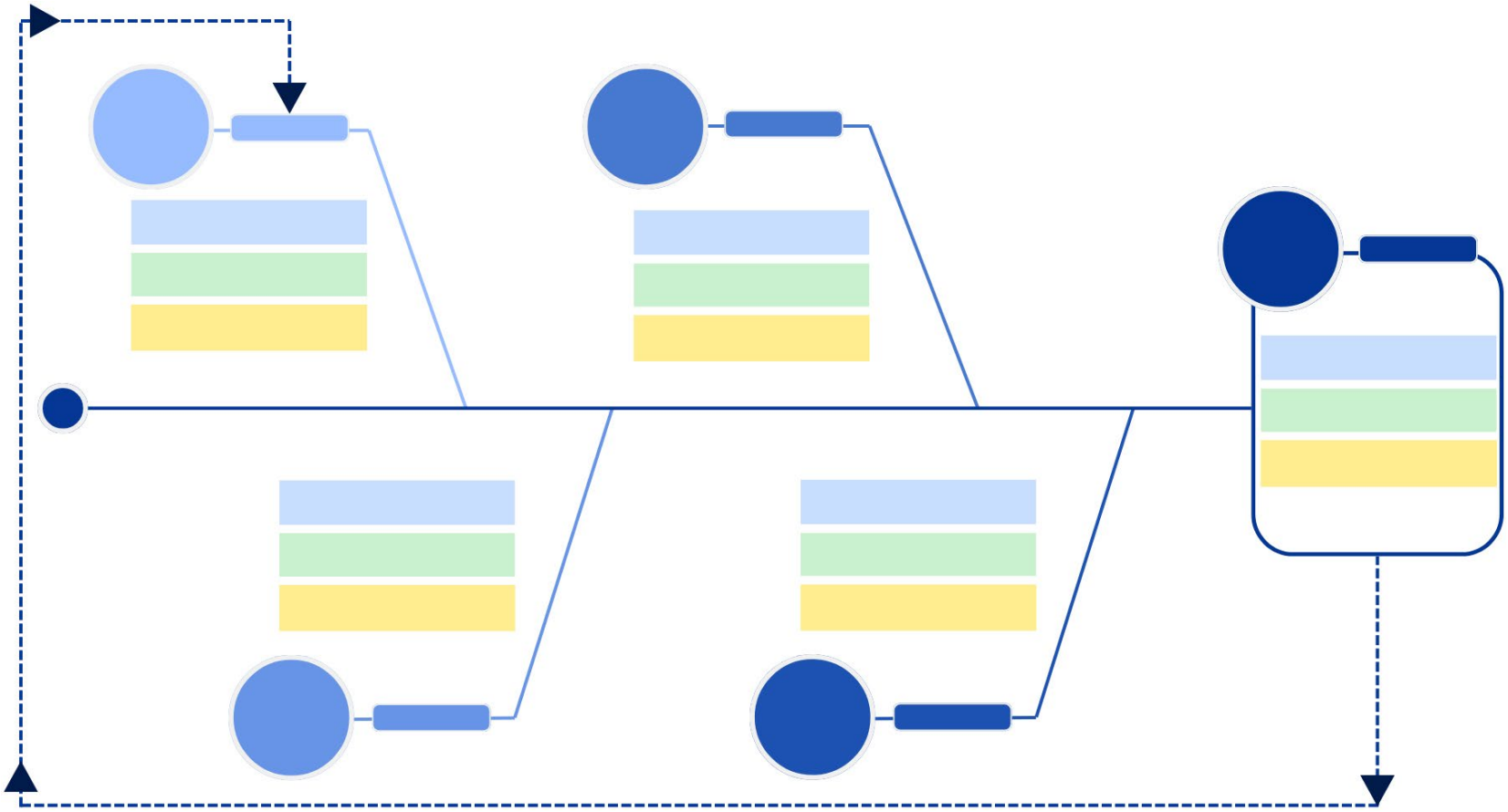
NARUC
National Association of Regulatory Utility Commissioners

Reliability Cohort Roadmap

NARUC Task Force on Natural Gas Resource Planning



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Introduction

This roadmap describes a vision for an idealized planning process for a natural gas distribution utility (gas LDC), from a public utility commission perspective, designed to align with state policy goals for reliability. Developed by commissioners and commission staff members in the NARUC Task Force on Natural Gas Resource Planning Reliability Cohort, with input from subject-matter experts, the roadmap presents a planning process that a Commission could use as a model for advancing reliability goals in gas utility planning processes. Specifically, the roadmap identifies key planning elements that the Commission should evaluate to ensure that the gas LDC's long-term planning process supports the state's reliability goals.

