included below, with emphasis added:

- *"Older pipelines and pipelines known to leak based on their material (e.g., legacy materials such as cast iron, wrought iron, unprotected steel, and certain historic plastics), design, or past operating and maintenance history are generally more susceptible to leaks."*

- *"Moreover, while progress has been made on efforts to replace or remediate any pipeline known to leak based on material (such as cast iron, unprotected steel, wrought iron, and*



historic plastics with known issues), design, or past operating and maintenance history, it remains an issue."

- *"Lastly, as previously discussed in section II.E of this NPRM certain types of pipe materials cause a disproportionate number of leaks. In particular, pipe and fittings made of cast iron, unprotected steel, wrought iron, and historic plastics with known issues are more likely to leak than coated and protected steel and modern plastics.* ***Replacing these pipelines*** *and other pipelines known to leak can be an effective, long-term solution to systematic leak susceptibility for such pipelines."*

- *"Section 114 of the PIPES Act of 2020, moreover, requires operators of all pipeline facilities with maintenance and inspection procedures to update pertinent manuals to address the elimination of hazardous leaks and minimize releases of natural gas—whether fugitive emissions from leaks or intentional releases due to venting from maintenance and other activities—****and repair or remediate pipelines known to leak.*** *And section 118 of the PIPES Act of 2020 clarified that PHMSA must consider environmental benefits equally with public safety benefits."*

The Congressional mandates in the PIPES Act of 2020 and the resulting proposed rule from PHMSA that vintage plastics and other pipelines known to leak be replaced to both enhance pipeline safety and to address the environmental impacts of such leaks. As indicated by Figure 5.27, Annual Below Ground Leak Repair Rate Per Mile of Main, discussed below, AGL's analysis supports replacing these pipes.

II. Present Drivers:

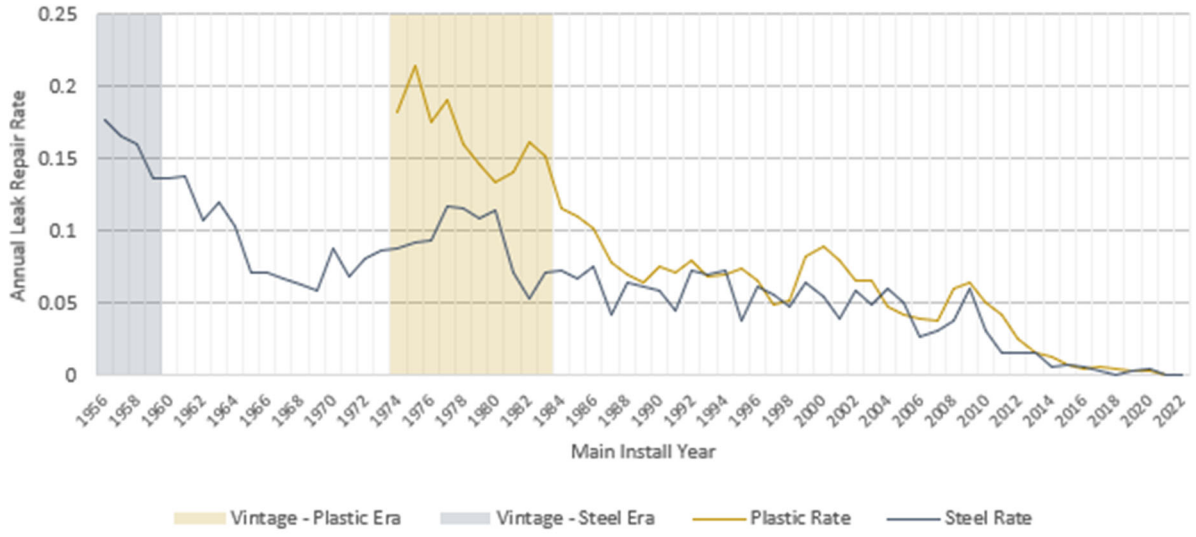
The increased leak rate on mid-vintage plastic pipelines is often caused by the pipe material becoming brittle over time, making it subject to cracking leaks. Accordingly, the risks associated with the earliest vintage plastic was the basis for the Commission approved VPR Program that was completed in 2017. This program included the replacement of all known pre-1974 plastic mains and some of the highest risk mid-vintage plastic (pipe that was made and installed 1974-1983).

The first steel pipeline coatings used by the industry back in the 1950s were not as durable as modern steel pipe coatings. Consequently, this material has also demonstrated an elevated leakage rate compared to more modern steel and plastic pipe materials.

The chart in Figure 5.27 below includes leaks per mile of steel and plastic gas main by year of installation based on recent leak survey results. The shaded areas highlight the pre-1960 time period, as well as the 1974-1983 time period that was only addressed in limited quantities in the VPR program mentioned above. As illustrated below, steel mains installed pre-1960 and mid-vintage plastics installed in 1974-1983 exhibit the highest leak rates within the AGL system.

Figure 5.27: Annual Below Ground Leak Repair Rate Per Mile of Main

Leak rate represents leak per mile per survey cycle of active gas main by year installed and material. Excavation, outside force, above ground, and meter set leaks are excluded.



III. Current DIMP Process

A multi-tiered approach to risk ranking has been developed to evaluate the risks associated with the distribution pipeline. This more sophisticated risk analysis approach has been created to better understand and react to threats occurring in the system. This approach ensures all significant threats, and their potential consequences are considered and addressed in a manner appropriate with the threat.

A risk analysis hierarchy has been provided in Figure 5.28 to allow for macro and micro understanding of threats in the system. Accordingly, the risk analyses provide different perspectives where threats may be identified and addressed.

Figure 5.28: Risk Evaluation

Risk Evaluation	System / Local	Update Frequency
System Level Threat Assessment	System	Annually
Subject Matter Expert Risk Assessment	System/Local	Annually
Pipeline Integrity Risk Assessment	Local	Annually
PHMSA Audit Risk	System/Local	Annually

The **System Level Threat Assessment** considers leak sub-causes per facility type. The trend (likelihood of failure), frequency (likelihood of failure), and hazardous percentage (consequence of failure) of all leak repairs in the system to calculate a risk score.

The **Subject Matter Expert Risk Assessment** is performed by region, material, and sub-cause. This assessment considers all threats, leak repairs, and SME background knowledge to determine a relative score for both (consequence of failure) and (likelihood of failure) to calculate a risk score.

The **Pipeline Integrity Risk Assessment** assigns a risk score based on geographical location to each segment/neighborhood. This assessment is geospatially aware which means the cause and consequence scores are unique to the geographical location of the pipeline. The risk model uses both the attributes of the pipeline, premises density, business district, and leak data while considering the physical location of the data to produce geographically accurate risk scores. For example, large and high-pressure pipelines in an urban area have a higher consequence of failure score and vintage material pipelines will have a higher likelihood of failure score than pipelines made with more modern materials.

The **DIMP Identified Risks** report is comprised from the System Level Threat Assessment and the Subject Matter Expert (“SME”) Risk Assessment. This approach ensures that leak volumes and SME expertise are considered when determining the top risks to the distribution system.

PHMSA issued a report in February 2020 entitled *Pipeline Risk Modeling: Overview of Methods and Tools for Improved Implementation.* AGL plans to refine its approach to pipeline integrity risk assessment to incorporate some of the recommendations detailed in this report to develop a probabilistic DIMP risk assessment approach going forward. The probabilistic risk model enables AGL to predict hazards more accurately by quantifying the likelihood and impact of different risk



scenarios, which leads to better-informed decision-making and improves pipeline safety and reliability.

IV. Funding Requirements:

As of the end of 2022, AGL had 1,541 miles of known or assumed to be pre-1960 coated steel mains and 2,583 miles of known or assumed to be mid-vintage plastic mains in its system. The estimated costs to replace these facilities is approximately $1.9 billion.

Furthermore, the Company is at a critical decision point related to its ability to proactively address all aging distribution infrastructure. At the Company's current retirement rate of approximately 10 miles per year and starting with the oldest first (assuming unknown is included and worked first), all pre-1960s main would be renewed by approximately the year of 2188 with an asset age of 229 years and all pre-1970s main would be renewed by approximately the year of 2642 with an asset age of 673 years. In contrast, a retirement rate of 100 miles per year would result in the pre-1960s main retirement to be completed in approximately 2039 with an asset age of 80 years and pre1970s main in approximately 2084 with an asset age of 115.

As can be seen in the table Figure 5.29 below, proposed DIMP spending in the first three years of the Plan continues to be in the $20-$25 million per year range to allow for other projects related to compliance and system stability to be completed. Beyond the first three years, AGL anticipates the need to increase these replacements to manage the pace at which these aging pipelines are removed from the system. This rate of DIMP replacement growth will bring DIMP budget parameters up to $75 million per year, as outlined in the 2019 Rate Case and 2022 i-CDP filings. Also as outlined above, if the currently proposed PHMSA Distribution Rule is adopted as written, there will likely be federal mandates that will necessitate a supplemental request from AGL to revisit these investments.

Figure 5.29: DIMP Budget Parameters

Item	2022 i-CDP Filing				Current Actuals/Plan				2022-2024 Act/Plan vs. Filing	2025-2034 i-CDP Proposals ($ millions)									
	2022 (bud)	2023	2024	Filing Sub-Total	2022 (act)	2023 (act)	2024 (bud)	Current Sub-Total		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
DIMP	20.6	20.0	25.0	**65.6**	18.4	14.6	7.6	**40.5**	**(25.1)**	20.0	20.0	20.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
DIMP-Pipeline Replacements	0.0	0.0	0.0	**0.0**	0.0	0.0	0.0	**0.0**	**0.0**	0.0	0.0	0.0	25.0	50.0	50.0	50.0	50.0	50.0	50.0

5.13 Gas Operations -Measurement & Controls

I. Introduction:

The mission of the Measurement & Controls department within Gas Operations is to provide safe, reliable, and cost-effective flow measurement of natural gas to AGL's end-use customers. The Measurement & Controls group not only provides AGL customers with industry and American Gas Association approved measuring equipment but also ensures proper installation and calibration for the life of the devices. Measurement & Controls manages and supports the complete lifecycle of approximately 7,344 industrial gas meters, 345 transportation customer sites, and 86 Gate Stations for custody-transfer of natural gas from suppliers as well as overseeing the AGL PT Meter sampling program.[24] Gas Measurement & Controls is also responsible for the IT support of the control system used by Gas Control to monitor and safely deliver natural gas throughout the state of Georgia. Continued investment in the installation, upgrade, and replacement of these measuring and control facilities is necessary to ensure the safety, reliability, and accuracy of this equipment.

II. Present Drivers:

Major drivers of Measurement & Controls expenses and investments include regulatory requirements around end-use customer measurement equipment calibration, new customer count increases, and PHMSA/TSA cyber security guidelines.[25] With the recent rise in cyber security concerns and related hacking threats, the need for constant updating of electronic software and equipment used to measure, monitor, and control gas flow is expected to continue to increase over time.

Additionally, AGL has an ongoing a multi-year initiative to increase safety through remote monitoring of Mercaptan levels at approximately 35 locations where AGL receives odorized gas from pipeline suppliers. While AGL has and will continue to complete the required in-person verifications of the levels of odorant within its system as required by current regulations, the installation of monitors at these locations that provide readings every 1 to 4 hours, coupled with 24/7 monitoring of any alarms triggered by these readings through AGL's Gas Control, will significantly reduce the risk of odorant levels being too high or too low at these locations where the odorization is not managed by AGL.

[24] The PT Meter sampling program is described in section 5.20.
[25] PHMSA and the Transportation Security Administration (TSA), which are agencies within the U.S. Department of Transportation, announced an updated pipeline security agreement in February 2020, which resulted in new guidelines for the industry.



Also, AGL has a multi-year replacement program of existing remote electronic pressure recorders ("ERXs"). These ERXs fulfill telemetering requirements at pressure regulating stations as required by CFR 192.741 and must be replaced over time to maintain operability and to address required technology upgrades due to changing communication platforms. The current program extends through 2030 but will adjust as necessary based on changing technologies and any new regulations.

Finally, an expansion of the installation program for ERXs is proposed to begin in 2028 and extend at a $2 million per year level beyond 2034 to further expand the locations where ERXs are installed. This expansion of up to an additional 3800 units would provide live visibility to all distribution regulator stations in the system and would enable timely responses to system issues. AGL's planed program expansion is based on industry best practices. Nonetheless, similar requirements of the recently proposed PHMSA Distribution rule could require a larger and/or accelerated program in the future.

III. Funding Requirements:

The proposed investment levels in the table in Figure 5.30 below include the normal run rate spending for these facilities along with near-term increases to implement remote monitoring and cybersecurity initiatives as outlined above plus the proposed ERX program expansion.

Figure 5.30: Gas Operations – Measurement & Control Budget Parameters

Item	2022 i-CDP Filing				Current Actuals/Plan				2022-2024 Act/Plan vs. Filing	2025-2034 i-CDP Proposals ($ millions)									
	2022 (bud)	2023	2024	Filing Sub-Total	2022 (act)	2023 (act)	2024 (bud)	Current Sub-Total		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Measurement	2.3	2.0	2.5	6.7	1.1	2.1	1.6	4.7	(2.0)	2.3	2.7	3.7	5.5	5.8	4.8	3.2	3.0	3.0	3.0

5.14 DOT Driven Facility Relocations

I. Introduction:

The majority of AGL's pipeline facilities are located within state, county, or municipal DOT road right-of-way. These facilities fall under right-of-way agreements that require AGL to relocate its facilities when there is a conflict with future roadway, drainage, or related construction. This roadway construction work is proposed, scheduled, and controlled by these government entities and the timing largely driven by federal DOT funding and revenues from state and local tax programs for road construction. AGL must conform to the state, county, or municipal governments' scheduling requirements.



Typically, relocation of AGL's facilities to accommodate DOT-type projects must be funded by AGL. There are two relatively rare scenarios where AGL is reimbursed for gas facilities relocations driven by road construction work:

- AGL obtains certain easements and/or purchases property outside of DOT right-of-way where needed for certain larger pipelines and critical facilities. If AGL facilities located within existing Company-owned easements or property are determined to conflict with a DOT project, the governmental entity is required to reimburse AGL for the cost of the relocations as well as procurement of any necessary replacement easements or property.

- There are existing federal programs that allow State discretion to reimburse utilities for DOT driven facility relocations, but these reimbursements are rare.

II. Present Drivers:

Most DOT related relocation costs for AGL are driven by projects funded with state gasoline tax revenues, county, or regional Special Purpose Local Option Sales Taxes ("SPLOST") programs, and federal funding for transportation.

Most SPLOST programs at the county level are approved by voters for multiple years at a time. SPLOST programs in some of the larger Metro Atlanta counties such as Gwinnett, Cobb, and Fulton can cause AGL to incur millions of dollars of required gas facility relocations each year. Examples of some of the larger county transportation SPLOSTs are included below:

- Cobb County – Current SPLOST was renewed by the voters in November 2020 and will run to December 31, 2027. The 2022-2027 SPLOST includes funding specifically for transportation projects totaling approximately $330 million over the six-year program along with city SPLOST estimations of another $183 million with a large portion of those dollars also supporting city DOT work.

- Gwinnett County – The current six-year SPLOST began April 1, 2023, and is expected to raise $1.35 billion over that time with $736.3 million for roads, streets, bridges, facilities, and equipment.

- Fulton County – The current SPLOST runs from 2022 to 2027. All funding from this SPLOST can be spent on transportation improvements.



Federal funding initiatives also provide additional dollars for interstate highways and other improvements. The amount of available funds can vary based on federal budgets, revenues, and programs intended to spur jobs and economic growth.

Additionally, one of the largest and most stable funding sources for DOT projects is the state gasoline tax and related revenue. The Transportation Funding Act of 2015 (GA HB 170) resulted in a significant increase in DOT expenditures for AGL at or near a rate of $30 million per year.

The combination of cost increases and a significant increase in large GDOT road widening and other improvement projects pushed AGL's DOT-related annual expenditures to $49.9 million in 2023. This approximately 65% increase in AGL's DOT related expenditures is not expected to substantially subside in the near future based on current and known upcoming projects and potential additional transportation funding from current federal and state infrastructure legislation. Current DOT projects with significant spend that began in the latter part of 2023, included:

- 27 projects with estimated spend of over $1 million; and
- 129 projects with estimated spend of less than $1 million.

These 156 projects had an estimated total required investment of approximately $112 million. In addition to these active projects, AGL currently knows of another 34 projects with required spends likely to exceed $1 million per project with known or likely release by GDOT in 2024 and 2025. The table in Figure 5.31 below shows these historical and current investment changes by year.

Figure 5.31: Historic DOT Relocation Work Investments

Historic DOT Relocation Work Required/Proposed Investments										
Actual Required Investment										Current Budget
2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024 (Budget)
17.2	21.3	17.0	26.8	36.2	30.5	28.2	27.0	37.9	49.9	42.8
Pre 2015 Gas Tax			Post 2015 Gas Tax			Minor Pandemic Slowdown		Pandemic Recovery, Additional Infrastructure Investments, & Heavy Impact Large State Hwy Widenings		

III. Funding Requirements:

Since moving lines for road work is required as a part of AGL's permit and right-of-way agreements with the State and other governmental agencies, AGL must perform this work regardless of other budgetary pressures or priorities. While AGL tries to minimize the costs of these projects where possible through subsurface utility engineering and other methods, AGL originally expected to see its continued DOT project investment requirements at the $40 million level or higher annually going forward when the 2025 i-CDP budgets were being finalized in December 2023.

Just before filing this Plan, Governor Kemp unveiled his budget agenda during the Georgia Chamber of Commerce "Eggs and Issues" Breakfast on January 10, 2024, which included an additional $2 billion in proposed investments with a large portion dedicated to infrastructure projects to support the State's continued growth. This additional infrastructure investment, if authorized by the General Assembly, would likely increase the proposed investment requirements shown in Figure 5.32, Potential DOT Budget Parameters, below.

