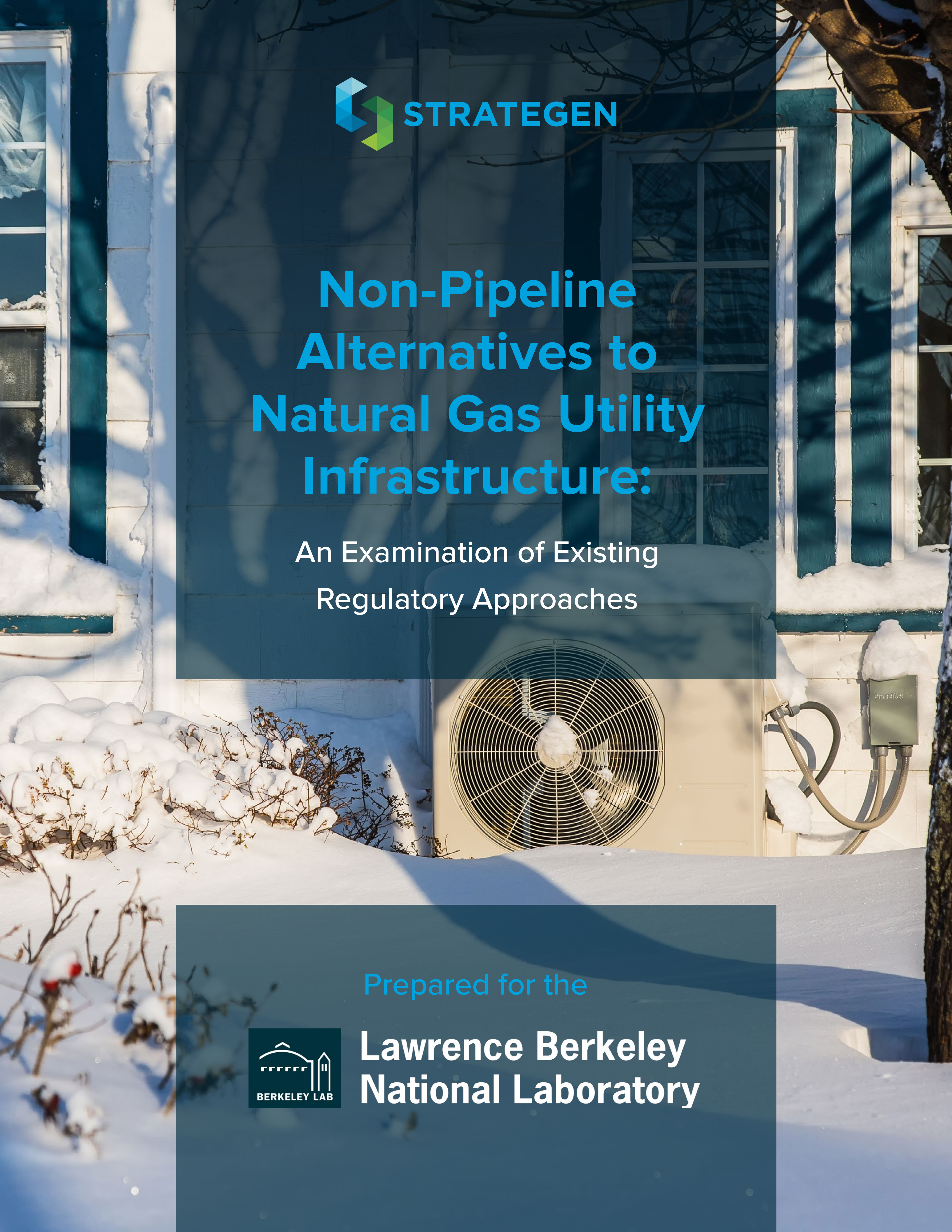

STRATEGEN

Non-Pipeline Alternatives to Natural Gas Utility Infrastructure:

An Examination of Existing Regulatory Approaches

Prepared for the

Lawrence Berkeley National Laboratory

Disclaimer

www.strategen.com

This document is prepared by Strategen Consulting, Inc. for the Lawrence Berkeley National Laboratory.

Authors

Strategen:
Ron Nelson
Bradley Cebulko
Thomas Van Hentenryck
Vassilisa Rubtsova
Thanh Nguyen

Berkeley Lab:
Natalie Mims Frick

Acknowledgments

The authors would like to thank the U.S. Department of Energy's Office of Policy and Building Technologies Office for funding this work, and Mark LeBel, Rudy Stegemoeller, Catherine Elder, and Michael Florio for reviewing this document.

Contents

Introduction

The primary audience of this paper is public utility commissions (PUCs) that are considering the role of Non-Pipeline Alternatives (NPAs) in gas utility planning. The purpose of this paper is to examine the existing proceedings, rules, and studies that are currently or have been under consideration to inform PUCs as they consider developing their own NPA frameworks. This is the first of two papers on the topic of non-pipeline alternatives. The second will address best practices in the construction of an NPA framework.

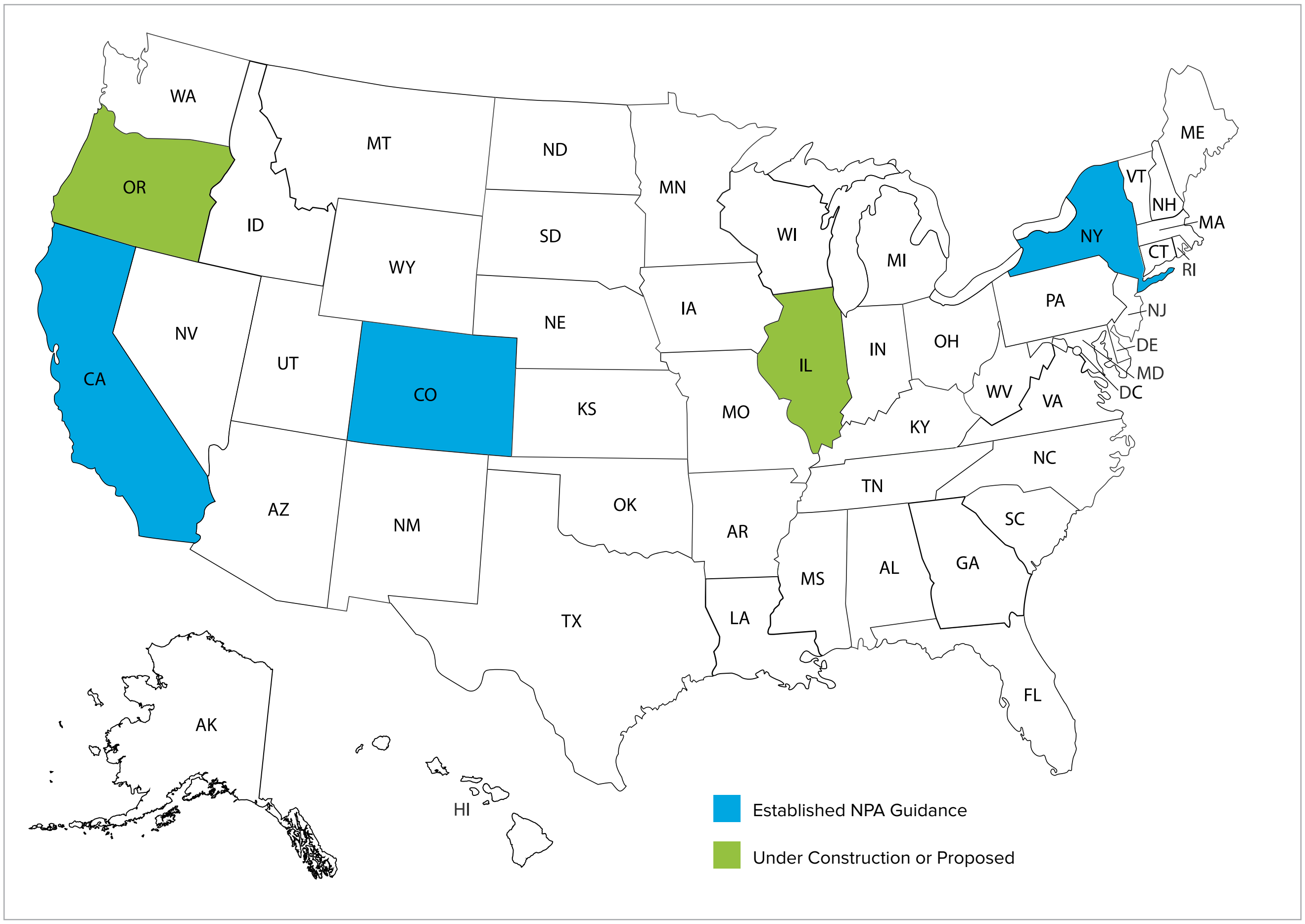

FIGURE 1: States That Have Proposed a Non-Pipeline Alternative Proceeding

Strategen reviewed NPA case studies and examples from four states with established NPA processes (Colorado, New York, Rhode Island, and California) to analyze underlying regulatory frameworks and policy goals (*Table 1*). The organization of this literature review largely follows the steps of developing and acquiring an NPA with the following sections:

+ **Definitions** —This section identifies how each of the four states defines an NPA.
+ **Public Policy and Filing Requirements** —The purpose of this section is two-fold. First, to examine each state's statutory or regulatory reasoning for pursuing the development of NPAs. Second, to identify the type of information and analysis a gas utility needs to present to a public utility commission for approval.