The roadmap incorporates representative data types, alternatives, analyses, and planning steps that would enable the Commission to understand and properly evaluate the LDC's plans. The roadmap includes:

- A flowchart of the entire planning process
- Descriptions and explanations of each step of the planning process
- Guidance, resources, and examples that can augment understanding and offer starting points for action

Please note that this roadmap is not intended to endorse the pursuit or adoption of any particular state goal. To that end, a fictional state persona was created to guide the development of this roadmap. Comparable roadmaps have been produced by other NARUC cohorts focused on the state policy goals of affordability, clean energy, and economic development [hyperlinks to each will be added in production]. These roadmaps do not focus on electricity system planning related to gas-fired power generation;[1] the focus is on in-state gas distribution utilities.

How to Read this Roadmap

This roadmap describes activities contained in an **idealized** planning process for a gas LDC located in a state with reliability goals. **Steps** are largely sequential; outputs from each step serve as inputs to subsequent steps (though iteration is expected). Many of the steps involve gathering information or data from the gas LDC or from customers, state agencies, or other stakeholders to provide evidence to support eventual regulatory decisions.

Comprehensive stakeholder engagement throughout the planning process is key to an informed, robust process that ultimately arrives at decisions that further state policy goals and the public interest. To that end, where appropriate, the descriptions of each step note when and how stakeholders can provide input or otherwise engage in the planning process.

This roadmap describes an **idealized planning process, not an actual one**. While this exact process might not be implemented in any instance and any actual process must, of course, be adapted to the particular situation at hand, some Commissions have implemented portions of this process for gas or other regulated utilities. The Cohort expects that the roadmap could offer a starting point for considering state-specific implementation, so where possible, the roadmap notes relevant resources and examples from across the U.S. that can be referenced and adapted as helpful.

Finally, the roadmap does not contain a timeline for the planning process, as timing could vary widely across states based on the particular situation.

1 Please see the NARUC Gas-Electric Alignment for Reliability (GEAR) Task Force report (November 2025) for recommendations from a diverse group of commissioners and industry stakeholders about how to improve electric and gas coordination at the wholesale level.

About the Reliability Cohort's State

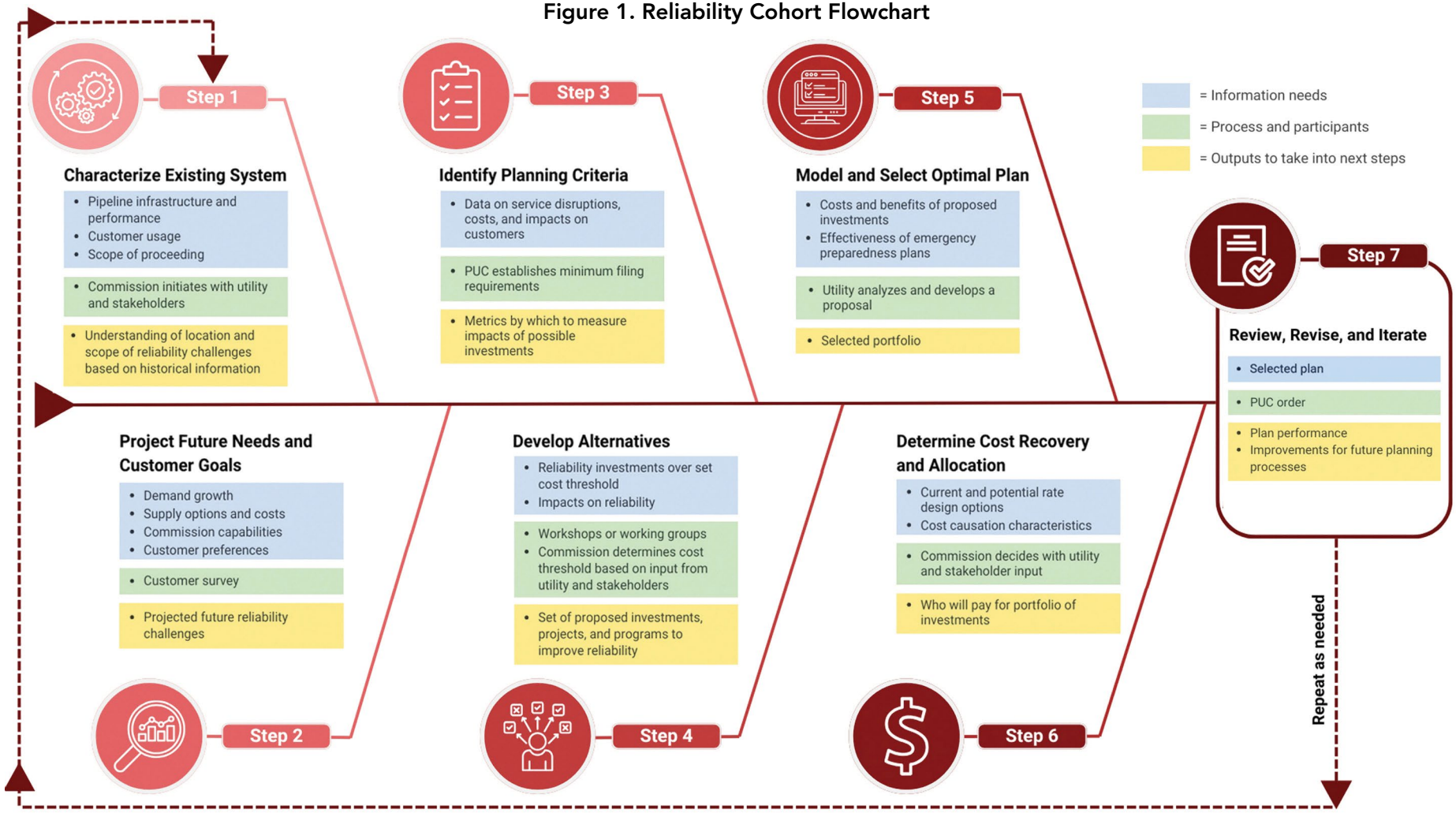
The fictional representative state that the Reliability Cohort is supporting has some key characteristics that provide context for the cohort's vision of an ideal planning process. As with all aspects of the idealized planning process, the divergence between this fictional state and a real state could result in deviations from the gas planning process offered as a potential starting point.