Figure 5.32: Potential DOT Budget Parameters

Item	2022 i-CDP Filing				Current Actuals/Plan				2022-2024 Act/Plan vs. Filing	2025-2034 i-CDP Proposals ($ millions)									
	2022 (bud)	2023	2024	Filing Sub-Total	2022 (act)	2023 (act)	2024 (bud)	Current Sub-Total		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
DOT Projects	30.7	30.3	30.9	**91.9**	37.9	49.9	42.8	**130.7**	**38.8**	44.3	43.2	41.3	41.5	42.3	43.2	44.0	44.9	45.8	46.7

5.15 Pressure Improvements

I. Introduction:

As new customers are added to the system and existing customers increase their natural gas usage, increased demand causes a reduction in the operating pressure of the system on higher demand days. This reduction in pipeline pressure reduces the capacity of the downstream pipelines and regulating facilities and can result in customer outages on the coldest days of the year.

As these system constraints are identified through pressure modeling and field measurements of actual pressures on the system on high-demand days, projects are designed to alleviate the pressure constraints.

II. Present Drivers:

There are two primary drivers for the increased need for pressure improvement projects within the AGL system. They are system demand growth and constraints on the major pipelines feeding into the regional systems.

System Demand Growth - The increase in new customers as outlined in section 5.9 above, as well as increased use of natural gas by commercial and industrial customers based on lower cost and/or lower emissions than other traditional fuel sources, continues to strain local pressure systems. The need for a pressure improvement project may be the result of a single large commercial load, a large commercial or residential development being added to a system, or multiple smaller loads being added over time.

Major Pipeline Constraints – As outlined in Section 5.10 on System Reinforcement, many of AGL's primary supply pipelines are already constrained to where they are near or even below minimum pressures on high-demand days. When these primary supply pipelines are operating at or below minimums, the connections to the regional systems start out constrained and get worse between the regional system feeds and the customers. This may limit the system's ability to absorb additional growth without upsizing existing pipelines or adding new system connections. With so many of the larger primary supply pipelines already constrained, AGL will continue to require increased spending on pressure improvements to continue to serve growth on the system.

III. Funding Requirements:

AGL has traditionally been investing approximately $10 million annually to maintain the resiliency of the system (the higher 2022 totals also include the completed large Piedmont PRIM outlined in previous rate proceedings), but recent cost increases and other pressures have necessitated delaying certain planned pressure improvement projects and addressing only those projects where customers at immediate risk of losing gas service on a day with near Design Day conditions. By not addressing projects that are below system minimums but are not yet at critical levels based AGL's system pressure model, AGL is adding significant risks to system stability and resiliency. For example, a 300 psig system that is at its system minimum pressure of 125 psig in the Company's pressure model on a Design Day has used up approximately 90% of the intrastate pipeline's actual capacity. From this point, even minor operational issues or relatively small additional loads can quickly put the system in jeopardy. For these reasons, as well as the reality of cost pressures, as is reflected in the table in Figure 5.33, AGL is proposing to return annual



pressure improvement investments to previous levels through 2027 and then begin a stepped increase of $5 million per year to move back away from just-in-time PRIMs.

Figure 5.33: Pressure Improvements Budget Parameters

Item	2022 i-CDP Filing				Current Actuals/Plan				2022-2024 Act/Plan vs. Filing	2025-2034 i-CDP Proposals ($ millions)									
	2022 (bud)	2023	2024	Filing Sub-Total	2022 (act)	2023 (act)	2024 (bud)	Current Sub-Total		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Pressure Improvement (PRIM) - SRR	19.9	10.7	9.0	**39.7**	24.5	12.3	6.4	**43.2**	**3.5**	10.8	11.0	10.3	15.5	15.7	16.0	16.2	16.4	16.6	16.6

5.16 Renewals

I. Introduction:

AGL's plans for Renewals includes multiple project types associated with replacement and capital repairs of existing facilities. The primary project types included in the Renewal Plan are:

- General Renewals.
- Exposed Mains.
- Emergency Districts.
- RCVs.
- Partition Valve Remediation.

Some of these items within the Plan are supported by budgets based on run-rates from previous years to address safety, compliance, and system integrity issues as they arise. Others, such as the partition valve remediations, are program-specific with known scopes and, in many cases known, durations. Plans regarding the RCV program have been changed significantly due to the 2023 PHMSA RMV rule.

II. Present Drivers:

Although all Renewal work is generally associated with replacement or capitalized repair of existing facilities, the drivers behind the work can vary. Included below are details for each of the major Renewal work types:

- **General Renewals** – This is the unplanned work each year that must be done in response to issues identified on the system. Examples include pipeline replacements because of localized corrosion on steel pipelines, damages, and segments of pipelines with multiple leaks identified through means other than DIMP. This work is generally unplanned and is driven by issues identified in the field by Company or contractor personnel. Historical



spending in this area has been approximately $6-$7 million per year but has increased in recent years due to cost increases as well as unrepairable leaks on aging transmission line valves. While it is very difficult to predict what issues will arise in the coming years that will require remediation, it is expected that higher-than-normal run rate investments will be needed in this area through 2026, which is summarized in Figure 5.34.

Figure 5.34: General Renewals

Historic / Planned General Renewals Investments (in $ millions, direct spend only)							
Actuals			11+1 Outlook	Budgeted	Proposed		
2020	2021	2022	2023	2024	2025	2026	2027
6.1	6.6	7.2	7.6	17.8	11.9	12.7	7.7

The types of ongoing general renewal projects include:

- Odorant Fade Remediation Projects – AGL has identified a few areas of large steel main extensions in rural areas where limited flow on the mains, especially outside of the heating season, is resulting in odorant fade issues. Without proper odorization levels in the mains, any leaks or abnormal equipment operation can become more difficult to identify, leading to safety concerns for AGL and its customers. While AGL crews are employing special tools such as field bypass odorizers to maintain the safety and compliance of these pipelines, these efforts are costly and burdensome, requiring weekly and even daily monitoring. Approximately 30% of the increases in General Renewals from 2024-2026 are for more permanent solutions to these issues.

- 16” Main Replacement at the Port of Savannah – AGL has approximately 3,000 ft of 16” steel pipeline installed along a viaduct at the Port of Savannah that is aging and in conflict with proposed port expansion work. While most of this project is expected to be completed in 2024, it will likely extend into 2025 due to ongoing design and other changes.



- **Exposed Mains** – The Company identifies and remediates sections of buried mains that may become exposed due to natural causes such as general erosion, creek and riverbank failures and changes, floods, etc. In many cases, it is less costly to remediate the environment around the pipeline than it is to replace the pipeline itself. This is generally done with concrete revetment mats as shown in the picture, courtesy of www.Submar.com/products. The 2022 i-CDP assumed that work would continue at a pace based on historical data to remediate these issues as they are identified in the field. While additional exposed mains have been identified, investments in these projects have been challenged in recent years by budget reprioritizations resulting in a significant backlog of work. This i-CDP includes plans to begin addressing this backlog.



- **Emergency Districts** – This investment is necessary to maintain an ability to shut off gas to specific areas or key facilities in the event of a major system problem, natural disaster, or other unforeseen issue. As systems grow or are connected to other systems for back feeds or pressure improvements, these emergency districts are affected. This may require the installation of additional valves at key points in the system to maintain customer count maximums per district or other strategic limiting factors. The Company routinely spends approximately $0.5 million per year reviewing, refining, and maintaining these districts. At the time of the development of this i-CDP filing in January 2024, there is currently a PSC Facilities Protection Staff NOPR draft, which includes proposed additional requirements concerning valve placement and inspection programs and the associated districts. A proposed rule has yet been issued, making it difficult to accurately estimate to the potential impacts of these proposed new rules. Nonetheless, the current NOPR will likely require approximately $375,000 in additional capital and approximately $270,000 in additional O&M annually (for Emergency District work alone) if implemented consistent with the most recent version Facilities Protection Staff shared with the operators.

- RCVs – In response to the 2010 pipeline rupture in San Bruno, CA as well as several other incidents, in 2011, Congress directed PHMSA to issue new regulations requiring the use of ASVs or RCVs on newly constructed or replaced transmission pipelines where it is economically, technically, and operationally feasible. This congressional mandate was in response to concerns over the amount of time it takes to shut down pipelines during incidents. This led to a new PHMSA rule titled "Pipeline Safety: Requirement of Valve Installation and Minimum Rupture Detection Standards" that fully went into effect on April 10, 2023. While the majority of the new mandate is focused on requiring ASVs/RCVs on new or "*Entirely Replaced*" transmission pipelines, revisions to 192.935(c) titled "*Risk analysis for gas releases and protection against ruptures*" require that "*If an operator determines, based on a risk analysis, that a rupture-mitigation valve (RMV) or alternative equivalent technology would be an efficient means of adding protection to a high-consequence area (HCA) in the event of a gas release, an operator must install the RMV or alternative equivalent technology*." AGL's TIMP program has always considered potential installation of RMVs (as RMVs were provided as an option in the previous version of 192.935) and has an ongoing project to retrofit some existing valves on a 36-inch transmission pipeline just west of downtown Atlanta (see the picture). The language in the updated version of 192.935 enhances these installation requirements for HCA transmission pipelines. For this reason, AGL is proposing a significant multi-year acceleration in investment around existing transmission pipeline valves to ensure compliance with the new mandates. This accelerated investment, as shown in the table in Figure 5.34, Renewals Budget Parameters below, will begin with detailed assessments of existing transmission block valves within HCAs from 2025-2027 to develop detailed plans. Until this detailed review is completed, it will not be possible to accurately estimate the full costs to comply with this new mandate. Some valves may only require retrofits at an estimated cost a few hundred thousand dollars each, while others may require full pipeline relocations to create a suitable RCV location, with costs easily ranging from $500 thousand to well over $10 million each. Once the detailed review is completed, AGL will expand its plans accordingly to ensure compliance with the PHMSA



mandate. Since the expanded program will not be underway during the first three years of this Plan, AGL will be able to revise these estimates before the 2028 i-CDP filing. Once fully implemented, these additional RCVs will allow AGL to be able to shut down segments of existing transmission pipelines more quickly in the event of an emergency.

Partition Valve ("PV") Remediation – There were approximately 115 valves within the AGL system that served as a single separation point between systems operating at different pressures. These valves may separate systems with differing pressures of as low as 15 psi or as high as hundreds of pounds of pressure and may be the result of previous construction, system pressure changes, pressure regulating facility removals or replacements, or strategic installations to allow for emergency back feeds. The Company identified the chance of potential over-pressurization of the downstream systems as a risk, should the valve leak or be inadvertently operated, and thus began removing or remediating these valves in 2020. Originally as outlined in the 2022 i-CDP, these valves were planned to be remediated by the end of 2024. Due to cost increases and budget reprioritizations since that time, this work has been slowed significantly. As of September 2023, there were 67 remaining PVs to be remediated with an expectation that the work will be completed in 2028 due to work reprioritizations. The PV remediation work is being completed as a part of the General Renewals budget line shown in Figure 5.35, Renewals Budget Parameters, below.

Figure 5.35: Renewals Budget Parameters

Item	2022 i-CDP Filing				Current Actuals/Plan				2022-2024 Act/Plan vs. Filing	2025-2034 i-CDP Proposals ($ millions)									
	2022 (bud)	2023	2024	Filing Sub-Total	2022 (act)	2023 (act)	2024 (bud)	Current Sub-Total		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
RENEW-General Renewals	5.4	5.4	5.4	**16.3**	7.2	7.4	17.8	**32.4**	**16.1**	11.9	12.0	7.7	7.7	6.5	6.6	6.7	6.8	6.9	6.9
RENEW-Remote-Controlled Valves	0.5	2.0	3.0	**5.5**	0.2	0.1	0.4	**0.7**	**(4.9)**	3.0	4.2	4.2	10.0	10.0	10.0	10.0	10.0	10.0	10.0
RENEW-Emergency Districts	0.8	0.8	0.8	**2.5**	0.0	0.3	0.3	**0.6**	**(2.0)**	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6
RENEW-Exposed Mains	1.0	1.0	1.1	**3.1**	0.0	0.0	1.0	**1.0**	**(2.1)**	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Renewals - Total	**7.8**	**9.3**	**10.3**	**27.4**	**7.4**	**7.7**	**19.5**	**34.6**	**7.2**	**20.4**	**21.7**	**17.4**	**23.2**	**22.0**	**22.1**	**22.3**	**22.4**	**22.5**	**22.5**

5.17 Regulator Stations

I. Introduction:

AGL has approximately 4,700 pressure regulating facilities from tap stations that include pipeline heaters and odorization equipment to small district stations that may feed a neighborhood or commercial development. Due to obsolescence and identified needs, AGL began replacing these key facilities in 2017 as shown in the table in Figure 5.36 below.



Figure 5.36: Historic/Planned Regulator Station Investments

Regulator Station Investment ($ millions)							
2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023 Outlook**	**2024 Budget**
11.5	13.6	13.2	15.2	20.6	17.0	19.0	28.3

In the Fall of 2018, 50 miles of pipeline were over-pressurized in Merrimack Valley, Massachusetts when a regulator station was improperly retired. This resulted in one fatality, 28 injuries, multiple house fires, and the loss of service for more than 8,600 customers for three months. More than 100 buildings were destroyed, and many more structures were damaged. The local utility paid $80 million in a settlement with the three communities, $143 million in a court-approved class action settlement in which more than 175,000 people were eligible to receive compensation, and a $56 million-dollar criminal fine. Numerous individual personal injury claims and individual property damage claims were resolved for amounts estimated to be greater than an additional $1 billion. This incident prompted the review of regulator station configurations for utilities across the entire United States, including at AGL.

In the months following this incident, guidance was issued from multiple agencies including the NTSB, PHMSA, and the GPSC Facilities Protection Staff regarding actions that should be taken concerning these facilities to help ensure that another event such as happened in Merrimack Valley would not happen again. In addition, the American Gas Association and its members, including AGL, developed and released a white paper with additional recommendations.

AGL convened a team to review all this guidance and evaluate its risks in this area. The review indicated that AGL is not likely to have a catastrophic, over-pressurization event identical to the one in Merrimack Valley. The reason for this is because of the Commission's foresight in allowing AGL to replace its low-pressure bare steel and cast-iron pipelines with the last ones being retired in 2014. Nonetheless, over-pressurization is possible at some individual regulator stations and many of the recommendations from the various agencies and industry groups also apply to elevated pressure stations and related facilities.

II. Present Drivers:

As outlined below and in the Company's 2022 i-CDP filing, AGL has multiple ongoing initiatives to enhance the safety of these facilities as well as to address known issues such as age and



obsolescence, unsafe station locations, drainage issues, and other items that can negatively affect the safety and proper operation of these critical facilities. Unfortunately, cost increases for this work as well as other capital investments resulted in less of this work being done than what had been proposed in the 2022 i-CDP filing. Figure 5.37 presents a comparison of the 2022 Plan to actual for the years 2022-2024 as shown below.

Figure 5.37: Regulator Station Cost Comparison

Reg Stn Budget	2022	2023 Outlook	2024 Budget	Totals
2022 i-CDP Plan	27.1	30.6	33.1	90.7
Actual/Planned Investments	17.0	19.0	28.3	64.3
Variance	(10.1)	(11.6)	(4.8)	(26.4)

AGL also must consider station age and obsolescence when determining the adequacy of its station replacement programs. As can be seen from the table in Figure 5.38 below, AGL has a significant number of distribution as well as tap or other large stations that are more than 50 years old or have an unknown installation date. Given the criticality of these facilities, it is imperative that AGL increase efforts to minimize station obsolescence risks.

Figure 5.38: Station Types by Age

Approximate Station Quantities by Station Age in Years					
Station Type	**< 30**	**30-40**	**40-50**	**50+ or Unknown**	**Totals**
Distribution Stations	2082	1009	368	1055	4514
Tap/Large Stations	86	13	4	44	147
Total Stations	**2168**	**1022**	**372**	**1099**	**4661**

There are also multiple proposed regulatory rules that have the potential to significantly impact the amount of required investment in these facilities. These proposed rules include:

- The PIPES Act of 2020 – The Pipes Act of 2020 is a congressional mandate to PHMSA that includes requirements to propose multiple rules concerning pressure regulating station safety. In compliance with this mandate, PHMSA has recently released a proposed rule titled “Pipeline Safety: Safety of Gas Distribution Pipelines and Other Pipeline Safety



Initiatives." While still a proposed rule, the current language includes multiple proposed mandates around common modes of failure, venting of natural gas at these facilities, adding additional overpressure protection, and other potentially significant additions that will mandate significant changes to current work plans.

- GA PSC Proposed Facilities Protection Staff Rule – This proposed rule has not yet been issued for comment but has been included as an agenda item in recent Energy Committees. In the most recent version provided to operators in Georgia, the draft NOPR includes a mandate to ensure that all new pressure regulating facilities have an inlet shutoff valve (Fire Valve) at a distance of at least 25 feet from the station unless the operating pressure of the regulator requires a greater minimum distance. For any stations existing prior to the effective date of the final rule, the Operator shall provide documented proof that the actual inlet valve location is at a safe distance from the regulator station sufficient to permit the operation of the valve during an emergency that might preclude access to the station.

For clarity, AGL currently has a 10+ year Fire Valve program in place as a part of its risk assessment work as outlined below, but budget limitations continue to slow the completion of this work. Otherwise, there is currently no additional work planned to address these proposed mandates. As these new rules progress through the administrative process, the Company will work with Staff and the Commissioners to address the additional costs that must be incurred to comply with these Georgia-specific mandates.

The Company has embarked on three primary initiatives to address already identified risks, quantify some additional risks, and to do a full multi-year review of all stations to allow for a comprehensive DIMP type plan to prioritize all station work in the future.

The first initiative was an assessment of potential risks, based off key recommendations stemming from the Merrimack Valley incident. These assessments were completed, and the following multi-year programs are currently underway to address these risks:

- **Installation of Strainers on all 2" and Larger Regulator Stations** – Strainers are being added to these stations to prevent debris in the gas stream from causing regulator failures. In recent years, all new 2" and larger stations have been installed with strainers or other similar protection, but there are a significant number of these older stations in the system that do not have this protection. The Company began a 10-year initiative to add strainers



to increase safety while balancing the impacts to rates by spreading the work over multiple years. AGL has installed strainers at 69 stations to-date.

- **Redundant Overpressure Protection at Tap Stations** – The Company began a program in 2020 at 18 tap stations across its system where the primary overpressure protection ("OPP") for the pressure reduction from interstate pipeline levels is provided on the supplier side of the interconnection with the interstate pipeline. While this equipment is properly maintained by the suppliers within all regulations and AGL employees verify that this equipment is being properly maintained, the Company began an initiative to install redundant OPP on its side of these interconnection facilities to better control the protection of the downstream system and its customers. This initiative began in 2020, and AGL has completed installations at 12 stations to date. Initial plans were to complete the program in 2024 but cost increases, 2 additional identified locations, and other challenges have extended the expected program completion to 2026.

