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EARTHJUSTICE

February 23, 2021

VIA ELECTRONIC FILING

Brinda Westbrook-Sedgwick
Commission Secretary
Public Service Commission
of the District of Columbia
1325 G Street, NW, Suite 800
Washington, DC 20005

Re: **Formal Case No. 1167,**
***In the Matter of the Implementation of Electric and Natural Gas Climate Change Proposals*.**

Dear Brinda Westbrook-Sedgwick:

Attached for filing please find the Response of Sierra Club to the Office Of People's Counsel for the District Of Columbia's Motion for Implementation of Next Steps.

Thank you for your attention to this matter. Should you have any questions, please contact me at smiller@earthjustice.org.

Respectfully submitted,

Susan Stevens Miller

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Counsel for Sierra Club

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA

IN THE MATTER OF THE IMPLEMENTATION OF ELECTRIC AND NATURAL GAS CLIMATE CHANGE PROPOSALS	**Formal Case No. 1167**

RESPONSE OF SIERRA CLUB TO THE OFFICE OF PEOPLE'S COUNSEL FOR THE DISTRICT OF COLUMBIA'S MOTION FOR IMPLEMENTATION OF NEXT STEPS

Pursuant to Rule 105.8 of the Public Service Commission of the District of Columbia ("Commission") Rules of Practice and Procedure, Sierra Club hereby respectfully submits this Response to the Motion for Implementation of Next Steps ("Motion" or "OPC Motion") filed by the Office of People's Counsel for the District of Columbia ("OPC") in the above-captioned proceeding.[1]

In its Motion, OPC requests that the Commission establish the criteria and guiding principles it will use to review any utility applications and proposed projects to ensure that they meet the District's climate change commitments in an equitable and affordable manner.[2] OPC also recommends that the criteria and guiding principles should be developed in concert with the framework being developed in GD2019-04-M.[3] Finally, OPC encourages the Commission to hire an independent consultant to advise and make recommendations for the criteria and principles that will be used to ensure alignment with the District's goals, solicit input from the public, and establish a thorough set of questions to develop a clear climate change policy.

Sierra Club supports the recommendations set forth in OPC's Motion. However, Sierra Club does not believe that OPC's recommendations alone are sufficient to ensure that the

[1] Formal Case No. 1167 ("FC No. 1167"), *In the Matter of the Implementation of Electric and Natural Gas Climate Proposals*, Order No. 20662 (Nov. 18, 2020) ("Order No. 20662").
[2] OPC Motion at 2.
[3] *Id.*; Formal Case No. GD-2019-04-M, *In the Matter of the Implementation of the 2019 Clean Energy DC Omnibus Act Compliance Requirements*.

Commission can meet its obligation "to develop a plan that furthers the purposes of the Clean Energy Act and aligns with the targets established by Clean Energy DC and Sustainable DC."[4] Sierra Club remains convinced that utilities and energy companies who only supply and distribute gas and other pipeline fuels cannot be relied upon to put forth the cost effective and transformative proposals necessary for the District to achieve its climate commitments.[5] Sierra Club believes that OPC's proposals complement the recommendations set forth in Sierra Club's Motion to Modify Commission Order No. 20662 which was filed December 18, 2020.[6] The Commission should adopt both the proposals set for in Sierra Club's Motion to Modify and OPC's Motion, thereby creating a clear, transparent pathway designed to achieve the purposes of the Clean Energy Act and the targets established by Clean Energy DC and Sustainable DC.

I. BACKGROUND

On November 18, 2020, the Commission opened Formal Case No. 1167.[7] In this proceeding, the Commission will consider whether, and to what extent, utility or energy companies under the Commission's purview meet and advance the District of Columbia's achievement of its energy and climate goals.[8] The Commission also intends to take action, where necessary, in this proceeding to guide the companies in the "right direction."[9] The Commission directed that to the extent that regulated utilities seek approval of new proposals that would assist the District in meeting and advancing its climate goals that are not required to be filed in other

[4] Order No. 20662 at 4, n.19.
[5] Order No. 20662 leaves it to the utilities' and energy companies' discretion to file proposals *should they chose to do so. Id.* ¶ 12.
[6] Formal Case No. 1142 ("Formal Case No. 1142"), *In the Matter of the Merger of AltaGas Ltd.'s and WGL Holdings, Inc.*, and Formal Case No. 1167, Sierra Club's Mot. for Modification of Comm'n Order No. 20662 (Dec. 18, 2020) ("Motion to Modify").
[7] Order No. 20662.
[8] *Id.* ¶ 1.
[9] *Id.*

existing Commission proceedings, those proposals should be filed in this proceeding. The Commission also stated that this proceeding "could include the development of a comprehensive plan for how utility or energy companies can help the District achieve its 2032/2050 goals and satisfy the directives of the Clean Energy Act."[10]

On December 18, 2020, the Sierra Club filed a motion to modify Commission Order No. 20662 to include steps designed to better advance the District's climate change goals.[11] Specifically, Sierra Club recommended that an independent consultant, rather than utilities and energy companies, review the Clean Energy DC plan and provide a proposal and study for each District utility to determine the steps necessary for each utility to achieve the milestones set forth in the Clean Energy DC plan and achieve the District's climate commitments. Sierra Club also requested that the independent consultant be selected based on a Request for Proposals ("RFP") drafted by a stakeholder committee and that this stakeholder committee shall be responsible for selecting the winning bidder.[12]

Potomac Electric Power Company ("Pepco") and AltaGas Ltd. ("AltaGas") opposed Sierra Club's Motion to Modify.[13] On January 15, 2021, the Commission issued a tolling order for an additional 30 days.[14] On February 9, 2021, the Environmental Defense Fund ("EDF") filed a motion for clarification of the scope of Formal Case 1167, wherein it recommended next steps in this proceeding.[15] On February 12, 2021, the Commission issued a second tolling order

[10] *Id.* ¶ 11.
[11] Motion to Modify.
[12] *Id.* at 6–7.
[13] Formal Case No. 1142 and Formal Case No. 1167, AltaGas Ltd.'s Opp'n to Sierra Club's Mot. for Modification of Comm'n Order No. 20662 (Jan. 4, 2021); Formal Case No. 1142 and Formal Case No. 1167, Resp. of Pepco to Sierra Club's Mot. for Modification of Comm'n Order No. 20662 (Jan. 4, 2021).
[14] Formal Case No. 1142 and Formal Case No. 1167, Order No. 20685 (Jan. 15, 2021).
[15] Formal Case No. 1167, Mot. for Clarification of EDF (Feb. 9, 2021).

tolling the deadline to for action on the Motion to Modify for additional 30 days.[16] On February 17, 2021, AltaGas filed a response to EDF's motion.

II. DISCUSSION

The District of Columbia has adopted aggressive climate change commitments, including the reduction of greenhouse gas emissions by at least 50% below 2006 levels by 2032 through increasing renewable energy sources and decreasing consumption; and achieving carbon neutrality by 2050. The District should be commended for its leadership in fighting climate change. However, these necessary and important commitments will not be achieved without this Commission's dynamic leadership and concerted, focused efforts. Time is of the essence. The District now only has approximately 10 years to realize its commitment to reduce greenhouse gas emissions by 50% by 2032.

Both Sierra Club and OPC have requested that the Commission retain an independent consultant. An independent consultant will ensure that the stakeholder discussions and the ultimate recommendations to the Commission are aligned with the District's climate change commitments. Sierra Club also agrees that a logical first step in this complicated process is to establish the criteria and guiding principles the Commission will use to review and approve any proposals.

Sierra Club believes that the starting point for the independent consultant's advice and recommendations regarding the criteria and guiding principles should be Clean Energy DC, a framework which the Commission concedes it must align its decisions with.[17] The Department of Energy and Environment ("DOEE") performed extensive analysis and created the roadmap

[16] Formal Case No. 1142 and Formal Case No. 1167, Order No. 20699 (Feb. 12, 2021).
[17] Order No. 20662 at 4, n.19.

the District needs to achieve its climate commitments. Rather than "reinvent the wheel," the independent consultant should build on the work previously performed by DOEE.

Once the issues of the overall criteria and guiding principles have been resolved, it will be critical for the Commission to consider new policies and structures under this analytical framework. Undoubtedly, some utilities will be required to make significant changes to their planning processes and business models in order to conform them to the District's climate commitments. The Commission should rely on the independent consultant's expertise at this stage as well. The independent consultant will provide expert unbiased analysis and identify strategies in analyzing any filed proposals to ensure that the filings are designed to accomplish the District's climate commitments. But also, given that some utilities could elect not to file proposals, the Commission should direct the independent consultant to provide proposals and studies for each District utility to determine the steps necessary for each utility to achieve the milestones set forth in the Clean Energy DC plan and achieve the District's climate commitments. Since no utility or energy company is required to file a proposal, this requirement will ensure that the Commission actually receives proposals designed to achieve the District's climate commitments.

The independent consultant also can develop further refined frameworks necessary to analyze specific proposals. Broad criteria and guidelines may not be sufficient to ensure that a specific utility or energy company proposal is designed in a manner that will meet the District's climate commitments. Moreover, specific frameworks will enable easier review of projects. For example, Consolidated Edison Company ("ConEd") of New York, Inc., a utility that provides both gas and electric service, recently proposed a new framework for evaluating and implementing Non-Pipeline Alternatives ("NPA") projects that could be used to defer or replace traditional natural gas distribution infrastructure projects.[18] Elements of this framework include: i) integrating NPA into gas planning processes; ii) qualifying gas budget categories for NPA; iii) developing suitability criteria for project selection and determining sourcing approaches; iv) developing NPA portfolios; v) implementing a Benefit Cost Analysis ("BCA") Handbook; vi) addressing cost recovery; vii) receiving performance incentives; and (ix) reporting on NPA progress and lessons learned.[19] Once the Commission approves the different strategies utilities and energy companies must use to achieve the climate commitments, the independent consultant can develop and recommend a framework for analyzing the proposals designed to implement those specific strategies. These expertly designed specific frameworks will ensure an efficient process and enable the Commission to examine individual proposals in a transparent manner.

III. CONCLUSION

WHEREFORE, for the reasons discussed above, Sierra Club respectfully requests that the Commission adopt the recommendations set forth in both OPC's Motion and Sierra Cub's previously filed Motion to Modify.

Dated: February 23, 2021.

Respectfully submitted,

Susan Stevens Miller

Susan Stevens Miller
Staff Attorney, Clean Energy Program
Earthjustice

[18] Case 19-G-0066, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Gas Service*, Proposal for Use of a Framework to Pursue NPA to Defer or Eliminate Capital Investment in Certain Traditional Natural Gas Distribution Infrastructure (NY PSC Sept. 15, 2020) (Sr. No 43) (Attached as Appendix A), http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=19-G-0066.

[19] *Id.* at 2.

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APPENDIX A

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Gas Service	**))))**	**Case 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

Under its existing Rate Plan,[1] Consolidated Edison Company of New York, Inc. ("Con Edison" or the "Company") must propose a new Framework for evaluating and implementing Non-Pipeline Alternatives ("NPA") projects that could be used to defer or replace traditional natural gas distribution infrastructure projects.[2] This NPA Framework Proposal describes the Company's process for identifying, developing, implementing, and recovering costs and establishing performance incentives for NPA projects that would defer or eliminate traditional natural gas distribution infrastructure projects. Con Edison respectfully requests New York State Public Service Commission ("Commission") approval of the specific proposed process (*i.e.*, the

[1] Case 19-G-0066, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Gas Serv., et al.,* Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plan (issued January 16, 2020).

[2] *Id*., pp. 32-33. The Company's Rate Plan specifically addresses the use of NPA for infrastructure that the Company would own, which is distribution infrastructure. The Company has previously sought to use NPA to defer interstate pipeline infrastructure in its Smart Solutions for Natural Gas Customers program and addresses the continued use of those kinds of non-pipe solutions in its Gas Planning proceeding filing. *See,* Case 17-G-0606, *Petition of Consolidated Edison Company of New York, Inc. for Approval of the Smart Solutions for Natural Gas Customers Program* and Case 20-G-0131, *Proceeding on Motion of the Commission in Regard to Gas Planning Procedures* ("Gas Planning Proceeding"), Con Edison and Orange & Rockland Status Report and Proposals for the Use of Demand-Reducing Programs to Address Supply and Demand Imbalances (Filed August 17, 2020) *and* Gas Planning Proceeding, Consolidated Edison Company of New York, Inc. Orange and Rockland Utilities Inc. Supply and Demand Analysis for Regions Vulnerable to Supply Constraints (Filed July 17, 2020). The Company notes in addition that as the Company learns from its NPAs approaches implemented for distribution, the Company will apply that learning to interstate transmission pipeline constraints when, as appropriate, it applies them at that level.