Geography and Economy	
• The state is geographically large with population distributed across rural and urban areas. • The state has aggressive economic growth goals and seeks to maintain its agricultural interests. • The state experiences strong weather patterns across the four seasons with a few recent extreme cold snaps and some natural disasters. It is a top destination for winter tourism.	• The state expects large amounts of load growth on the electric system, which will be unevenly distributed. • Gas demand within the state generally peaks during the winter. • The state is a net importer of energy, with limited in-state energy production resources.
Infrastructure	
• Gas distribution infrastructure is aging and in need of modernization. • Smart gas meters are in place.	• Customers are predominantly heated by gas-based systems, but policies and incentives exist to enable electrification. • Questions about expansion, replacement, and abandonment of gas systems have been raised by various stakeholders.
Utility Demographics	
• Gas-electric and gas-only utilities operate in the state and have performance-based incentives. • Policies are in place to increase reliability and to decarbonize.	• An integrated resource planning (IRP) process is established for gas and electric utilities. • Gas bills have high fixed charges, fluctuate frequently, are increasing steadily overall, and are higher than electric bills.
Customer Characteristics	
• A significant proportion of the population is low- and fixed-income that struggle with utility bills.	• Environmental justice concerns have been raised by some customers.

Roadmap Features

The flowchart shown in **Figure 1** outlines a series of steps designed to gather and process relevant information that would aid in developing a comprehensive reliability plan for a gas LDC. The seven steps in the Reliability Cohort's roadmap are: (1) Characterize Existing System, (2) Project Future Needs and Customer Goals, (3) Identify Planning Criteria, (4) Develop Alternatives, (5) Model and Select Optimal Plan, (6) Determine Cost Recovery and Allocation, and (7) Review, Revise, and Iterate. Each step is described in more detail in the following sections, which highlight information needs [in blue], processes and participants [in green], and outputs to take into the next step [in yellow] along with

Figure 1. Reliability Cohort Flowchart



relevant resources and examples. See the NARUC Task Force on Natural Gas Resource Planning online library for supplementary materials, such as expert presentations, data sources, and regulatory tools.

The planning process is intended to be iterative, with periodic reassessments during which utility regulators, utilities, and stakeholders identify opportunities for refinement and improvement. The plan, once completed, will be reviewed and approved or acknowledged by the utility regulator and will serve as a resource going forward for all stakeholders.

Regulatory decisions are based on state law and evidence submitted by utilities and stakeholders. During the planning cycle, the Commission may need to evaluate new tools or services to customers even in cases where available evidence is limited. Evidence will change over time as technologies and customer preferences evolve, so the completed plan and its future iterations will likely be dynamic.

Step 1. Characterize Existing System

- Pipeline infrastructure and performance
- Customer usage
- Scope of proceeding

- Commission initiates with utility and stakeholders

- Understanding of location and scope of reliability challenges based on historical information

Before information gathering begins, the Public Utility Commission (Commission) will establish clear objectives for the planning process as well as establish a baseline understanding of the existing natural gas distribution system, setting the stage for the remainder of the planning process. A baseline understanding of the natural gas distribution system helps inform the process of establishing reliability goals and the specific actions needed to achieve those goals.