+ **Project Eligibility Atandards** — This section discusses the criteria and thresholds that need to be met for a gas utility to evaluate an NPA.
+ **NPA Eligible Resources** —This section explores which demand- and supply-side resources can be used as part of an NPA solution.
+ **NPA Project Identification and Acquisition** — The purpose of this section is two-fold. First, to examine how a gas utility identifies the resource or resources that make up an NPA solution. Second, to examine how a gas utility is expected to acquire the resource. Although NPA identification and acquisition are separate processes that occur at different times, in practice the NPA identification and acquisition processes are closely linked and merit a shared discussion.
+ **Benefit-Cost Analysis (BCA)** —This section examines each state's guidance on the preferred benefit-cost analysis test for screening the cost-effectiveness of the NPA.
+ **Equity** —This section discusses if and how states require an examination of the impacts on disadvantaged communities as part of the NPA analysis.

Each section of the paper begins with an examination of Colorado's requirements and then comparatively evaluates examples from New York, Rhode Island, and California.

Non-Pipeline Alternatives

NPA Definition

Broadly stated, NPAs are investments or activities that defer, reduce, or avoid the need to build or upgrade gas delivery system infrastructure. While there is not a commonly accepted definition of an NPA at this time, Colorado, New York, Rhode Island, and California have similar definitions. Each of these states recognizes that both capital expenditures (i.e., investments) and programs like energy efficiency or demand response (i.e., activities) are NPA resources and that the goals of an NPA are to remove the need for a traditional gas delivery system investment, deferring the investment, or reducing the size of the investment.

A non-pipeline alternative (NPA) is an investment or activity that defers, reduces, or avoids the need to construct or replace a pipeline.

State	Source	Definition
Colorado	Regulation	Programs, equipment, or actions that avoid, reduce, or delay the need for investment in certain types of new gas infrastructure and may include energy efficiency, demand response, and beneficial electrification.
New York	Ad hoc approval by the New York Public Service Commission (NY PSC)	Varies by utility, but generally describes the deferral or removal of traditional natural gas infrastructure projects.
Rhode Island	Rhode Island PUC (RI PUC) approval of System Reliability Plan	Any targeted investment or activity that is intended to defer, reduce, or remove the need to construct or upgrade components of a natural gas system, or "pipeline investment."[1]
California	N/A	Has not yet adopted a definition for an NPA.

TABLE 1: Summary of NPA Definitions

1 RIPUC Docket 5080 2021-2023 System Reliability Procurement Three-Year Plan, November 20, 2020.

Colorado[2]

In Senate Bill 21-264, which set greenhouse gas reduction requirements for gas utilities and required them to file Clean Heat Plans with the Colorado Public Utilities Commission (CO PUC), the legislature specified that utilities must consider demand-side management (including beneficial electrification), energy efficiency, and load reductions in their plans, but did not define an NPA. The legislation required the CO PUC to adopt rules for gas distribution utilities to develop their Clean Heat Plans. In its Rules Regulating Gas Utilities, the CO PUC defined NPAs as "programs, equipment, or actions that avoid, reduce, or delay the need for investment in certain types of new gas infrastructure and may include energy efficiency, demand response, and beneficial electrification."[3]

New York

In New York, each utility proposes its own set of NPA criteria for demand- and supply-side resources, subject to approval by the NY PSC. The New York utilities use broad definitions of NPAs (Table 2).

Utility	NPA Definition
Consolidated Edison	"Projects that could be used to defer or replace traditional natural gas distribution infrastructure projects."[4]
New York State Electric and Gas Corporation	"A reduction in gas demand or increase in gas or gas equivalent supply (whether a single project or a portfolio of multiple projects) that has the effect of reducing the natural gas demand at a specific point in NYSEG's natural gas Distribution System, and thus allowing the deferral of specific distribution system infrastructure construction."[5]
New York National Grid	"[T]he inclusive term for any targeted investment or activity that is intended to defer, reduce, or remove the need to construct or upgrade components of a natural gas system, or 'pipeline investment.'"[6]

TABLE 2: New York Gas Utility NPA Definition[7]

Rhode Island

Like New York, Rhode Island has not defined NPA within commission order or rule. The state defers to the utilities to define NPAs in the System Reliability Procurement Plans (SRP). Rhode Island Energy, the only regulated gas utility in the state, (formerly Narragansett Electric Company) uses the same definition as National Grid in New York, which is "the inclusive term for any targeted investment or activity that is intended to defer, reduce, or remove the need to construct or upgrade components of a natural gas system, or 'pipeline investment.'"[8]

California

Although the California Public Utilities Commission (CPUC) has discussed the concept of an NPA and identified a threshold for requiring NPA analysis, it has not yet adopted a definition.[9]

2 For more information on Colorado's Gas Infrastructure Plans and Clean Heat Plans, see *Appendix A.*

3 Colorado Department of Regulatory Agencies Public Utilities Commission 4 Code of Colorado Regulations (CCR) 723-4 Part 4 Rules of Regulating Gas Utilities, p.5 Decision No. C23-0117.

4 19-G-0066, Proposal for Use of a Framework to Pursue Non-Pipeline Alternatives to Defer or Eliminate Capital Investment in Certain Traditional Natural Gas Distribution Infrastructure. September 15, 2020. Page 1.

5 "Non-Pipe Alternatives." New York State Electric and Gas. https://www.nyseg.com/documents/40132/5899449/NYSEG%2BCanandaigua%2BNPA%2BAttachment%2BA%2B-%2BDefiniti_07.29.22+%281%29.docx/2774522a-755a-9382-bb65-200fb18c9be3?t=1662755838606.

6 "What is an NPA?" National Grid. https://www.nationalgridus.com/Business-Partners/Non-Pipeline-Alternatives/What-is-an-NPA.

7 NY PSC 20-G-0131
NY PSC 17-G-0606
NY PSC 19-G-0066
NY PSC 17-G-0460
NY PSC 17-G-0432

8 RIPUC Docket 5080 2021-2023 System Reliability Procurement Three-Year Plan, November 20, 2020.

9 CPUC Rulemaking 20-01-007, Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Perform Long-Term Gas System Planning, p. 4-13. January 27, 2020.

Public Policy Premise and Filing Requirements for Performing an NPA Evaluation

All of the states reviewed identified the same two public policies to support their interest in NPAs: to reduce costs to customers, and to reduce greenhouse gas emissions attributable to the gas utility. Colorado, New York, and Rhode Island also explicitly tie NPA analysis to the gas utility's planning process. To assess the potential of an NPA for a specific project, the utility needs to identify the traditional investment, its location, and when the project is necessary. This type of assessment is a logical outcome of a gas utility's planning process. California's public policy goals for NPAs go further than the other states and identifies the use of NPAs as a tool for avoiding stranded gas utility assets as the state transitions away from the use of natural gas.

Colorado is more prescriptive about its utility NPA filing requirements than New York, Rhode Island, and California. However, in practice, gas utilities will likely have to include similar information, namely, the costs and benefits of both the pipeline and non-pipeline solutions.

Uniquely, New York requires the utility to file a shareholder incentive mechanism worth up to 30 percent of the net benefits of the project in its application. A gas utility will earn less profit through the successful deployment of an NPA than it otherwise would have by building a traditional gas delivery system investment. That is because a utility earns its profits by building capital investments, which an NPA seeks to defer, reduce, or avoid. New York is attempting to reduce utility opposition to pursuing an NPA by allowing the gas utility to financially share in the benefits of an NPA.

Colorado

In its gas planning rulemaking, the CO PUC stated that the utilities' analyses in their Gas Infrastructure Plans (GIP) are intended to capture investments and expenditures beyond the short-term plan period, including considerations for customer costs and meeting statewide greenhouse gas emissions reduction goals.[10] The CO PUC recognized that NPAs are a resource that the utilities can use to advance the goals of reducing customer costs and greenhouse gas emissions in the long term, and therefore should be included in the utilities' GIP.

Specifically, the utilities' GIP must include any planned projects within the planned action period that will require a Certificate of Public Convenience and Necessity (CPCN). When filing a CPCN, the utility must present an analysis of the costs of the alternatives and the criteria used to rank or eliminate alternatives. The NPA analysis must consider or include:[11]

+ The technologies or approaches evaluated or proposed,
+ The projected timeline and annual implementation rate for the technology or approach evaluated,
+ The technical feasibility of the alternative, assuming full adoption of the technologies and approaches evaluated,
+ The utility's strategy to implement the technologies or approaches evaluated,
+ One or more applicable clean heat resources consistent with the utility's Clean Heat Plan, Demand-Side Management plan, or Beneficial Electrification plan,
+ A cost-benefit analysis that includes the social cost of carbon and methane, and
+ Best available employment metrics associated with each alternative.[12]

10 https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=955970&p_session_id=.

11 Colorado Department of Regulatory Agencies Public Utilities Commission 4 Code of Colorado Regulations (CCR) 723-4 Part 4 Rules of Regulating Gas Utilities, p.26 Decision No. C23-0117.

12 Ibid., 27.

New York

Like Colorado, NPA evaluations in New York are linked to gas system planning. In 2022, the NY PSC cited several factors that contributed to establishing a gas planning proceeding, including utility-imposed moratoria on new gas customer service connections to address reliability issues, meeting economy-wide emissions reduction targets set in the New York Climate Leadership and Community Protection Act's (CLCPA) draft scoping plan, and lack of transparent infrastructure planning.[13]

In its final order establishing a gas planning process, the NY PSC required gas utilities to establish and file a long-term plan every three years that includes the following elements:[14]

+ Third-party review of the analysis of gas utility filings,
+ A 20-year demand and supply forecast that is adjusted for energy efficiency, electricity, and other impacts,
+ A "no infrastructure option" in long-term plans that includes a mix of demand-response and NPA measures to address system challenges,
+ Annual reports detailing whether leak-prone pipes could be abandoned in favor of NPAs, and
+ Projected cost impacts for traditional solutions and alternatives.