Company will consult with Department of Public Service Staff ("DPS Staff") in the development of NPA and file such proposals with DPS Staff prior to implementing an NPA), and the Company's incentive proposal.[3] In developing this Framework, the Company has relied upon experience gained through the implementation of numerous Non-Wires Solutions ("NWS") projects as well as its experience in implementing its Smart Solutions for Natural Gas Customers program. Elements brought together under this Framework include: i) integrating NPA into natural gas planning processes; ii) qualifying natural gas budget categories for NPA; iii) developing suitability criteria for project selection and determining sourcing approaches; iv) developing NPA portfolios; v) implementing a Benefit Cost Analysis ("BCA") Handbook; vi) addressing cost recovery; vii) receiving performance incentives; and (iv) reporting on NPA progress and lessons learned.

Con Edison supports the State's clean energy objectives,[4] including the Climate Leadership and Community Protection Act's ("CLCPA")[5] ambitious goal of reducing greenhouse gas ("GHG") emissions by 85 percent from 1990 levels by 2050. The Company recognizes that reducing the GHG emissions associated with the combustion of natural gas for heating, cooling, cooking, and hot water (among other uses) will help limit overall GHG emissions.[6] In its recently released clean energy commitment, the Company notes its plans to

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[3] The Company notes that the elements of this Framework do not require Commission approval (*e.g.*, integrating NPA into its gas planning processes and the BCA handbook) and clarifies that its request for approval is limited to the process established by the Framework.

[4] In addition to the CLCPA, the Commission's January 16, 2020 *Order Authorizing Utility Energy Efficiency And Building Electrification Portfolios Through 2025* in Case 18-M-0084 ("NENY Order") directs an incremental 35.8 TBtu utility-driven energy efficiency savings, with corollary goals of achieving (i) 3 percent annual reduction in electricity sales by 2025 and 1.3 percent of natural gas sales, (ii) an aggregate reduction of 3.6 TBtu through heat pump deployment, and (iii) the continued provision and enhancement of programs for low and moderate income ("LMI") customers.

[5] Chapter 106 of the Laws of 2019. The CLCPA is available at https://legislation.nysenate.gov/pdf/bills/2019/S6599

[6] *See*, New York State Energy Research and Development Authority, *New York State Greenhouse Gas Inventory and Forecast: Inventory 1990-2011 and Forecast 2012-2030* (Published June 2015), p. S-8. At: https://energyplan.ny.gov/-/media/Files/EDPPP/Energy-Prices/Energy-Statistics/2015-greenhouse-gas-inventory.pdf

work with our customers, stakeholders, government and industry and expand its efforts to reduce the use of fossil fuels for heating to achieve a clean, smart and reliable energy future.[7]

As the State transitions to a low-emissions economy, the uses, sources, and delivery of natural gas will evolve. The Company is significantly expanding its energy efficiency programs to reduce natural gas use and prepare customers for efficient electrification through deeper efficiency measures, including building envelope tightening.[8] The Company actively encourages customers to electrify their heating equipment through its Clean Heat New York programs that recommends customers use air- and ground-source heat pumps in lieu of natural gas equipment to meet their heating needs.[9] In a national first, the Company implemented non-traditional approaches designed to manage peak-day demands on its natural gas system to mitigate constraints on existing natural gas pipeline infrastructure.[10]

In parallel to the efforts described in this filing, the Company is also deploying solutions to help manage system-wide gas needs, including in the Westchester County moratorium area. The Company will also continue to coordinate with National Grid to resolve system needs both in its service territory as well as in Brooklyn and the areas of Queens where the companies' respective electric and natural gas delivery systems overlap. In addition to these efforts, the Company is actively participating in the Commission's Gas Planning Proceeding,[11] which directs New York's local gas distribution companies ("LDCs") to develop supply and demand analyses,

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[7] *See*, https://www.coned.com/en/our-energy-future/our-energy-vision/our-energy-future-commitment
[8] NE:NY Order.
[9] Case 18-M-0084, *In the Matter of a Comprehensive Energy Efficiency Initiative*, NYS Clean Heat: Statewide Heat Pump Program Implementation Plan (Filed May 29, 2020).
[10] Case 17-G-0606, *Petition of Consolidated Edison Company of New York, Inc. for Approval of the Smart Solutions for Natural Gas Customers Program*, Request for Approval of Non-Pipeline Solutions Portfolio in the Smart Solutions for Natural Gas Customers Program (Filed September 18, 2018).
[11] Case 20-G-0131, *Proceeding on Motion of the Commission in Regard to Gas Planning Procedures* ("Gas Planning Proceeding"), Order Instituting Proceeding (Issued and Effective March 19, 2020).

evaluate gas planning processes, and investigate demand reducing measures as alternatives to infrastructure upgrades. The Company anticipates that relevant outcomes from the Gas Planning Proceeding will be incorporated into this NPA Framework.

The Company recognizes that even more work is needed to harmonize the currently necessary maintenance and safe and reliable operation of natural gas infrastructure with New York's low-emissions future. This filing proposes a Framework to guide the Company's efforts to pursue alternatives to traditional infrastructure projects on the natural gas distribution system. Following consultation with stakeholders and DPS Staff to prepare this filing, there is much to learn and numerous opportunities to advance the Company's approach. While this filing represents a step forward, it is the beginning, and not the end, of the Company's efforts in this area. In line with its experience in implementing NWS, the Company anticipates learning many lessons as early NPA are implemented. As such, the Company anticipates evaluating, modifying, and potentially expanding its approach to NPA in the coming years, in line with its commitment to deliver a clean energy future for its customers.[12]

Through this Framework, the Company seeks to evaluate as many traditional gas system infrastructure investments as feasible for deferral or replacement with an NPA project. In this Framework, the Company evaluates each of its natural gas capital budget categories for NPA qualification and establishes suitability criteria that will guide which projects are selected to move forward with NPA consideration. Upon Commission approval of this Framework, the Company will begin evaluating projects in qualified budget categories, with the goal of screening one hundred percent of qualified expenditures to determine if they should be further considered

[12] *See*, https://www.coned.com/en/our-energy-future/our-energy-vision/our-energy-future-commitment

for deferral or displacement. Qualified budget categories primarily consist of gas distribution projects and currently represent roughly $400 million in annual expenditures based on the current gas rate plan.[13] Additional expenditures may be offset through the Company's efforts to encourage customers to implement changes through the Company's Clean Heat and energy efficiency programs.[14] This approach reflects that many projects within the gas capital budget may be a fit for NPA review. An example of such a fit are gas distribution infrastructure projects associated with load growth. Other investments, however, such as Information Technology ("IT") systems, Advanced Metering Infrastructure ("AMI"), and non-distribution-infrastructure capital investments are not directly related to gas distribution and cannot be offset or eliminated by alternatives. Similarly, emergent safety risks[15] – such as an active gas leak – must be resolved as quickly as practicable in order to 1) maintain public, customer, and employee safety; 2) comply with state and federal law; and 3) manage the release of methane into the environment. These budget categories are also not qualified for NPA consideration.

Maintaining the safety and reliability of the natural gas system remains critical to considerations of how alternatives to traditional infrastructure maintenance can be applied, but this does not mean that NPA cannot be evaluated or tested for any of these projects. Instead, under this Framework, the Company proposes to evaluate planned safety- and reliability-related infrastructure projects (*e.g.*, planned future work under its Main Replacement Program) for replacement using an NPA and attempts to shed light on the many unanswered questions in this

[13] The $400 million estimate is based on the Company's currently active Rate Plan and may change over time as the Company's approved revenue requirement is adjusted within future rate plans.
[14] As discussed further below, because NPA require a longer implementation timeframe than can be captured in an annual budget, offsets to capital expenditures resulting from NPA will be realized in future years.
[15] Emergent safety risks that do not qualify for NPA consideration include replacement of leaking services; replacement of gas mains with active leaks; replacement of main segments due to water intrusion or contractor damage; and replacement of cast iron main due to encroachment activity.

uncharted territory.[16] For example, an NPA used to replace a project in the Main Replacement Program would require all customers receiving gas service via the segment scheduled for replacement to voluntarily transition their homes and businesses off natural gas to retire the segment.[17] While these kinds of considerations present complexity, with enough lead time, it may be possible to leverage alternatives, like targeted energy efficiency and beneficial electrification, to resolve certain future safety and reliability concerns. In identifying candidates for NPA, the Company's natural gas planning processes will provide lead time for NPA project development, enabling the Company to implement as-yet-untested approaches, document lessons learned, and share findings with stakeholders. The lessons gained from early efforts under this Framework can inform future NPA approaches both at Con Edison and across the State.

The Company proposes to tailor NPA approaches based on project characteristics – favoring streamlined alternatives, such as expanding energy efficiency programs in a targeted footprint for smaller, shorter-term projects (*e.g.*, main work needed in 18 months impacting two or fewer streets in a neighborhood) and soliciting innovative solutions from the market when there is a project with sufficient scale and adequate lead-time for a solicitation (*e.g.*, regulator station project needed in 36 months to supply gas to a large area).

Once a single or portfolio of solutions has been developed to address a system need, the Company will apply a Benefit-Cost Analysis ("BCA") that compares the benefits and costs associated with implementing NPA. The BCA will consider factors, such as costs offset by avoided investment in natural gas distribution and transmission, avoided purchases of natural

[16] Parallel efforts, such as the Company's active District Energy Initiative, will provide important data and lessons learned as NPA for main scheduled for replacement via the Company's Main Replacement Program are considered.
[17] The Company notes here its obligation to serve all customers who choose gas as their source of energy for heating.

gas, costs associated with the alternative investments, and avoided emissions. To the extent that the benefits of an NPA portfolio outweigh its costs or the costs of the NPA portfolio are lower than those that would be incurred to implement the traditional solution, the Company will move forward with implementing the NPA in consultation with DPS Staff.[18]

As NPAs are implemented, the Company will expand the current understanding of how various alternative measures impact peak day gas usage in Con Edison's service territory. The Company will use its expertise in Evaluation, Measurement and Verification ("EM&V") to develop strategies by which the estimated impact of such initiatives are routinely evaluated across both programs and technologies to identify the solutions that are most impactful and ideal for addressing the peak system constraints. As more experience is gained, more effective portfolios of alternatives can be developed, and NPAs can be tailored and potentially expanded and implemented in shorter time frames.

This Framework proposes to recover costs associated with NPA deployment over a 20-year amortization period, treating these investments as regulatory assets. The 20-year period generally aligns with the lifetime of key alternative measures and will allow customers to contribute to these costs as the benefits of the investments are realized.

In line with New York's treatment of NWS, the Company also proposes a performance incentive equivalent to 30 percent of the net benefits of a project, as determined by the BCA. The Company also proposes to maintain the general structure applicable to NWS with respect to the calculation of performance incentives as changes to specific programs occur, including savings

[18] In cases where a portfolio does not deliver a positive BCA but is expected to cost less than the traditional solution, the Company will continue to evaluate alternative options and an approach to pursue them.

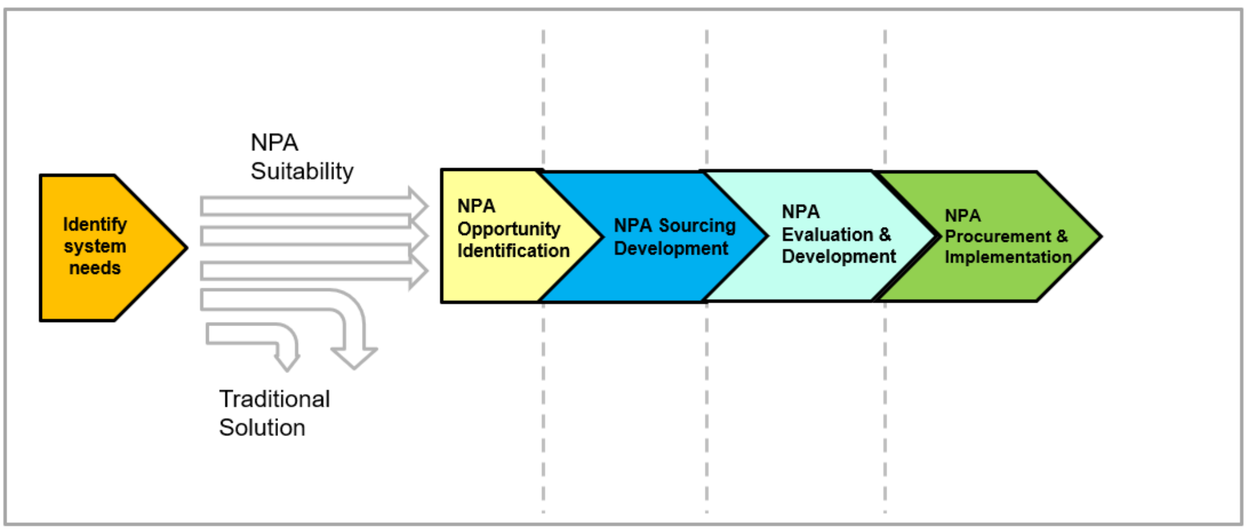
sharing mechanisms, such that the Company is incented to reduce costs from forecasted amounts while an NPA project is in-flight. Further detail on these mechanisms is provided below.