Information needs

The Commission will establish the scope of the proceeding (e.g., reliability planning for natural gas distribution utilities) and articulate key terms and concepts. For the purposes of this roadmap, *reliability* refers to the natural gas distribution system's ability to consistently deliver natural gas to end users at the required pressure, volume, and time, especially during cold weather events.

Information is needed from the utility for this process. Requests for information can be burdensome to the utility and should be limited to information and data that will aid in the development of the next steps. The utility in this step will share pertinent information that is currently available and develop a plan to provide missing or incomplete information in the future. Where information is available but not public (e.g., due to privacy or proprietary concerns), the regulators and the utility will develop a process and an avenue for information sharing. A non-disclosure agreement (NDA) is an example of a mechanism to address the sharing of sensitive information. Although originally designed for decision-making about electric data, the NARUC 2023 Grid Data Sharing Framework could provide a helpful framework for Commissions to establish expectations about scope, granularity, resolution, and audience if they do not have data access procedures already in place.

Information about the system can be grouped into the following categories:

- Physical system attributes
  - Basic system statistics about the pipeline distribution system, including pipe vintage, size, material, and length
  - Information about key facilities both on the utility side (e.g., storage) and the customer side (e.g., behind-the-meter cogeneration facilities)
  - Map(s) of pipeline system, including locations of key facilities (e.g., storage facilities); major customers (e.g., behind-the-meter cogeneration facilities and manufacturers that use natural gas) and whether their supply is interruptible; and previously detected leaks
- System demand: historical energy usage over the course of the year and on peak days, as well as related weather data

- System supply:
  - Supply contracts that the utility relies on to meet natural gas demand and their characteristics (e.g., firm versus non-firm contract, contract length)
  - New gas pipeline or storage capacity that is expected to come online
  - The utility's hedging strategy and current state hedging policy (if applicable), and the historical performance of the strategy
  - Availability of energy efficiency and demand response programs (including interruptible rates), the number of participants, and the collective demand response capacity
  - Historical cost of supply services as well as historical rates
- Reliability records: history of reliability events such as unplanned interruptions, their root cause analyses, and remediation actions recommended and / or taken
- Leak detection plan and reporting process, including specific technologies and methods used in compliance with industry, state, and federal standards
- Emergency preparedness plans, including designated critical facilities and other facilities whose service is prioritized in the event of an emergency. This step may include a review of winter preparedness reports, including data from the previous year and recent multi-year trends, as well as customer education and outreach programs to prepare communities for emergency events.

In addition, it is important to gain insights into customer characteristics such as:

- Current and historical number of customers by type (residential, commercial, industrial) and their usage histories
- Information about low-income and vulnerable customers, including available low-income tariff rates, and enrollment numbers of participants in local and federal energy assistance programs

Process and participants

The Commission will develop evaluation criteria to assess potential solutions that will come out of this process (e.g., least cost, best value) and specify key planning parameters (e.g., planning horizon). The Commission can also consider an appropriate stakeholder engagement process for the proceeding. See NARUC, Public Utility Commission Stakeholder Engagement: A Decision-Making Framework, 2021 for some considerations and examples.

The Commission may also assess existing policy impacting reliability by cataloging the existing regulatory authority's rules and policies to address reliability, including emergency powers and the conditions under which an emergency can be declared.

The commissioners and commission staff will take the lead in this step of the process. They will work closely with the utility to define the scope of data needed to characterize the existing system. Stakeholders may propose baseline information and supporting data that they consider essential for reliability planning, along with a clear rationale for each request. The utility will have the opportunity to respond to the specific burdens associated with collecting any requested data it opposes providing. Ultimately, utility regulators will determine which data requests to proceed, based on a balanced assessment of the value of the information against the effort and cost required to obtain it.

In the event that certain critical information is not available, the utility may propose a plan to fill the data gaps, either within the timeline of the current gas planning cycle, or in the next planning cycle. The missing information should not impede the current planning process; rather, the planning process should move forward without that information. Stakeholders can work with the utility to determine how that information can be collected and used in the future.

Outputs

This step will produce parameters that guide the remainder of the planning process and a shared understanding of the location and scope of reliability challenges based on historical information and system performance.

Step 2. Project Future Needs and Customer Goals

A key assessment in this step is whether and how the utility can meet expected demand for natural gas effectively while complying with existing policies, including providing natural gas at least cost to customers.