The NY PSC also requires utilities to develop an NPA framework in their long-term plan establishing NPA suitability criteria, an NPA shareholder incentive mechanism, and NPA cost recovery details. These criteria are subject to review upon each subsequent long-term plan filing.[15]

Gas utilities in New York are also financially incentivized to adopt an NPA when "appropriate and cost-effective,"[16] as they are allowed to collect revenues equal to 30 percent of project net benefits through the shareholder incentive mechanism.[17] Since the incentive is based on a net benefits projection, the final incentive amount is subject to actual project costs, with 50 percent of project cost savings added to the initial incentive (or subtracted in the event of an overrun). The NY PSC approved the incentive structure shown in Figure 2.[18]

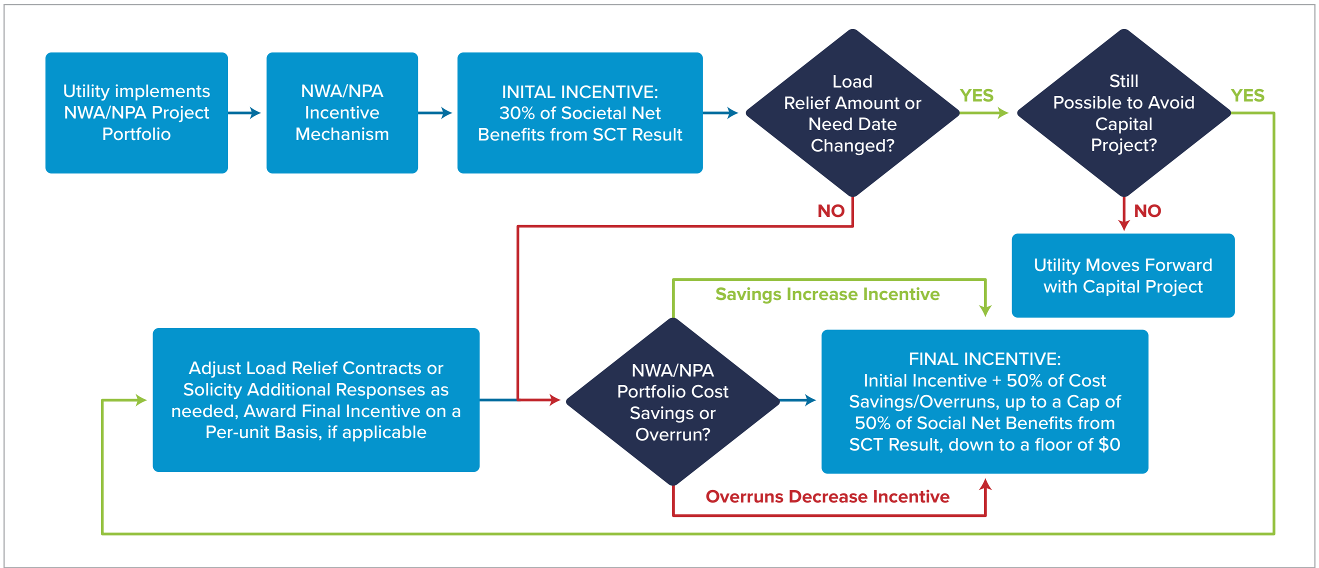

FIGURE 2: New York NPA Incentive Mechanism

13 20-G-0131 Order Adopting Gas System Planning Process, May 12, 2022, pages 2-5.
14 20-G-0131 Order Adopting Gas System Planning Process, May 12, 2022.
15 20-G-0131 Order Adopting Gas System Planning Process, May 12, 2022, Page 40.
16 19-E-0378, Order Approving Electric and Gas Rate Plans in Accord with Joint Proposal, With Modifications. p.161.
17 Ibid.
18 Ibid. Appendix HH.

Rhode Island

The impetus for NPA review in Rhode Island appears to be similar to other states: identifying least-cost procurement solutions and reducing emissions.[19] NPA evaluations in Rhode Island have their roots in Rhode Island General Law 39-1-27.7, which required the Commission to establish standards for least-cost procurement of system reliability, energy efficiency, and conservation. This law stipulates that the Commission is to approve "all energy-efficiency measures that are cost-effective and lower cost than the acquisition of additional supply."[20] The Commission has periodically revised regulatory rules to comply with the standards, called the "Least Cost Procurement Standards." The most recent revisions, effective August 25, 2020,[21] established a Three-Year System Reliability Plan.[22] In its SRPs, the utility identifies NPA criteria and opportunities.[23] Additionally, the utility files annual SRP Year-End Reports in which the utility provides a summary of status commitments and reporting requirements, including active and implemented projects.[24]

California

In California, the state's emissions reduction requirements are also the primary motivation for requiring utilities to perform NPA analysis. In 2020, the CPUC opened docket 20-01-007 to comprehensively overhaul the policies, processes, and rules that govern natural gas utilities in the state. The CPUC cited three factors that resulted in the need for this proceeding: gas pipeline and storage safety-related incidents; operational issues and capacity constraints; and local and statewide greenhouse gas legislation.[25] In the CPUC's ruling setting the scope for the docket, NPAs are identified as a strategy to avoid the repair or replacement of gas distribution infrastructure and facilitate the proactive decommissioning of distribution lines, helping to avoid stranded assets as the state pursues decarbonization goals and transitions away from natural gas-fueled technologies.[26] The California NPA requirement is targeted at larger, transmission-level investments (greater than $75 million). A separate CPUC process is looking at the potential to avoid distribution-level investments through NPAs and the potential to decommission portions of the distribution system.[27]

Gas utilities are required to annually file a Report of Planned Gas Investments detailing planned infrastructure projects that cost more than $50 million over the next 10 years.[28] This list includes both projects that require an NPA analysis (CPCN projects with a cost greater than $75 million) and other projects that cost between $50 - $75 million. For each planned project the annual report must include a detailed description of the project, whether the project is located within an environmental and social justice (ESJ) community, the projected capital expenditure, and the environmental impact of the project. For each CPCN project scheduled to be in service within 5 years, the reports must include a high-level analysis of NPAs, the projected lifetime reliability cost savings, the projected construction expenditures, and the projected lifetime operating costs.[29]

Pacific Gas & Electric (PG&E), an investor-owned electric and gas utility in California, also voluntarily offered a small-scale electrification program, called the Integrated Investment Program, which facilitates gas asset retirement, as part of their rate case.[30] Project examples include downrating a pipe from transmission to distribution pressure, and decommissioning radial lines.

19 RIPUC Docket No. 5080, 2021-2023 System Reliability Procurement Three-Year Plan. November 20, 2020. Page 8.
20 Rhode Island General Law 39-1-27.7
21 Docket 5015.
22 Docket 5015 Order, page 18.
23 RIPUC Docket No. 5080, 2022 System Reliability Procurement Plan Year-End Report, June 1, 2023. Pages 9-17.
24 RIPUC Docket No. 5080, 2022 System Reliability Procurement Plan Year-End Report, June 1, 2023. Page 1-3.
25 CPUC Rulemaking 20-01-007, Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Perform Long-Term Gas System Planning, p. 4-13. January 27, 2020.
26 CPUC Rulemaking 20-01-007, Assigned Commissioner's Amended Scoping Memo and Ruling, p. 5-6. January 5, 2022.
27 CPUC Rulemaking 20-01-007, Staff Proposal on Gas Distribution Infrastructure Decommissioning Framework in Support of Climate Goals, p. 21-22. December 21, 2022.
28 CPUC Rulemaking 20-01-007, Decision Adopting Gas Infrastructure General Order, Attachment A, p. 12-14.
29 CPUC Rulemaking 20-01-007, Decision Adopting Gas Infrastructure General Order, Attachment A, p. 14.
30 Pacific Gas and Electric Company 2023 General Rate Case Prepared Testimony Exhibit (PG&E-3). Pages 1-10.

Project Eligibility Standard That Triggers NPA Analysis

The states reviewed have different criteria to determine if a utility must include an NPA analysis when considering gas investments, and not every project proposed by a utility must include it. In all of the states, NPAs must be considered when the utility proposes a gas capacity expansion project, when the proposed project is over a cost threshold, and if the project meets other preliminary screening criteria (e.g., date of project implementation).

Capacity expansion and new business projects are the focus of the states' rules, although in some states utilities may still assess NPAs for reliability and safety projects. Colorado limits its NPA requirements to capacity expansion projects. New York and California recognize the opportunity for using NPAs to avoid capacity expansion but also identify other types of system investments. For example, New York requires gas utilities to examine NPA analysis as an option to avoid replacing leak-prone pipes, and California requires NPA analysis for any project that has "significant air quality impacts."

Cost threshold requirements vary significantly among the states reviewed. Rhode Island Energy proposed to apply an NPA analysis for all projects that cost more than $500,000 (and meet other criteria; see below for more details). Colorado gas utilities must consider NPAs when the proposed projects exceed a minimum cost threshold, which depends on the size of the gas utility. California requires NPA analysis when a proposed project exceeds $75 million, a substantially higher threshold than in any other state that is targeting California's extensive intrastate transmission system.[31] New York does not have a defined cost threshold but determines the level of scrutiny for a project based on cost. Generally, the utilities have identified that proposed projects that cost less than $2 million are considered small, and subject to less scrutiny than proposed projects that exceed $2 million.

Common to all of the states examined is an exemption for projects necessary for safety or an "emergency." However, it is not clear, based on the language of the exemptions, how projects in any of the states are determined necessary for safety or are classified as an emergency.