The Company looks forward to working with the Commission, DPS Staff, and Stakeholders to discuss and refine this proposed framework as it gains implementation experience.

I. NPA Process Overview

This Framework proposes an end-to-end process for NPA implementation, including: 1) identifying system needs; 2) screening for eligible NPA candidates; 3) sourcing, developing and evaluating NPA portfolios; 4) procuring and implementing the NPA; 5) recovering NPA costs; and 6) encouraging strong utility performance through incentives. Each of these steps are discussed below.

Figure 1: NPA Identification & Sourcing



Because NPA are an innovative approach to meeting natural gas distribution infrastructure needs, the process will necessarily evolve with time as lessons are learned and opportunities for improvement are identified. As a result, while the process outlined in this Framework is expected to remain largely constant, elements of NPA execution are likely to change over time as experience is gained.

II. Identifying Natural Gas Distribution System Needs

Con Edison maintains 4,300 miles of natural gas distribution infrastructure across Westchester County, the Bronx, Manhattan, and a portion of Queens. The majority of Con Edison's planned infrastructure work occurs to maintain the safety and reliability of the existing system.

The Company's planning processes assess the system's current and expected future operating conditions relative to the Company's design standards and methodology, considering forecasted changes in localized peak day demand. The planning process also accounts for changes in regulations, such as those currently being finalized by the federal Pipeline and Hazardous Materials Safety Administration ("PHMSA"). Through this process, system engineers identify system needs and develop various options for addressing those needs. These options are then assessed for: (1) effectiveness in meeting the need; (2) cost; (3) implementation timing; and (4) risks. Solutions are prioritized by balancing available capital and resources against the risk of not addressing the system need within the timeframe of the capital plan.

As new needs arise throughout the year (*e.g.*, an excavation contractor accidentally strikes or damages a gas main, a water main break undermines a cast iron gas main, a municipality announces a new road paving schedule that affects natural gas infrastructure,[19] or a

[19] Much of the Company's natural gas infrastructure is located beneath roadways. The vibration caused by milling and repaving a roadway is a known cause of new leaks appearing on leak-prone pipe, which require digging up the freshly paved roadway to address. For leak prevention, the Company coordinates its infrastructure work to align with municipal paving schedules to the extent practicable.

main replacement is required to eliminate an active leak), the Company continuously rebalances its annual plan to address these "emergent" conditions. Should a natural gas main that is scheduled for replacement in a future year through the Main Replacement Program be implicated as an "emergent" condition, the work to replace that segment of main can be accelerated. The annual plan can be similarly adjusted if, for example, a new customer connection requires an upgrade to a segment of main that might otherwise have been replaced at a future time.

Through this Framework, the Company proposes to integrate NPA into its natural gas planning process, including by beginning NPA work one or more years earlier than work on a traditional project is scheduled to begin. As infrastructure work is identified and planned, the NPA screening and suitability criteria defined below will determine which projects are a good fit for NPA.

III. Identifying Infrastructure Projects that can be Deferred or Replaced by Non-Traditional Alternatives

A. NPA Qualified Natural Gas Budget Categories

This Framework evaluates each natural gas capital budget category to determine whether it is qualified for deferral or replacement by an NPA. In defining the qualified budget categories, the Company applied the following qualification factors:

Table 1: Summary of Initial Budget Category Qualification Factors
See additional descriptions in text below

Qualification Factor	Summary Description
Non-Distribution Infrastructure	Is the proposed expenditure a non-distribution infrastructure project? Non-distribution infrastructure investments, like IT systems and AMI, cannot be replaced by NPA.
Emergent Safety	Is the proposed expenditure needed to resolve an emergent safety risk? The Company is required by state and federal law to address emergent safety risks expediently and therefore these investments cannot be replaced by an NPA.
Regulatory Requirement	Is the proposed expenditure needed to meet a regulatory requirement, such as PHMSA regulations? Near-term infrastructure upgrades needed to meet regulatory requirements cannot reasonably be replaced by an NPA due to the volume of work that is required to be completed in a short time frame. As the NPA program grows, future projects may be evaluated for possible replacement with an NPA.

While certain budget categories do not qualify for NPA consideration (as discussed below), the Company expects that many natural gas distribution infrastructure projects will be evaluated for NPA. The budget categories qualified for NPA consideration include:

- **Load Relief:** The Company's load relief program includes the installation and replacement of gas mains to support continued reliability in areas where the system is constrained to provide a sufficient quantity of natural gas to customers during a peak day. With sufficient time to implement, these projects can be a natural fit for NPA projects because heating electrification, demand response, and efficiency measures deployed across the customer population in a given geographic area can be combined to reduce overall demands below the threshold needed to maintain reliability.

- **Regulator Station Upgrade Programs:** The Regulator Station Upgrade Program improves existing regulator stations to meet gas demand. The work required for each regulator station varies depending on its design and the projected future gas load. This program can involve the installation of new regulator station vaults, inlet and outlet piping, replacement of regulator hardware, and installation of new communication to data and control systems. Regulator station upgrades may be a strong fit for deferral or replacement using NPA because heating electrification, demand response, and efficiency measures deployed across the customer population in a given geographic area can be combined to reduce overall demands below the threshold needed to maintain reliability.
- **Main Replacement Program:** The Company's Main Replacement Program is designed to replace leak-prone gas mains, which are small diameter, cast iron, wrought iron, and unprotected steel (pre-1972) mains. Roughly 1,600 miles of leak-prone main remain on Con Edison's system. Segments of main designated for replacement within the Main Replacement Program are prioritized and scheduled based on numerous factors, including public safety risk, geographic bundling of projects for cost-effectiveness, and emergent conditions on the system. NPAs can be undertaken in lieu of replacing a given segment of main as long as the NPA solution results in the elimination of the cast-iron or unprotected steel pipe. This would necessitate all existing gas customers receiving service from that particular segment of main to voluntarily convert to an alternative fuel,

presenting significant challenges for the successful deployment of NPA solutions.[20]

Additional capital expenditures may also be offset through both the service replacement program and the new customer connections program, which provide new or expanded services to individual customers or buildings. As part of its current Rate Plan, the Company has eliminated all incentives for customers to switch to natural gas. As part of this Framework, the Company will encourage customers in need of a new, expanded, or replacement natural gas service to consider alternatives, including available electrification, energy efficiency, and interruptible rate options through the Company's various programs and offerings.[21]

B. Non-NPA-Qualified Budget Categories

As discussed above, maintaining the safety of the public, customers, and employees as well as system reliability is of primary importance when considering an NPA project as an alternative to a traditional infrastructure solution. As a result, the following budget categories will not qualify for NPA consideration at this time. As more experience is gained with NPA, however, the Company may seek to expand the use of NPA to include future projects driven by changing regulatory requirements (*i.e.*, the anticipated PHMSA rulemaking).

[20] To the extent that a single customer affected by this change declined to convert to natural gas, the Company would be obligated to proceed with the infrastructure replacement.

[21] The Company notes that its statutory obligation to serve customers within its natural gas service territory restricts the Company from denying service to customers requesting natural gas outside of the boundaries of its Westchester moratorium area.

Non-Distribution Infrastructure

The Company's overall gas capital program includes funding for non-distribution infrastructure projects that cannot be replaced or offset by an NPA project and will therefore not be eligible for further NPA consideration. These expenditures include:

- **Technical & Metering Operations:** Projects include gas meters, pressure regulators and instrumentation (*e.g.*, volume correctors), and natural gas detectors (*e.g.*, as are installed in customer homes and businesses to detect gas leaks).
- **Information Technology:** This category primarily includes investments in the Company's work and asset management system that plans and manage all types of work. Other investments include the Leak Detection Equipment project, a program designed to enhance the Company's ability to detect natural gas leaks using state-of-the art mobile leak detection equipment.

Emergent Safety

As discussed above, the Company's capital program includes projects necessary to address emergent safety risks. This work cannot be addressed through an NPA. The Company's response to these conditions is governed by state and federal law.[22] Projects that fall within this category include: replacement of leaking services; replacement of gas mains with active leaks; replacement of main segments due to water intrusion or contractor damage; and replacement of cast iron main due to encroachment activity.

[22] *See*, NYCRR 255 and 49 USC §§ 60105-60106.

Regulatory Requirement

The Company's capital expenditures also include projects designed to keep the system in compliance with various regulatory requirements that specify mandatory operating pressures and design conditions for high- and low-pressure natural gas distribution systems.[23] Specific expenditures in this category cannot be alleviated by reducing demand or throughput and include remotely operated valve installations, over-pressure protection, pressure control projects, and distribution system isolation valves. These expenditures allow operators to control pressure on the system, and to shut down various sections of the system – in some cases with the touch of a button or when a sensor has been activated – to stop the flow of gas when a leak or operational condition has been detected. Infrastructure work required by anticipated PHMSA regulations is also included in this category of expenditures due to the large volumes of customers affected by the infrastructure in question and the short lead time for compliance.[24] Project types that would not qualify for NPA include large-Diameter and Supply Mains, which act as a primary supply to large areas of the natural gas distribution system; pressure control; and reinforcement work needed to satisfy demand projected for the upcoming winter season. As greater experience is gained with NPA implementation, certain future projects within this budget category may be considered for deferral or replacement with NPA.

IV. NPA Suitability Criteria

Once a project is deemed eligible to proceed for NPA consideration, the Company will evaluate the costs, size of the load relief needed, and available timeline, among other factors, to

[23] *See*, NYCRR 255.621 – 255.623 and 49 USC §§ 60105-60106.

[24] *See*, 85 FR 35240.

determine feasibility of proceeding with an NPA, and, if feasible, how to approach sourcing and procuring the assets needed to make up the NPA portfolio. The Company's experience in implementing NWS has indicated that larger projects that have greater load relief needs and/or are spread over a larger geographic area may take more time and effort to achieve the needed load reduction, but may also open up opportunities for soliciting innovative third-party solutions. Smaller projects with smaller load relief needs and/or spread over a smaller geographic area may be better suited to leveraging existing Company programs through providing additional incentives and targeted outreach.

Understanding the timeline of system needs helps to identify the time by when the project needs to be implemented and operational, the lead time available to implement an alternative, and the amount of time the Company has to implement a traditional solution, if needed. Implementing alternative solutions takes longer than a traditional project because the Company must engage customers and the market, where applicable, and provide sufficient time for installation, verification and operation of alternative solutions.

The geographic location of the project will also be considered in evaluating the feasibility of an NPA. Projects may be prioritized by focusing on vulnerable locations.[25] Where possible, the Company will seek to implement NPA in those areas to support load relief by deferring or eliminating eligible distribution infrastructure projects.

[25] Vulnerable locations are defined as a portion of the system where gas may not be able to be delivered safely and reliably within the next five years. *See*, Gas Planning Proceeding, Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc. Supply and Demand Analysis for Regions Vulnerable to Supply Constraints (filed July 17, 2020), p. 17.

Table 2: Suitability Criteria for NPA Consideration and Sourcing Approach

Categorization	Timeline	Costs
Large Project	>36-60 months	>$2M
Small Project	>18 months	≤ $2M
Projects in areas identified as "vulnerable locations"[26] will be prioritized.		

Following these guidelines, large projects will typically cover larger geographic areas – and potentially be associated with significant regulator station upgrades or larger mains. Projects that involve several streets or a small neighborhood could qualify as either a large or small project, depending on their size and timeline. Projects that involve a single street or only a few services will be classified as a small project. Ultimately, the timeline and costs of a proposed traditional project will determine which NPA procurement pathway is selected.

V. Sourcing, Developing, Assessing, and Implementing NPAs

A. Phase 1: Determining the NPA Sourcing Approach

In the sourcing and development phase, data needed for accurate evaluation, effective communication, and planning is compiled to help inform the best path for determining feasibility of implementing an NPA. This phase augments the categorization of NPA as "large" or "small" projects, as described above, to further tailor the approach the Company will take as it determines whether to use increased incentives and outreach through existing programs to meet

[26] *Id.*

the system need, to conduct a market solicitation, or to develop a portfolio that includes a combination of both approaches. These factors include:

- Project type;
- Customer type;
- Geographic area; and
- Current programs and measures in place.

These characteristics will inform the procurement path for the specific project – particularly where leveraging existing programs is combined with market solicitations. Existing programs currently in market have been proven to provide greater amounts of peak demand reduction more quickly than market solicitations. Existing programs may also be well-positioned to engage with specific customers, or to provide specific types of load relief. As a result, projects that require near-term load relief, or incremental load relief over a period of time may have a greater chance of success if existing programs are used, potentially alongside a market solicitation to address longer-term needs.

Market solicitations, such as an RFI or RFP, provides the opportunity to animate the third-party market and enables the Company to learn about potential technologies or business models that could provide valuable insight.

B. Phase 2: Developing NPA Solutions and Portfolios

Once the Company has determined the sourcing and procurement approach, the Company will work to develop an optimal solution or portfolio of solutions for the specific system need. In developing this portfolio, the Company will take numerous factors into account, as described below in Table 3.