- **Kerotest Valve Replacements** – Older 2" x 1.25" Kerotest valves installed within primarily below-ground stations have known dissimilar-metal-driven (galvanic) corrosion issues with the primary bolts on the valve. Over time, some of these bolts have failed, causing significant safety risks for Company personnel maintaining them. These valves also have a tendency for accelerated leak rates, resulting in required replacements to meet existing leak repair rules. Since many older stations may have 5 to 7 of these valves plus other age-related issues, full station replacements are generally warranted. In the 2022 i-CDP filing, it was expected that the Kerotest Valve program would be completed in 2024. Since that time, the identification and addition of additional valves to the program as well as repeated budget reprioritizations to comply with rate impact commitments have resulted in a significant slowing of this program, pushing the completion of the program to 2031. While the pace of these replacements has been slowed in recent years due to higher costs, AGL has remediated 585 of these valves since the start of the program and expects program completion to extend to approximately 2030 at cost and current investment levels.





- **Fire Valves** – The Company has identified a significant number of stations where isolation valves are not easily accessible or may be closer to the station than desired to safely operate the valves in an event of a station emergency. This has also been an identified area of concern by GPSC Facilities Protection Staff's Inspectors on recent audits and is within a recent draft NOPR Facilities Protection Staff prepared as referenced above. All new stations are now being designed with both inlet and outlet valves that are 25 feet away where feasible. For existing regulator stations, the Company has begun a targeted program to review and remediate issues with existing stations. While AGL has significantly increased its investment in this area, the proposed rules as written could require even further acceleration of this investment to achieve compliance with these Georgia-specific rules. Until the final regulations and timelines are known and then each station is reviewed against the new requirements, AGL cannot accurately quantify the potential costs to comply with this NOPR, but it is possible that the proposed rules will require a revision to the i-CDP.

The second initiative was a targeted interim review of all stations by Company System Operations personnel in conjunction with AGL's annual inspections of each station during 2020 and 2021. This effort was focused on better identifying and quantifying many of the issues outlined above, as well as identifying other areas of concern, such as needle valves on sense lines that may be blocked by debris leading to improper regulator operation. This information has been used to adjust program quantities and timelines for the items listed above.

The final initiative, the RSRP, is a detailed records and field review of all AGL pressure regulating stations. This program is still ongoing with a current anticipated completion in 2028. While initially planned to be completed by 2022, AGL has slowed this work significantly to address higher priority work and adjust for cost increases in the overall Plan initiatives. These ongoing inspections include the following:

- Conducting detailed reviews of all current station records.
- Conducting field reviews of each station targeting recommended items resulting from industry and regulatory guidance from the Merrimack Valley incident as well as other related Company initiatives.
- Updating of any existing drawings or other system information as needed.



- Creating additional flow diagrams and detailed station features lists not currently available today for most stations.
- Creating a station health scorecard for each station.

Once completed, the station health scorecard and this other information will be used to prioritize future station upgrade and replacement work using a DIMP -like risk-based approach.

In addition to the primary station work, this Plan also includes the necessary replacements and upgrades to other equipment related to these pressure regulating facilities including pipeline heaters and odorization tanks and equipment.

AGL currently has 55 pipeline heaters in-service at various locations across the state. These facilities generally have an operational life of approximately 35 years and may also need to be replaced due to significant load growth in an area. Current investment plans include the targeted replacement of 7 heaters that are already past their expected life plus others that are at or above their maximum capacity. This work is strategically managed between AGL's Engineering and System Operations teams to coordinate replacements with other facility work, when possible, to reduce overall costs.

AGL also has more than 50 tanks and odorization equipment in place to provide the required odorization of its gas system. While recent year investments have helped to ensure the operability of these items, AGL is proposing a multi-year program to install canopies and containment units for these units to limit the potential environmental impacts should there be a leak or other issue at any of these facilities. Additionally, AGL is planning a program over approximately 10 years to install supplemental odorization at locations where the Company currently receives odorized gas from its suppliers due to multiple instances where these odorization levels have not consistently met AGL standards.

III. Funding Requirements:

Proposed funding for the RSRP program is based on estimated costs to complete the program by 2028. Proposed funding for Regulator Station work is as follows:

- Tap and Large Stations - $7.5 - $12 million annual investments to address these critical stations while also coordinating the work with required TIMP assessments to avoid millions of dollars of incremental mandated TIMP work where possible.



- District Regulator Stations - $5.5-$6.5 million annually to address top risk-based station replacements not included in planned risk assessment work below plus mandatory replacements due to damages or other issues. Note: This rate of investment is proposed to increase starting in 2028 by $5 million annually to accelerate the replacement of these aging facilities and to more align with replacement rates necessary to align with station obsolescence rates as outlined above.

- Completion of Ongoing Risk Assessment Initiatives – Proposed completion of multiple ongoing programs to address the station risk items outlined in the 2022 i-CDP and as outlined again earlier in this section. Full completion of all these programs is expected to require investments of over $150 million spread over periods ranging from a few years to more than 10 years.

- Obsolescence replacements for existing pipeline heaters and odorant tanks as estimated each year based on actual equipment anticipated life cycles.

- Supplemental odorization at key sites as outlined earlier in this section with an estimated $5.5 million cost spread over 10 years.

All funding associated with regulator stations is summarized in the table in Figure 5.39 below.

Figure 5.39: Regulator Stations

Item	2022 i-CDP Filing				Current Actuals/Plan				2022-2024 Act/Plan vs. Filing	2025-2034 i-CDP Proposals ($ millions)									
	2022 (bud)	2023	2024	Filing Sub-Total	2022 (act)	2023 (act)	2024 (bud)	Current Sub-Total		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
REG STN-Regulator Station Projects	23.1	27.1	31.6	**81.7**	13.5	18.4	26.9	**58.8**	**(22.9)**	33.4	34.0	36.0	43.1	43.4	44.3	44.1	33.0	33.1	33.1
REG STN-RSRP Program Projects	4.0	3.5	1.5	**9.0**	3.5	0.2	1.4	**5.1**	**(3.9)**	3.0	3.0	3.0	2.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Regulator Station Investment	**27.1**	**30.6**	**33.1**	**90.7**	**17.0**	**18.6**	**28.3**	**63.9**	**(26.8)**	**36.4**	**37.0**	**39.0**	**45.1**	**43.4**	**44.3**	**44.1**	**33.0**	**33.1**	**33.1**

5.18 Removals and Inactive Services

I. Introduction:

The Removals-Inactive Services part of this Plan is for retiring of certain existing active gas services that are being maintained by the Company, but where there is no active customer currently using natural gas.

II. Present Drivers:

Removal spending is primarily driven by investments in the other budget categories as indicated above and must be adjusted based on changes in DOT, Renewals, DIMP, and other investment



programs. There are also sporadic retirement specific projects associated with the retirement of existing mains. Examples include retiring facilities that no longer have the potential to serve customers due to redevelopment, DOT realignments, etc.

In certain situations, there may be an existing service at a location with no opportunity for future gas use. In such situations, the inactive service is at a higher risk of excavation and/or demolition damage since an excavator or building demolisher may assume that there are no active gas facilities on site.

The risks associated with these inactive services has also been identified by the Commission's Facilities Protection Staff and proposed new requirements concerning inactive services are included in the current draft of the Facilities Protection NOPR. AGL continues to budget approximately $2 million per year with an escalator for inflation to address its highest risk inactive services. It should be noted that the proposed new Georgia-specific rule, which was still in consideration at the time this Plan was drafted, not only greatly increases the requirements around inactive services but also extends similar requirements to service stubs that have no prospect for reuse. If this draft proposed rule is ultimately passed with the existing or similar language concerning inactive services and stubs, this i-CDP will likely be modified to account for this new mandate.

III. Funding Requirements:

The funding requirements for the retirement and removal of inaction services is summarized in the table in Figure 5.40, below.

Figure 5.40: Retirement and Removal of Inactive Services Budget Parameters

Item	2022 i-CDP Filing				Current Actuals/Plan				2022-2024 Act/Plan vs. Filing	2025-2034 i-CDP Proposals ($ millions)									
	2022 (bud)	2023	2024	Filing Sub-Total	2022 (act)	2023 (act)	2024 (bud)	Current Sub-Total		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
REMOV-Removals	13.5	13.5	14.5	**41.6**	10.5	13.3	14.5	**38.4**	**(3.3)**	14.5	14.5	14.5	14.5	15.0	15.0	15.0	15.1	15.2	15.2
REMOV-Removals (inactive services)	2.1	2.1	2.2	**6.4**	0.6	0.0	0.4	**1.0**	**(5.4)**	2.2	2.2	2.3	2.3	2.3	2.3	2.3	2.4	2.4	2.4
Removals - Total	**15.6**	**15.6**	**16.7**	**48.0**	**11.1**	**13.3**	**14.9**	**39.4**	**(8.6)**	**16.7**	**16.7**	**16.8**	**16.8**	**17.3**	**17.3**	**17.3**	**17.5**	**17.6**	**17.6**

The Removals budget line primarily contains anticipated retirement costs associated with many of the other capital support categories including DIMP, DOT, Renewals, and Pressure Improvements. The Company has budgeted the above removal dollars by year with adjustments associated with changes in proposed spending in the related work categories.



For inactive services, investments during the initial i-CDP term have been slowed due to increased costs, thereby allowing funds to support tariff-mandated functions such as New Business or other categories such as Regulator Stations with higher risk profiles. The Company has allocated approximately $2 million dollars annually for targeted retirements of facilities (consistent with what was proposed in the 2022 i-CDP filing) and is planning to continue this level of investment until more is known around the potential additional requirements stemming from the Commission's Facilities Protection Staff's current draft NOPR.

5.19 Maximum Allowable Operating Pressure ("MAOP")

I. Introduction:

MAOP refers to the maximum allowable operating pressure, which for each pipeline is the highest pressure at which the Company is allowed to operate.

Following the 2010 gas transmission pipeline explosion in San Bruno, California, federal legislation mandated that PHMSA establish regulations requiring pipeline operators to reconfirm the MAOP on each of their existing transmission pipelines that operate in the suburban and urban areas of the country. The PHMSA updates requiring MAOP validation went into effect on July 1, 2020.

II. Present Drivers:

The relevant PHMSA regulation requires "traceable, verifiable and complete" records, above and beyond historic requirements. AGL will need to comply with the new requirements to continue operating its transmission pipelines at their current MAOPs. The regulations apply to all transmission pipelines in suburban and urban areas, even those installed prior to implementation of the initial minimum pipeline safety standards in 1971. The Company's approach to MAOP reconfirmation follows an industry best practice that is safer than the minimum federal requirement because the Company is evaluating entire length of each transmission pipelines, not just those segments within suburban or urban areas. AGL's approach is not limited to areas where an incident could damage higher populated areas, but rather AGL's approach acknowledges that all Georgians, rural and urban, should have safe natural gas facilities. Moreover, even if an incident in a rural location may cause less damage, the



service disruption would have far-reaching consequences for all communities served by the transmission pipeline.

Included within the MAOP project is funding to modify pipelines to allow the use of internal inspection tools or smart pigs. Currently, AGL uses all three assessment methods allowed by federal regulation (49 CFR 192.921*):* (a) smart pigs, (b) pressure testing, and (c) direct assessment.

AGL uses inline inspection tools or smart pigs to assess approximately 65% of its transmission pipeline miles. AGL uses direct assessment or pressure testing to assess the remaining approximately 35% of its transmission pipeline miles. Much of the approximately 35% of pipelines that are not assessed using inline inspection tools are not suitable for smart pig use due to factors that do not allow passage of a smart pig through the pipeline. Since inline inspection using smart pigs is AGL's preferred method of assessment[26], AGL must address these factors that prevent smart pig use on these transmission pipelines.

III. Funding Requirements:

For each AGL transmission pipeline lacking traceable, verifiable, and complete records, the Company must choose from several alternatives to meet the new standard. Options include but are not limited to: taking the pipeline out of service and pressure testing it to reconfirm the MAOP, abandoning the pipeline, lowering the MAOP of the existing pipeline, or performing extensive in-service material testing for characteristics such as pipe strength or wall thickness. In most instances, if AGL were to lower MAOP or abandon an existing pipeline, AGL must then construct a new replacement pipeline to restore the lost system capacity. Consequently, reconfirming MAOP is strongly preferred.

The Company's initial estimate for the remaining cost of MAOP reconfirmation was approximately $700 million as submitted in the 2022 i-CDP. The new regulations will allow pipeline operators up to 15 years to complete this process. The Company's current estimate as of Q4 2023 is $1.2 billion for the remaining cost of MAOP reconfirmation. The key drivers for this cost increase include further refinement of the program scope through 2035 including adjustments in work type between hydrotest, investigation and replacement and the addition of potential RIN-2

[26] The Company prefers to assess its pipelines using smart pigging because this method provides the best data for assessment. Additionally, both PHMSA and NTSB have expressed a preference for this method as it provides more data for analysis, which leads to better decisions and further enhances pipeline safety.



transmission mileage to the program. Annual inflation factors have been included in this submission as well as rising project costs driven by labor and material. The Company will continue to refine the estimate and solidify reconfirmation methods.

Currently, the Company has created the Dig Program to administer the MAOP validation work as well as coordinating the TIMP work to gain the synergies of these two programs. The 10-year outlook is shown below, in Section 5.20, in the table in Figure 5.41, and includes MAOP and TIMP, and details the funding to modify pipelines for smart pigging. If these measures are not funded at the levels shown at the end of section 5.19, AGL could be put in a position where it must forego spending in other areas to comply with the new regulations, which could pose additional risk elsewhere.

5.20 Transmission Integrity Management Program (TIMP)

I. Introduction:

To assess its transmission pipelines to comply with federal regulations (49 CFR 192, Subpart O) under its TIMP program, AGL is required to use one or more of the following assessment methods to ensure the operational integrity of its transmission lines: (a) internal inspection tools or smart pigging, (b) pressure testing, (c) excavation and direct examination, (d) guided wave ultrasonic testing (GWUT), (e) direct assessment, or (f) other technology.

AGL has been assessing its transmission pipelines since the implementation of the Gas Transmission Pipeline Integrity Management regulations in 2003. Additional gas transmission pipeline integrity management regulations were implemented by PHMSA in 2019.

II. Present Drivers:

AGL maintains an assessment schedule for its transmission pipelines to ensure compliance with the regulations.

III. Future Drivers:

In 2016, PHMSA published a Notice of Proposed Rulemaking adding MAOP reconfirmation and materials verification requirements and expanding TIMP and Corrosion Control requirements. Through the rulemaking process, PHMSA split the proposed regulations into parts 1, 2, and 3. Requalification Identification Number (RIN) 1 & RIN 3 were issued in October 2019 and November 2021, respectively. In 2023, Phase 2 of PHMSA's expanded TIMP and corrosion control



requirements (RIN-2) took effect via adoption of the rule titled Pipeline Safety: Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments with an effective date of May 24, 2023. These new regulations resulted in major impacts to TIMP including Management of Change ("MOC"), data integration requirements, and changes to repair criteria.

IV. Funding Requirements:

As this ongoing program is mandated by federal regulations, funding has been included within the 10-year plan to accommodate these needs. As described in Section 5.19, the capital funding for the MAOP Validation and the TIMP work has been combined within the Dig Program, which is presented in the table in Figure 5.41. If this program is not funded at the budgeted amounts, AGL could be put in a position where it must forego spending in other areas to comply with these regulations, which could pose additional risk elsewhere.

Figure 5.41: TIMP Budget Parameters

Item	2022 i-CDP Filing				Current Actuals/Plan				2022-2024 Act/Plan vs. Filing	2025-2034 i-CDP Proposals ($ millions)									
	2022 (bud)	2023	2024	Filing Sub-Total	2022 (act)	2023 (act)	2024 (bud)	Current Sub-Total		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
TIMP-Dig Program	43.3	56.5	86.3	**186.1**	40.9	54.1	108.0	**202.9**	**16.8**	93.4	118.3	130.8	144.8	158.3	173.9	181.3	179.3	181.1	171.7
TIMP-ILI Retrofits	7.2	18.2	20.7	**46.1**	8.3	19.8	3.2	**31.3**	**(14.8)**	2.0	2.0	2.0	11.8	12.6	12.4	12.5	16.6	17.0	17.0
TIMP-Other	3.2	5.0	5.0	**13.2**	0.9	0.2	1.0	**2.1**	**(11.1)**	1.9	2.7	2.9	5.2	5.5	5.8	6.1	6.5	6.8	8.0
TIMP Program - Totals	**53.6**	**79.7**	**112.0**	**245.3**	**50.0**	**74.1**	**112.1**	**236.3**	**(9.0)**	**97.3**	**122.9**	**135.8**	**161.8**	**176.4**	**192.1**	**199.9**	**202.4**	**205.0**	**196.7**

5.21 Other (PT Meters, Operations, Tools, Other Support)

PT Meters

The Company must periodically test its diaphragm natural gas meters to verify the meters are working properly. The PT Meter program at AGL complies with Rule 9 of AGL's Tariff and is comprised of two components: Sampling and Remediation.

The Sampling Program uses statistical sampling to determine whether to accept or reject an entire meter group by determining the number of defective meters in a sample from the group. Meters are randomly selected by meter size, type and capacity. Sampling selections do not consider set dates. Meters removed during this process are used in the analysis process.

Remediation is required when the sampling data fails the meter group, and the Company must change/remove the rejected meters. Since the groups are in larger volumes, the meter changes occur over a four-year timeframe.



The quantity of a meter group will have a direct impact on total capital need as the entire group will need to be removed if it fails. The 10-year capital forecast has a more current run rate for testing and failures. There is a risk in any given year that a large meter group may fail requiring increased spending above these run rates.

The cost of this program is presented in Figure 5.43, PT Meters, below.

Vehicular Protection - Bollards

The vehicular protection program is designed to protect Company facilities, mains, services, meters, and regulators from accidental damage in accordance with requirements defined by 49 CFR 192, Subpart D. The capital budget for this work is based up the historical rate of facilities identified as needing additional vehicular protection and associated installations required. The Plan for this work reflects a reduction over time resulting from remediation of current facilities and the up-front installation of needed protection for new facilities.