Colorado

Colorado gas utilities are required to provide NPA evaluations for new business and capacity expansion projects. New business projects are defined as any project that includes "utility investment and spending needed to provide gas service to new customers or customers requiring new gas service."[32] Capacity expansion projects include "both individual projects and sets of inter-related facilities needed to maintain system reliability and meet a specified capacity expansion need." The CO PUC rules do not require facilities that are considered "safety and integrity projects" to undergo an NPA analysis.

Colorado gas utilities must file a CPCN if the new business or capacity expansion project exceeds a certain dollar threshold, depending on the size of the utility (Table 3).

Size of Utility (# of customers)	Project Cost Threshold (2020$)
> 500,000	12 million
50,000 – 500,000	10 million
< 50,000	5 million

TABLE 3: Colorado CPCN Investment Threshold

31 CPUC docket number R.20-01-007.
32 4 Colo. Code Regs. § 723-4-4553(a)(III)(B).

New York

In New York, long-term plan rules require annual reports that include the location of specific segments of leak-prone pipes that could be abandoned for NPAs and where capital investments may be needed to ensure system reliability.[33] As a result, NPA projects are expected to be considered in cases where the utility would traditionally invest in pipeline replacements or expansions. The Commission encourages gas utilities to take a “neighborhood approach,” and work with local groups and state agencies on a comprehensive program that simultaneously removes leaking or leak-prone infrastructure and employs programs such as weatherization, demand response, and building electrification.[34] Similar to Colorado, New York exempts projects that meet a certain safety threshold from NPA regulations. New York defines these projects as “immediate threats to public safety or system reliability.”[35]

Each utility must also file screening and suitability criteria for NPA projects as part of the long-term plan and are similar to each other (Table 4). Small projects, as defined by each utility, undergo a streamlined review, while large projects require a “full-scale” solicitation of NPA with a benefit-cost analysis that is presented to the Commission for review.[36]

<table>
<tr><th>LDC</th><th colspan="2">Cost</th><th colspan="2">Timeline</th><th colspan="3">Size</th></tr>
<tr><th></th><th>Large Project</th><th>Small Project</th><th>Large Project</th><th>Small Project</th><th>Large Project</th><th>Small or Large Project
(could go either way)</th><th>Small Projects</th></tr>
<tr><td>NFG</td><td>> $2 million</td><td>< or equal to $2 million</td><td>36-60 months</td><td>24-36 months</td><td rowspan="4">Covers a larger geographic area; associated with significant regulator station upgrades or larger high-pressure mains</td><td rowspan="4">Involves several streets or a small neighborhood</td><td rowspan="4">Involves a limited number of streets or only a few services</td></tr>
<tr><td>ConEd</td><td>> $2 million</td><td>< or equal to $2 million</td><td>36-60 months</td><td>24-36 months</td></tr>
<tr><td>O&R</td><td>> $2 million</td><td>< or equal to $2 million</td><td>36-60 months</td><td>24-36 months</td></tr>
<tr><td>Central Hudson</td><td>> $2 million</td><td>< or equal to $2 million</td><td>> 24 months</td><td>12-24 months</td></tr>
<tr><td>KEDLI and NMPC*</td><td>> $2 million</td><td>$500k to $2 million</td><td>> 36 months</td><td>24-36 months</td><td rowspan="4">Covers a larger geographic area; associated with significant regulator station upgrades or larger high-pressure mains</td><td rowspan="4">Involves several streets or a small neighborhood</td><td rowspan="4">Involves a limited number of streets or only a few services</td></tr>
<tr><td>KEDNY*</td><td>> $3 million</td><td>$750k - $3 million</td><td>> 36 months</td><td>24-36 months</td></tr>
<tr><td>Corning</td><td>Project costs equal to or greater than 2% of utility plan less than depreciation reserve and deferred income tax</td><td>Project costs less than 2% of utility plan less than depreciation reserve and deferred income tax</td><td>36-60 months</td><td>24-36 months</td></tr>
<tr><td>SLG</td><td>> $500k</td><td>$100k - $500k</td><td>36-60 months</td><td>24-36 months</td></tr>
<tr><td>NYSEG and RG&E</td><td>> $2 million</td><td>< or equal to $2 million</td><td colspan="2">Minimum 12 months to start of construction</td><td colspan="3">No commentary provided</td></tr>
<tr><td colspan="8">* National Grid LDCs KEDLI/NMPC and KEDNY placed explicit cost eligibility floors at $750k and $500k, respectively.</td></tr>
</table>

TABLE 4: Comparison of New York NPA Criteria [37]

33 20-G-0131 Order Adopting Gas System Planning Process, p. 21-22.
34 20-G-0131 Order Adopting Gas System Planning Process, p. 39.
35 20-G-0131 Order Adopting Gas System Planning Process, p. 37.
36 20-G-0131 Order Adopting Gas System Planning Process, p. 37.
37 20-G-0131, Comments of Environmental Defense Fund on Proposed Non-Pipes Alternative Criteria, December 19, 2022.

Rhode Island

Rhode Island Energy is required to procure the least-cost resources and implement reliable energy efficiency and conservation measures that are less costly than the acquisition of additional supply.[38] The utility is required to propose criteria for NPA as part of its SRP plan and provide annual procurement reports. In its 2021-2023 plan, Rhode Island Energy[39] stated that it will prioritize capacity-constrained locations and proposed three criteria (Table 5).[40]

Criteria Type	Criteria Requirement
Timeline suitability	The start date of the traditional solution implementation is at least 24 months in the future.
Cost suitability	The cost of the traditional solution is greater than $0.5M.
Reliability of the gas system	The traditional solution investment has negligible or no effect on the critical reliability of the local or broader gas system. This effect on critical reliability will be determined through gas system modeling and will be determined based on engineering judgment.

TABLE 5: Rhode Island Energy NPA Criteria

California

Like Colorado, gas utilities are required to conduct an NPA analysis when filing for a CPCN. The CPUC requires California gas utilities to apply a CPCN before commencing the construction of large gas infrastructure projects that cost more than $75 million or have significant air quality impacts, except for “emergency projects” and projects required by any regulatory agency for safety reasons.[41] CPCN applications are required to include general project information, the need for the project, project costs, equity considerations, and analysis of NPAs.[42]

38 General Law 39-1-27.7.
39 Rhode Island Energy is a dual-fuel utility providing both electric and gas services.
40 RIPUC Docket No. 5080, 2021 Year-end report page 16.
41 CPUC Rulemaking 20-01-007, Decision Adopting Gas Infrastructure General Order, Attachment A, p. 3-4.
42 CPUC Rulemaking 20-01-007, Decision Adopting Gas Infrastructure General Order, Attachment A, p. 7-11.

NPA Eligible Resources

All of the states evaluated allow demand-side resources to participate as part of an NPA solution and do not prohibit participation of supply-side resources (Table 6). Demand-side resources may include energy efficiency, building electrification, demand response, and other behavioral programs. Supply-side resources may include alternative fuels (i.e., renewable natural gas and hydrogen CNG, gas storage, and LNG. Given that one reason policymakers are seeking to use NPAs is to reduce emissions, there is an implicit (and in Rhode Island, explicit) expectation that demand-side resources will be heavily featured in an NPA solution.

State	Demand Side	Supply Side
Colorado	Energy efficiency, demand response, and beneficial electrification	Recovered methane, green hydrogen, beneficial electrification, pyrolysis of tires, and other cost-effective technology that reduces emissions
New York	Energy efficiency, demand response, and electrification	Renewable natural gas, green hydrogen, and CNG injection (if aligned with state emission reduction goals)
Rhode Island	Cost-effective energy efficiency and conservation	Not defined but permitted
California	Not defined	Not defined but not prohibited

TABLE 6: Summary of Eligible NPA Demand and Supply Resources; by State

Colorado

Demand-side resources considered in NPAs in Colorado include energy efficiency, demand response, and beneficial electrification. Colorado law defines beneficial electrification as “converting the energy source of a customer’s end use from a nonelectric fuel source to a high-efficiency electric source, or avoiding the use of nonelectric fuel sources in new construction or industrial applications, if the result of the conversion or avoidance is to (1) Reduce net greenhouse gas emissions over the lifetime of the conversion or avoidance; and (2) Reduce societal costs or provide for more efficient utilization of grid resources.”[43]

Colorado’s rules do not explicitly prohibit the use of resources with emissions as an NPA solution, however, the gas utility has an obligation to comply with the state’s emissions reduction requirements through its Clean Heat Plan. Clean heat resources are defined as demand-side management programs, recovered methane, green hydrogen, beneficial electrification, pyrolysis of tires, and other cost-effective technology that reduces emissions.[44]

New York

In New York, demand-side resources, including electrification, energy efficiency, and weatherization, may be used in an NPA and must provide long-term reductions.[45] Like in Colorado, New York utilities can use supply-side resources, including renewable natural gas, green hydrogen, and CNG injection, as long as they align with the New York Climate Action Council's scoping plan —which seeks an 85% reduction in 1990 emissions by 2050.[46] Notably, solutions that result in a switch to other fossil fuels, such as propane, are not viable.[47]

43 §40-1-102(1.2), C.R.S.
44 Section 4 CCR 723-4-4730.
45 Case 17-G-0606, Petition of Consolidate Edison Company of New York, Inc. for Approval of the Smart Solutions for Natural Gas Customers Program. Request for Proposals of Non-Pipeline Solutions to Provide Peak Period Natural Gas System Relief. December 21, 2017.
46 New York State Climate Action Council. 2022. “New York State Climate Action Council Scoping Plan.” climate.ny.gov/ScopingPlan.
47 Case 17-G-0606, Petition of Consolidate Edison Company of New York, Inc. for Approval of the Smart Solutions for Natural Gas Customers Program. Request for Proposals of Non-Pipeline Solutions to Provide Peak Period Natural Gas System Relief. December 21, 2017.