Table 3: Evaluation Considerations for Potential NPA Measures

Evaluation Consideration	**Description**
Cost Effectiveness	Total cost, incentive levels and impacts associated with incentivizing projects, as well as other costs to implement the programs, such as marketing
Execution Risks	The expected ease of project implementation within the timeframe required for the NPA (*e.g.*, permitting, construction risks, and operating risks)
Coincidence with peak	The extent to which the solution is expected to provide demand reduction during the peak day in the targeted area
Vendor Qualifications	The relevant experience and past success of solution providers implementing measures in the Company's service territory or other locations
Availability & Reliability	Ability of a solution or measure to reliably provide permanent or temporary load relief as required; technology maturity
State Policy/ Community Impacts	Positive or negative impacts that measures may have on the community in the identified area (*e.g.*, noise); alignment with state policy goals
Customer Acquisition	Ease of engaging customers to implement a particular solution, including a detailed plan and proof of customer relationships and level of commitment to implement NPAs are considered
Timeliness	Ability to meet the timeframe needed for demand reduction
Benefit Cost Analysis	Ability of a portfolio to deliver a positive benefit-cost analysis result using the Societal Cost Test ("SCT") as defined through the Benefit Cost Analysis Handbook

In addition to these factors, the Company's experience in implementing alternative solutions both on the electric system and through its early efforts through its Smart Solutions for Natural Gas Customers program indicates the importance of maintaining a diversity of solutions and flexibility in implementing alternative portfolios. Planned work on the utility- or customer-side can evolve, measures that were expected to be installed can be delayed, accelerated or cancelled, and forecasted demands can shift. Especially for larger projects, portfolios that can adapt to these changes demonstrate higher success rates than those that cannot.

Because implementation of NPAs are reliant on engagement and cooperation with customers and customer interest and third parties' ability to pursue solutions, there are risks such as not providing predictable and sustainable load relief levels at the same level of certainty as traditional solutions. To help balance these risks, the Company will pursue diverse portfolios while learning and adjusting as their impacts are further proven. These diverse portfolios, where applicable, are meant to account for risks, such as operational delays, and provide the ability to adjust quantities as load relief needs change during the implementation period. The Company's goal is for a portfolio that can meet load relief needs in a timely manner and thus mimic traditional solutions' level of reliability; or, in cases where load relief needs cannot be met, to allow for sufficient time for an alternate traditional solution to be implemented to maintain system reliability.

Should the Company determine that the project needs align well with a market solicitation, the Company will develop and issue a market solicitation, which is generally in the form of an RFP. The Company will engage with relevant stakeholders, trade organizations, state agencies, and prior solicitation participants to raise awareness of the opportunity and encourage the greatest number of competitive responses. As part of this process, the Company may also amend or develop new contracts detailing requirements for load relief needs to be met. Once responses are received, the Company will bring together a cross-functional team to evaluate proposals and select those that show the greatest promise.

Taking into account the factors described above, the Company will compile a diverse mix of measures and solutions that align with the characteristics of the need, the customers affected, and the total load relief that needs to be achieved to offset or defer the project. The costs and load relief provided is calculated for each measure or solution. These are then analyzed and combined to form a portfolio of solutions, which is then evaluated through a BCA and compared to the costs of the traditional infrastructure project to determine whether the portfolio is cost beneficial and/or cost effective. During this process, the Company may modify the portfolio and re-run a portfolio level BCA to further optimize the solution sets.

Once the optimal portfolio has been developed and the BCA has been completed, the Company will develop a recommendation whether to proceed with the NPA. Similar to the process currently in place for NWS, the Company proposes to then share its proposed solution or portfolio, as well as its recommendation to proceed, with DPS Staff for feedback. Should this consultation result in a decision to proceed with the NPA, the Company will engage stakeholders, develop the implementation, contracting, and measurement and verification plans, and other actions needed to support the project. If the Company will not move forward with the NPA, it will inform stakeholders, and proceed with the traditional project as planned.

C. Phase 3: NPA Implementation

Finally, the Company will proceed with implementing the NPA. In cases where existing programs will be used, the Company may quickly increase incentive levels in the targeted areas and direct its business development managers, implementation contractors, and market partners to begin expanded outreach within the NPA footprint. The Company may also engage stakeholder and community organizations within the area, update its websites, develop and deploy new marketing materials, and participate in local events to raise awareness of the program. If the NPA involved a market solicitation, the Company will notify selected bidders, complete final contracting, and instruct successful bidders to begin outreach or solution development as appropriate.

As these projects are installed, the Company will use methodologies described below to determine load relief, which will support the continuous iteration and improvement on the process for developing, selecting and implementing alternatives.

D. Evaluation, Measurement & Verification

The goal of EM&V is to accurately account for total load relief from alternative solutions. EM&V will seek to maximize the benefit from metering studies performed on the gas system by leveraging available granular load information (for example, in areas where AMI has been deployed) and applying those lessons to NPA areas. EM&V will be ongoing and concurrent until program completion.

Con Edison uses the Statewide approved Technical Resource Manual ("TRM") or custom methodologies consistent with professional engineering judgement, as applicable, to estimate gross annual savings attributable to its demand-side programs. These gross savings are adjusted consistent with Verified Gross Savings ("VGS") regulatory guidance[27] to estimate the observed impact. Peak demand savings are then calculated utilizing a peak day impact methodology developed by an independent evaluation contractor for the purpose of estimating impact at the design condition.

This peak day impact methodology is used to develop a Peak Load Shape Factor ("PLSF"). The PLSF is defined as the summation of the hourly fractional gas loads for a

[27] Office of Clean Energy, CE-08: Gross Savings Verification Guidance, August 23, 2019, http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/255ea3546df802b585257e38005460f9/$FILE/GSVG%208_23_2019.FINAL.pdf

prototypical building over a 24-hour period that coincides with the winter peak design day,[28] consistent with Con Edison forecasting methods.

A PLSF was computed for 17 different customer segments with as many as three different equipment end-use categories using a typical meteorological year ("TMY") weather-modified version of the U.S. Department of Energy ("US DOE") residential and commercial gas load shape curves.[29]

$$\textit{Peak Load Shape Factor} = \sum_{i}^{n} \textit{Hourly Fractional Load}_i$$

$$PLSF = HFL_{Hour\ 1} + HFL_{Hr\ 2} + HFL_{Hr\ 3} + HFL_{Hr\ 4} \dots + HFL_{Hr\ 23} + HFL_{Hr\ 24}$$

where i = the hour during peak period for n hours

Currently, the average peak day impact is calculated by multiplying the PLSF by annual verified gross energy savings. The Company will develop procedures so that alternative solutions have EM&V oversight, via desk-review or verification before and/or after measure installation. Additionally, the Company may use ex-ante and ex-post in-situ (on-site) metering and analysis for particularly large or not well characterized measures. The EM&V process that the Company intends to use is expected to result in VGS estimates at the program or measure level with 90/10 confidence/precision, the industry standard and consistent with the DPS evaluation guidance.

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[28] A zero-degree Fahrenheit temperature variable measured at the Central Park weather station over a two-day period. Temperature variable is defined as a weighted average of the current and prior day gas day average (GDA) temperature between 10 am on the current day to 10 am on the following day. The current GDA is given a weight of 70 percent and the previous GDA is given a weight of 30 percent.

[29] https://bcl.nrel.gov/node/72351[30] The Company may encounter NPA projects that result in a net reduction in customer bills but does not pass the societal BCA (*e.g.*, some applications of heating electrification). For such lower cost projects that the Company may pursue to advance state policy objectives, such as electrification, the Company will propose an alternative cost effectiveness metric and shareholder incentive.

A variety of EM&V methods, consistent with the International Performance Measurement and Verification Protocol (IPMVP®) will be used on a case-by-case basis. Programs employing scale with numerous measures that have relatively low impact will largely be reliant upon evaluation methods where measures anticipated to yield significant savings will be likely be subject to on-site (in-situ) EM&V to estimate impact.

The Company may also use additional EM&V strategies designed for routine (*i.e.*, seasonally dependent) heating and cooling systems and non-routine (*i.e.*, not seasonally dependent) resources, such as process loads. Where possible, the Company will leverage any available energy management data available to expedite the EM&V process.

VI. Benefit Cost Analysis

As described above, the Company proposes to conduct a BCA to determine the cost effectiveness of an NPA. The Company previously developed and filed an Interim Benefit-Cost Analysis Handbook for Non-Pipeline Solutions ("BCA Handbook"), which is used to evaluate projects currently being implemented to address supply side constraints, primarily in Westchester County. The Company updated and concurrently filed the revised handbook (Attachment A) to outline the methodology for assessing the cost effectiveness of NPA projects and inform decisions to pursue non-traditional solutions. The Company anticipates that this Handbook may be revised to conform with decisions and guidance issued through the Gas Planning Proceeding.

The Company will use the SCT as the primary methodology to determine cost effectiveness.[30] The SCT net benefits ("Net Benefits") is equal to the present value of the total

[30] The Company may encounter NPA projects that result in a net reduction in customer bills but does not pass the societal BCA (*e.g.*, some applications of heating electrification). For such lower cost projects that the Company may pursue to advance state policy objectives, such as electrification, the Company will propose an alternative cost effectiveness metric and shareholder incentive.

societal benefits minus the present value of the total societal costs. Societal benefits include the value of the deferred or avoided traditional projects, the value of avoided gas commodity purchases, the value of other avoided energy-related costs that a participating customer might otherwise incur (*e.g.*, reduced cooling costs achieved through insulation), and the value of reduced GHG emissions. Societal costs include the costs of running NPA programs, incentives paid to customers to adopt demand reduction measures, and the associated post-incentive incremental costs incurred by the participating customers. The net benefits[31] will be used in the calculation of the NPA project performance incentive.

VII. Cost Recovery and Accounting for NPA

As approved in the Rate Plan, to the extent new NPAs result in the Company deferring or displacing a capital project reflected in the Average Gas Plant In Service Balances, the balance(s) will be reduced to exclude the forecasted net plant associated with the displaced project. The carrying charge on the reduction of the Average Gas Plant in Service Balances that would otherwise be deferred for customer benefit will instead be applied as a credit against the recovery of the NPA in the Monthly Rate Adjustment ("MRA") mechanism. In the event the carrying charge on the net plant of any displaced project is greater than the NPA recovery, the difference will be deferred for the benefit of customers.

As provided in the Gas Rate Plan, the Company's costs for NPA implementation, including the overall pre-tax rate of return on such costs, will be recovered as a regulatory asset. The Company is proposing an amortization period of 20 years because this generally aligns with the projected useful life of the measures that are expected to be installed and appropriately

[31] Net benefits is total societal benefits minus total societal costs, as specified by the SCT.

spreads out costs for customers. A single amortization period for the NPA portfolio also provides administrative and accounting consistency and simplicity. The Company proposes recovery of NPA costs and any applicable incentives during this Gas Rate Plan through the MRA. The Company shall file to incorporate unamortized NPA costs, including the return, into the Company's base rates when gas base delivery rates are next reset.

VIII. Performance Incentive

The Company proposes a performance incentive mechanism designed to drive NPAs that provide meaningful achievement and net benefits to customers. This mechanism mirrors the approach presently used for NWS and incorporates the detail and lessons learned that have been added to that approach as implementation realities and experience have been gained.[32] The key components of the incentive proposal are:

1. A performance incentive whereby customers retain 70 percent and the Company 30 percent of Initial Net Benefits as determined by the SCT performed prior to program implementation;
2. A cost-containment performance incentive that rewards the Company for reducing costs during NPA implementation with a cap equivalent to 50 percent of the Initial Net Benefits;
3. A provision to address a situation in which an NPA project is not able to defer or eliminate the traditional project as initially intended; and
4. Provisions for a change in timing or capacity needs for an active NPA project.

[32] This incentive is not related to program cost recovery.

The proposed NPA incentive mechanism is applicable to both Large and Small projects. These two categories, as defined above in the Suitability Criteria, are used to reflect the range of load relief projects and the associated cost of traditional infrastructure capital spending that the Company may seek to delay or avoid through the NPA program. The Company proposes consistent treatment of the incentive, whether Large or Small, as the process for development, evaluation, and implementations remain consistent to ultimately achieve load relief.

A. Calculation of Incentive

Similar to that in use for NWS, the Company proposes a performance incentive mechanism that includes a share of net societal benefits using the SCT as defined in Company's BCA Handbook.[33] As described above, the Net Benefits is equal to the present value of the total societal benefits minus the present value of the total societal costs.

For the performance incentive, the Company's 30 percent share of net benefits represents the "Base Incentive" which is potentially adjusted based on a process flow timeline, as described in Attachment B.[34]

The Company's proposed performance incentive represents a reasonable distribution of benefits for the proposed NPA Framework, as it is beneficial to all gas customers who receive a majority of the net societal benefits. Additionally, the incentive encourages the Company to pursue NPA projects that maximize societal net benefits by maximizing demand and energy savings while minimizing costs.