- Demand growth
- Supply options and costs
- Commission capabilities
- Customer preferences

- Customer survey

- Projected future reliability challenges

Information needs

The utility will develop a gas demand forecast, whose inputs may include:

- Macroeconomic conditions, including economic changes within the service territory and broader region, any changes in population, and information from economic development agencies
- Weather and climate patterns, including a review of the historical design day (i.e., planning for the coldest day of the year) and the applicability of the design day going forward
- Customer counts and customer characteristics, and how both are expected to change over time
- Customer needs and preferences based on survey data
- Utility programs that affect demand on the system, such as energy efficiency, demand response, and non-pipeline alternatives
- The effect on gas demand due to new electrification policies. This may also include analysis of electrification costs

The utility will develop a supply plan to meet the forecasted demand subject to the state's policy objectives (e.g., least cost). The supply plan will analyze the available supply options as well as their technological maturity, implications on reliability, and costs. Further, the plan can specify short- and long-term supply contracts and, if applicable, alternative fuel supply contracts (e.g., renewable natural gas, hydrogen, etc.) that the utility can pursue. The supply plan may include provisions for timely equipment procurement in the event of supply chain disruptions.

The utility needs to examine if their forecasts are in alignment with the state's clean energy policy, if one exists. Scenario analysis may be needed to capture the uncertainty associated with each of the above inputs. For example, what portfolio(s) of supply-side and demand-side options can the utility pursue in order to achieve the state's emissions reduction targets? In some cases, pathway studies can be conducted to assess technical achievability and costs across multiple scenarios of interest. Lastly, the Commission may review the utility's approach to hedging to minimize natural gas price volatility and assess consistency with the state's goals and customer needs.

Process and participants

The gas LDC will lead development of the forecast. Customers' preferences can be assessed in various methods such as surveys to ensure that the utility's forecast is reflective of its users' preferences. Surveys could seek information about customers' satisfaction with the reliability and affordability of their gas service, demand sensitivity to extreme weather events, interest in alternative fuel options, and other data that may impact the utility's forecast for demand and supply plan.

The Commission can establish a series of non-adjudicatory educational sessions or technical workshops where regulators, regulatory staff, and potentially key stakeholders can better understand how the utility

Report on the New York State Electric & Gas Supply Readiness for 2024-2025 Winter

The New York State Department of Public Service (DPS) conducts annual winter preparedness review with local gas distribution companies (LDCs) in the state. As part of this review and oversight effort, DPS collects data related to supply adequacy, demand projections, physical and financial hedging position, capacity planning, and overall system reliability over the next five years. See winter supply review letter and questionnaire 2024 – 2025, Case 24-M-0205 Winter Supply 2024 – 25 Forms, and letter from DPS Staff to New York State Department of Environmental Conservation.

developed its forecasts. (If this is not the inaugural planning cycle, then the utility will provide how its forecasts performed in previous years, and what updates or improvements should be made to the process.) This step will involve relevant state agencies, such as the state's economic development office. During these sessions, the regulators and regulatory staff can review the utility's supply contracts against expected demand to ensure supply adequacy. Likewise, there can be a session dedicated to reviewing the performance of the utility's hedging plan and identifying potential areas for improvement. In advance of this step, commissioners will determine the need for additional staffing, training or other resources.

Atlanta Gas Light's Integrated Capacity and Delivery Plan

As required by the Georgia Public Service Commission, Atlanta Gas Light (AGL) submits an Integrated Capacity Development Plan (i-CDP) at least once every three years. The i-CDP outlines AGL's ten-year strategy to meet customer natural gas needs in a safe, reliable, affordable, and environmentally responsible manner. Developed to optimize the integration of AGL's interstate, intrastate, and distribution systems, the plan includes a ten-year forecast of capacity asset requirements and a detailed three-year capital and operations and maintenance (O&M) spending plan. Key elements of the filing include:

- Forecasts of customer demand for natural gas and associated demand drivers
- Forecasts of interstate and intrastate capacity asset requirements
- Projections of capital budgets and related O&M spending over ten years
- Proposed projects to meet forecasted demand, benefits, and planning methodology

The i-CDP is developed to provide transparency into AGL's long-term capacity planning and investment strategy and is intended for reference across multiple ratemaking proceedings, including Georgia Rate Adjustment Mechanism (GRAM) and System Reinforcement Rider (SRR) filings.

These resources can also be used for increasing staff expertise. They can include software to enable hydraulic system modeling, pipeline mapping, economic modeling, and related tools.

Outputs

This step will result in a set of projected reliability challenges based on forecasted demand and supply conditions.

Step 3. Identify Planning Criteria

The objective of this step is to establish reliability-focused planning criteria and metrics to support transparent, data-driven utility investment decisions.