Rhode Island

NPAs in Rhode Island must consider cost-effective energy efficiency and conservation measures first, but supply-side resources are also permitted.[48] Rhode Island Energy produced a gas capacity study to address constraints on Aquidneck Island and assessed several NPA solutions, including demand-side measures, alternative fuels, and LNG storage, to avoid a transmission capacity increase project.[49] In the end, the company selected a portable LNG project as "the only viable option for providing additional natural gas supply to the Aquidneck Island natural gas distribution system to address the existing gap between available capacity and peak demand."[50]

California

While specific resource eligibility has not been established in California, the state's newly adopted gas infrastructure rules refer to electrification, energy efficiency, conservation, demand response, and "alternative methods to provide necessary energy supplies" as potential NPAs.[51] The state has not indicated that supply-side resources, including emitting supply-side resources, are prohibited as part of an NPA solution.[52]

NPA Project Identification and Acquisition

After a gas utility determines that it must conduct an NPA assessment, the next step is to identify cost-effective solutions that can defer, reduce, or avoid the pipeline infrastructure. Relatedly, if the utility then determines that an NPA is a cost-effective solution, it must also acquire the NPA. There are two options to identify and acquire NPAs: the utilities can either use competitive solicitations or develop their own NPA portfolios.

In competitive solicitations, non-utility businesses bid their proposed solution to the gas utility, and the utility – with oversight by the PUC – evaluates the bids based on a set of criteria. At this early stage in the development of NPAs, whether the utility identifies and develops the NPA or relies on the competitive market depends on the requirements and norms of the state. New York and Rhode Island, which generally emphasize the use of competition in the electric and gas markets, require gas utilities to use the competitive market for identifying and developing NPA solutions. Colorado is situated differently than the Northeastern states. The CO PUC states that it prefers acquiring clean heat resources most cost-effectively and it instructs the gas utility to use competitive solicitations to the maximum extent practical. However, there isn't a requirement for the utility to use competitive solicitations for NPA development and acquisition, and the first utility to file a GIP with the CO PUC is proposing to develop its own NPA portfolios.

It is possible a utility could identify its own NPA portfolios and then acquire that NPA through a competitive solicitation. No utility has yet sought that path.

Colorado

The CO PUC directs utilities to acquire clean heat resources (which include NPA resources) through competitive solicitation whenever possible.[53] However, the GIP does not require gas utilities to use competitive solicitations for procuring NPAs. In May 2023, the Public Service Company of Colorado (PSCo) filed its first GIP and identified eight projects for NPA analysis.[54] PSCo developed portfolios of NPA solutions using its internal estimated costs and benefits. PSCo GIP did not mention using competitive bidding processes for identifying or acquiring NPAs.

48 R.I. General Law 39-1.27.7.
49 National Grid Aquidneck Island Long-Term Gas Capacity Study, p. 8.
50 https://www.portsmouthri.gov/DocumentCenter/View/4600/Portable-LNG-Vaporization-Project-Siting-Report--May-2021
51 CPUC Rulemaking 20-01-007, Decision Adopting Gas Infrastructure General Order, Attachment A, p. 8.
52 Colorado Department of Regulatory Agencies Public Utilities Commission 4 Code of Colorado Regulations (CCR) 723-4 Part 4 Rules of Regulating Gas Utilities, p.37 Decision No. C23-0117.
53 Colorado Department of Regulatory Agencies Public Utilities Commission 4 Code of Colorado Regulations (CCR) 723-4 Part 4 Rules of Regulating Gas Utilities, p.37 Decision No. C23-0117.
54 Docket No. 23M-0234G, Public Service Company of Colorado's Initial 2023-2028 Gas Infrastructure Plan. May 18, 2023.

To develop a portfolio of resources as an NPA solution, PSCo GIP ranked and eliminated NPA resources using an energy efficiency potential assessment methodology. The utility first identified a technical potential, and then an achievable potential that was screened through a BCA (Figure 3).[55] PSCo was the first gas utility to file a GIP with the CO PUC and it did not use a competitive solicitation for identifying NPA solutions, nor has it indicated that it intends to use competitive solicitations to implement its NPA solutions.

FIGURE 3: Public Service Company of Colorado NPA Methodology [56]

New York

New York looks to the competitive market for identifying the cost, benefits, and availability of NPA resources. Several NY gas utilities have issued requests for proposals (RFPs) to solicit NPA projects, including National Grid's RFP to resolve the North Queens capacity constraint[57] and New York Electric and Gas's RFP to eliminate the need for a compressor station in Tompkins County.[58] Each New York gas utility develops its own criteria and weighting to evaluate proposals, several of which are common (Table 7).

Common Criteria	
Proposal Content	Safety
Bidder Experience	Customer and Socio-economic Impacts
Environmental Impacts	Scheduling
Project Viability	Offer Price
Functionality	Customer Acceptance
Technical Reliability	Cost-effectiveness

TABLE 7: New York Gas Utility Common Criteria for Evaluating NPAs

New York utilities are not required to divulge the weighting or relative importance of each category. The evaluation criteria provide some indication of preference, though; for example, a Consolidated Edison RFP emphasizes the duration of the solution and its location as key factors in the company's evaluation of proposals.[59]

55 Docket No. 23M-0234G, Public Service Company of Colorado's Initial 2023-2028 Gas Infrastructure Plan. May 18, 2023. Page 56.
56 Docket No. 23M-0234G, Public Service Company of Colorado's Initial 2023-2028 Gas Infrastructure Plan. May 18, 2023. Page 56.
57 Request for Proposal. December 13, 2021. https://www.nationalgridus.com/media/pdfs/bus-partners/non-pipeline-alternatives/dny-rfp-sow-north-queens.pdf
58 NY PSC 17-G-0432. Request For Proposal. December 18, 2017. https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={C74BA648-2919-4A7F-A1C9-CA57A0E58AA6}
59 Consolidated Edison considers solutions that alleviate capacity or reliability constraints in the long term, i.e., 20 years, as preferable, see: Case 17-G-0606, Petition of Consolidate Edison Company of New York, Inc. for Approval of the Smart Solutions for Natural Gas Customers Program. Request for Proposals of Non-Pipeline Solutions to Provide Peak Period Natural Gas System Relief. December 21, 2017. p. 22

Rhode Island

Like New York, Rhode Island relies on competitive sourcing for identifying and procuring NPA solutions. The state defers to the utility to develop RFP procedures. Rhode Island Energy established a four-round process to assess NPA bids (Table 8).[60]

Round	Evaluation Focus
Round 1	Go/No-Go: Preliminary BCA, bidder qualifications, technology type and maturity, schedule, engineering
Round 2	Detailed Technical Review: engineering, controls, communications and operations, customer acceptance, permitting, schedule, and milestones
Round 3	Detailed Economic Review: full BCA, credit rating assessment, financing structure, payment structure, additional included costs and incentives
Round 4	Final Review of Shortlisted Bidders, winning bidder selection as applicable, contract negotiation

TABLE 8: Rhode Island Energy NPA Evaluation Process

Rhode Island Energy states that it will select NPA proposals that meet the baseline requirements (i.e., cost-effectiveness) and "score the highest in total across all categories."[61] For Rhode Island Energy, the evaluation categories include proposal content & presentation, bidder's experience, environmental impacts, project viability, functionality, technical reliability, safety, customer and socio-economic impacts, scheduling, offer price, adherence to terms, credit, customer acceptance, and cost-effectiveness.[62] Despite the lack of specification in NPA acquisition regulations, Rhode Island Energy's NPA acquisition criteria are similar to those of New York utilities. The utility must assess NPAs in its SRP Plan but can still implement pipeline solutions if NPA solutions are not cost-effective.

California

The CPUC has not articulated guidance on how gas utilities should identify and acquire NPAs.

Benefit-Cost Analysis[63]

The National Standard Practice Manual, a U.S. Department of Energy funded guidance document to assist jurisdictions in developing their cost-effectiveness tests for conducting benefit-cost analysis, defines a benefit-cost analysis as a "systematic approach for comparing the benefits and costs of alternative options to determine whether the benefits exceed the costs over the lifetime of the program or project under consideration."[64] Generally, a BCA with a benefit-to-cost ratio of 1.0 indicates that the investment is cost-effective, and those with a benefit-to-cost ratio of less than 1.0 do not. It is well documented that the selection of costs and benefits included in the BCA significantly impact the outcome of the analysis.

60 Narragansett Electric Company System Reliability Procurement 2021 Year-End Report, page 16.
61 Narragansett Electric Company 2020 System Reliability Procurement Year-End Report, page 17.
62 Narragansett Electric Company 2020 System Reliability Procurement Year-End Report, page 17-18.
63 For more information on benefit-cost analysis, benefit-to-cost ratios and cost-effectiveness, please see: https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/.
64 National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources. https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/.

Colorado and California have not settled on the types of benefits and costs that are used for evaluation, nor have they specified the appropriate discount rate. The higher the discount rate, the greater the short-term benefits and costs impact the outcome of the analysis. A lower discount rate means that long-term benefits, such as emission reductions, provide greater benefits.

New York and Rhode Island have adopted BCA components from the electric sector and are refining them for the gas space. Appendix A is a summary of all costs and benefits used by Colorado, Rhode Island, New York, and California.