Service Renewals

This portion of the Plan addresses miscellaneous capital service replacements completed by Operations personnel on an as-needed basis due to damages, leaks, and other issues.

Tools (New Business, Field, and Construction Operations)

The capital tools section of the Plan provides for equipping field personnel with appropriate tools to safely complete their work. The capital forecast makes assumptions around the useful life of the various tools and replacement because of failure. AGL is forecasting a levelized run rate spend to reflect purchasing equipment and prioritizing spend for needed items.

In addition to run rate capital tool purchases, AGL's Plan includes increased investments in the following areas:

- Cross-Compression Equipment – In support of AGL's net-zero emissions goals and aligned with proposed rules from PHMSA,[27] AGL continues to evaluate and invest in cross-compression equipment to significantly reduce the amount of methane released during pipeline maintenance, repair, and replacement activities. AGL continues to use

[27] The use of cross-compression technologies is a proposed option to reduce methane emissions within the currently proposed Pipeline Safety: Gas Pipeline Leak Detection and Repair NOPR under a proposed new section of code titled CFR 192.770 Minimizing Emissions from Gas Transmission Pipeline Blowdowns. The NOPR can be found on the Federal Register at the following link: https://www.govinfo.gov/content/pkg/FR-2023-05-18/pdf/2023-09918.pdf



contractors to perform significant portions of these cross-compression activities where feasible and economical, while slowly expanding its internally owned and operated equipment for use when financially appropriate.

- Respirator Replacement Program - Supplied air respiratory protection equipment is required for employees during natural gas release emergency response operations. As required by federal regulations, this equipment is mandated for anyone entering an IDLH (Immediately Dangerous to Life and Health) environment. AGL's respiratory protection equipment purchased over the last 20+ years was manufactured by Honeywell. In 2022, Honeywell made a business decision to discontinue its compressed gas/respiratory protection business, including replacement parts. Therefore, AGL's on-hand equipment cannot be repaired when parts fail, potentially jeopardizing AGL's emergency response capabilities. AGL needs to acquire supplied air respiratory protection equipment from another manufacturer to equip newly hired employees and to replace current equipment.

ERT Replacements (Automated Meter Reading devices)

The life span of the batteries powering ERT units is approximately 20 years, and it is not possible to just replace the batteries, the entire unit must be replaced. Typically, AGL budgets for the cost of replacing failed ERTs each year is based on an historical run rate. Figure 5.42 below shows the number of ERT units on the AGL system scheduled to reach the life expectancy threshold between 2025 and 2034. It is expected that nearly 1 million ERT batteries installed in the 2009-2011 time frame are more likely to fail in the near future, so starting in 2028, the Company is planning for an increase in ERT replacements that outpaces the historical run rate.

Figure 5.42: ERT End of Life

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ERTs Turning 20 Years Old	29,980	46,256	23,872	158,537	511,081	295,759	42,566	158,019	44,357	39,533

The ERT units currently used by AGL employ an older 100G technology, which the manufacturer is in the process of phasing out. Replacement ERT units of this type may not be available in the necessary quantities, and AGL has already experienced difficulty procuring these units. The ERT manufacturer has introduced a new ERT model that uses 500G technology, which are expected to be available in the necessary quantities in future years. The cost of replacing an ERT device with the new 500G ERT unit with similar functionality to the 100G is comparable in price. The



Company plans deploy some 100G units in the near term but will transition to the 500G units in the near future.

AGL's current ERT units use Advanced Meter Reading ("AMR") technology and are read via radio frequency transmission by vehicles that must drive by in proximity to the units to receive the radio signal. AGL has been reviewing other available metering technologies, one of which is referred to as Advanced Metering Infrastructure ("AMI"). AMI allows for remote meter reading via a fixed mesh, or cellular network. AMI ERT devices, when integrated with a network service, have real-time usage that improve customer experience and can reduce overall consumption to support environmental initiatives. Additionally, when AMI is combined with a modern meter, enhanced safety functionality beyond meter reading, such as remote shutoff, excess flow detection, temperature and pressure sensing can automatically shut off the meter. AMI technology is considered and deployed by many gas utilities across the country. 500G ERT units that are AMI compatible are available in the market today but are a more expensive product than the non-AMI compatible 500G unit. This Plan does not request any of the other functionality beyond remote meter reading and AGL will not add any AMI functionality beyond meter reading without prior express Commission approval.

Figure 5.44 below shows the Company's planned capital expenditures over the ten-year period of 2025-2034 for replacement of ERT units in the line labeled Ops – ERT/AMR Projects. These costs include replacement of the 100G units with new 500G ERT units, but do not include cellular network connectivity. In addition, for informational purposes, a line labeled Ops – AMI Tech is also included in Figure 5.44 indicating capital expenditures totaling approximately $200 million during 2028-2034 segment of this Plan. This additional $200 million would be necessary if AGL and the Commission subsequently determine that the best course of action is to upgrade the 500G ERT units with additional AMI features.

The tables below in Figure 5.43 PT Meters Budget Parameters, Figure 5.44 Operations Budget Parameters, and Figure 5.45 Capitalized Tool Purchases Budget Parameters, outline the current and proposed funding requirements for each of the Operations Support subcategories listed above:

Figure 5.43: PT Meters Budget Parameters

Item	2022 i-CDP Filing				Current Actuals/Plan				2022-2024 Act/Plan vs. Filing	2025-2034 i-CDP Proposals ($ millions)									
	2022 (bud)	2023	2024	Filing Sub-Total	2022 (act)	2023 (act)	2024 (bud)	Current Sub-Total		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
PT Meters	6.8	8.0	8.3	**23.1**	6.7	8.3	10.2	**25.2**	**2.0**	11.0	11.6	12.1	12.7	13.4	14.1	14.8	15.5	16.3	16.3



Figure 5.44: Operations Budget Parameters

Item	2022 i-CDP Filing				Current Actuals/Plan				2022-2024 Act/Plan vs. Filing	2025-2034 i-CDP Proposals ($ millions)									
	2022 (bud)	2023	2024	Filing Sub-Total	2022 (act)	2023 (act)	2024 (bud)	Current Sub-Total		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
OPS-Bollard Projects	2.1	1.8	1.8	**5.7**	0.9	0.8	1.1	**2.9**	**(2.8)**	1.2	1.1	1.1	1.0	1.0	0.9	0.9	0.9	0.8	0.8
OPS-ERT / AMR Projects	0.7	1.2	2.7	**4.6**	0.4	0.6	1.0	**2.0**	**(2.6)**	2.4	2.3	3.2	3.2	14.0	18.4	44.7	14.2	14.3	14.3
OPS-Blanket Service Renewal Projects	1.1	1.0	1.0	**3.0**	0.7	0.6	0.8	**2.1**	**(0.9)**	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1.0	1.0	1.0
Operations Capital - Totals	**3.8**	**4.0**	**5.6**	**13.4**	**2.1**	**2.0**	**3.0**	**7.1**	**(6.3)**	**4.5**	**4.3**	**5.1**	**5.2**	**15.9**	**20.3**	**46.5**	**16.1**	**16.1**	**16.1**
Ops-ERT - AMI Tech	0.0	0.0	0.0	**0.0**	0.0	0.0	0.0	**0.0**	**0.0**	0.0	0.0	0.0	28.6	28.6	28.6	28.6	28.6	28.6	28.6
Operations Capital including AMI - Totals	**3.8**	**4.0**	**5.6**	**13.4**	**2.1**	**2.0**	**3.0**	**7.1**	**(6.3)**	**4.5**	**4.3**	**5.1**	**33.7**	**44.5**	**48.9**	**75.1**	**44.6**	**44.7**	**44.7**

Figure 5.45: Capitalized Tool Purchases Budget Parameters

Item	2022 i-CDP Filing				Current Actuals/Plan				2022-2024 Act/Plan vs. Filing	2025-2034 i-CDP Proposals ($ millions)									
	2022 (bud)	2023	2024	Filing Sub-Total	2022 (act)	2023 (act)	2024 (bud)	Current Sub-Total		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Tools	1.9	1.1	1.9	**4.8**	1.4	2.0	2.5	**5.9**	**1.0**	4.2	4.0	4.5	5.5	5.4	4.7	4.3	3.1	3.5	3.5

5.22 Corrosion Control, Shorted Casings, and AC Mitigation

I. Introduction:

Corrosion Control is an important component of pipeline safety for AGL's steel pipelines. Due to the Commission's foresight, AGL has already replaced its bare steel pipelines. In addition to a pipeline's protective coating, the Company applies cathodic protection to the pipelines to prevent corrosion. The requirements for Corrosion Control are defined by federal regulation (49 CFR 192, Subpart I). This subpart defines the requirements for the protection of metallic pipelines from external, internal, and atmospheric corrosion. Additionally, this subpart requires mitigation of stray currents that can lead to external corrosion. As such, AGL has an established Corrosion Control program that addresses these code requirements.

II. Present Drivers:

Within the current Corrosion Control capital plan, there are three distinct areas: 1) installation, inspection, and replacement of cathodic protection measures and coatings, 2) mitigation of stray current on pipelines, inclusive of AC mitigation measures, and 3) the shorted casing mitigation program. Each of these areas are required to comply with the existing federal regulation. Also, the shorted casing program reflects a commitment by AGL to the Commission Facilities Protection Staff.

III. Future Drivers:

In 2016, PHMSA published a NOPR adding MAOP reconfirmation and materials verification requirements and expanding TIMP and Corrosion Control requirements. Through the rulemaking process, PHMSA split the proposed regulations into parts 1, 2, and 3. Requalification Identification



Number (RIN) 1 & RIN 3 were issued in October 2019 and November 2021, respectively. In 2023, Phase 2 of PHMSA's expanded TIMP and corrosion control requirements (RIN 2) took effect via adoption of the rule titled Pipeline Safety: Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments with an effective date of May 24, 2023. These new regulations will result in major impacts to Corrosion Control related activities driven primarily by additional survey requirements related to both transmission and distribution pipelines in 49 CFR 192.473(c) to address any identified interference currents "greater than or equal to 100 amps per meter squared alternating current…."

While AGL has completed 677 of the original 711 casings included in its shorted casings program commitment to the Commission Facilities Protection Staff and expects to complete the 711 by the 2025 commitment, an additional 589 casings have been identified throughout the nearly seven year initial program that also need to be assessed and remediated as necessary. To date, AGL has also completed 143 of these additional casings.

IV. Funding Requirements:



As this ongoing program is mandated by federal regulation, AGL has included parameters within the 10-year Plan to accommodate these needs. The 10-year outlook is shown below in the three tables. In Figure 5.46, Corrosion Budget Parameters, is the capital funding for area 1, which includes the installation, inspection, and replacement of cathodic protection measures and coatings. Capital funding for area 2, presented in the table in Figure 5.47, AC Mitigation Budget Parameters, includes mitigation of stray current on pipelines, inclusive of AC mitigation measures, based on expected results from the newly required interference surveys. Capital funding for area 3, Figure 5.48, Shorted Casings Budget Parameters, includes the existing shorted casing mitigation program, as well as a smaller ongoing budget for multiple years thereafter to assess and remediate as necessary the remaining 446 of the additional identified casings as well as any new additional casings as identified. If these initiatives are not funded as budgeted below, AGL could be put in a position where it must forego spending in other areas to comply with the regulations, which could pose additional risk elsewhere.

Figure 5.46: Corrosion Budget Parameters

Item	2022 i-CDP Filing				Current Actuals/Plan				2022-2024 Act/Plan vs. Filing	2025-2034 i-CDP Proposals ($ millions)									
	2022 (bud)	2023	2024	Filing Sub-Total	2022 (act)	2023 (act)	2024 (bud)	Current Sub-Total		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Corrosion	6.7	6.4	6.4	**19.5**	5.2	3.6	5.6	**14.3**	**(5.2)**	7.1	7.4	7.5	7.6	7.7	7.7	7.7	7.7	8.0	8.0

Figure 5.47: AC Mitigation Budget Parameters

Item	2022 i-CDP Filing				Current Actuals/Plan				2022-2024 Act/Plan vs. Filing	2025-2034 i-CDP Proposals ($ millions)									
	2022 (bud)	2023	2024	Filing Sub-Total	2022 (act)	2023 (act)	2024 (bud)	Current Sub-Total		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
AC Mitigation	5.0	6.5	6.5	**18.0**	3.0	3.8	3.9	**10.7**	**(7.3)**	10.6	12.1	9.1	9.1	11.1	11.1	12.1	12.1	12.1	12.1

Figure 5.48: Shorted Casings Budget Parameters

Item	2022 i-CDP Filing				Current Actuals/Plan				2022-2024 Act/Plan vs. Filing	2025-2034 i-CDP Proposals ($ millions)									
	2022 (bud)	2023	2024	Filing Sub-Total	2022 (act)	2023 (act)	2024 (bud)	Current Sub-Total		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Shorted Casings	4.0	6.0	4.5	**14.5**	2.1	3.3	5.0	**10.4**	**(4.1)**	5.0	5.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0

5.23 Facilities

I. Introduction

The mission of Facilities Management is to provide safe, reliable, and cost-effective maintenance and repairs of Company facilities, supporting the business requirements of AGL. Facilities Management manages and supports the care and maintenance of 32 buildings at 27 locations across the state of Georgia. Those facilities include one customer care center, six depots, one fleet facility, one storage/weld shop, 17 regional business centers and one training center—for a total of 264,000 square feet.

Capital investments in Company facilities include routine, periodic renovations, reconfigurations, and construction of new buildings as well as replacement of HVAC and other facility systems, repaving of parking lots, replacement of office furniture, and other related items necessary to support Company operations.

II. Present Drivers:

There are multiple key facilities in need of replacement, expansion, or other major renovation to continue to provide the necessary support for operations. Major projects by plan year are listed below:

- AGL's Calhoun Depot needs replacement. The current facility is a modified storage container without proper electrical service, plumbing facilities, or internet access. Plans



are to negotiate with the current landlord to construct a small building on the same property. This project is scheduled for 2025.

- Year 2025 of the Plan includes completion of construction for the Gwinnett Regional Business Center—a total renovation of an existing building purchased in 2021 from Georgia Power. AGL currently leases an office building in Gwinnett and owns a second depot that houses field operations personnel and parts inventory. AGL plans to not renew the current lease for the current office building once the newly remodeled property is completed.

- The 2025 Plan also includes an interior renovation of the Athens Service Center. This renovation will include much needed lighting/ceiling replacement, paint, flooring replacement and new systems furniture.

- An existing building known as the former “SWAT” building on the Riverdale campus is currently underutilized. Plans are to perform minor renovations in 2025 to allow additional storage space for multiple departments on the campus.

- Year 2025 of the Plan also includes design of a new building to house AGL’s Savannah Regional Business Center. The current facility is undersized for the number of personnel at the location. Further, the current building is not capable of withstanding a major weather event such as a hurricane. The new building will enable critical field operations to be conducted during a major weather event and will provide the additional space necessary to conduct field operations. Construction is planned to begin in 2026 and complete in 2027.

- Additionally, year 2026 of the Plan includes the purchase of an existing building or land in Marietta. This property will house the Company’s Marietta Regional Business Center. Similar to Gwinnett, AGL owns a depot that houses field personnel and inventory and leases an office building. AGL plans to consolidate Marietta field operations into one facility at a single location. Design and construction for this facility would start in 2027 and complete in 2028.

- Years 2028 – 2034 of the Plan are for typical facility refurbishments.

III. Funding Requirements:

All of these facilities are incorporated into the table in Figure 5.49, Facilities Budget Parameters, below.

Figure 5.49: Facilities Budget Parameters

Item	2022 i-CDP Filing				Current Actuals/Plan				2022-2024 Act/Plan vs. Filing	2025-2034 i-CDP Proposals ($ millions)									
	2022 (bud)	2023	2024	Filing Sub-Total	2022 (act)	2023 (act)	2024 (bud)	Current Sub-Total		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Facilities	16.3	8.5	21.9	**46.6**	19.6	(8.7)	1.4	**12.2**	**(34.4)**	9.0	15.3	15.6	32.2	37.3	38.6	24.0	25.0	26.0	27.0

5.24 Fleet

I. Introduction:

The mission of Fleet Operations is to provide safe, reliable, and cost-effective transportation and power-operated equipment supporting the business requirements of AGL. Fleet Services manages and supports the complete lifecycle of over 1,500 pieces of transportation and power-operated equipment from acquisition to maintenance and repairs to disposal at locations across the state of Georgia.

II. Present Drivers:

Major drivers of Fleet capital spend include market driven price increases of vehicles, incorporating safety and technology enhancements (collision avoidance, lane departure, telematics) and the incremental increase in vehicle count because of additional Company staffing requirements.