[33] Until a statewide BCA handbook is developed in consultation with DPS Staff, the Company proposes to utilize the BCA Handbook submitted with this filing to quantify the benefits and costs of implementing the NPA.
[34] The percent share of net benefits that is calculated as the Company's share and that forms the basis for Company's collection of the incentive, from the inception of the NPA through implementation and true-up as explained in this document, will be on a pre-tax basis.

As illustrated in Attachment B, the "Base Incentive" for all projects will be based on the "Initial Net Benefits" at the point when the Company has either entered into contracts with solution providers for the entire portfolio, or when the Company determines, after consultation with DPS Staff, there is "reasonable certainty"[35] regarding the likely price of the portfolio of solutions that will enable deferral or displacement of the traditional infrastructure.

DPS Staff will have the opportunity for observation and oversight of the calculation of the project-specific BCA analysis, which is the basis of the 30 percent share of Initial Net Benefits, and the procurement process. The Company proposes a reasonable bi-directional and capped incentive for it to manage and reduce the utility's cost to procure solutions during the period after the Initial Net Benefits have been determined through the end of the NPA Deferral or Avoidance Period. The NPA Deferral Period refers to the period that begins when the Initial Net Benefits are set and extends through the time that the NPA portfolio delays or eliminates the traditional infrastructure build, as determined at the time of setting the Initial Net Benefits.

To determine the final value of the incentive following the implementation of the alternative portfolio of solutions, the Initial Net Benefits will be trued-up based on actual program spending. The Difference in Utility NPA Cost is defined as the difference between the total utility NPA spending of solutions assumed for the Initial Net Benefits calculation and the actual total utility NPA spending after the implementation of the NPA portfolio. The sum of

[35] Reasonable certainty regarding the likely price of the portfolio may be used in situations such as: 1) projects with longer lead times or that require incremental solution procurements over multiple years and would benefit from a contractual structure that allows for staged procurement, or 2) projects that involve direct contractual relationships with private customers or public entities whose budgetary cycles and consequent ability to enter into contractual agreements may occur at some point later in time after an agreement on price is reached.

Initial Net Benefits and 50 percent of the difference in Utility NPA Cost (planned minus actual utility NPA spending) will result in the "Final Net Benefits."[36]

This Company share in NPA portfolio cost reductions or overruns would be subject to the conditions that the final incentive will a) have a "floor" so as not be negative and b) have a "cap" so as not be greater than 50 percent of the Initial Net Benefits.[37]

The Company will begin collecting the Initial Incentive once 70 percent of the NPA portfolio is operational. The incentive will be amortized over the remaining NPA Deferral Period (*e.g.*, if 70 percent of NPA portfolio is operational in three years out of a five-year Deferral Period, the incentive will be recovered over the remaining two years of the Deferral Period) or Avoidance Period. The Company will collect all incentive payments, inclusive of the overall pre-tax rate of return, through the MRA, using the same cost recovery mechanism approved in the Company's Rate Plan for other program costs.

B. Change in NPA Portfolio Amounts

The Company performs periodic gas reliability assessments as part of its responsibility to maintain the overall reliability of the gas distribution system. Reliability assessments are conducted at least annually as part of the Company's capital planning process.

1. Reduction in NPA

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[36] For example, if the Initial Incentive were $100, and the Difference in Utility NPA Cost were negative $50 (*i.e.*, a $50 overrun in the NPA cost), then the Company's Initial Incentive would be reduced by $25 (50 percent of $50 overrun) to provide a Final Incentive of $75.

[37] For example, if the Initial Incentive were $100 and the Difference in Utility NPA Cost were negative $300 (*i.e.*, the NPA portfolio had a $300 cost overrun), the Company's Final Incentive would be set at $0 (the floor) and not be negative $50 ($100 Initial Incentive less 50 percent of the $300 Difference in Utility NPA Cost). Similarly, if the NPA solution had Initial Net Benefits of $$335 and thus an Initial Incentive of $100 (30 percent of Initial Net Benefits), and the Difference in Utility NPA Cost was $300 (*i.e.*, the Utility cost of the NPA portfolio was $300 under budget), the Initial Incentive would be set at the cap of $168 (*i.e.*, 50 percent of $335 Initial Net Benefits), not increase by $150 (50 percent of Difference in Utility NPA Cost) to $250.

If the reassessment results in a determination that a material reduction (see below) in the amount of an NPA project will not impact the intended avoidance or deferral of a traditional infrastructure project and maintain safety and reliability, then the Company will plan to reduce NPA procurements accordingly, to the extent contractually feasible.[38] However, if the Commission directs the Company otherwise, then the Company will proceed with NPA procurement as originally planned, based on the Commission's directive. Similarly, if the Company, following consultation with DPS Staff, determines that it should not reduce NPA procurements to reflect all or part of the material reduction, it may continue NPA procurements at such higher level, upon notice to the Commission of its intent to do so, unless and until the Commission directs otherwise.

Regarding the associated incentive, if the Company moves forward with a material reduction in the amount of NPA being procured, as explained above, the Company proposes a true up of the incentive following the implementation of the NPA portfolio. This true up will reduce both the Company incentive and the required level of NPA peak reduction needed to earn the Company incentive to reflect the reduced amount of NPA needed to achieve the intended deferral or avoidance.

The Company proposes the following process. First, the Initial Incentive will be converted to an "Initial Unit Incentive" by dividing the Initial Incentive by the amount of NPA peak (Dth-day) load reduction target at the time of setting the Initial Net Benefits. Second, the Difference in Utility NPA Cost described in the earlier section will be calculated on a unit basis per peak day Dth load reduction. The Final Incentive will be calculated as the sum of the Initial Unit Incentive plus or minus the Unit Difference in Utility NPA cost, then multiplied by the load

[38] A "material reduction" is defined as 1) a consistent, downward trend over a period of three years, and 2) in excess of 30 percent of the amount of NPA that was determined as necessary at the time of determining Initial Net Benefits.

relief delivered (Dth-day), subject to the same “Cap” and “Floor” described in the Performance Incentive section. This is a lower monetary incentive for the Company even as it provides the benefit of achieving the intended deferral or avoidance at a lower cost. It also provides additional time and flexibility to determine if the traditional infrastructure being targeted for deferral is ultimately needed.

2. Increase in NPA

If the reliability needs assessment results in the determination that an increased amount of NPA is necessary to achieve the intended deferral or avoidance of traditional infrastructure and maintain safety and reliability, then the Company will plan to increase the NPA procurement accordingly, or if technically or operationally infeasible, plan to implement a traditional, reliability backstop solution instead. If additional NPA acquisitions are feasible, the Company will plan to procure additional NPA following the cost recovery approved described above and therefore forego any additional incentives. The additional Dth will not be included in the calculation of the Difference in Utility NPA cost described above. If the reliability needs assessment results in the determination that an increased amount of NPA within the same targeted area could result in additional opportunities for deferral of traditional infrastructure build, separate from the traditional infrastructure originally targeted for deferral, then the Company will a develop a new incremental NPA portfolio to address the new opportunity and will receive an incentive as if it were a new project being pursued under the NPA program to address the newly determined reliability need.

Recovery of any incentive, if applicable, will be halted, without requiring a refund of amounts collected to date, if at any time it is determined that continuing the NPA project is operationally or technically infeasible.

IX. Reporting

Once there is reasonable certainty of costs for an NPA project, the Company will file with the Secretary to the Commission (1) an implementation and verification plan; (2) a portfolio of solutions to be implemented; (3) anticipated costs of NPA; (4) any costs of NPA projects that are incremental to Company's revenue requirement or will be displacing a project subject to the Capital Investment Reconciliation; (5) a customer outreach plan, if appropriate; and (6) BCA results. Implementation plans shall be filed and updated annually.

X. Conclusion

In conclusion, this NPA Framework Proposal describes the Company's process for identifying, developing, implementing, recovering costs and establishing performance incentives for NPA projects that would defer or eliminate traditional natural gas distribution infrastructure projects. The Company respectfully requests Commission approval of the specific proposed process (*i.e.*, the Company will consult with DPS Staff in the development of NPA and file such plans with DPS Staff prior to implementing an NPA) and the Company's incentive proposal.

Attachment A: Gas Benefit Cost Analysis Handbook

Gas Benefit-Cost Analysis Handbook

September 14, 2020

Background

Consolidated Edison, Inc. (Con Edison or the Company) provides an expansive portfolio of energy-regulated products in the Northeastern States. Through its regulated subsidiary, Consolidated Edison Company of New York (CECONY), it provides natural gas service to approximately 1.2 million customers in Manhattan, the Bronx, Queens, and Westchester Country.

The CECONY Gas Benefit-Cost Analysis Handbook was developed to evaluate many different resources across various policy contexts (e.g. Energy Efficiency Programs, Non-Pipeline Programs, etc.). The handbook provides a framework to evaluate the benefits and costs associated with supply-side and demand-side technologies and programs. The Gas Benefit-Cost Analysis (BCA) approach included herein is modeled on the CECONY Electric BCA Handbook, which was developed by CECONY in collaboration with the New York Joint Utilities to provide consistent and transparent statewide methodologies for electric non-wires solutions and other electric demand-side measures.[1] When applicable, this Gas BCA Handbook integrates the guidance provided by the New York State Public Service Commission in the BCA Order on Non-Wires Solutions BCA[2] and guidance provided through Staff.[3]

The Gas BCA Handbook presents applicable BCA methodologies and describes how to calculate individual benefits and costs for proposed solutions as well as how to apply the necessary cost-effectiveness tests for performing a complete BCA. The BCA Handbook also presents general BCA considerations and notable issues regarding project and investment benefits assessments. Definitions and equations for each benefit and cost are provided along with key parameters.

[1] "Benefit-Cost Analysis (BCA Handbook) Version 1.2", July 31, 2018.
[2] Case 14-M-0101 "Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision", Order Establishing Benefit-Cost Analysis Framework, January 21, 2016.
[3] "Benefit-Cost Analysis Filing Requirement Guidance," New York Department of Public Service, Case 15-M-0252, May 15, 2018.

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Version History

Version	File Name	Last Updated	Document Owner	Updates since Previous Version
V1.0	CECONY Gas BCA Handbook - v1.0	September 14, 2020	CECONY	First Issue

Acronyms and Abbreviations

Acronyms and abbreviations are used extensively throughout the Interim BCA Handbook and are presented here at the front of the Handbook for ease of reference.

BCA	Benefit-Cost Analysis
BCA Order	Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Establishing the Benefit-Cost Analysis Framework (issued January 21, 2016)
CECONY	Consolidated Edison Company of New York
CNG	Compressed Natural Gas
CO_2	Carbon Dioxide
Commodity Cost	The cost of natural gas at wholesale prices
CRG	Avoided Company Retained Gas, as further defined in Section 2.
Peaking Services	Gas supply services delivered to the city-gate acquired from a third-party (not a pipeline)
DR	Demand Response
Dth	A dekatherm of natural gas; an industry standard term referring to a quantity of natural gas containing 1 million British thermal units of energy, and represents about 1,000 cubic feet of natural gas
LBMP	Locational Based Marginal Prices, wholesale electricity prices
LNG	Liquefied Natural Gas
MMBtu	Million Btu's or one dekatherm
NO_x	Nitrogen Oxides
NPS	Non-Pipeline Solutions
NYISO	New York Independent System Operator
O&M	Operations and Maintenance
On-System	Infrastructure and/or supplies that are located downstream from CECONY's city gates
Off-System	Infrastructure and/or supplies that are located at or upstream of CECONY's city gates
Renewable Natural Gas	Pipeline quality gas (primarily methane) that has been recovered from a biological or other process (generally diverted from waste streams such as landfills, animal manure and waste treatment facilities) and upgraded to be compatible with other gas supplies delivered to customers
RIM	Rate Impact Measure
SCT	Societal Cost Test
SO_2	Sulfur Dioxide
UCT	Utility Cost Test

WACC	Weighted Average Cost of Capital
WACOPS	Weighted Average Cost of Peaking Services

1. INTRODUCTION

This handbook ("Gas BCA Handbook") lays out a framework for calculating the benefits and costs of projects and investments associated with the reduction, deferment, or elimination of expenditures related to the procurement and delivery of natural gas to CECONY customers. These solutions include demand-side efforts, such energy efficiency, electrification, and demand response programs, and supply-side efforts, such as the construction of on-system natural gas supply resources (e.g. interconnected renewable gas and CNG storage). An overriding principal is that any such investment or program produce results that do not fundamentally affect the core reliability of the service provided to CECONY customers.