In most of the states studied, a net positive BCA result qualifies an NPA project for implementation. A net negative result does not necessarily disqualify a project, as other considerations, like project type and equity, play an important role in project evaluations. However, in New York, the NY PSC has stated that the BCA is just one of its many tools for evaluating proposals, indicating that it considers other quantitative and qualitative factors in its decision-making.

Colorado

Under Colorado's rules regulating gas utilities, every NPA analysis is required to include a BCA[65] that includes direct investment costs, social costs of carbon and methane, and other costs. The Commission does not specify the methodology to conduct a BCA for NPA evaluations, however, the PSCo does provide direction on conducting BCA for utility demand-side management (DSM) programs (which may be used as an NPA resource). The PSCo identified the "Modified Total Resource Cost (TRC) test" as its primary BCA test for DSM, and identified costs and benefits the utilities must be included in the test (Table 9).[66]

Benefits	Cost
Avoided transmission and distribution capital cost savings connected to the reduction in design peak demand growth	Utility costs
Energy costs	Participants cost
Avoided operating and maintenance costs for program participants	
Social costs of carbon dioxide and methane as defined in law	

TABLE 9: CO PUC Identified Costs and Benefits for Demand-Side Management Programs in Colorado

In Colorado, cost-effectiveness is determined at the portfolio level and is required to have a projected value greater than or equal to 1.0.67 The utility is allowed to propose DSM programs for income-qualified customers or customers in disproportionately impacted communities that have Modified TRC test values lower than 1.0.[67]

The CO PUC has not specified the appropriate discount rate for NPAs. In its initial GIP, the PSCo used weighted average cost of capital as the discount rate.

New York

New York's BCA framework, which applies to electric and gas utilities, identifies a list of benefits and costs to be included.[68] Benefits are grouped into four main categories: bulk system, distribution system, reliability/resilience,

65 Colorado Department of Regulatory Agencies Public Utilities Commission 4 Code of Colorado Regulations (CCR) 723-4 Part 4 Rules of Regulating Gas Utilities, p.12 Decision No. C23-0117.

66 Colorado Department of Regulatory Agencies Public Utilities Commission 4 Code of Colorado Regulations (CCR) 723-4 Part 4 Rules of Regulating Gas Utilities, p. Decision No. C23-0117. The Colorado Public Utilities Commission considers its primary test to be a "modified" total resource cost test because it requires the inclusion of societal benefits, including improved public and participant health outcomes, and allows a benefit adder as determined by the Commission.

67 Colorado Department of Regulatory Agencies Public Utilities Commission 4 Code of Colorado Regulations (CCR) 723-4 Part 4 Rules of Regulating Gas Utilities, p.46 Decision No. C23-0117.

68 14-M-0101.

and external benefits, which measure avoided energy, infrastructure, O&M, and outages. The framework also defines program costs, such as rebates, incremental utility and participant costs, lost utility revenue, and other societal costs, such as emissions and noise. The framework provides illustrative calculations, but utilities are charged with developing and updating these methodologies. The BCA framework uses the same costs and benefits criteria as it does for non-wires alternatives (NWA) for electric system planning.

The order establishing a gas system planning process did not modify existing regulations governing the BCA framework, but the PSC did require the formation of an "Avoided Cost of Gas Working Group" to refine the calculations of certain indices, including costs and benefits, used in the BCA framework to account for differences between electric and gas BCAs.[69]

The BCA framework applies the societal cost test (SCT),[70] because it best reflects the impacts of climate change and pollution on society.[71] Consequently, the BCA framework adopts a three-percent societal discount rate.[72] New York utilities must still calculate the utility cost test and rate-impact measure, but the results are only meant to provide assessments of projects that have passed the SCT. Each utility is required to file a BCA Handbook and provide an update coinciding with the electric distribution System Implementation Plan filings.

The full list of current costs and benefits included in the framework for NPA and NWA are identified in Table 10:[73]

Benefits			
Bulk System	**Distribution System**	**Reliability & Resilience**	**External Benefits**
Avoided generation capacity, including reserve margin	Avoided distribution capacity infrastructure	Net avoided restoration costs	Net avoided greenhouse gases
Avoided energy	Avoided O&M	Net avoided outage costs	Net avoided criteria air pollutants
Avoided transmission capacity infrastructure and related O&M	Avoided distribution losses		Avoided water impacts
Avoided transmission losses			Avoided land impacts
Avoided ancillary services			Net non-energy benefits related to utility or grid operations (e.g. avoided service terminations, avoided uncollectible bills, avoided noise and odor impacts, to the extent not already included above)
Wholesale market price impacts			
Costs			
Program administration costs (including rebates, costs of market interventions, and measurement & verification costs)			
Added ancillary service costs			
Incremental transmission & distribution and DSP costs (including incremental metering and communications)			
Participant DER cost (reduced by rebates if included above)			
Lost utility revenue			
Shareholder incentives			
Net non-energy costs (e.g., indoor emissions, noise disturbance)			

TABLE 10: Benefits and Costs Included in NWA and NPA Analysis in New York

69 20-G-0131 Order Adopting Gas System Planning Process, May 12, 2022. Pages 62-63.
70 The SCT captures benefits and costs that apply to society as a whole and most BCA benefits and costs are included. Measures such as lost utility revenue are not captured since the measure quantifies a transfer of wealth rather than a net impact.
71 14-M-0101: Jan 21, 2016, Order page 12.
72 14-M-0101 Order establishing BCA framework page 27.
73 14-M-0101 Order establishing BCA framework, Appendix C.

The NY PSC reviews the cost-effectiveness of an NPA at a portfolio level,[74] and ruled that NPAs do not need a cost-benefit ratio above 1.0 to be the most reasonable option for reliability projects.[75] For example, in the Tompkins County NPA RFP, NYSEG selected a portfolio that included electrification, energy efficiency, industrial waste heat recovery, and demand response measures.[76] Of those resources, only the industrial waste heat recovery passed the BCA.[77]

Intervenors argued that projects with an SCT value of less than 1.0 should not be included in the portfolio.[78] The Commission disagreed, stating that the Tompkins County project is reliability-based and that such projects are not typically subjected to the SCT.[79] Notably, the PSC also opined that, while the BCA is a critical decision-making tool, it is not the only tool.[80] In its order approving the NPA, the PSC wrote, "[n]ot all programs which pass BCA tests are inherently reasonable, nor are all programs which do not pass BCA tests inherently unreasonable."[81] The NY PSC determined that implementing the NPA project was reasonable in that instance since the NPA was the least-cost solution for meeting reliability needs in that area, and approved the utility's portfolio selection with slight modifications.

Rhode Island

Rhode Island's BCA framework, or the "Rhode Island Test," applies to gas and electric utility investments and is approved for use in energy efficiency programs and NPA analysis.[82] The benefits identified in Table 11 were initially developed for the electric sector.

Bulk System Level	Distribution System Level	Customer Level
Generation capacity costs (Forward Capacity Market)	Distribution capacity costs	Program participant costs/ benefits
Energy supply costs (Locational Marginal Price (LMP))	Distribution operation and maintenance costs	Program non-participant/ benefits
Transmission capacity infrastructure costs	Ancillary services costs	
Ancillary services costs	Distribution system reliability loss/gain	
Energy DRIPE (demand reduction induced price effects)	Distribution system resiliency loss/gain	
Capacity DRIPE	Distribution system safety loss/gain	
Greenhouse gas emissions costs (Avoided Regional Greenhouse Gas Initiative price embedded in LMP)	Program administrative costs	
Criteria air pollutant emissions costs (avoided compliance costs embedded in LMP)	Non-energy costs/benefits (e.g. economic development)	
Non-energy costs/benefits (e.g. economic development		

TABLE 11: Benefits and Costs Included in the Rhode Island Test

74 4-M-0101: Jan 21, 2016, Order p.33.
75 NY PSC 17-G-0432, Order Approving Petition for Non-Pipeline Alternative Projects, With Modifications. June 21, 2021. p.17.
76 While the solutions adopted in the Tompkins County RFP were demand-side solutions, the utility considered several supply-side proposals. See: NY PSC 17-G-0432, Order Approving Petition for Non-Pipeline Alternative Projects, With Modifications. June 21, 2021. p. 6-9.
77 NY PSC 17-G-0432, Order Approving Petition for Non-Pipeline Alternative Projects, With Modifications. June 21, 2021. p. 7.
78 NY PSC 17-G-0432, Order Approving Petition for Non-Pipeline Alternative Projects, With Modifications. June 21, 2021. p. 13.
79 NY PSC 17-G-0432, Order Approving Petition for Non-Pipeline Alternative Projects, With Modifications. June 21, 2021. p. 17
80 NY PSC 17-G-0432, Order Approving Petition for Non-Pipeline Alternative Projects, With Modifications. June 21, 2021. p. 17.
81 17-G-0432 Order Approving Petition for Non-Pipeline Alternative Projects, With Modifications. June 21, 2021. p. 17.
82 RIPUC Docket 4600 Draft Cost Benefit Framework.

Rhode Island Energy recognizes that some costs and benefits may not be easy to quantify. In their BCA assessment of the Aquidneck Island Long-Term Gas Capacity Study, the utility calculated all Rhode Island Test categories except "Non-Energy Impacts" and "Economic Development Impacts," since the Company argues that these categories would hamper comparisons between alternatives.[83] Rhode Island Energy states that the analysis would vary by project type.