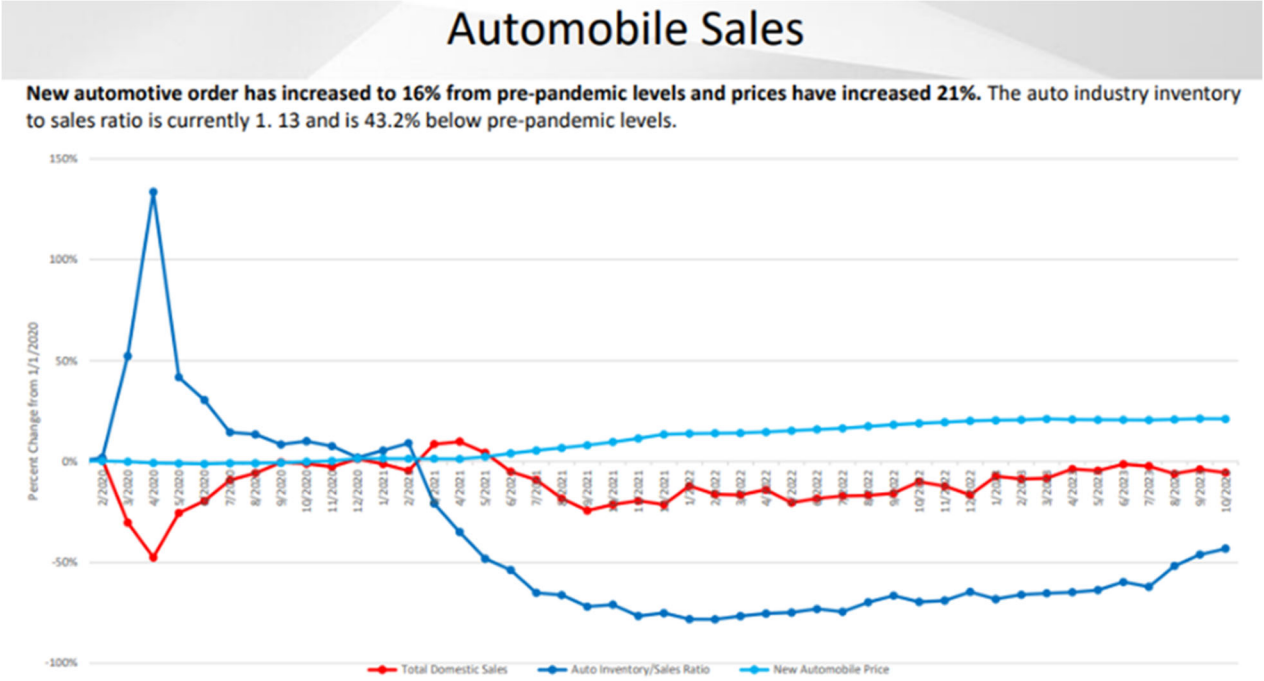
Proposed investments are higher than the Fleet run rate in the current 2022 i-CDP Plan due to multiple pandemics, supply chain, and cost increases, including:

- Recent year reductions in vehicle purchases due to supply chain limitations have resulted in vehicles remaining in use longer than planned leading to higher related O&M costs. These delays will require AGL to catch up on these purchases in the coming years to minimize additional O&M impacts.

- Significant increases in vehicle and other equipment costs driven by cost increases and supply chain challenges. As can be seen in the graphic below in Figure 5.50, since early 2021, new automobile prices (light blue trend line) have increased approximately 21%.



Figure 5.50: Automobile Sales



Source: Bureau of Economic Activity, Bureau of Labor Statistics

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III. Funding Requirements:

The table in Figure 5.51 below includes the estimated capital investments necessary to provide Company personnel with vehicles and equipment required to perform their daily activities. While no adjustments have been made to the current forecasted budgets to accommodate any changes in vehicle types, AGL is currently evaluating the potential for increased investment in alternative fuel vehicles and equipment that may require adjustments to these forecasts.

Figure 5.51: Fleet Budget Parameters

Item	2022 i-CDP Filing				Current Actuals/Plan				2022-2024 Act/Plan vs. Filing	2025-2034 i-CDP Proposals ($ millions)									
	2022 (bud)	2023	2024	Filing Sub-Total	2022 (act)	2023 (act)	2024 (bud)	Current Sub-Total		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Fleet	11.1	12.8	12.4	**36.4**	7.9	12.0	14.0	**33.9**	**(2.4)**	13.5	14.1	14.8	16.7	17.4	18.1	18.8	19.6	20.3	19.3

5.25 IT

I. Introduction:

AGL's Information Technology ("IT") proposes to invest capital in four general categories to benefit AGL's customers: (1) Base Investments to replace aging technology at the end of its useful life as well as improvements to existing technologies; (2) the Company's MATRIX initiative, which is consolidating Asset Data, Work Management, Compliance Management, and Mobile Data

Solutions; (3) AGL's Digital Transformation Strategy, including seamless enhancements to the AGL-specific Georgia Customer Management Application; and (4) AGL's ROOT program (Restore and Optimize Our Technology) to address the reliability, efficiency, supportability, and sustainability of our technology.

- Base Investment – These are the technology investments required to run the business including replacement of technologies at end of life as well as improvements to existing technologies. These investments mitigate the risk of technology obsolescence disruption impacting reliable service to customers. They also extend the useful life of past investments to ensure the continued affordability of our service to our customers. These investments span application and data solutions for Customer, Field, Construction & Engineering, Asset Compliance, and Gas Operations, as well as infrastructure and robust cyber security protections. AGL benefits from lifecycle upgrades and improvements to existing technologies to maximize efficiency and productivity. Examples include GIS, Work Management, Gas Leak Survey, Field Service Rep work capture & scheduling, vehicles connectivity, and tracking. Other investments include itemized end user devices such as laptops and toughbooks for specific employees as they serve our customers.

- MATRiX—GAS Enterprise Asset and Work Management Program—is a data-driven program to transform how we operate across the Asset Management Lifecycle (Plan, Construct, Operate, Analyze, and Retire) and the Work Management Lifecycle (Initiate Work, Plan Work, Schedule Work, Execute Work, and Close Work) of AGL's fixed plant gas assets. MATRiX is an initiative to benefit AGL's customers by consolidating Asset Data, Work Management, Compliance Management, and Mobile Data Solutions for all fixed plant gas assets across AGL and the other Southern Company Gas LDCs. The plan includes a consolidated technology platform across GIS (ESRI ArcGIS), asset (IBM Maximo) and field service.

  In the past, AGL has operated as many as 83 custom, bespoke applications that required extensive in-house maintenance and upgrades. Part of AGL's MATRiX transformation is moving to off-the-shelf applications like IBM's MAXIMO that enable for more seamless customer service. For example, when a Field Service Representative visits a customer premise, previously that FSR had to return to his or her truck to use a "Toughbook"—or field computer—to obtain data and enter service notes. MAXIMO Mobile enables



smartphone and table access to the same date and interface, making for quicker and more efficient service to our customers.

- Digital Transformation Strategy (DTS) – Southern Company Gas has a long-term strategy to consistently deliver seamless experiences, optimize operations, and lead with an innovation mindset as technology evolves and stakeholder expectations shift. Execution of the program has been planned out with a crawl, walk, run approach to transformation across multiple business functions over the long term.

- The ROOT (Restore and Optimize Our Technology) initiative is a program to improve the reliability, efficiency, supportability and sustainability of our technology ecosystem that enables effective operations across customer, asset, field, gas operations, engineering, and construction in a rapidly evolving business and technology environment. In 2023, the Company began to see stability and reliability concerns across aging applications, making these investments imperative.

  For example, to update or repair any one of most of the 83 custom applications AGL currently uses, taking that application offline also required the taking offline of as many as 50 of the other applications because of the legacy interoperability of these applications. ROOT investments will allow us to modernize our technology ecosystem to couple our interoperable applications more loosely, making it necessary to take fewer applications offline when repairing or upgrading one.

  AGL is reinforcing its ROOT program by establishing a Business Operations Technology Services (“BOTS”) group that will collaborate closely with the Gas Technology Solutions organization (“GTS”) to ensure the seamless implementation of ROOT initiatives, with a primary focus on governance, organization change management, and value realization.

  AGL’s current technology platform faces challenges in terms of stability, reliability, and supportability. Legacy systems hinder AGL’s ability to keep up with regulatory, safety and customer needs. AGL’s outdated gas technology ecosystem poses risks to responsiveness of our operations to adapt to change including technology updates and increasing cybersecurity threats. The ROOT initiative is vital to address these issues, providing a solid foundation for innovation, reducing downtime, and improving overall system reliability. The ROOT Initiative will also encompass foundational technologies like data management and analytics (via EDGE), modernized system integration architecture



and readily supportable ecosystem for technology development, deployment, and management (GTS and BOTS). To support these efforts – the following organizations have been established.

BOTS (Business Operations Technology Services)
BOTS will work together with the existing Technology organization – Gas Technology Solutions (GTS), providing specialized expertise in demand and portfolio management of technology projects, governance and change management to enhance the overall effectiveness of the ROOT initiative. BOTS will facilitate the governance framework for the ROOT initiative and all other technology investment, ensuring adherence to best practices, compliance standards, effective risk management, and value realization. In addition, BOTS will play a pivotal role in managing organizational change. This involves fostering a culture of adaptability, providing training programs, and facilitating communication to minimize disruption during the implementation of new technologies.

EDGE (Enterprise Decision Support and Data Governance)
AGL established the EDGE organization to manage and improve enterprise data, a foundational part of the ROOT Initiative. This dedicated group will focus on optimizing data governance, ensuring data quality, and leveraging insights for informed decision-making. The EDGE organization will play a pivotal role in aligning data strategies with business objectives as foundational elements of the overall technology platform for the company.

GTS (Gas Technology Solutions)
GTS is AGL's technology organization function. The legacy focus of GTS was to focus on affordability. However, that affordability came at the expense of technology ecosystem reliability. With the ROOT initiative there is a recognition that in a technology driven world, our technology foundation for AGL must be reliable. This balance of delivering both affordability and reliability is at the core of ensuring AGL has a sustainable technology foundation for the future.

Marketer Request on Appointment Scheduling Upgrade

Marketers have requested that AGL implement real-time appointment scheduling within its Georgia Customer Management Application ("GCMA") system. Marketer web sites and Customer



Information Systems currently cannot interface with AGL's GCMA system for purposes of scheduling appointments.

At present, customers that desire a visit from an AGL Field Service Representative make an appointment through their marketer's online systems. The marketer's online system offers appointment time slots so that the customer can select the time slot most convenient for them. However, marketer customer service representatives must complete the appointment scheduling at a later time by logging into the AGL GCMA system and comparing the selected time slot with available time slots. Because of the amount of time that elapses between scheduling and follow-up by marketer customer service personnel, the time slot selected by the customer is often not available resulting in the customer having to reschedule the appointment a second time. The marketers agree that this is the primary customer issue that needs attention.

Data indicates that customers prefer to engage with service providers through online methods, that these online methods are more important than in-person experiences, and that these online methods continue to improve in delivering products and services. Better online experiences are as important as the products or services offered by service providers.

The proposed solution suggested by the marketers is to adapt AGL's GCMA system to implement real-time web services. The marketers request that the cost of implementing real-time web services into the GCMA system be included in this Plan.

Depending on the scope of a project, the costs of implementing this functionality could range between $1 million and $10 million. AGL has not proposed any capital expenditures in this Plan for this item.

AGL has not yet taken a position on this issue because of the potential for cyber warfare against energy infrastructure by infiltrating operational systems and the potential for data breaches resulting in the unintentional release of customer information.

II. Present Drivers:

Base investment represents funding necessary to maintain and enhance the technology required to continue to deliver safe, reliable, and affordable natural gas to AGL customers.



The **MATRiX** program is justified by several converging issues including:

1. Redundant systems with minimal data integration limit the ability to manage fixed plant asset risk, safety, and compliance reporting holistically across all business units and departments.
2. Currently we manage assets by asset types and business areas using different applications and processes creating integration and standardization challenges limiting our ability to realize the full value of our investments.
3. A comprehensive Asset and Work Management program is needed to support the Safety Management System regulatory commitment and streamline activities through a centralized platform.
4. Public, legislative, and regulatory pipeline safety and risk management expectations have increased and require more insight and knowledge related to the lifecycle of fixed plant assets.
5. Evolving regulatory requirements, such as MAOP validation and material traceability, exceed existing systems capabilities.

Given the needs and issues identified above, maintaining the current collection of redundant and decentralized systems would not resolve identified issues or meet current needs. As such, maintaining the status quo is not considered a viable alternative.

The Digital Transformation Strategy (**DTS**) aims to consistently deliver seamless experiences, optimize operations, and lead with an innovation mindset as technology evolves and stakeholder expectations shift. Digital and operational improvements are being brought together to deliver frictionless experiences to our internal, external, and prospective customers. DTS capabilities span several initiatives including data, customer experience, field and gas operations, innovation, training and more.

Specific drivers for our **ROOT** program include:

1. Enhanced Performance: Modernizing our technology platform will result in improved system reliability, and responsiveness, improving the efficiency and effectiveness of our employees and the experience of the customers we serve.



2. Agility and Innovation: A stabilized platform enables quicker adoption of emerging technologies, fostering innovation, and ensuring we stay ahead in the market. An important example of this is the development of the data and analytics platform and infrastructure needed to effectively operate and provide our services to AGL customers.
3. Resilience Improvement: Upgrading our technology platforms, architecture and capabilities will strengthen our technology infrastructure adaptability, recoverability and security posture. These improvements will safeguard against disruption from disaster, potential cyber threats and vulnerabilities to our operations, and assure compliance with regulations.

Reduction of complex interdependency: Due to the outdated architecture of our current systems, issues emanating from one system impact the rest of the ecosystem due to the tightly integrated nature of our architecture. This impact creates risk of system issues whenever technology patches, updates, enhancements and upgrades are delivered even to individual systems within the ecosystem. This initiative will modernize the integration architecture of the ecosystem to improve reliability, supportability and maintain the operational efficiencies it enables.

III. Funding Requirements:

Itemized technology investment plans for AGL are shown below in their representative categories of Base, ROOT, MATRiX, and DTS.



Figure 5.52: Detailed Proposed Technology Budget Parameters

	2025	2026	2027	
Itemized - New Base Investments for AGLC reduced 3%	**$ 18,135,000**	**$ 18,135,000**	**$ 18,135,000**	**In Service dates**
Equipment, Infrastructure & Data	$ 1,000,000	$ 2,500,000	$ 2,500,000	Annual
Enterprise Technology Life Cycle Replacement & Improvements	$ 1,000,000	$ 1,000,000	$ 1,000,000	Annual
Customer Technology Life Cycle Replacement & Improvements - allocated	$ 500,000	$ 500,000	$ 500,000	June & November
Customer Technology Life Cycle Replacement & Improvements - AGL only	$ 750,000	$ 750,000	$ 750,000	Quarterly
Field Technology Life Cycle Replacement & Improvements	$ 3,000,000	$ 3,000,000	$ 3,000,000	August
Construction & Engineering Technology	$ 3,000,000	$ 3,000,000	$ 3,000,000	August
Gas Operations Technology Life Cycle Replacement & Improvements	$ 2,000,000	$ 750,000	$ 750,000	In 2025 (Aug); all other years - Quarterly
Asset Compliance Technology Life Cycle Replacement & Improvements	$ 1,500,000	$ 1,500,000	$ 1,500,000	Quarterly
Cyber Security, Sustainability, Innovation, Growth	$ 5,385,000	$ 5,135,000	$ 5,135,000	Annual
			$ 18,135,000	
Itemized - Root Investments	**$ 4,290,000**	**$ 6,240,000**	**$ 6,240,000**	**In Service dates**
Disaster Recovery and Business continuity (2025, 2026)	$ 590,000	$ 590,000	$ -	November
Information Lifecycle Management-purge and archive (2025, 2026, 2027)	$ 900,000	$ 900,000	$ 900,000	Annual - August
Removal of stored procedures (2025, 2026,2027)	$ 400,000	$ 400,000	$ 400,000	Annual - Nov
Integration layer replacement (SSIS, BizTalk. Apigee) (2025, 2026, 2027)	$ 600,000	$ 600,000	$ 600,000	Annual-Nov
Environment standardization and management (2025, 2026, 2027)	$ 650,000	$ 650,000	$ 700,000	Annual-Nov
EDGE	$ 800,000	$ 800,000	$ 800,000	Quarterly
EDI Standardization (2026, 2027)	$ -	$ 500,000	$ 500,000	Annual-Nov
Stabilization	$ 350,000	$ 1,800,000	$ 2,340,000	Annual-Nov
Itemized - EAM/Matrix Investments	**$ 5,850,000**	**$ 3,900,000**	**$ 3,900,000**	**In Service dates**
Measurement, Sysops to Mobile, OFS/HCM, Timesheets, CPDM, Contractor Payments	$ 3,120,000		$ -	June 2025
Service Distribution to Maximo and Mobile	$ 2,730,000		$ -	December 2025
Legacy Construction Migration - Release 4.1	$ -	$ 1,950,000	$ -	June 2026
Legacy Construction Migration - Release 4.2	$ -	$ 1,950,000	$ -	December 2026
MAS 8 or 9 upgrade	$ -	$ -	$ 1,950,000	June 2027
Transmission, Storage & peaking	$ -	$ -	$ 1,950,000	December 2027
Itemized - DTS Investments	**$ 3,510,000**	**$ 3,510,000**	**$ 4,680,000**	**In Service dates**
GCMA migration	$ 1,000,000.00	$ 3,000,000.00	$ 4,000,000.00	Q3 2027
Onboarding	$ 250,000.00	$ -	$ -	Q3 2025
Seamless Customer experience	$ 2,260,000.00	$ 510,000.00	$ 680,000.00	Annual - Dec

Acronyms Defined:

SSIS	SQL Server Integration Services
EDGE	Enterprise Decision Support and Data Governance
EDI	Electronic Data Interchange
OFS	Oracle Field Service
HCM	Human Capital Management
CPDM	Cathodic Protection Data Manager
MAS	Maximo Application Suite

Figure 5.53: IT Projects Budget Parameters

Item	2022 i-CDP Filing				Current Actuals/Plan				2022-2024 Act/Plan vs. Filing	2025-2034 i-CDP Proposals ($ millions)									
	2022 (bud)	2023	2024	Filing Sub-Total	2022 (act)	2023 (act)	2024 (bud)	Current Sub-Total		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
IT-IT (Base Business)	13.1	12.1	12.4	**37.7**	2.6	31.1	22.5	**56.2**	**18.5**	18.1	18.1	18.1	19.5	19.5	19.5	19.5	19.5	19.5	19.5
IT-IT (EAM)										5.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
IT-IT (ROOT)										4.3	6.2	6.2	5.9	5.9	5.9	5.9	5.9	5.9	5.9
IT-IT (DTS)										3.5	3.5	4.7	4.7	5.9	5.9	2.0	2.0	2.0	2.0
IT Totals (Includes Allocations from AGSC)	**29.1**	**28.1**	**28.4**	**85.7**	**2.6**	**31.1**	**22.5**	**56.2**	**(29.5)**	**31.8**	**31.8**	**33.0**	**33.9**	**35.1**	**35.1**	**31.2**	**31.2**	**31.2**	**31.2**

Note: 2022-2024 i-CDP Filing totals in the table above include the submitted $16 million per year for IT Allocations in the original filing.

5.26 Overheads and Allowance for Funds Used During Construction ("AFUDC")

I. Introduction:

The cost of resources and funds required to support capital projects at AGL is captured in Overheads and AFUDC. Overheads consists of Services Company and AGL specific capitalized expenses necessary to support these projects. This may include but is not limited to Engineering, permitting, land rights, Supply Chain, construction management, inspection, Accounting, and other personnel and expenses associated with these capital projects. AFUDC is intended to recover the cost of funds (debt and equity) used during the construction of these projects.