The BCA framework set out herein is guided by the principles that a BCA should, insofar as possible:

1. Present clear methodologies
2. Identify and evaluate benefits and costs, recognizing the need to use broader assumptions at times (e.g., when more granular details are not readily available or reasonably quantifiable)
3. Evaluate projects and programs within the broader context of a portfolio (rather than as individual measures or investments), allowing for consideration of potential synergies and economies of scale across the portfolio
4. Address the full lifetime of investments
5. Provide an assessment of the underlying risk of performance of an investment or program via sensitivity analysis on key assumptions
6. Compare benefits and costs to traditional alternatives instead of valuing them in isolation

The Gas BCA Handbook reviews key considerations and methodologies affecting BCA. This includes a review of core valuation parameters applicable to the BCA, specific categories of costs and benefits included in the BCA framework, discussion of input assumptions and possible sources for input data, and modeling methodologies applicable to a broad range of such projects. The methodology underlying the handbook is intended to be technology-neutral and broadly applicable to all projects and portfolio types, with modest adjustments as necessary. However, specific projects or portfolios of projects will typically require additional project-specific information, inputs, assumptions, and adjustments to the generic methodologies summarized herein.

The handbook also reviews the three key tests that will be used to assess the benefits and impacts of each proposed project/program. The results of these tests are used to arrive at overall recommendations regarding approval of portfolios of projects.

1.1 Application of the Gas BCA Handbook

The Gas BCA Handbook provides a common methodology to be applied across investment projects and portfolios. Common input assumptions and sources that are applicable on a global basis across all projects are provided within (e.g. assumptions that are not specific to the Utility or assumptions by the Department of Public Service (DPS) Staff[4]). Individual BCAs for specific projects or portfolios are likely to require additional, project-specific information and inputs.

Table 1-1 lists the global assumptions and their respective sources to be used for the BCA and referenced in this Handbook.

[4] "Benefit-Cost Analysis Filing Requirement Guidance," New York Department of Public Service, Case 15-M-0252, May 15, 2018.

Table 1-1: Global Assumptions

Global Assumptions	Source
Inflation Rate	DPS Staff BCA Guidance, May 2018
Cost of Carbon Emissions	DPS Staff BCA Guidance, May 2018
Gas Commodity Price Forecast	NYISO CARIS Natural Gas Price Forecast

Utility-specific assumptions include data embedded in various utility published documents such as rate cases. Table 1-2 lists the suggested utility-specific assumptions for the BCA Handbook.

Table 1-2: Utility-Specific Assumptions

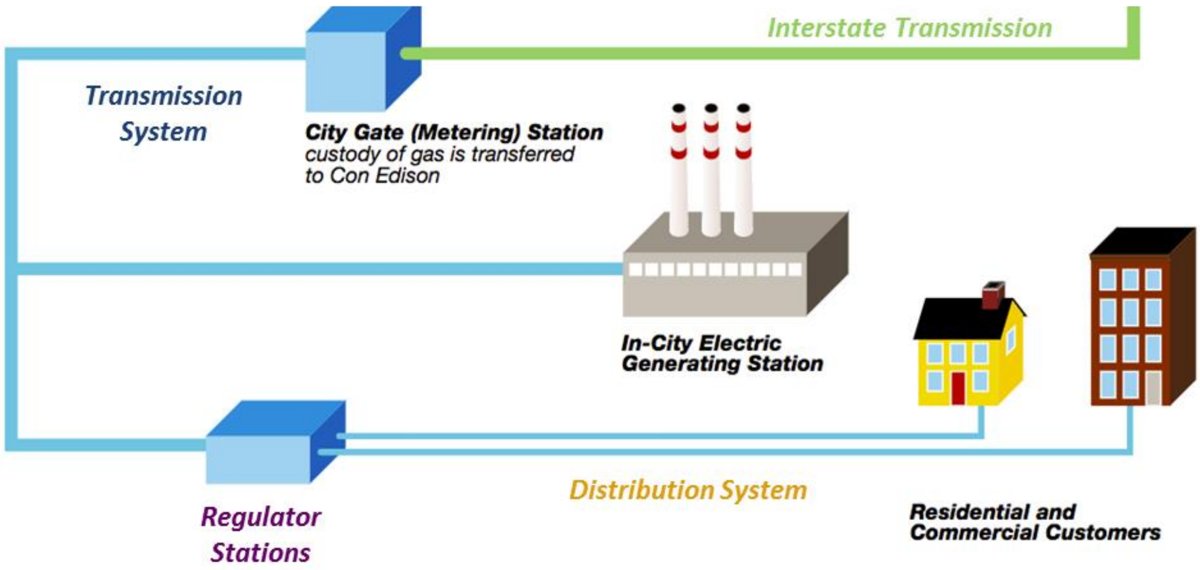
Utility-Specific Assumptions	Source
Weighted Average Cost of Capital	CECONY Gas Rate Case 19-G-0066 (12 months ending December 31, 2020)
Weighted Average Cost of Peaking Services	CECONY
Weighted Average Cost of Pipeline & Storage Capacity	CECONY
Gas Commodity Price Forecast Blending Weights	CECONY
Marginal Cost of Service	CECONY
Company Retained Gas	CECONY

The global and utility-specific assumptions that are included in the 2020 version of the Gas BCA Handbook (as listed in Table 1-1 and Table 1-2) are typically values by industry or government agency averages or utility system averages. The application of the Gas BCA framework will require the standard inputs provided in the Gas BCA Handbook as well as project-specific information that captures locational and temporal aspects of the investment under analysis.

1.2 Overview of the CECONY's Gas System

CECONY manages a complex, underground natural gas transmission and distribution system designed to serve customers in Manhattan, the Bronx, Queens, and Westchester. CECONY transports more than 300 million dekatherms (Dth) of natural gas annually and serves approximately 1.2 million gas customers. CECONY's gas system comprises three main components – the CECONY transmission system, regulator stations, and the distribution system, as shown in Figure 1-1. This section provides an overview of each component of CECONY's gas system and generally describes how CECONY procures natural gas commodity.

Figure 1-1: – CECONY Gas System

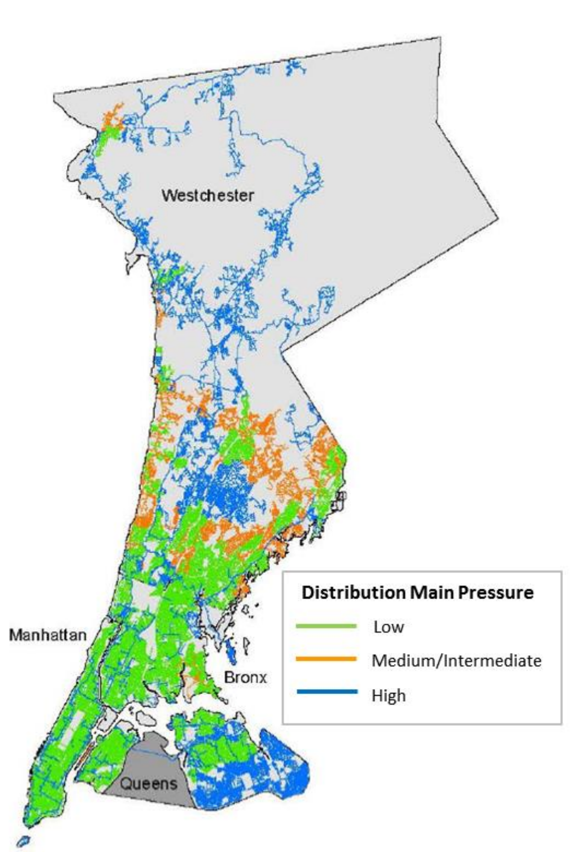


Natural gas is transported by interstate transmission pipelines to one of eleven citygates where it then enters the CECONY-owned gas system. For purposes of the Gas BCA Framework, infrastructure and sources of supply upstream of and including the citygates are considered “off-system.” Whereas, infrastructure and sources of supply downstream of the citygates are considered “on-system.” CECONY’s transmission system is supplied by seven city gate stations located in Manhattan, Queens, the Bronx, and Westchester County. The remaining four citygate stations supply gas directly from the interstate pipelines into CECONY’s distribution system in northern Westchester. CECONY’s transmission system consists of over 90 miles of mains operating at pressures ranging from 125 psig to 350 psig. The transmission system is part of a larger regional network called the New York Facilities System, which is jointly owned and operated by CECONY and National Grid. The CECONY transmission system moves gas to regulator stations throughout CECONY’s service territory.

Regulator stations receive gas from the transmission system and then step it down to distribution-level pressures. Regulator stations are located throughout the service territory and are used to transfer gas to distribution supply mains and support local pressures on the distribution system. There are also distribution regulator stations, which step down pressures from a higher distribution pressure to a lower distribution pressure.

CECONY distribution system consists of more than 4,300 miles of mains, operating at pressures less than 99 psig in Manhattan, the Bronx, Queens, and Westchester. The distribution system is comprised of three interconnected sub-systems operating at three different pressures – high pressure, medium/intermediate pressure, and low pressure (see Figure 1-2). Emanating from the distribution mains, approximately 375,000 gas services connect the distribution system to customer premises. Firm gas Customers are served off the high, medium, or low-pressure distribution system, depending on where they are located within the service territory.

Figure 1-2: CECONY Gas Distribution System

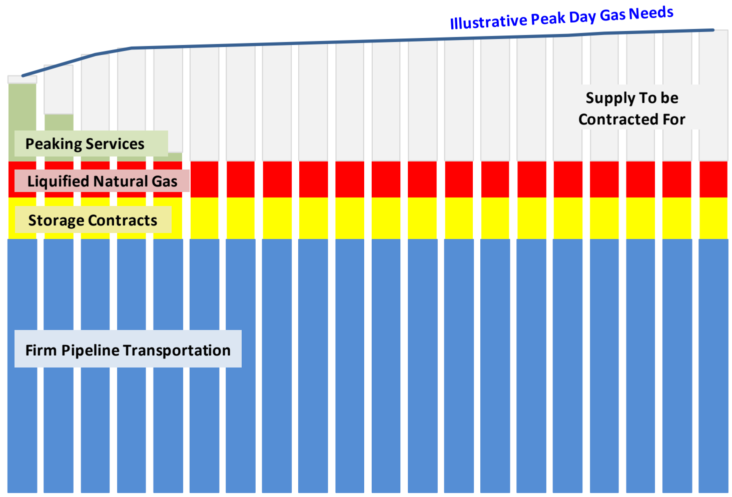


Source: CECONY 2019-2038 Gas Long Range Plan, Figure 2-1

CECONY uses both on-system and off-system supplies to provide reliable gas service to customers. The majority of CECONY's supply is from firm pipeline transportation and storage contracts, shown in blue and yellow in Figure 1-3, which provides an illustrative supply stack of CECONY's sources of gas. CECONY uses off-system pipeline and storage contracts to deliver gas to its citygates. The firm pipeline transportation contracts are diversified by production regions and can source gas from several regions, such as the Gulf Coast, Canada, and Northeast (e.g., New York, Pennsylvania, etc.). CECONY has access to storage fields in the Gulf Coast and the Northeast, where gas is injected during off-peak periods and withdrawn during high-demand periods to meet customer needs.

To meet demand on high demand days during the winter the Company uses citygate delivered supplies, which include Peaking Services. Peaking Services (shown in green in Figure 1-3) are contracts that allow the Company to call upon a third party to deliver a quantity of gas to the citygate, with limited advance notice. Peaking Services are typically contracted before the start of the winter season. The quantity of Peaking Services procured is based on the forecasted peak day demand and the quantity of other sources of peak day supply. Other types of city gate supplies include baseload delivered services and spot citygate purchases.

Figure 1-3: Illustrative Supply Stack



Notes: While this figure is broadly consistent with the supply stack for CECONY, it is not reflective of the Company's supply stack in any specific year.

In addition to its off-system supply, CECONY uses on-system sources of supply, notably Liquefied Natural Gas ("LNG") and compressed natural gas ("CNG"). The Company uses its LNG facility to maintain adequate supply, provide gas during high demand days, as well as provide supply for an operational contingency. Finally, the company uses CNG trucking as an additional source of on-system supply in constrained areas such as the portion of Westchester County currently subject to a moratorium on new gas customers.

In the context of the Gas BCA framework, Peaking Services are considered the marginal source of supply during peak times. That is, to the extent a project or program reduces peak demand, there is first a direct benefit in terms of reducing Peaking Services costs. Only after the need for Peaking Services is reduced or eliminated can other sources of supply (such as supply associated with the storage and pipeline capacity portfolio) be considered a marginal source of supply during peak periods.

1.3 BCA Handbook Version

This Gas BCA Handbook provides techniques for quantifying the benefits and costs related to supply-side and demand-side solutions. To the extent they are relevant to this framework, this Handbook also includes benefits and costs identified in the BCA Order. Interim revisions will be limited to material changes to input assumptions and/or new guidance or orders.

1.4 Structure of the Handbook

The remaining sections of the Handbook explain the methodology and assumptions to be applied under the BCA Framework:

> **Section 2. General Methodological Considerations** describes key issues and challenges to be considered when developing project-specific BCA models and tools based on this Gas BCA Handbook.

Section 3. Relevant Cost-Effectiveness Tests defines each cost-effectiveness test included in the Gas BCA Framework. These include the Societal Cost Test ("SCT"), the Utility Cost Test ("UCT"), and the Rate Impact Measure ("RIM"). The BCA Order specifies the SCT as the primary measure of cost-effectiveness.