California

California has not yet articulated or adopted a specific BCA methodology for NPA analysis. However, it has identified several criteria for an NPA evaluation, including:

+ The potential environmental impacts of NPAs, including emissions;
+ An estimate of the environmental and health impacts of the project; and
+ The direct and indirect costs of the project.[84]

The order did not provide any further discussion on whether the utilities should use a societal cost of greenhouse gases for calculating emissions, and if that cost would be inclusive of estimated environmental, emissions, and health impacts. It also did not identify the types of indirect costs that may occur as a result of an NPA project.

Equity

Three of the four states[85] reviewed require consideration of NPA impacts on disadvantaged communities, but only California explicitly calls out the requirement to consider impacts on ESJ communities in its NPA guidance. Specifically, if the proposed NPA project is located within an ESJ community, the utility must discuss whether it is possible to relocate the project, and, if so, take steps to locate the project outside the community.[86] A CPCN application in California must also include a detailed statement explaining how the project is consistent with the goals of the CPUC's ESJ Action Plan, as well as a summary of outreach and engagement efforts with local communities likely to be impacted by the proposed project.[87] The CO PUC is required to create rules to "consider how best to provide equity, minimize impacts and prioritize benefits to disproportionately impacted communities and address historical inequities" in all of its work.[88] New York also has an equity mandate and is implementing policies and requirements to ensure disadvantaged communities benefit from the energy transition. The state's Climate Leadership and Protection Act requires disadvantaged communities to receive at least 35 percent of the benefits of spending on clean energy and energy efficiency programs.

83 National Grid Aquidneck Island Long-Term Gas Capacity Study, p. 93-94.
84 CPUC Rulemaking 20-01-007, Decision Adopting Gas Infrastructure General Order, Attachment A, p. 8.
85 Rhode Island does not have an equity requirement in general regulation or specifically for NPA evaluations.
86 CPUC Rulemaking 20-01-007, Decision Adopting Gas Infrastructure General Order, Attachment A, p. 9.
87 CPUC Rulemaking 20-01-007, Decision Adopting Gas Infrastructure General Order, Attachment A, p. 10-11.
88 Colorado Public Utilities Commission (PUC) Invites the Public to Comment on Ways Its Regulation of Utilities Can be More Equitable and Address Historical Inequalities, Colorado Department of Regulatory Agencies.
Available at: https://dora.colorado.gov/press-release/colorado-public-utilities-commission-puc-invites-the-public-to-comment-on-ways-its

Distributional Equity Analysis for Energy Efficiency and Other Distributed Energy Resources[89]

Energy equity is a complex topic that encompasses many dimensions of equity, including recognitional, procedural, distributional, and restoration elements (among others). The dimensions may overlap – for example, creating a process where stakeholders from disadvantaged communities can participate in utility investment decision-making is a form of procedural equity, and that may be needed to promote distributional equity of distributed energy resources.

As discussed above, a BCA is a commonly used tool to determine if the benefits of a project are greater than the costs. Generally, a BCA with a value of greater than 1.0 produces net benefits and those with a value of less than 1.0 do not. A robust BCA identifies all costs and benefits, and uses them to determine whether a proposed action has benefits that exceed the costs. In the electric and gas utility industries, BCAs inform decisions about whether and how utilities should invest in different generation, transmission, and distribution resources.

While a BCA is a valuable tool for identifying the advantages and disadvantages of specific investments, it is insufficient for understanding equity issues. It is not designed to distinguish how costs and benefits might affect some populations differently than others. To address this gap, Synapse Energy Economics, Berkeley Lab, and e4TheFuture are developing guidance on conducting a distributional equity analysis (DEA).

A DEA is an analytical framework that accounts for equity impacts in ways that are not possible or practical in conventional BCA. A DEA differs from a BCA in that it separates customers into different groups – priority populations and other customers – which allows practitioners to assess how costs and benefits will affect each group (US OMB, page 61). DEAs are not a replacement for BCAs. Instead, they complement BCAs and use many of the same principles, concepts, assumptions, and inputs. DEAs extend beyond BCAs by (a) breaking out the population of customers into priority populations versus other customers, and (b) applying metrics specifically designed to assess equity issues.

Observations and Conclusion

Utilities have deployed targeted NPAs for years by using supply-side resources including CNG, LNG, underground storage, and propane-air to cost-effectively address capacity constraints. Interest in NPAs has grown in the past few years, stoked by two recent developments —a proliferation of decarbonization policies and the emergence of cost-effective, high-efficiency electric appliances—Policymakers in each of the four examined states have identified NPAs as a potential tool to reduce customer costs, reduce emissions, and in the case of California, reduce the risk of stranded assets in the future.

A comparison of the four state’s NPA processes reveals significant similarities, especially concerning the definitions of NPAs, eligible resources, and the use of BCA. The most prominent similarity across the four states, however, is the infancy of developing and implementing NPA frameworks.

Project eligibility requirements are also similar in each state, however, the specific thresholds and implementation timelines vary depending on the size of the utility. NPA thresholds range from $500,000 in Rhode Island to $75 million in California. PUCs may want to carefully consider appropriate cost thresholds as they develop NPA frameworks.

89 For more information, see https://emp.lbl.gov/publications/distributional-equity-analysis.

The tailoring of the project cost threshold to the size of the utility is critical: too high of a threshold and there will not be eligible NPAs, and too low of a threshold may result in the inefficient use of resources (i.e., evaluation of NPAs is more costly than the solution).

Each of the states has BCAs that provide a baseline test that can be used for initial NPA evaluations, even if the tests are not specifically tailored for NPA evaluations. States can rely on these tests while they further investigate the impacts of NPAs on both the gas and electric sectors. Access to electric system data will be imperative for determining the impacts of electrification and the NPA. Access to electric data becomes even more complex for a single-fuel gas utility that does not have ready access to the costs and benefits of adding load in a specific location. Ultimately, PUCs may have to determine what costs and benefits to the electric system a gas utility must include in its NPA analysis. Forthcoming guidance on distributional equity analysis will provide an option for states to consider the cost-effectiveness and equity implications of NPAs.

There are emerging differences in NPA frameworks, including the types of projects eligible for NPA review. Although all four states require utilities to consider NPAs for capacity expansion projects, New York and Rhode Island require gas utilities to also consider NPAs for reliability projects. California requires NPA evaluations for large projects or those with significant air quality impact.

The most significant difference between the states is in the identification and acquisition of resources. Both New York and Rhode Island rely on competitive solicitation to inform the cost of the NPAs and their acquisition. California and Colorado allow — and in the case of Colorado encourage — competitive bidding. However, neither state requires competitive bids for NPA identification and acquisition. This allows utilities to develop internal estimates and implement their own projects.

Each approach has its benefits and challenges. Competitive solicitations are likely to lead to proposals on the leading edge of technology, capability, and price as providers are competing against each other. However, it takes significant time and resources to develop and evaluate an RFP process, which reduces the cost-competitiveness of NPAs and the amount of time that is available for implementing NPAs before the resource need occurs. Conversely, utility-developed projects that rely on utility estimates are more streamlined but may not be the most cost-effective solution available.

Appendix A. Colorado Context

In 2021, the Colorado legislature passed House Bill 21-1238 (among other bills related to a clean energy transition), which required the CO PUC to facilitate a rulemaking process to align demand-side management programs with the targets set by the Clean Heat Target and identified the appropriate cost of emissions.[90] This legislation led to the development of several processes aimed at improving the way the CO PUC regulates gas utilities.

The legislature and CO PUC identified NPA projects as resources that can help the utility achieve its state emissions reduction requirements cost-effectively. To facilitate the development of NPAs, the Commission identified a need for developing a "non-pipeline alternatives" analysis framework. The CO PUC sought technical assistance from Lawrence Berkeley National Laboratory, who then hired Strategen Consulting to develop this literature review to better inform Colorado's development of an NPA evaluation framework.

Senate Bill 21-264 set greenhouse gas reduction requirements for gas utilities, and required the gas utilities to file plans with the CO PUC that describe the steps the utility will take to achieve these goals.[91] The emissions reduction requirements, called the Clean Heat Target, require certain gas utilities to reduce emissions by 4% by 2025 and 22% by 2030 from a 2015 baseline. The emissions reduction plan, called a Clean Heat Plan, is defined as a "comprehensive plan submitted by a gas distribution utility that demonstrates projected reductions in methane and carbon dioxide emissions that, together, meet the reductions required at the lowest reasonable cost."[92] The bill also grants the CO PUC the authority to require a gas utility to evaluate non-pipeline alternative projects as an important tool for achieving the gas utility's emissions reductions.

Clean Heat Plans and Gas Infrastructure Plans

In response to the legislature's directives, the CO PUC initiated a proceeding to conduct a review of the information available on safety and integrity investments, customer rates, utility costs, and emissions.[93] In a 2020 settlement agreement, gas utilities filed a joint petition for a Rulemaking on Short-Term Gas Infrastructure Planning and Reporting.[94] In rejecting this joint petition, the Commission decided that comprehensive gas planning required a broader approach that considered short- and long-term gas planning.[95] On October 1, 2021, the Commission issued a Notice of Proposed Rulemaking to develop amendments to gas rules to implement SB 21-264 and HB 21-1238.[96] The CO PUC adopted rules on December 1, 2022, that required gas utilities to file Gas Infrastructure Plans and Clean Heat Plans (CHP). [97] GIPs and CHPs work in tandem to increase transparency in the gas utility planning process, manage customer costs, and address greenhouse gas emissions. A key tool for addressing the state's policy goals, for both GIP and CHP contexts, is the development and integration of NPA solutions.

90 Colorado House of Representatives. Concerning the Modernization of Gas Energy Efficiency Programs. House Bill 21-1238. https://leg.colorado.gov/sites/default/files/2021a_1238_signed.pdf.