II. Present Drivers:

Overheads are projected and allocated to the direct capital for projects planned for each year. The allocation is based upon the cost of resources required to support capital projects in relation to the total capital spend on a monthly basis. The cost of resources required to support capital projects is based upon the Company's 5-year plan. The overhead forecast beyond the 5-year plan remained flat for the purpose of this filing. AFUDC is estimated based upon the forecasted Construction Work in Progress ("CWIP") balances related to the expected project in-service dates. Year-over-year changes in the AFUDC amounts are related to expected CWIP balances and project completions during each year.

III. Funding Requirements:

The overheads and AFUDC breakouts are presented in the table in Figure 5.54.



Figure 5.54: Overheads & AFUDC by Currently Proposed Category

Overheads & AFUDC	2022 i-CDP Filing				Current Actuals/Plan				2022-2024 Act/Plan vs. Filing	2025-2034 i-CDP Proposals									
	2022 (bud)	2023	2024	Filing Sub-Total	2022 (act)	2023 (act)	2024 (bud)	Current Sub-Total		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Overheads & AFUDC - GRAM-S&C					16.5	23.8	22.6	**62.9**		18.4	17.7	18.4	19.3	19.6	19.4	18.2	18.7	20.3	33.2
Overheads & AFUDC - GRAM-Other - New Bus	6.2	6.5	6.4	**19.0**	12.2	10.5	13.6	**36.3**		15.1	17.3	18.0	18.7	18.7	17.9	17.7	17.3	16.7	22.2
Overheads & AFUDC - GRAM-Other - Rate Base	42.9	47.2	48.2	**138.3**	12.6	8.3	11.1	**32.0**		8.5	9.5	9.6	9.7	9.7	9.2	9.1	8.9	8.6	10.9
Overheads & AFUDC - SRR					11.2	12.3	15.9	**39.5**		17.3	18.1	21.9	29.0	23.9	28.6	21.0	26.9	31.1	37.2
Overheads & AFUDC - Cherokee LNG					6.9	10.1	7.4	**24.3**		6.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Overheads & AFUDC - Econ-1							0.3	**0.3**		0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.3	0.9
Overheads & AFUDC - Valdosta LNG										1.6	3.0	4.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Overheads & AFUDC - Ops-ERT - AMI Tech										0.0	0.0	0.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Overheads & AFUDC - DIMP-Pipeline Replacements										0.0	0.0	0.0	0.5	0.6	0.6	0.6	0.6	0.6	0.6
Overheads & AFUDC - RNG										0.0	0.0	0.0	4.2	0.0	0.0	0.0	0.0	0.0	0.0
Overheads & AFUDC - Totals	**49.1**	**53.7**	**54.6**	**157.4**	**59.5**	**65.0**	**70.9**	**195.4**	**38.1**	**67.6**	**66.0**	**72.5**	**82.3**	**73.4**	**76.7**	**67.5**	**73.3**	**78.2**	**105.5**

NOTE: Overheads & AFUDC in the 2022 i-CDP filing were initially set up as New Business or Rate Base per the i-CDP guidance document.

5.27 Incremental O&M Expenses Directly Related to New Capital Projects

While the majority of the proposed capital investments as outlined within Chapter 5 of this document will be supported by existing resources, there are some new incremental expense requirements related to the capital investments for the initiatives in this Plan, including:

1. Valdosta Satellite LNG Plant – The proposed satellite LNG plant is currently scheduled to be completed by 2027 and will require approximately $600 thousand for operating personnel as well as the expenses for operating and maintaining the facility. This does not include the cost of the LNG, nor the expense associated with trucking the LNG to fill on-site storage as those costs are expected to be included in the Cost of Gas. Approximately $300,000 of this total is estimated as fully loaded payroll cost with a 2% annual overall increase for estimated labor and other inflationary costs.

2. Mobile LNG Vaporizer Staffing & Maintenance – AGL utilizes mobile LNG vaporizer units as an emergency system support mechanism until permanent solutions can be put in place to help ensure adequate system supplies and pressures on the coldest days of the year. Traditionally, these systems have been used on a very limited basis and has been supported with existing Peaking Operations personnel with support from Engineering, Construction, and System Operations personnel. The delays in key System Reinforcement projects driven by cost increases, supply chain disruptions, and other challenges as well as significant growth in the Valdosta region have led to the need for the potential mobilization of three mobile vaporizer units as shown below for the Winter of 2023/2024:



- Mobilization of one of AGL's two larger 250 MCF/H units to support the Dahlonega area on a 49 HDD (16 degrees Fahrenheit average temperature) day. The solution to this pressure issue is the completion of the Cumming to Hall System Reinforcement project scheduled for 2025.

- Mobilization of the Company's lone 150 MCF/H unit to support the Woodstock area on a 54 HDD (11 degrees Fahrenheit average temperature) day. The solution for this pressure issue is the completion of the Wade Green Phase II System Reinforcement project currently scheduled for the end of 2027, which may be pushed out further to accommodate potential project reprioritizations as system pressures and supply challenges change.

- Mobilization of AGL's lone ambient vaporizer unit in Valdosta to support the limited supplemental gas needed on a Design Day for the winter of 2023/2024. With the known large load additions/conversions in 2024, AGL will have to use its other 250 MCF/H unit in Valdosta for the Winters of 2025/2026, 2026/2027, and potentially 2027/2028 until the planned Valdosta Satellite LNG project is completed.

In the Winter of 2025/2026, AGL has the potential to mobilize all three of its larger mobile LNG units to the projects listed above leaving nothing but the much smaller ambient unit available to address any other system issues caused by additional growth, supplier maintenance outages, delays of other System Reinforcement projects, or other issues. Adding in the risk that these units have significant lead times for replacement parts or other failures, it is necessary for AGL to purchase another 250 MCF/H mobile vaporizer unit in early 2025 to have the necessary equipment available until the backup of known System Reinforcement and supply issues are resolved. This capital purchase is included in the Gas Ops-Peaking budget parameters.

Since AGL has not supported mobilization of more than two vaporizer units at one time and will have the potential to need to support up to four units as early as 2025 (including the unit proposed to be purchased in 2025), AGL's Plan includes four additional resources in Peaking Operations or System Operations to ensure that AGL has adequate staffing to not only maintain and operate these units but also provide the necessary support for system issues on the coldest days of the year based on the increasing need and frequency to implement these emergency measures. The estimated O&M cost for these four personnel will be approximately $600 thousand with an estimated 2% escalator.



3. Cherokee LNG Expansion – An addition of approximately $1.4 million annually beginning in 2024 was included in the 2022 i-CDP filing for personnel and other operating expenses for the expanded Cherokee LNG facility.

Funding Requirements:

The O&M requirements for these capital projects is summarized below in Figure 5.55.

Figure 5.55: Valdosta Satellite LNG and Mobile LNG Vaporizer Related Incremental O&M Budget Parameters

Estimated Incremental O&M Associated with Proposed Capital Projects/Programs ($ thousands)										
Item	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Proposed Valdosta Satellite LNG Plant Personnel and Operating Expenses			600.0	612.0	624.2	636.7	649.5	662.4	675.7	689.2
Proposed Mobile LNG Vaporizer and other System Support Staffing Related to the Capital Addition of a New Unit and the Ongoing System Reinforcement capital projects	600.0	612.0	624.2	636.7	649.5	662.4	675.7	689.2	703.0	717.1
Personnel and Related Operating Costs for the Cherokee LNG Expansion (continued from the 2022 i-CDP request)	1,400.0	1,400.0	1,400.0	1,400.0	1,400.0	1,400.0	1,400.0	1,400.0	1,400.0	1,400.0
O&M Related to Proposed Capital Projects	**2,000.0**	**2,012.0**	**2,624.2**	**2,648.7**	**2,673.7**	**2,699.2**	**2,725.2**	**2,751.7**	**2,778.7**	**2,806.3**

CHAPTER 6. BEST PRACTICES PROGRAMS

6.1 Introduction

The following sections address "Best Practices," which the Company categorizes as ongoing O&M related initiatives that improve safety, quality, and/or reliability of the AGL pipeline system. These programs address existing identified risks or future potential risks for the AGL system or records. In the 2022 i-CDP, the Company identified several key initiatives to better improve system operability and safety. Such programs that remove and prevent cross-bores, reduce third party excavation damage, improve construction records data quality and accessibility, and implement new programs directed to quality assurance and other safety practices result in fewer leaks and accidental breaks. These programs provide significant benefits to all AGL customers and the larger communities AGL serves. In this Plan, the Company requests Commission approvals to continue building on the success of these programs.

Identifying, adopting, and refining industry "Best Practices" continues to be essential in providing safe, reliable, affordable natural gas services. State and federal regulators mandate many of the standards that govern local gas distribution system operations. The federal system of natural gas facilities protection regulations establish "minimum" standards. Often, operational "Best Practices" can outpace updates to federal mandates. Indeed, as strategies for operational challenges are perfected, industry "Best Practices" may offer far superior approaches and results than minimum regulatory requirements to ensure a safe, reliable system. This Chapter describes some of the ongoing "Best Practices" that influence AGL's approach to delivering safe and reliable service.

6.2 Plexco Service Tee Celcon Caps

I. Introduction:

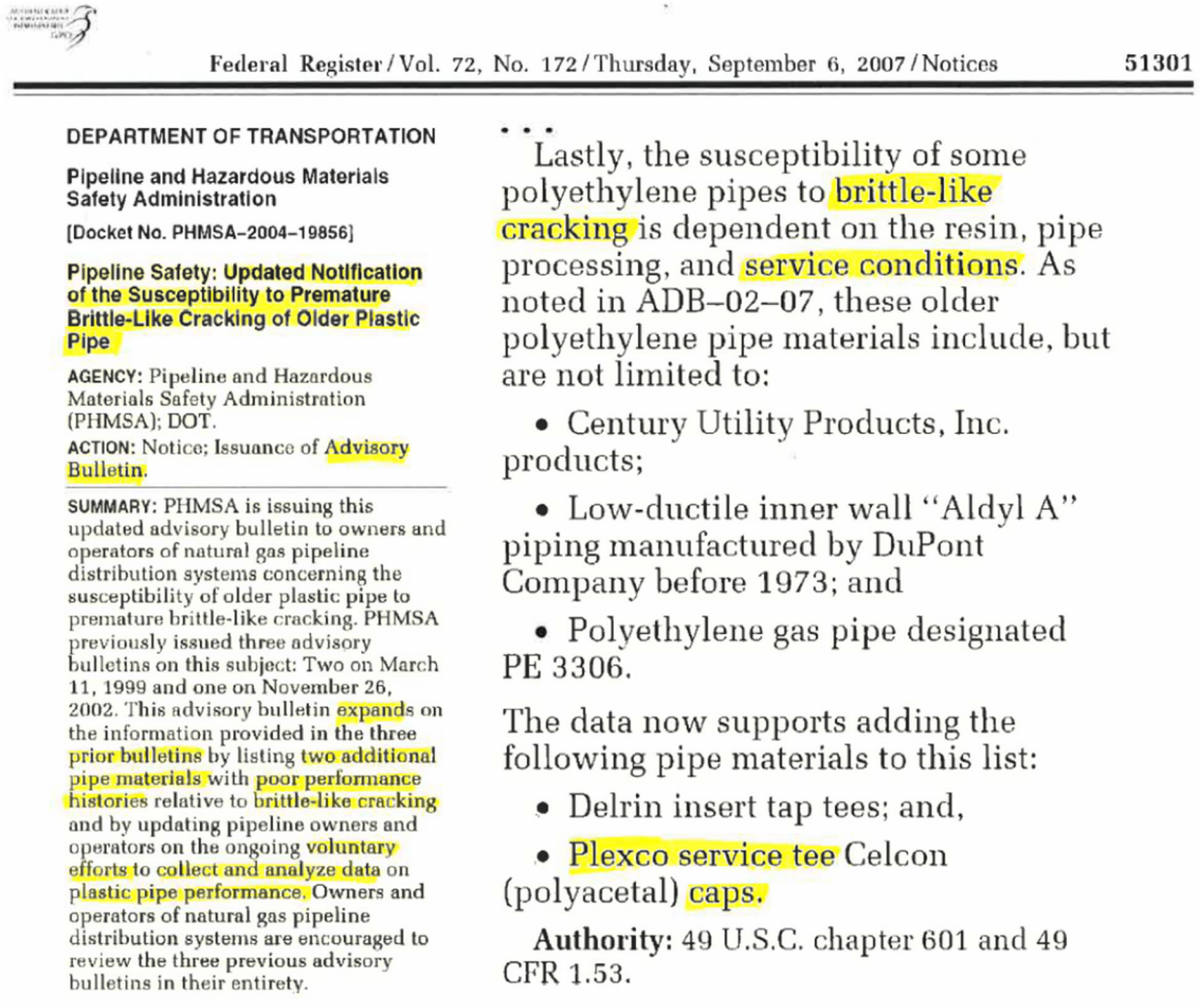
In 1984, the Company started transitioning away from the use of Dupont Aldyl-A plastic for mains and services and started using a medium density Polyethylene ("PE") plastic manufactured by Plexco. AGL made this transition because of Plexco's improved material characteristics as compared to the Dupont Aldyl-A.

While the new pipelines and service tees that connected service lines to mains were made entirely of PE, the caps threaded onto the top of the tees were made of an early plastic resin called Celcon, which is a polyacetal plastic.





The Company installed these caps between 1984 and 1995, and it is now known that these caps are prone to stress cracking. Accordingly, leakage rates are higher on gas systems with Celcon caps. In 2007, PHMSA issued the below notice in the Federal Register concerning Plexco Service Tee Celcon caps:



Federal Register / Vol. 72, No. 172 / Thursday, September 6, 2007 / Notices 51301

DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

[Docket No. PHMSA–2004–19856]

Pipeline Safety: Updated Notification of the Susceptibility to Premature Brittle-Like Cracking of Older Plastic Pipe

AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA); DOT.

ACTION: Notice; Issuance of Advisory Bulletin.

SUMMARY: PHMSA is issuing this updated advisory bulletin to owners and operators of natural gas pipeline distribution systems concerning the susceptibility of older plastic pipe to premature brittle-like cracking. PHMSA previously issued three advisory bulletins on this subject: Two on March 11, 1999 and one on November 26, 2002. This advisory bulletin expands on the information provided in the three prior bulletins by listing two additional pipe materials with poor performance histories relative to brittle-like cracking and by updating pipeline owners and operators on the ongoing voluntary efforts to collect and analyze data on plastic pipe performance. Owners and operators of natural gas pipeline distribution systems are encouraged to review the three previous advisory bulletins in their entirety.

. . .

Lastly, the susceptibility of some polyethylene pipes to brittle-like cracking is dependent on the resin, pipe processing, and service conditions. As noted in ADB–02–07, these older polyethylene pipe materials include, but are not limited to:

- Century Utility Products, Inc. products;
- Low-ductile inner wall "Aldyl A" piping manufactured by DuPont Company before 1973; and
- Polyethylene gas pipe designated PE 3306.

The data now supports adding the following pipe materials to this list:

- Delrin insert tap tees; and,
- Plexco service tee Celcon (polyacetal) caps.

Authority: 49 U.S.C. chapter 601 and 49 CFR 1.53.

II. Present Drivers:

AGL continues to experience a number of cracked caps every year. Additionally, the leakage rate on plastic facilities installed on AGL's system between 1984 and 1995 is higher than on more current plastic facilities. The cracked caps most commonly result in non-hazardous leaks at a service tee, which is typically located near the street. Nonetheless, in areas where a capped service tee is installed closer to a building (typically apartment complexes, condominiums, and commercial premises), such leaks are potentially hazardous.

Therefore, several years ago, the Company proactively began to replace service tee caps in those situations described above where the original pipelines were installed between 1984 and 1995 and connected to short service lines (causing the service line tee to be in close proximity to a structure).

Between 2016 and 2023, AGL replaced 2,750 of the estimated 7,000 Celcon caps at multi-family and commercial facilities and other short-service line installations with a leak history. Currently, the Company spends approximately $1.1 million dollars per year replacing these caps. At that rate, the Company expects to replace at least 90% of the higher-risk Celcon caps by 2032, barring the need to shift funding to address safety projects with higher priority.

If additional Celcon caps are subsequently identified, this could extend the period of work or increase the annual spend associated with the program.

III. Funding Requirements:

Figure 6.1: Celcon Caps Budget

Celcon Caps ($ millions)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
	1.1	1.1	1.1	0	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2

6.3 Cross-bores

I. Introduction

AGL has remediated a total of 306 cross-bores through this program since 2022. The Company clears approximately 150 cross-bores annually. A cross-bore occurs when an operator installs a gas pipeline through an existing, underground sanitary sewer or storm sewer pipe. If a cross-bored pipe becomes clogged, a sewer employee, plumber, or homeowner can damage the gas line if they attempt to clean out the sewer line with a rooter-type, drain-cleaning device without first investigating the cause of the blockage. This can result in a significant natural gas leak into the sewer system, which can quickly accumulate in surrounding homes and businesses and may result in fires and explosions.

II. Present Drivers:

AGL continues to prioritize mitigation of cross-bores because of the inherent safety hazard that cross-bores present. Investigations in areas with previously identified cross-bores and remediation of cross-bores remain ongoing to reduce the risk to AGL's pipelines and the public resulting from damage by drain cleaning equipment. Since AGL's 2019 Rate Case, the program has become more effective at identifying cross-bores. As a result, the number of investigation areas to be added to the 10-year program has increased. Additionally, inspection costs inclusive of sewer cleaning, traffic control, and excavation expenses have increased due to the previously discussed negative economic factors.

III. Future Drivers:

Current construction and installation practices greatly mitigate the risks of a significant number of new cross-bores occurring. Additional areas in the AGL system with cross-bores have been identified since the program began. As such, the Company is planning on an additional phase to the cross-bore identification and remediation program. AGL is also evaluating some potential future enhancements to the technology used to identify those areas most at risk for cross-bores such as cross bore detection technology, artificial intelligence initiatives for the risk modeling prioritization of known inspection areas, predictive analytics of unknown areas, and automated quality control of video inspection.

IV. Funding Requirements:

The 10-year O&M budget for the cross-bore program is below and is exclusive of the Future Drivers.