- Data on service disruptions, costs, and impacts on customers
- PUC establishes minimum filing requirements
- Metrics by which to measure impacts of possible investments

Information needs

In this step, the Commission and stakeholders will develop key planning criteria and metrics related to reliability. Frequency, duration, number of affected customers, and impacts of service disruption may be among the top metrics that the utility will report. In addition, the cause of disruptions as well as the cost and time to restore and respond are also important. Metrics should seek to capture the effects of reliability disruptions on customers. Other metrics may include:

- Accuracy of demand and supply forecasts (note the focus should be on identifying factors that can improve the accuracy of future forecasts)
- Distribution of reliability investments across the utility's service territory
- Investment costs (especially compared against similar investments in the past or investments made by other comparable utilities)
- Number of customer complaints or calls

Process and participants

It is important for regulators, the utility, and key stakeholders to align on what key planning criteria will be and why these criteria are important to reliability planning. The planning criteria and metrics may be benchmarked against utilities of similar profiles, or utilities serving similarly situated gas customers (e.g., similar demographics, customer preferences, etc.). The Commission will use this information to establish minimum filing requirements.

Outputs

This step produces metrics by which to measure impacts of possible investments in future steps.

Step 4. Develop Alternatives

The key objective of this step is for the utility to develop long-term reliability investment plans for different timeframes (e.g., five, ten, twenty years).

- Reliability investments over set cost threshold
- Impacts on reliability

- Workshops or working groups
- Commission determines cost threshold based on input from utility and stakeholders

- Set of proposed investments, projects, and programs to improve reliability

Information needs

The investment plans will include a list of major proposed reliability projects (where "major" can be defined based on a pre-determined investment threshold). During this step, it is important to clarify the reliability impacts of different investments in terms of reduced frequency, likelihood, and duration of outages.

Process and participants

To the extent possible, the plans will be informed by input from key stakeholders, which can be collected through a series of workshops that could be led by the utility, Commission, or stakeholders. In some cases, a technical work group or technical conferences may be needed to address some of the more complex issues associated with reliability planning. In those instances, external experts may be invited to participate and assist the regulators in analyzing proposed and alternative reliability investments. For example, the utility may analyze new or emerging technologies that can be used to revamp existing infrastructure instead of wholesale replacement (e.g., relining pipeline instead of pipeline replacement). Stakeholders participating in these workshops are welcome to suggest alternative reliability solutions that the utility can consider.

The Commission will seek input from the utility and stakeholders on what constitutes a "major" repair and the threshold at which an investment is considered significant. Also critical is input from stakeholders regarding emerging technologies that can cost-effectively address acute / localized or long-term reliability needs. Such input may include risk assessment and commercialization status to assist the Commission in understanding the full profile of a new technology and when it is appropriate to allocate ratepayer funding towards an emerging tool.

Outputs

This step will result in a set of proposed investments, projects, and / or programs to improve reliability with associated cost estimates.

Step 5. Model and Select Optimal Plan

After proposing capital investment plans and alternatives, the utility will need to conduct economic analysis to determine the impacts of the proposed investments on cost of service, the utility's return on equity, and customer rates and bills. In general, utilities can evaluate if a proposed investment passes a benefit-cost test, or a different cost-effectiveness test as required by regulations.

- Costs and benefits of proposed investments
- Effectiveness of emergency preparedness plans

- Utility analyzes and develops a proposal

- Selected portfolio

Information needs

A key input to evaluating the benefits of proposed investments is to determine how much customers value having continuous natural gas service (analogous to customer's value of lost load in the power sector),

but such an input is not widely established and calculated across the gas industry. Indeed, there are multiple efforts within the power sector to develop metrics that accurately reflect this concept. For more discussion, see NARUC and NASEO, Valuing Resilience for Microgrids: Challenges, Innovative Approaches, and State Needs, 2022.

In addition, studies to understand tariff structure and rate offerings may be needed, especially if the proposed investments do not neatly fit into the existing cost-of-service structure. In some cases, such as in jurisdictions with decarbonization mandates, the utility may need to conduct economic analysis of fuel switching (e.g., where gas appliances are electrified) to examine the economic tradeoffs of different reliability solutions. Other key considerations in such analysis include upfront investment requirements, the timeline and costs of decommissioning existing infrastructure, customer willingness to investigate different technologies, and availability of incentives or grants for customers.

Beyond the economic analyses, regulators can also review the cost-effectiveness of demand-side programs and their actual impacts during high-demand days. Likewise, regulators can review how the utility has used its emergency preparedness plans during actual emergencies, and whether and how such plans can be updated and improved. (Eversource's Energy Emergency Response Program and CenterPoint Energy's Emergency Operations Plan for Gas Operations provide examples for how such emergency preparedness plans can be developed[2]).