91 Colorado Senate. Concerning the Adoption of Programs by Gas Utilities to Reduce Greenhouse Gas Emissions, and, in Connection Therewith, Making an Appropriation. Senate Bill 21-264. https://leg.colorado.gov/sites/default/files/2021a_264_signed.pdf.

92 Colorado Senate. Concerning the Adoption of Programs by Gas Utilities to Reduce Greenhouse Gas Emissions, and, in Connection Therewith, Making an Appropriation. Senate Bill 21-264, Section 1(2)(b). https://leg.colorado.gov/sites/default/files/2021a_264_signed.pdf.

93 Colorado Department of Regulatory Agencies Public Utilities Commission, Docket No. 21M-0395G, C21-0516 Decision Opening Miscellaneous Proceeding to Engage with Gas Utilities and Interested Stakeholders and Collect Comment and Information to Inform Future Commission Rulemaking Proceedings. August 25, 2021.

94 Colorado Department of Regulatory Agencies Public Utilities Commission, Docket No. 21M-0168G, Commission Decision Declining to Accept Petition for Rulemaking C21-0446. July 23, 2021.

95 Ibid.

96 Colorado Department of Regulatory Agencies Public Utilities Commission, Docket No. 21R-0449G, Notice of Proposed Rulemaking C21-0610. October 1, 2021.

97 Colorado Department of Regulatory Agencies Public Utilities Commission, Docket No. 21R-0449G, Commission Decision Adopting Rules C22-0760. December 1, 2022.

Gas utilities first file GIPs, which are used "to establish a process to determine the need for, and potential alternatives to, capital investment, consistent with the objectives of maintaining just and reasonable rates, ensuring system safety, reliability, and resiliency, protecting income-qualified utility customers and disproportionately impacted communities, and supporting utility efforts to meet applicable clean heat targets." A utility is obligated to file a GIP every two years unless otherwise required by the Commission. The GIP rules require that proposed facilities meeting the definition of a new business project or a capacity expansion project must present an analysis of alternatives, including NPAs.

Within the GIP, the gas utilities identify the methodology, criteria, assumptions, variables, and system planning and infrastructure modeling processes that were used to create the plan. The GIP is also required to include a range of forecasts that identifies system capacity needs under various future conditions.

The GIP must also include any planned projects within the planned action period that will require a Certificate of Public Convenience and Necessity. When filing a CPCN, the utility must present an analysis of the costs of the alternatives and the criteria used to rank or eliminate alternatives.

An NPA analysis must consider or include:

+ One or more applicable clean heat resources consistent with the utility's CHP, DSM plan, or Beneficial Electrification Plan;
+ A BCA including the social cost of carbon and methane; and
+ Best available employment metrics associated with each alternative.

The Commission also requires gas utilities to file CHPs, which outline how the utility will utilize clean heat resources to meet Clean Heat Targets and promote the maximum utilization of clean heat resources. The Commission identifies clean heat resources as DSM programs, recovered methane, green hydrogen, beneficial electrification programs, pyrolysis of tires, and any other technology approved by the Commission and the Air Pollution Control Division. An NPA will consist of one or more clean heat resources. The CHP application has three key requirements:

1. Plan to utilize clean heat resources throughout the action period;
2. Demonstrate that the CHP will achieve greenhouse gas emissions reductions to meet clean heat targets; and
3. Exhibit that the contents of the CHP will enable the utility to meet future greenhouse gas emission reduction targets.

The CHP also requires the utility to file initial forecasts, portfolios, portfolio forecasts, components of a portfolio, and cost recovery proposals. Through the CHP, utilities will be able to identify optimal clean heat resources.

GIPs and CHPs are the CO PUC's pathways for promoting the adoption of clean heat resources, including NPAs, as shown in Figure A-1 below. The GIP identifies the gas utility's capital plan, including the specific projects that are then required to undergo an NPA analysis before the utility's CPCN application is approved by the Commission. The transparency of the company's capital planning process is necessary for determining whether an NPA is appropriate in any specific situation. A CHP identifies and evaluates the specific resources that can be used for meeting the state's emissions reduction requirements, and will also be used to develop portfolios of resources such as an NPA.

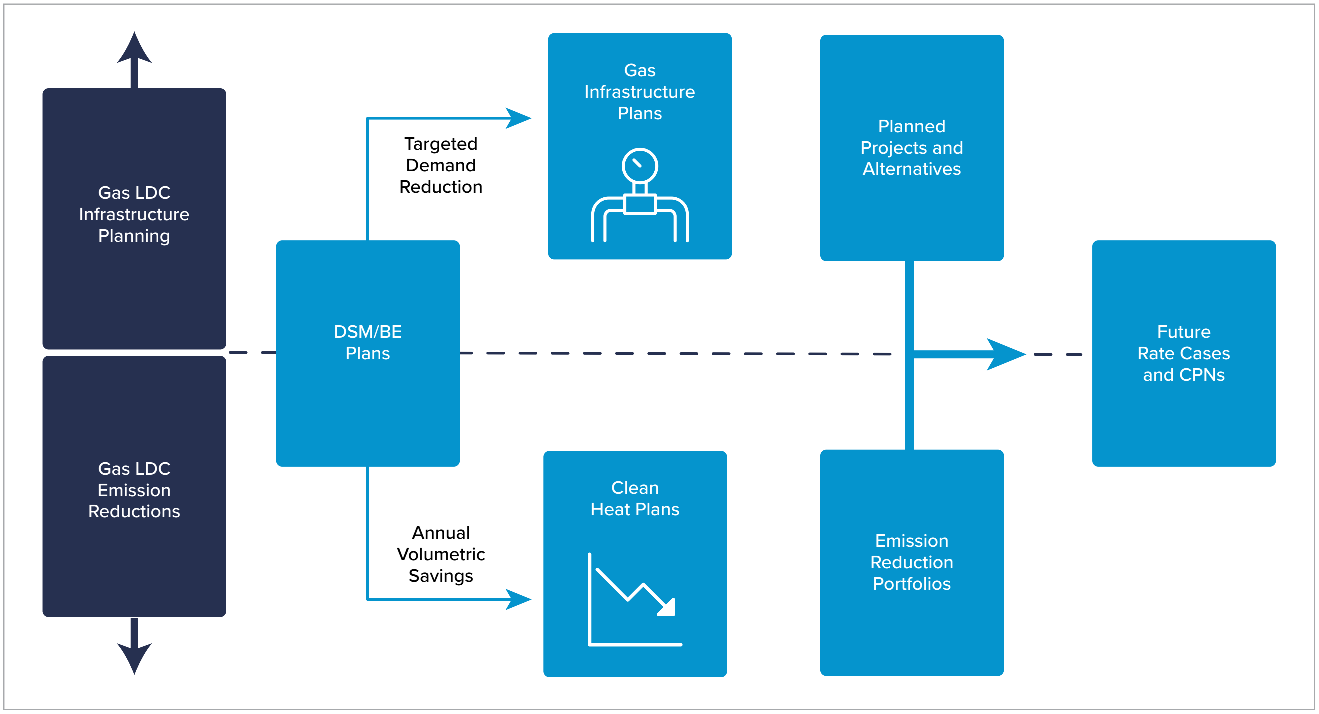

FIGURE A-1: Public Service Company of Colorado's Key Gas Planning Regulatory Process[98]

98 Public Service Company of Colorado, Initial 2023-2028 Gas Infrastructure Plan, Proceeding No. 23M-0234G, May 18, 2023.

Appendix B. Benefits and Costs Summary

	Benefits	Colorado	New York	Rhode Island	California
Bulk System	Avoided Generation Capacity		✓	✓	
	Avoided Transmission Capacity		✓	✓	
	Avoided Energy	✓	✓	✓	✓
	Ancillary Service Costs		✓	✓	
	Avoided Transmission Costs	✓			
	Avoided Transmission Losses		✓		
Distribution System	Avoided Distribution Capacity		✓	✓	
	Ancillary Service Costs			✓	
	Avoided Distribution Costs	✓			
	Avoided Distribution Losses		✓		
	Avoided O&M		✓	✓	
Reliability / Resiliency	Distribution System Reliability Loss/Gain			✓	
	Distribution System Resiliency Loss/Gain			✓	
	Net avoided restoration costs		✓		
	Net avoided outage costs		✓		
Customer Level	Avoided O&M costs for participants	✓			
	Program participant benefits			✓	
	Program non-participant benefits			✓	
External Benefits	Avoided Greenhouse gas emissions costs	✓	✓	✓	✓
	Avoided Air pollutant emissions costs	✓	✓	✓	✓
	Avoided Water impacts		✓	✓	✓
	Avoided Land impacts		✓		
	Non-energy benefits		✓		
	Benefits to Disadvantaged Communities		✓	✓	

STRATEGEN

Your trusted partner to navigate the energy transformation.

Strategen advises and empowers leading organizations — utilities, government agencies, NGOs, and industry clients — to design innovative, practical solutions that capture the promise of a clean energy future, strengthen resilience and adaptability, and are equitable, collaborative, and impactful.

Headquartered in Northern California, Strategen's mission-driven experts leverage a global perspective and market-leading capabilities to deliver novel, high-impact, stakeholder-aligned approaches across the policy, regulatory, and market design spheres that sustainably accelerate the deployment of low-carbon energy systems.

Strategen's expertise spans corporate strategy, emerging technology acceleration, clean energy system planning, regulatory innovation, and multi-stakeholder engagements and convenings. We take an integrated, multidisciplinary approach, informed by our core values of intellectual honesty, humility, sustainability, diversity, and inclusion.

www.strategen.com