Figure 6.2: Cross-bores Budget

Cross-bores ($ millions)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
				2.7	3.4	4.2	5.0	5.7	10	10	10	10	10	10

6.4 Reducing Third Party Excavation Damages

I. Introduction

AGL has implemented a “Watch and Protect” Program to improve pipeline safety by reducing damages from third party excavators. Watch and Protect contributed to a 5% reduction in damages from 2022 to 2023, resulting in cost savings for repairing damaged pipelines in excess of $350,000 based on average cost to repair a third-party damage. The Watch and Protect Program uses the Company’s GIS and locate ticket management system to identify excavation near critical pipeline facilities. At that point, Watch and Protect personnel engage directly with the excavator to help ensure that critical facilities are not damaged. The Company uses Watch and Protect on high-risk excavations, such as transmission and large diameter pipelines and high consequence areas, among others.

II. Present Drivers:

The number of excavations continues to increase, and AGL is committed to ensuring that this program meets the demand for locate services. Because third party damage is a significant safety

risk to AGL's pipelines, AGL plans to continue this program to ensure that third party excavation damages further decline.

III. Future Drivers:

As the number of excavations increases, AGL will ensure that its Watch and Protect Program meets the growing demand. This program, coupled with potentially moving a portion of locating services away from contract locators to internal personnel and potential use of future innovative technology and increased analytics discussed in Section 6.4 above, will assist the Company in reducing third party excavation damages.

IV. Funding Requirements:

The 10-year O&M budget for the Watch and Protect program is below.

Figure 6.3: Reducing Third Party Excavation Damages Budget

Watch & Protect Program ($ millions)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
				1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1

6.5 Improving Data Quality and Accessibility

I. Introduction

AGL has developed a source record validation process, which requires verifying and updating historical asset information within the Company's GIS to ensure that data is accurate and complete. AGL's efforts include scanning historical construction records (as-builts, pressure test charts, bills of materials, etc.), indexing these source records into the Enterprise Asset Management ("EAM") system, and updating GIS as needed. Source record validation improves pipeline safety by making more accurate records available to field personnel. AGL has completed facility records scanning for all service centers and is currently in the process of validating the information for accuracy within the GIS system. This is the fourth year of an estimated 10-year program.

II. Present Drivers:

AGL plans to continue validating the facility records information for accuracy within the GIS system. Once scanning and indexing is complete, the records will be stored in the EAM system

that allows the scanned images to be searchable using the indexed data fields. The EAM system makes the information available to field personnel digitally.

III. Funding Requirements:

AGL will identify and make necessary updates to the GIS, which AGL anticipates will be an on-going task through 2029.

Figure 6.4: Improving Data Quality and Accessibility Budget

Source Record Validation ($ thousands)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
	120	120	120	120	120	120	120	120	120	120	0	0	0	0

6.6 Expanding Quality Assurance

I. Introduction

In general terms, Quality Assurance ("QA") is the evaluation of work being performed to ensure the desired level of quality. QA focuses on both personnel and pipeline safety by providing an independent internal review of how a company's employees and contractors are performing their work in the field.

II. Present Drivers:

AGL has three quality assurance specialists to assess construction work as it is being conducted in the field by the Company's construction contractors to validate that appropriate procedures are being followed. AGL plans to continue this work.

III. Future Drivers

The positions discussed above are limited in scope to construction work. As discussed in the 2019 Rate Case and the initial i-CDP, AGL plans to expand this program into additional areas of O&M work performed by employees and contractors in the field, including work performed in customers' homes, as available resources permit.

IV. Funding Requirements:

Figure 6.5: Quality Assurance Budget

Quality Assurance ($ thousands)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
			0	0	0	0	0	0	0	0	0	0	0	0

6.7 Applying PSMS

I. Introduction

In 2015, the pipeline industry, working together with federal and state pipeline safety regulators and pipeline safety advocates, developed a recommended practice (API RP 1173) on PSMS. This American Petroleum Institute ("API") designed its practice specifically for pipeline operators, similarly to the practices used by the Airline and Nuclear industries. PSMS are designed to enhance pipeline safety by applying a "Plan-Do-Check-Act" cycle to how the pipeline operators approach safety. This holistic approach, in general terms, determines the steps that need to be taken across operations, completes those steps, periodically reviews those steps, and makes any changes or improvements as necessary following that review. By applying these steps to its operations, AGL will improve personnel and pipeline safety in a variety of areas around the Company.

The Company has implemented a PSMS program that complies with API's best practice RP 1173. Since filling the manager role in 2020, AGL has developed a management of change ("MOC") process meeting the requirements of PHMSA's RIN-2 regulation previously discussed and executed a gap analysis of existing operational practices and procedures with external consultants to establish the current level of maturity with API RP 1173 elements. AGL will conduct the first assessment of the program in 2024 in conjunction with API, with subsequent assessments occurring every three years thereafter. The Company utilizes five (5) additional shared services personnel to the PSMS department and has developed a formal incident investigation and continuous improvement program.

II. Present Drivers:

Improving PSMS is an ongoing process. Going forward, the Company will develop a more comprehensive PSMS plan, documenting the processes and capabilities of AGL to execute the elements of API RP 1173. The Company has developed a roadmap and set of prioritized initiatives to improve PSMS program maturity and adoption across the organization. This will be an iterative process moving forward as the Company implements its PSMS program, completes initiatives, measures performance, and undertakes subsequent initiatives. The Company also anticipates filling an analyst position in CY 2025 to support the PSMS program and processes at AGL.

III. Funding Requirements:

Figure 6.6: PSMS Budget

Pipeline Safety Management System ($ thousands)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
			416	220	100	220	100	100	100	100	100	100	100	100

6.8 Future Best Practices

In late December 2020, Congress passed a new Pipeline Safety Reauthorization Bill. The bill signed by the President in December has many directives from Congress for PHMSA and other groups to undertake that will, over the coming years, add to or significantly modify the way the Company operates and maintains its pipeline system. These new statutory mandates in many ways require "Best Practices" that will be tied to future pipeline safety regulations.

As the examples below show, Congress has directed PHMSA to develop new regulations that will affect pipeline operations and lead to higher future costs. These examples are discussed more fully in the sections of Chapter 5 detailing new and proposed pipeline safety initiatives:

1. Enhance leak investigation programs using new technology to find leaks.
2. Require the repair of non-hazardous leaks that have emissions.
3. Enhance emergency response plan communications with first responders, government officials and the public.
4. Develop MOC procedures for work done on pipelines.
5. Add additional regulations on over-pressure protection of existing pipeline systems.
6. Ensure system pressure test records are traceable, reliable, and complete.
7. Put in place new construction and operating procedure requirements that reduce the release of natural gas into the atmosphere.

These new regulatory requirements will ultimately require AGL along with other pipeline operators to adopt new technologies, develop new procedures, and establish additional programs. Therefore, it is quite possible that these additional programs driven by congressional mandates and ensuing PHMSA regulations could result in additional costs that will be borne by the Company and its customers in the future.

These evolving regulatory standards illustrate the relationship between federal minimum standards and industry best practices. Current industry best practices will continue to inform and guide development of new regulatory requirements. Indeed, PHMSA has incorporated more than 80 standards from standards developing organizations like API.[28] Likewise, industry best practices, as compared to minimum regulatory standards, will continue to innovate compliance approaches, achieve better results, and capture efficiencies.

6.9 Conclusion on Best Practices

Development and refinement of "Best Practices" is an ongoing process. As technology and informed thinking continues to evolve and be refined in the field by the industry, AGL remains open to exploring the best ideas that are relevant to its operations and will enhance system safety and integrity while improving service to customers. AGL believes that implementing just the bare minimum required by federal or state regulations does not adequately serve its customers. Other programs reflected elsewhere in this Plan, such as ILI tools and RCVs, discussed in Chapter 5, constitute further "Best Practices" even if not called such. However identified, the Company's ongoing efforts to implement "Best Practices" for the benefit of customers and the communities AGL serves is itself a best practice that reflects the Company's corporate culture to deliver smart solutions anchored in remarkable service, resilience, and safety to the communities we are privileged to serve.

[28] The National Technology Transfer and Advancement Act of 1995 (Pub. L. 104-113) directs federal agencies to use voluntary consensus standards in lieu of government-written standards whenever possible.

CHAPTER 7.CUSTOMER RETENTION AND GROWTH PROGRAMS

AGL has designed and implemented programs to add customers, prevent attrition of customers at risk of leaving the system, and win, convert, and retain multifamily developments. These programs create downward pressure on rates by reducing O&M costs, adding, and retaining customers, and avoiding the need to prematurely retire certain infrastructure due to customer attrition. The four current AGL customer growth and retention programs described below are: 1) the Residential and Commercial Conversion Rebate Program; 2) the Single Burner Tip Attrition Mitigation Program; 3) the Multifamily Incentive Program; and 4) the Residential and Commercial Energy Efficiency (EE) Rebate Retention Program. AGL promotes awareness of these programs in its customer base through advertising and outreach. AGL is requesting that this Commission approve the continuance of the Residential and Commercial Conversion Rebate Program, the Single Burner Tip Attrition Mitigation Program, and the Multifamily Incentive Program, and the new Residential and Commercial Energy Efficiency Rebate Retention Program.

1. Residential and Commercial Conversion Rebate Program

AGL's Residential and Commercial Conversion Rebate Program provides incentives to new and existing customers to offset the cost of converting to natural gas equipment from other fuel sources. Fuel conversions to natural gas in existing structures may present significant costs because adding or modifying gas infrastructure into finished space is difficult when drywall, floors, and ceilings are already in place. Incentives encourage these conversions and remove some of the barriers for customers to install more efficient equipment with lower operating costs.

Conversion rebates help add new customers to the AGL system, create additional revenue from existing customers, and lower the attrition risk of existing customers. AGL pays about 100 new customer rebates annually. In addition, AGL lowers the attrition risk of an additional 200 existing customers annually, on average, by offering conversion rebates. Expected spend for rebate payments under this program is approximately $340K in 2025. A summary of the current conversion rebate offers available to customers is shown below and may be adjusted annually.



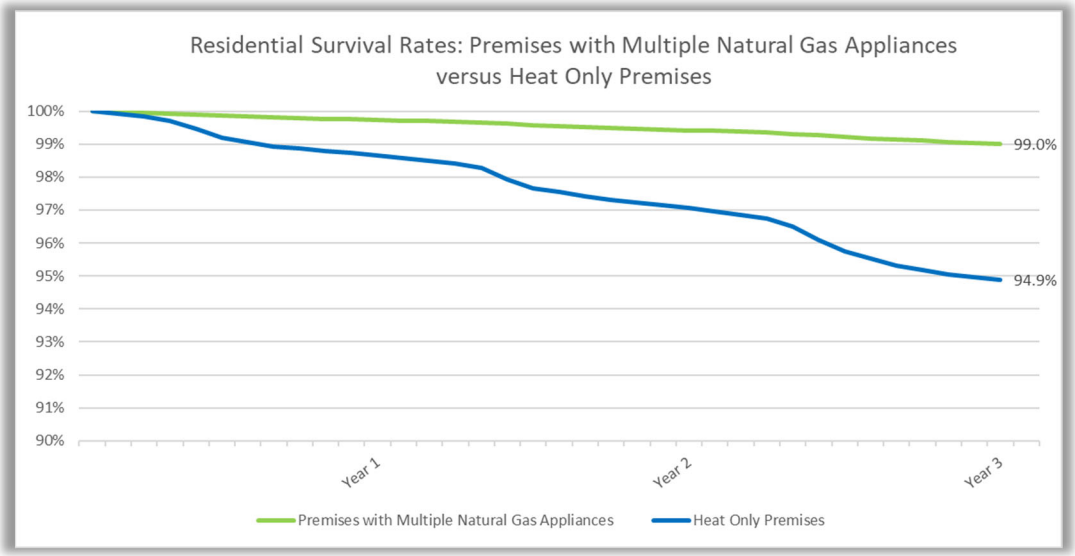
Figure 7.1: Current Conversion Rebate Offers



2. Single Burner Tip Attrition Mitigation Program

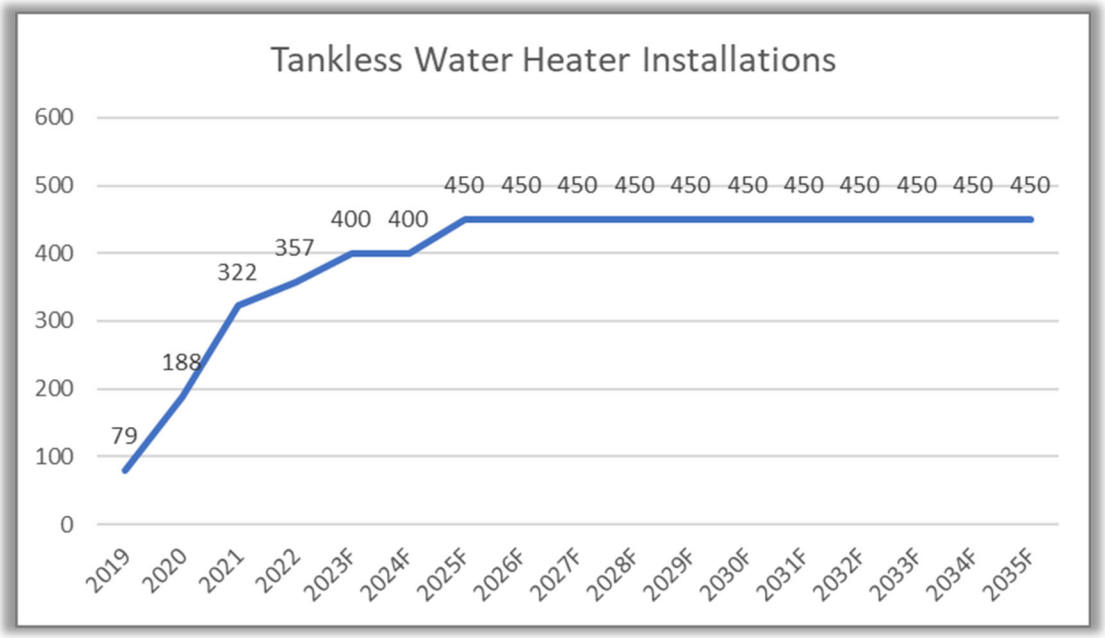
AGL's Single Burner Tip Attrition Mitigation Program provides at-risk customers with a free tankless water heater. Compared to customers with multiple natural gas end uses, a single burner tip customer is believed to have a four to five times higher risk of leaving the system. Therefore, adding a second appliance significantly reduces the attrition risk of these customers.

Figure 7.2: Premises with Multiple Natural Gas Appliances Versus Heat Only Premises



In addition to being high-risk for attrition, single burner tip heat only customers often require at least two visits from AGL each year, to deactivate service at the end of the heating season and to safely reactivate service at the beginning of the heating season. By converting single burner tip heat only seasonal customers to year-round, AGL increases revenue and reduces O&M costs by avoiding the turn-off and turn-on service calls. Additionally, by preventing attrition, this program avoids the capital expense required to retire inactive services at premises where a customer has left the system. Tankless water heater unit and installation costs are estimated to be approximately $1.4MM in 2025. Recent and forecasted tankless water heater installations are shown in the chart below.

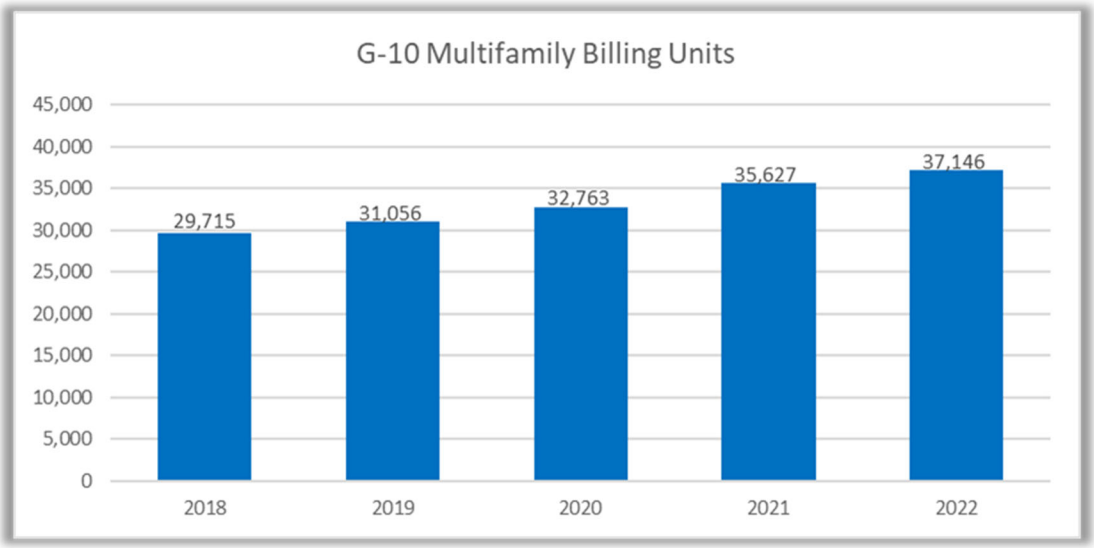
Figure 7.3: Actual and Forecasted Tankless Water Heater Installations



3. Multifamily Incentive Program

A multifamily development with a master meter under AGL's G-10 rate may have up to 2.5 miles of gas pipe downstream of the meter. Under this rate, the developer handles the cost of furnishing and installing gas pipe and the increased costs associated with properly installing and venting gas equipment. AGL provides incentives to help offset these costs and promote the installation of gas appliances in addition to electric appliances in multifamily developments. These incentives have helped AGL serve thousands of apartments. AGL also incentivizes multifamily apartments and condominiums under AGL's R-1 rate to build with natural gas, convert from electric to natural gas, and to continue to add natural gas burner tips to existing apartments and condominiums. AGL plans to commit $1.25MM in incentives annually to offset natural gas specific construction costs for developers and secure natural gas appliances in multifamily developments. These incentives are amortized over the contract life of 15 years.