Process and participants

The utility will analyze all relevant alternatives proposed in the previous step. Each alternative will then be evaluated based on the different evaluation criteria determined at the start of the planning process.

Input from stakeholders, including both gas and electric utilities and customers, is crucial to improving the Commission's understanding of the economic tradeoffs between gas and electric service. The effectiveness of customer programs and the emergency preparedness plan can also be illustrated through customer feedback. Further, stakeholders can provide valuable input to the Commission on affordability and the impacts of various rate structures on energy affordability and demand.

Outputs

This step will result in an optimal portfolio of reliability investments that the utility can implement during the planning horizon.

Step 6. Determine Cost Recovery and Allocation

- Current and potential rate design options
- Cost causation characteristics

- Commission decides with utility and stakeholder input

- Who will pay for portfolio of investments

The utility will present bill impact analysis, showing how customer bills would increase or decrease under the selected plan. Such analysis should specify customers who are facing acute energy burden (e.g., low-income customers, customers on fixed incomes). The utility can propose certain programs or new rate offerings to mitigate the most adverse bill impacts for these customers.

Information needs

In considering cost recovery pathways, incentives to the utility for meeting particular targets on reliability, affordability, and other state policy goals can be helpful in aligning profits to performance. The performance-based ratemaking (PBR) framework can be used to incentivize the utility to go above and beyond minimum expectations to pursue cost-effective improvements in service. Utilities generally propose PBR programs in a general rate case, and the gas planning proceeding can serve as a preliminary step where the utility and / or stakeholders can explore certain mechanisms or programs of interest.

2 See Eversource, "Eversource Gas Operations Emergency Response Plan, Revision 8," May 15, 2024. https://pubs.naruc.org/pub/610EF357-07BC-DA10-1DC8-D5BD1538A0C0. See also CenterPoint Energy, "2024 Emergency Operations Plan – Gas Operations, CenterPoint Energy (Redacted)," July 31, 2024. https://pubs.naruc.org/pub/61214EA2-C316-04AA-9DE6-BF0843AB3EF8.

Added scrutiny of the impacts of reliability investments on low- to moderate-income (LMI) customers will be undertaken during this step. The Commission may also consider the expansion of customer assistance programs with the overall effect of limiting the rate impacts of additional investments on those customers. As another option, the Commission can explore the appropriateness of using riders as a mechanism to target certain investment needs.

TIP: Cohort members recommend exploring the appropriateness of using securitization financing as an alternative mechanism to recover costs for large reliability projects. Appropriately designed, securitization can maintain customer bill stability while reducing overall costs through lower financing costs. This mechanism has been applied to recover costs of stranded assets and address wildfire and storm recovery costs.[3]

Lastly, the Commission may consider the appropriate allocation of reliability costs among customer classes. If growth among certain types of commercial or industrial customers is driving added reliability investments or emergency preparedness measures, the Commission can revisit those customers' portion of rate cases. As some Commissions are doing in states with rapid expansion of data center customers, the Commission may also consider the creation of new customer classes to capture users with markedly different consumption patterns and needs than existing customer classes.

In this step, it is important to assess the interaction between the utility's reliability mandate and broader policy objectives, such as clean energy and economic development goals. These interests may at times conflict or compete with one another, and the roadmap may need to be tweaked to accommodate these different requirements.

Process and participants

Input from customers on bill impacts and affordability associated with reliability investments will be important for regulators. Comments from LMI customers regarding ability to pay for reliability investments and effective mitigation measures are particularly critical. Further, understanding the demands of new customers connecting to the system and how their usage may impact reliability for existing customers is needed.

Outputs

The utility will receive approval from the Commission to proceed and implement the new gas plan with direction about where and when cost recovery will be considered.

Step 7. Review, Revise, and Iterate

- Selected plan
- PUC order
- Plan performance
- Improvements for future planning processes

This roadmap establishes a structured process for assessing system needs, forecasting demand and supply, identifying solutions, and aligning reliability investments of the utility with regulatory and policy objectives. It serves as the first step of a multi-year effort and will need to evolve through periodic reassessment and stakeholder engagement.