Section 4. Benefit and Costs Methodology provides detailed definitions, calculation methods, and general considerations for each benefit and cost.

Section 5. High Level Examples discusses which benefits and costs are likely to apply to different types of Gas BCA solutions and provides examples for a sample of selection of proposals.

2. GENERAL METHODOLOGICAL CONSIDERATIONS

There are numerous analytical choices and assumptions required for any BCA, some that will be common across analyses and others that will be project specific. This section reviews these considerations at a high level, and Section 4 provides a more detailed discussion of various benefits and costs that will vary based on the specifics of a proposed Gas BCA investment or project.

Accounting of Benefits and Costs across Multiple Value Streams

Any given project analyzed using the Gas BCA framework has the potential to provide benefits or impose costs across multiple value streams. For example, a demand response program may provide the benefit of avoided Peaking Services, commodity costs, and, based on its specific placement on the system, allow the utility to defer investment in incremental on-system distribution capacity. All three benefits should be incorporated into the BCA.

Care should be taken to avoid double counting of measured benefits or costs. Double counting can be avoided by: (1) careful tracking of the value streams resulting from multiple investment elements in a project, program, or portfolio; and, (2) clear definition and differentiation between the benefits and costs, and (3) careful consideration of how the related value propositions interact.

Incorporating Losses into Benefits

The measurement point of benefits and costs included in a BCA, which requires accounting for losses that occur between measurement points. For example, the savings from an energy efficiency program are measured at the point of consumption (i.e., the customer's meter). However, commodity savings measured at the point of consumption undercount the savings in total supply measured at the citygate due to the losses in the transmission and distribution system between the city gate and the point of consumption. To capture the total savings from the energy efficiency program, the savings measured at the point of consumption must be "grossed up" to account for these losses in the system.

The BCA framework focuses on on-system losses in the system, which are termed "Avoidable Company Retained Gas". As described in the example above, these losses occur between the measurement point at the citygate and the relevant measurement point in the system. Avoidable Company Retained Gas (CRG) primarily includes fuel used for heaters and compressors and excludes losses related to leakage and other factors that cannot be affected by reducing end use demand. Conceptually, a project located in the on-system transmission system will have the lowest measure of CRG and a project located at a customer's meter on the distribution system will have the highest measure of CRG. CRG does not account for losses that occur in the off-system interstate pipelines. To the extent that a project is able to remove pipe or other infrastructure from the gas system, the BCA shall account for the benefit of lower losses and emissions associated with the removed infrastructure.

The Gas BCA Handbook accounts for all Avoided Company Retained Gas by adjusting certain benefit and cost streams (e.g. change in peak day demand or change in emissions). The per unit impact benefit or cost is increased by grossing up the impact parameter (measured at the customer's meter) for Avoidable Company Retained Gas (i.e., dividing by (1 – CRG)).

Establishing Appropriate Analysis Time Horizon

Any BCA analysis must consider the appropriate time horizon for evaluating associated benefits and costs. Programs and projects, such as those under consideration for Gas BCA, have multiple components, including associated hardware, software, and related direct and indirect benefits and costs. For the purposes of this BCA Handbook, the relevant timeframe for each BCA analysis will be the projected life of the specific program or project being evaluated. Authoritative sources and engineering judgment will be used to make such determinations.

Using Appropriate Granularity of Data for Analysis

Ideally, the BCA would use program- or project-specific locational and temporal information. Practically, however, data to support the use of granular program- or project-specific inputs may be unavailable or too uncertain that their application might not increase the accuracy of the BCA. When the more granular data cannot be used, an appropriate annual average or system average maybe used, to reflect the expected savings from a Gas BCA project.

Performing Sensitivity Analysis

Comparative analyses of a project or a portfolio of projects may be improved by evaluating the expected performance relative to other projects or portfolios of projects under different conditions. To assist in this process, sensitivity analyses may be utilized to identify those assumptions and factors that are key to determining the overall net benefit of a project or portfolio.

Incorporating the Timing of Impacts

For the purposes of BCA analysis of Gas BCA projects, the timing of benefits and costs should be accounted for as follows:

- **Commodity and Operational** – Benefits and costs associated with commodity (e.g., increases or decreases in quantities consumed) or operational activities (e.g., associated O&M expenses) should be assumed to occur in the same year as the underlying projected impact. In other words, a program that reduces consumption in year X should be treated as having an associated benefit in year X.

- **On-System and Off-System Capacity** – Direct costs associated with capital investments or infrastructure changes should be assumed to occur in the year incurred. Benefits (or costs) associated with such investments should be assumed to occur in the year that actual effects occur (i.e., the benefits or costs are actually realized). For example, if a project reduces system peak load in winter 2020 but the portfolio of assets cannot be modified in 2020 to account for this reduction (e.g., due to prior contractual commitments to off-system capacity) then the benefit will be recognized the following year. Any benefit should not be recognized until the portfolio can be adjusted. However, to the degree Gas BCA impacts are known ahead of time and integrated into portfolio planning, the associated benefit should be credited to the project at the time the impacts are realized and then adjusted to the net present value.

Defining Seasons:
Natural gas winters are defined as the period from November 1 to March 31; whereas, natural gas summers are defined as April 1 to October 31.

3. RELEVANT COST-EFFECTIVENESS TESTS

The BCA Order states that the Societal Cost Test (SCT), Utility Cost Test (UCT), and the Rate Impact Measure (RIM) make up the relevant cost-effectiveness tests to be used in the BCA. These cost-effectiveness tests are summarized in Table 3-1.

Table 3-1: Cost-Effectiveness Tests

Cost Test	Perspective	Key Question Answered	Calculation Approach
SCT	Society	Is the State of New York better off as a whole?	Compares the utility and customer costs incurred to design and deliver projects with avoided costs (e.g., commodity, infrastructure, etc.) and the cost of externalities (e.g., carbon emissions).
UCT	Utility	How will utility costs be affected?	Compares the costs incurred to design, deliver, and manage projects by the utility with avoided utility expenditures.
RIM	Ratepayer	How will utility rates be affected?	Compares utility costs and utility bill changes with avoided commodity, infrastructure, and other delivery-related costs.

The BCA Order positions the SCT as the primary cost-effectiveness measure because it evaluates impact on society as a whole.

The role of the UCT and RIM is to assess the preliminary impact on utility costs and customer bills from the projects that pass the SCT. The results of the UCT and RIM test are critical to identify projects that may require a more detailed analysis of their impact to the utility and customers. Some projects may not provide benefits to the utility and customers, even if it is beneficial to society as a whole. It is important to note, however, that *if a measure passes the SCT but its results do not satisfy the UCT and RIM tests, the measure would not be rejected unless a complete bill impact analysis determines that such impact is of a "magnitude that is unacceptable".*[5]

Each cost-effectiveness test included in the BCA Framework is defined in greater detail in the following subsections. Which of the various benefits and costs to include in analysis of individual projects or investment portfolios requires careful consideration, as discussed in Section 2.

Table 3-1 summarizes which cost-effectiveness tests can be applied to the benefits and costs included in the BCA Order. The subsections below provide further context for each cost-effectiveness test.

[5] REV Proceeding, BCA Order, p. 13.

Table 3-1: Summary of Cost-Effectiveness Tests by Benefit and Cost

Benefit/Cost	SCT	UCT	RIM
Benefits			
Avoided Peaking Services	✓	✓	✓
Avoided Pipeline & Storage Costs	✓	✓	✓
Avoided Commodity Costs	✓	✓	✓
Avoided On-System Capacity Infrastructure	✓	✓	✓
Avoided O&M	✓	✓	✓
Reliability/Resiliency	✓	✓	✓
Avoided CO2 Emissions	✓		
Other Avoided Emissions	✓		
Non-Energy Benefits*	✓	✓	✓
Other External Benefits	✓		
Costs			
Program Administration Costs	✓	✓	✓
Incremental On-System Investments	✓	✓	✓
Lost Utility Revenue			✓
Shareholder Incentives			✓
Incremental Participant Costs	✓		
Alt. Fuel Costs	✓	✓	✓
Alt. Fuel CO_2 Emissions	✓		
Alt. Fuel Other Emissions	✓		
Net Non-Energy Costs*	✓	✓	✓
Other External Costs	✓		

*It is necessary to identify which cost-effectiveness test should include the benefit or cost in the Net Non-Energy Benefit or Net Non-Energy Cost as it may apply to the SCT, UCT, and/or RIM.

Performing a cost-effectiveness test for a specific project or a portfolio of projects requires the following steps:

- **Select the relevant benefits** for the investment.
- **Determine the relevant costs** from each cost included over the life of the investment.
- **Estimate the impact** the investment will have in each of the relevant benefit categories for each year of the analysis period (i.e., how much it will change the underlying physical operation of the electric system to produce the benefits).
- **Apply the benefit values** associated with the project impacts as described in Section 4.
- **Apply the appropriate discount rate** to perform a cost-effectiveness test for a specific project or portfolio. The discount rate is set in CECONY's rate cases at the utility's cost of capital.[6] Benefit and Cost streams should be discounted at the Weighted Average Cost of Capital ("WACC") unless specified otherwise.

[6] CECONY's Weighted Average Cost of Capital is currently 6.61% for the twelve months ending December 31, 2020. See CECONY Gas Case 19-G-0066

- **Treat inflation consistently** by discounting real cash flow by real discount rates and nominal cash flows by nominal discount rates. The guidance from DPS Staff states that DPS is the responsible party to provide the inflation rate, which is based on the Gross Domestic Product Price Index.[7]

3.1 Societal Cost Test

Cost Test	Perspective	Key Question Answered	Calculation Approach
SCT	Society	Is the State of New York better off as a whole?	Compares the costs incurred to design and deliver projects, and customer costs with avoided upstream and other supply-side resource costs; also includes the cost of externalities (e.g., CO2 Emissions and Net Non-Energy Benefits).

Most of the benefits included in the BCA Order can be evaluated under the SCT because their impact applies to society as a whole. This includes Avoided Peaking Services, Avoided Pipeline & Storage Capacity Costs, Avoided Commodity Costs, Avoided On-System Capacity Infrastructure, Avoided O&M, Reliability & Resiliency, Avoided CO2 Emissions, and Avoided Other Emissions.

Lost Utility Revenue and Shareholder Incentives do not apply to the SCT, as these are considered transfers between stakeholder groups that have no net impact on society as a whole.

3.2 Utility Cost Test

Cost Test	Perspective	Key Question Answered	Calculation Approach
UCT	Utility	How will utility costs be affected?	Compares the costs incurred to design, deliver, and manage projects by the utility with avoided on-system infrastructure costs.

The UCT looks only at impacts to the utility's direct costs. For this reason, external benefits such as Avoided CO2 Emissions and Other Avoided Emissions are not considered in the UCT.

Incremental Participant Gas BCA Costs are not considered in the UCT because Incremental Participant Gas BCA Costs are not a utility cost. Lost Utility Revenue is not included in the UCT, because any reduced revenues from Gas BCA are assumed to be made up by non-participating Gas BCA customers through future rate adjustments.

[7] "Benefit-Cost Analysis Filing Requirement Guidance," New York Department of Public Service, Case 15-M-0252, May 15, 2018.

3.3 Rate Impact Measure

Cost Test	Perspective	Key Question Answered	Calculation Approach
RIM	Ratepayer	How will utility rates be affected?	Compares utility costs and utility bill changes with avoided commodity, infrastructure, and other delivery-related costs.

The RIM test can address rate impacts to non-participants. External benefits such as Avoided CO2 Emissions and Other Avoided Emissions are not included in the RIM as they do not directly affect customer rates. Reliability/Resiliency benefits have no predictable effect on rates.

Incremental Participant Gas BCA costs do not apply to the RIM because the cost of a Gas BCA solution is not a utility cost. However, any reduced revenues from Gas BCA are included as increased costs to other ratepayers as Lost Utility Revenue because of revenue decoupling or other means that transfer costs from participants to non-participants.

4. BENEFITS AND COSTS METHODOLOGY

The following reviews key benefits and costs that are specific to Gas BCA investments and key to any associated BCA. Definitions are provided for each category, as well as theoretical calculation methodologies and complexities surrounding estimating associated future costs and benefits. While this section has been divided into a discussion of Benefits and a separate discussion of Costs, several of the items can fall into either category (e.g., negative benefit).

4.1 Summary of Gas BCA Benefits and Costs

The following sections provide a high-level summary of the categories of benefits and costs applicable to the BCA analysis. These categories are described in more depth in subsequent sections.

4.1.1 Benefit Categories

Benefits are divided into six main categories:

Avoided Peaking Services — Benefits derived from avoiding the need to hold Peaking Services contracts; these contracts are used for gas supply services delivered to the citygate acquired from a third party (i.e., exclude the storage and pipeline costs listed below) and include both a capacity and a commodity component. Peaking Services are currently considered the marginal source of supply during peak days.

Avoided Pipeline and Storage Capacity Costs — To the extent that Peaking Services is no longer the marginal source of supply, then supplies delivered with the pipeline and storage capacity portfolio would become the marginal source of supply. This benefit is derived from avoiding the need to hold capacity on off-system storage and pipeline assets required to deliver natural gas to CECONY’s citygates.