Figure 7.4: G-10 Multifamily Growth

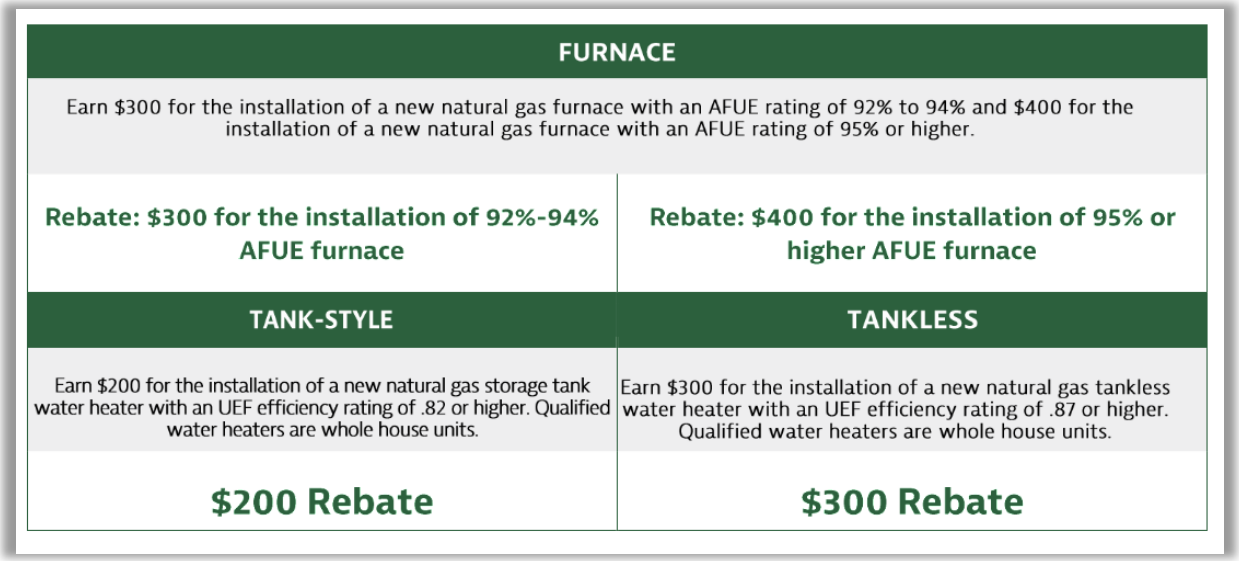


4. Residential and Commercial Energy Efficiency (EE) Rebate Retention Program

AGL's Energy Efficiency (EE) Rebate Retention Program provides customers with rebate incentives for purchasing and installing high efficiency gas appliances and remaining on the AGL system. With most federal incentives prioritizing rebates for electric appliances, it is important that AGL offer options for customers that wish to retain gas equipment and reduce their energy use because these customers are at risk of attrition due to appliance costs absent an incentive to remain connected to the natural gas system. Customers that participate in the program replace their current gas appliance with a brand new more efficient appliance and experience the added benefit of more modern appliances that will reduce energy bills and emissions associated with natural gas use over the new equipment's lifetime.

A summary of current EE retention rebates available to customers is shown below:

Figure 7.5: Current Energy Efficiency (EE) Rebate Retention Offers



AGL will continue to expand the reach of the Residential EE Rebate Retention Program through advertising and outreach efforts designed to promote awareness of the program while increasing optionality. This includes increased incentives on furnaces which is particularly important prior to the implementation of new federal energy conservation standards which take effect in 2029. This standard will eliminate non-condensing equipment and potentially lead to costly retrofits or forced fuel switching when the installation of condensing equipment isn't practical. AGL will also offer incentives to builders for high efficiency furnaces and water heaters in new construction in 2026 to ensure sustainable growth, weatherization rebates in 2027, and incentives on gas heat pumps in 2028.

AGL will begin offering a Low-income Weatherization Program in 2025. The goal of the Low-income Weatherization Program is to provide broad and deep energy management opportunities to income-eligible customers living in single-family homes and multi-family buildings.

AGL will begin offering a Commercial EE Rebate Retention Program in 2024. The goal of the Commercial EE Rebate Program is to provide measures for customers who have sustainability goals, as it is imperative that we offer these customers solutions. A Commercial EE Retention Program will provide annual energy cost savings for businesses, enabling those businesses to retain gas and be more competitive. AGL will promote awareness of the program through advertising and outreach efforts and expand the offered measures in 2027.

Expected spend for EE rebate payments and the low-income weatherization program is approximately $371K in 2025. AGL anticipates an increase in 2026 to $454K when it adds new construction incentives for builders, and expects participation increases of 10% and 20% respectively in subsequent years for the rebate payments and the Low-income Weatherization program. AGL expects an increase in 2027 to $642k associated with addition of residential weatherization rebates and other commercial efficiency measures. AGL anticipates an increase in 2028 to $1MM occurs with the addition of gas heat pump incentives.

Figure 7.6: Customer Growth & Retention Budget

Customer Growth & Retention										
Conversion Rebate Program	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Conversion Rebates	338,679	406,415	426,736	435,270	443,976	452,855	461,912	471,151	480,574	490,185
Single Burner Tip Attrition Mitigation Program										
Water Heater + Installation Costs	1.4MM	1.4MM	1.4MM	1.4MM	1.4MM	1.4MM	1.4MM	1.4MM	1.4MM	1.4MM
Multifamily Rebates										
Amortized payments	605,587	705,587	805,587	905,587	1MM	1.1MM	1.2MM	1.3MM	1.4MM	1.5MM
Energy Efficiency Program										
Energy Efficiency Rebates	220,800	274,300	426,700	773,100	946,600	1.2MM	1.5MM	2MM	2.6MM	3.5MM
Low Income Weatherization	150,000	180,000	215,000	257,500	310,000	372,500	447,500	537,500	645,000	775,000
Energy Efficiency Program Administration	114,500	120,225	309,596	454,781	488,788	526,948	567,851	610491	656,424	709,125
Total Spend	2.9MM	3.1MM	3.6MM	4.3MM	4.6MM	5.1MM	5.6MM	5.7MM	7.2MM	8.4MM
Advertising	147,105	294,355	321,718	474,198	526,803	579,538	582,409	635,425	688,590	741,915
Less non-customer funded contributions	-700,000	-700,000	-700,000	-700,000	-700,000	-700,000	-700,000	-700,000	-700,000	-700,000
Total Recoverable Spend	2.3MM	2.7MM	3.2MM	4MM	4.5MM	5MM	5.5MM	5.6MM	7.2MM	8.5MM

CHAPTER 8. ENVIRONMENTALLY-FOCUSED INITIATIVES

AGL believes natural gas will continue to play a vital role in meeting climate goals into the future. Natural gas is a cleaner alternative to other primary energy sources, but natural gas does contribute to greenhouse gas emissions ("GHG"), and policymakers, AGL customers, institutional investors, and society in general continue to expect, if not soon require, that the natural gas value chain from the wellhead to burner tip do its part to reduce and offset its net carbon footprint. In response, AGL has taken steps to reduce its carbon footprint and continues to evaluate further approaches to reducing emissions associated with gas system operation. AGL is also evaluating a capital investment in a renewable natural gas ("RNG") production facility in 2028.

AGL has committed to reducing its direct emissions of methane and CO2 through several current and proposed operational investments. The Company has developed an integrated approach to emissions reduction that includes building on past successes such as the PRP and i-VPR programs that replaced leaking pipelines by planning to continue replacement of aging pipelines prone to higher leakage rates going forward. Also, leak reduction remains a priority, and AGL plans to comply with new regulations addressing leak detection and response as discussed in Chapter 5. AGL continues to evaluate its operations to identify opportunities to reduce greenhouse gas emissions from gas-fired combustion equipment and other impacts associated with operations. As detailed in Chapter 7, the Company is also proposing the Residential and Commercial Energy Efficiency Rebate Retention program to build on the pilot program that the Company started in 2022, which will have the added benefit of reducing indirect emissions from end-use combustion with the installation of modern natural gas appliances.

AGL is also evaluating lower carbon forms of gas such as RNG and clean hydrogen to reduce its carbon footprint and customer emissions. RNG is interchangeable with geologic natural gas and can be used by customers to address emissions from the use of natural gas in existing natural gas appliances and equipment, and as such, AGL sees RNG development as a vital investment in retaining customers and attracting new businesses to the state. AGL has two (2) non-geologic natural gas facilities interconnected to its system under the TS-1 rate and an additional dedicated biogas pipeline constructed under AGL's TS-2 rate. AGL continues to work with landfill operators, wastewater and sludge treatment facilities, farming operations and other Georgia businesses with significant amounts of organic waste to evaluate opportunities to develop RNG production facilities in addition to the facilities currently in operation. AGL has been approached by current



and prospective commercial customers who look to AGL to provide solutions as they strive to meet their own sustainability goals and obligations. In the absence of solutions to address emissions from natural gas use, customers with sustainability goals may seek alternate energy solutions, and as such, some AGL customers have stated long term plans to completely electrify their operations. Furthermore, the availability of decarbonized fuels will be a vital tool in retaining and attracting companies to Georgia that prioritize sustainability goals.

In this Plan, AGL has included a $60 million strategic capital investment as a placeholder appearing in 2028 for an RNG production facility. Projects of this type create local gas supply and decarbonization solutions, RNG projects can meet the needs of an ever-increasing number of AGL commercial customers that are looking to AGL for sustainability solutions. RNG production facilities also provide waste management solutions and create jobs in the community where the facility is located.

AGL does not yet have a specific project to propose. Nonetheless, one of the stated purposes of the i-CDP process is to provide insight to the Commission and interested parties regarding the Company's longer-term plans. Because the Company is not proposing a specific project, it is also not yet proposing any specific regulatory structure to address the full costs and revenues that would be associated with an RNG production facility. Conceptually, revenues would be available from both the sale of RNG attributes as well as the sale of physical gas from an RNG facility. RNG attributes should be available to Marketers and commercial and industrial ("C&I") customers in the state of Georgia at prices competitive with or below national markets to help existing customers meet their targets and provide solutions to companies looking to expand or move operations to Georgia. RNG attributes not purchased by Georgia Marketers or C&I customers could alternately be sold in national or other available markets, such as the federal renewable fuels standard (RFS). Logically, revenues would be applied to the associated revenue requirements, and RNG benefits would logically inure first to the benefit of AGL's customers, with surplus environmental benefits, if any, used to offset AGL's GHG emissions, thereby benefiting all customers. The Company plans to provide proposals for Commission consideration prior to 2028.

Figure 8.1: RNG Budget

Item	2022 i-CDP Filing				Current Actuals/Plan				2022-2024 Act/Plan vs. Filing	2025-2034 i-CDP Proposals ($ millions)									
	2022 (bud)	2023	2024	Filing Sub-Total	2022 (act)	2023 (act)	2024 (bud)	Current Sub-Total		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Gas Ops - RNG (Proposed RNG Project)				0.0				0.0	0.0				60.0						

CHAPTER 9.CONCLUSION & ACTION PLAN

The 2025-2034 i-CDP reflects the Company's plan to continue to deliver safe, reliable, affordable natural gas to customers through ongoing and proposed projects and programs addressing pipeline safety, reliability and growth, industry best practices, and sustained, proactive steps in response to continually changing circumstances, governmental regulations, and economic and market conditions. In addition to the items specifically contained in the conclusion of Chapter 1, pending Commission approvals where necessary, the Company plans to take the following actions:

- Plan and manage the CSP process to continue to maintain an appropriate array of interstate pipeline and out-of-state storage services to meet customers' needs.
- Build, operate, and maintain the necessary natural gas delivery infrastructure to ensure adequate reliability and serve the needs of customers in Georgia.
- Ensure full compliance with state and federal minimum standards to deliver gas safely to customers in the communities AGL serves.
- As appropriate, implement industry best practices that exceed the government-mandated minimum requirements.
- Design and implement programs to retain and grow the natural gas customer base while balancing customer affordability and improving economic development in Georgia.
- Pursue opportunities to reduce emissions and increase supplies of renewable natural gas.

The Company requests that this Commission issue an order that does the following:

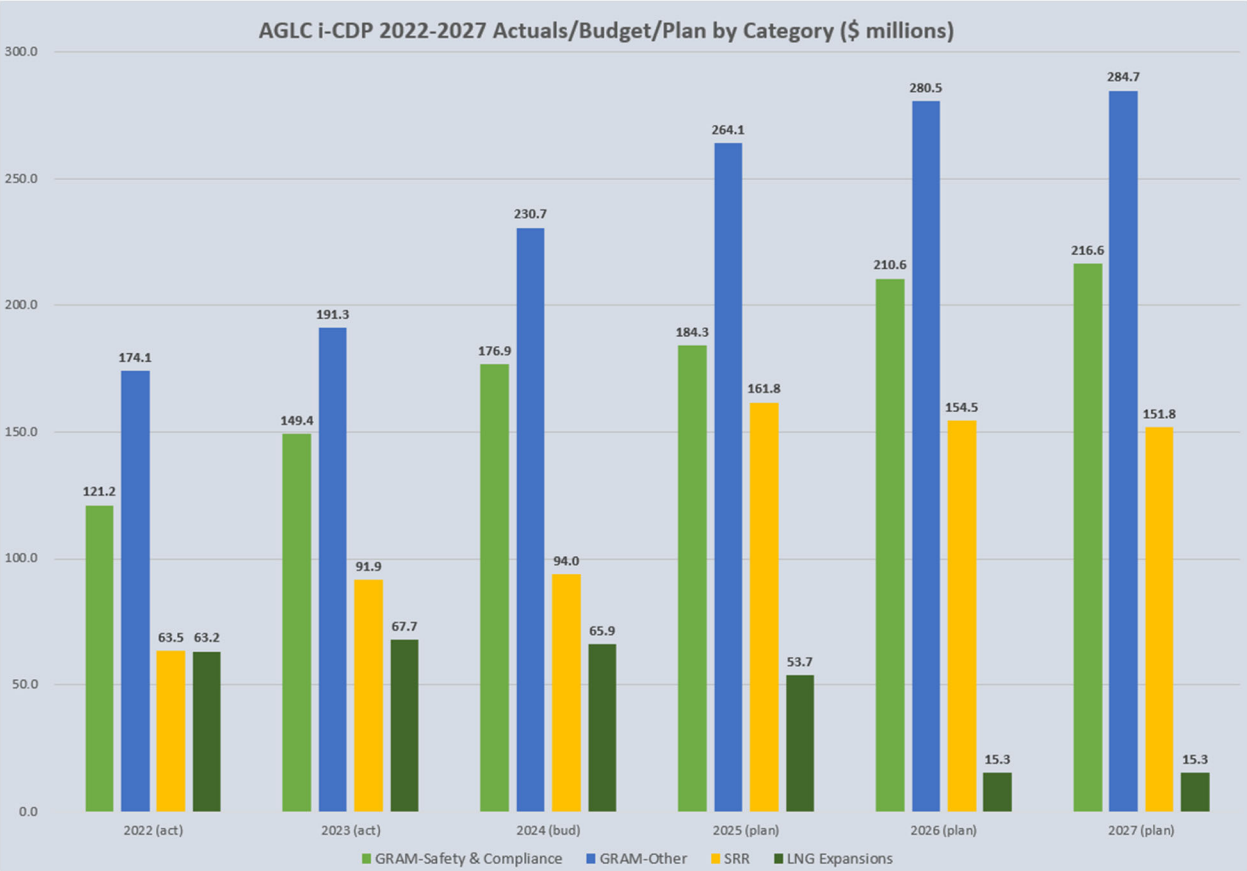
- Approves AGL's i-CDP for 2025-2034, which AGL will use a long-range planning tool for capacity supply and natural gas delivery.
- Makes findings of facts and conclusions of law that this Plan, the MFRs, testimony, and other supporting documentation complies with the requirements the Commission set forth for AGL's i-CDP.
- Makes findings of fact and conclusions of law that the forecasts in AGL's Plan are appropriate estimates of customers' needs for planning purposes during the initial three-year Planning Period.



- Approves those proposed projects during the initial three-year period of the Plan that are to be included within the Company's next GRAM filing and those which are to be included within the next SRR filing.
- Makes findings of facts and conclusions of law that the SRR-based capital projects set forth in the Plan are appropriate to meet the forecasted customer needs and provide safe and reliable natural gas service.
- Approves those parameters for capital budgets and related O&M spending capital projects identified by the Plan that are to be subsequently incorporated within the Annual GRAM Filings.
- Establishes a rate to be charged for the revenue requirements associated with the projects AGL will include within the SRR.
- Makes findings of fact and conclusions of law that the integrated capacity supply and infrastructure delivery planning process first approved by the Commission in its February 14, 2020, Order in Docket No. 42315, and the "Governance Document" Stipulation approved by the Commission's February 23, 2021, Order in Docket 42315, continues to be in the public interest, and that the i-CDP planning process should continue as set forth therein.
- Makes findings of fact and conclusions of law that in approving this Plan, the Commission is not preapproving revenue requirements for GRAM-based capital investment projects included within the initial three years of the Planning Period.
- Makes findings of fact and conclusions of law that AGL is not prevented from seeking approval to update the forecasts of customers' needs in a subsequent Capacity Supply Plan or Annual GRAM Filing.

AGL believes that approval of its Plan will continue to support the deployment of natural gas infrastructure so that natural gas will continue to be a fuel of choice for those Georgians who desire to have access to this clean and affordable energy source.

Figure 9.1: 2022-2027 Actuals/Budget/Plan by Category



ATTACHMENT A. SRR TARIFF SHEET

Atlanta Gas Light

TERMS OF SERVICE

All Rate Schedules
Revised Sheet No. 25.2
Effective: January 1, 2025

25. System Reinforcement Rider (SRR)

25.1 Applicability

The SRR charge will apply to all Rate Schedules of the Company that contain a separate charge based on Dedicated Design Day Capacity.

25.2 Purpose

The purpose of this Rider is for the Company to recover certain cost associated with system reinforcement and pressure improvement projects approved by the Commission to be included within the SRR.

25.3 Billing Rate

The SRR for each rate class shall be as follows:

R-1, G-10, AG-1 and S-51: $15.48 per customer annually ($1.29 per month)

G-11: $46.44 per customer annually ($3.87 per month); and

G-12: $387.00 per customer annually ($32.25 per month).



ATTACHMENT B. PROJECTED DESIGN DAY LOAD REQUIREMENT

PUBLIC DISCLOSURE

REDACTED

ATTACHMENT C. ARRAY OF INTERSTATE ASSETS

PUBLIC DISCLOSURE

REDACTED

PUBLIC DISCLOSURE

REDACTED