Information needs

As technologies advance, policies shift, and new risks emerge, continuous iteration will be essential to ensure that reliability planning remains responsive, cost-effective, and aligned with broader state goals. The roadmap will also be revised based on lessons learned from actual implementation experience. Regular updates to data collection processes, planning criteria, and investment strategies will likewise

3 See South Carolina Office of Regulatory Staff, "Utility Securitization and Storm Costs," https://ors.sc.gov/consumers/electric-natural-gas/utility-securitization-and-storm-costs; RMI, "What is Securitization?" April 2021, https://rmi.org/wp-content/uploads/2021/04/rmi-tx-securitization-memo.pdf; NARUC, "Mitigating Stranded Asset Risks to Utility Customers," February 2024, https://pubs.naruc.org/pub/D41DAF2A-9425-50CD-C1E2-70B694AAC1A4; and Walter R. Hall II, Energy Bar Association, "Securitization and Stranded Cost Recovery," 1997, https://www.eba-net.org/wp-content/uploads/2023/02/15_25EnergyLJ1732004.pdf.

be needed to ensure that the roadmap will continue to be a relevant and useful gas planning tool going forward. Areas for iteration and improvement may include:

- Identifying where information gaps exist and factoring the costs and benefits of added data collection
- Assessing performance through metrics; improving metrics to account for impacts on customers
- Improving forecasting methodologies for demand and supply
- Improving load growth prediction models, including better accuracy for the location and demand of new customers
- Improving extreme weather planning via modeling high-impact, low-frequency events

By committing to an iterative approach, regulators, utilities, and stakeholders can maintain a dynamic, resilient, and forward-looking reliability framework that protects customers and supports the state's long-term energy, cost, and environmental objectives.

Process and participants

Utilities and stakeholders can provide valuable input to identify areas of weakness in the planning process and offer methods of improving future plans.

Outputs

This final step results in an assessment of the selected reliability plan's performance on planning criteria and improvements to implement in future planning processes.

Additional Resources

Below is a compiled list of additional resources and examples that may be helpful to consider when implementing a reliability-focused natural gas distribution utility planning process. Resources are offered for: demand response and interruptible tariffs, physical and financial hedging, and leak detection programs.

Demand Response Programs and Interruptible Tariffs

Demand response programs and interruptible tariffs can serve as tools to reduce gas consumption during periods of elevated demand, ease the strain on gas delivery systems, and allow utilities to maintain system reliability.

- Demand Response Example: National Grid's Load Shedding Demand Response program in New York targets commercial and industrial (C&I) customers and multi-family units (Program link; 2024-2025 Gas DR Annual Report). Designed to provide net gas reduction on a daily basis, the program allows customers to choose the four-hour event window(s) during which they commit to reduce a preset quantity of gas. In exchange, an enrolled customer receives a Reservation Payment, which depends on the customer's load reduction potential and their participation mode (i.e., direct load control versus non-direct load control), and a Performance Payment. In the 2024-2025 heating season, 427 customers enrolled in the program, with over 30,187 dekatherm/day (Dth/day) total enrolled capacity. The company also offers a C&I load shifting program, where customers must reduce gas consumption during a four-hour period on event days, and a residential and small business bring-your-own-smart-thermostat program.
- Interruptible Rate Examples: Among the 20 largest gas utilities by sales volumes, more than half offer interruptible rates for at least one customer class (e.g., Nicor Gas Rate 21, Enbridge Gas Utah Interruptible Sales Service, PSEG BGSS-CIG). To enroll in an interruptible rate, customers are required to specify the maximum quantity of capacity they are willing to source as interruptible service from the utility. When a utility declares an interruption event, the customer may be asked to discontinue gas usage up to this capacity. In exchange, participating customers receive a reduced rate of service, often applied to the commodity charge. The rate discounts the per-Dth price the customer pays for gas year-round and applies a per-Dth penalty if the customer fails to interrupt load to the specified level during an event.

Physical and Financial Hedging

To manage volatility in supply, demand, and price, gas utilities can rely on storage, supply diversification, physical fixed price supply, and financial hedging. ONE Gas, National Grid, and The Brattle Group experts shared lessons learned in an April 2024 presentation to the Gas Task Force (recording is also available).

Leak Detection Programs

Gas distribution utilities can implement leak detection programs that combine regular systemwide leak surveys, advanced mobile and stationary detection technologies, and structured response/repair protocols.

- Washington Gas Light Company (WGL) conducts periodic leak surveys across the District of Columbia. These surveys involve systematic inspections by qualified technicians using gas detection equipment to identify leaks in the gas distribution network. The entire system is surveyed on a three-year cycle. WGL's leak detection program also makes use of advanced detection technology, such as vehicle-mounted sensing equipment.
- SoCalGas is equipping residential gas meters with advanced Residential Methane Detectors connected via their advanced meter network. If a leak is detected, an alert is sent to SoCalGas, which dispatches a technician for investigation and repair. These devices allow for faster, more efficient responses. The utility also uses aerial gas mapping technology to scan large pipeline areas, quantify methane emissions, and target the most significant leaks for abatement and repair.

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