These generally consist of fixed costs (e.g. reservation fees) and associated avoided variable costs (e.g. volumetric charges for the costs associated with physical delivery of natural gas to the city-gate).[8] The commodity component, associated with the physical molecules of natural gas that are delivered to CECONY's citygates, is covered in "Avoided Commodity Cost" below.

Avoided Commodity Costs: Benefits derived from avoiding the need to purchase natural gas to serve CECONY's gas customers. This includes off-system purchase of natural gas upstream of the Company's city gates, commodity purchases at the city gate, and on-system supply sources (e.g. CNG). On-system LNG is excluded from the Gas BCA framework.[9]

Avoided On-System Capacity Expense: Benefits derived from avoiding the need to invest in on-system infrastructure. On-system infrastructure includes CECONY's transmission system, regulators, and distribution system. These generally consist of avoided carrying charges (including items such as depreciation and applicable taxes) for capital additions necessary for expanding or upgrading the distribution system to accommodate new business and/or avoided O&M related to maintaining on-system infrastructure.

Reliability/Resiliency: Benefits that may be derived from specific Gas BCA projects in the form of greater resiliency of the distribution system (e.g., those providing pressure support at key locations) or ability to avoid system outages or recover more quickly from any such outages.

External Benefits: Indirect benefits associated with a Gas BCA project or program, such as reduced emissions or other societal benefits not primarily recognized by the utility via customer bill charges or other payment mechanisms.

4.1.2 Cost Categories

Costs are divided into seven main categories:

Program Administration: Administrative related costs directly associated with implementing a Gas BCA project or program. These can include costs associated with setting up a program, ongoing costs associated with monitoring and accounting for a program, and incentives paid to participants.

[8] Avoided pipeline and storage capacity costs are only available after peak demand has been reduced such that the need for Peaking Services is eliminated.

[9] CECONY's on-system LNG facility is utilized as a source of supply for an operational contingency. Therefore, due to the operational and reliability purposes of the facility, it is excluded from the Gas BCA.

Incremental On-System Capacity Expenses:	Infrastructure costs incurred by the utility to support the implementation of the Gas BCA project or program.
Lost Utility Revenue	Lost gas revenue from reduced Gas BCA participant demand.
Shareholder Incentives	Include the annual costs to customers of utility shareholder incentives that are tied to the projects or programs being evaluated.
Incremental Participant Cost	Total incremental costs incurred by Gas BCA providers relative to their baseline costs, including equipment and participation costs assumed by participants or providers, net of payments to provider or incentive/rebates to participants with a floor of zero. For example, if an energy efficiency program included an upgraded natural gas water heater, the participant cost included would reflect the difference between the higher and lower efficiency natural gas water heaters, net of incentives.
Alternative Fuel Costs:	Cost of using an energy source other than gas as a replacement for the service otherwise provided by gas.
External Costs:	Indirect costs associated with a Gas BCA project or program, such as increased emissions or other societal costs not primarily paid for by the utility or its customers, to the degree such costs are recognized in the broader market.

4.1.3 Applicable Units

Benefits and Costs are generally measured as either capacity related or volumetric related:

- **Capacity Measures** – These relate to impacts associated with peak day capacity to deliver gas to customers. These are generally represented as $ per Dth of peak day impact. Benefits or costs that are capacity in nature are those that can avoid or incur incremental capacity contracts or deliverability to the city gate.

- **Volumetric Measures** – These relate to impacts associated with consumption. They are generally represented as $ per Dth. Benefits or costs that are volumetric in nature are those that are associated with actual (or avoided) consumption.

4.2 Off-System Benefits

The specific Avoided Off-System Supply Costs associated with a Gas BCA program or investment is a function of the contractual rights to a particular upstream pipeline capacity resource or Peaking Services resources that CECONY would otherwise acquire to meet the associated gas delivery requirements of its customers. As part of any Gas BCA solicitation and/or program review, CECONY must assess the portfolio of off-system supply alternatives available to it that it would otherwise acquire to cover its projected gas supply requirements. The costs associated with these off-system supplies then determine the benefit of avoiding such services through the acquisition of Gas BCA options.

At any given point, it is unlikely CECONY will be faced with one discrete option for acquiring incremental off-system supply. Rather, under most circumstances multiple options will be under consideration, each with its own set of fixed and variable costs. Each option will also have a unique set of associated characteristics, such as trade-offs between fixed and variable costs, firmness of supply, duration of the supply (i.e., number of days the resource can perform), counterparty credit risk of the off-system supply provider, minimum contract size, location, and related factors.

Likewise, the ability of specific Gas BCA projects or programs to defer or otherwise avoid the acquisition of off-system supplies also depends on a number of characteristics, including: timing of the proposed project; duration of the impact; location; relation to other Gas BCA projects/programs and their associated characteristics; and cumulative size of the impact of the whole portfolio of Gas BCA relative to any minimum commitments required by off-system suppliers. As such, the combination of off-system supply options and Gas BCA proposals must be evaluated as a portfolio to assess the overall potential for cost avoidance.

4.2.1 Avoided Peaking Services

On peak demand days, CECONY relies on additional off-system supplies, such as Peaking Services. CECONY may acquire Peaking Services from a third party directly at CECONY's city gates. In such cases, the third party holds off-system capacity assets that enable it to provide firm supply directly to CECONY for a limited number of days during peak demand conditions (e.g., 15 days or 30 days). Peaking Services costs include: (1) a fixed reservation fee for the right to call upon the supply and (2) a variable commodity charge for when CECONY does call upon the supply.

The benefits associated with avoided Peaking Services include the fixed reservation fee component and the variable commodity charge component, which can be calculated using the frameworks outlined below. Peaking Services are currently considered the marginal source during the peak demand periods (see Figure 1-3 above). Gas BCA programs and investments that provide firm supply on peak days (or reduce peak day gas supply requirements) have the benefit of reducing CECONY's need to acquire incremental Peaking Services. As such, there is a direct benefit from such programs or investments in the form of avoided Peaking Service expenses. To the extent that the need for Peaking Services is reduced or eliminated, then other sources of supply (e.g., pipeline and storage based supplies) may become the marginal source of supply to serve peak day demand.

To receive maximum credit for Avoided Peaking Services, a Gas BCA project or program(s) should provide incremental supply and/or reduce demand during peak conditions, <u>and</u> provide this for a sufficient period of time to address the utility's projected design requirements. The specific duration of need required by the utility will be a function of the set of supply options in the utility's existing portfolio and the nature of the utility's projected loads on affected portions of its gas system. If the resource requirement calls for a quantity of gas on multiple days and the proposed Gas BCA project or program can provide benefits on only some of those days, then the Gas BCA project or program cannot, in and of itself, avoid the full marginal supply resource. However, this does not mean the project or program should be assigned no value toward avoiding marginal supply resources.

To the degree a project or program can be combined with other proposals in such a combination to provide incremental supply and/or reduce demand during peak conditions, then the project or program may be awarded some credit toward avoided supply costs. In concept, if the utility requires an equal amount of supply or demand relief on five days of supply and an asset only provides sufficient capacity to fulfill one day of that need, then the asset could arguably be credited for one-fifth of the avoided upstream asset cost. However, the actual dollar amount credited will be based on a portfolio assessment considering all alternative Gas BCA programs and how they might, in combination with each other, effectively address the projected need.

Estimating Project Specific Benefits – Avoided Peaking Services – Fixed Reservation Fee

Equation 4-1. Avoided Peaking Services – Fixed Reservation Fee

$$\text{Benefit}_{Y+1} = \sum \left(\frac{\Delta\text{Peak Load}_{Y,r}}{(1\text{-CRG}_Y)} * \text{Coincidence Factor}_{Y,r} * \text{Derating Factor}_{Y,r} * \text{WACOPS}_Y \right)$$

Where:

Y+1	The year that the benefit is recognized / realized through the actual avoidance of reservation fees associated with Peaking Services.
ΔPeak Load$_Y$	The project's potential maximum demand reduction capability, or "nameplate" impact, measured in Dth/day.
CRG$_Y$	The Avoidable Loss for the system applicable to year Y.
r	The specific retail delivery location.
Coincidence Factor$_Y$	Factor used to adjust the nameplate capacity of the project or program to account for the relationship between the coincidence of overall system's peak day requirements and the asset's expected contribution at such time.
Derating Factor$_Y$	Factor used to de-rate the coincident peak load benefit of the resource based on its expected availability during peak days.
WACOPS$_Y$	The Weighted Average Cost of Peaking Services is the fixed reservation fee component of the avoidable Peaking Services supply under the applicable scenario, measured in $/Dth/duration of service.

Considerations on Equation Components

Y+1

The benefit is assumed to be incurred in the year following the peak load reduction. This reflects the time differential between when Peaking Services contracts are procured and when peak load reduction is realized.

Peak Load$_Y$

The Peak Load factor measures the nameplate impact at the retail delivery or connection point. The nameplate capacity of a project is separate from its ability to impact coincident peak day requirements. The nameplate capacity is the underlying design capability of the asset or program, generally based on the associated underlying engineering principles. This input is project or program specific. For this factor, a positive value represents a reduction in peak load.

Coincidence FactorY

The coincidence factor quantifies a project's contribution to peak day supply (or demand reductions) relative to its nameplate impact. Peak day supply is procured based on forecasted demand under design day conditions.[10] Therefore, this factor should be used to adjust the nameplate capacity for various physical factors that affect the asset's ability to impact peak day demand under design day conditions. The factor should also account for any associated operational considerations that recognize how the program or asset impacts coincide with peak day requirements. For example, a project with a nameplate demand reduction capacity of

[10] The design day is the expected firm customer demand on a zero degree Temperature Variable (TV) for the CECONY service territory. The design day demand only reflects gas used by firm gas customers and does not include, for example, the gas supply needs of customers taking interruptible delivery service.

100 Dth with a system coincidence factor of 0.8 would reduce system peak demand by only 80 Dth. An asset's or program's performance may be negatively correlated with the factors that drive peak day demand (particularly temperature). The determination of the appropriate factor is project/program specific. However, consistent principles should be applied across all projects and programs.

Derating Factor$_Y$

The derating factor should be used to adjust for uncertainty-related factors that may affect the general availability of an asset, such as duration of service (e.g., one day or any day over the winter), or the likelihood that the asset or program will fail to perform, despite its physical capabilities. For example, an incremental supply may fail to perform because the facility is undergoing maintenance. The derating factor should also reflect distribution limitations that restrict the ability of an incremental supply (or demand reduction) at one point to fully reduce system requirements. Again, the specific factor adjustments will be project/program specific but should be consistently applied across all projects.

WACOPS$_Y$

On a peak day basis, Peaking Services are considered the marginal source of supply. For these contracts, the avoidable fixed cost is the associated reservation fee, measured in $/Dth/duration of service. The value of this benefit is measured based on the company's Weighted Average Cost of Peaking Services ("WACOPS").

Duration of service is the volume-weighted average number of days that CECONY can call upon Peaking Services, based on CECONY's prior year's Peaking Services portfolio. The total awarded benefit is project specific and is based on the proposal's duration of service during peak periods (i.e., the number of days it can provide peak demand reduction). The maximum benefit is awarded to proposals whose duration of service is equal to or greater than the weighted average duration of service of CECONY's prior year's Peaking Services portfolio. Proposals with a duration of service shorter than CECONY's peaking service portfolio can receive a benefit proportional to the Company's duration of service.

r

'r' represents the specific location of the Gas BCA program impact on the retail distribution system. To the extent that location specific information is available, portfolio analysis of Gas BCA programs will consider the location of the impact as it relates to specific off-system capacity commitments as not all locations will have the same impact. When either the data is not available or the program/portfolio is system-wide (e.g., energy efficiency programs), a system-average value will be used.

<u>Estimating Project Specific Benefits – Peaking Services Commodity Cost</u>

This benefit is associated with avoiding the commodity costs associated with Peaking Services. The variable peaking service commodity charge captures peak day commodity costs through the use of a multiplier applied to NYISO's CARIS Natural Gas Price forecast. This benefit is available only on the peak price days.

Equation 4-2 Avoided Peaking Services – Commodity Cost

$$\text{Benefit}_{Y} = \sum \frac{\Delta Peak\ Load_{Y,r}}{(1 - CRG_{Y})} * \text{Peaking Services Commodity Cost}_{Y,r}$$

Where:

Y	The year that the benefit is recognized/ realized through the actual avoidance of Peaking Services commodity costs.
ΔPeak Load$_{Y,r}$	The project's expected maximum demand reduction capability, or "nameplate" impact, measured in Dth/day.
CRG$_{Y}$	The Company Retained Gas for the system applicable to year Y.
r	The specific retail delivery location.
Peaking Services Commodity Cost $_{Y}$	The projected wholesale cost of gas delivered at CECONY's city-gate measured in $/Dth/day.

<u>Considerations on Equation Components</u>

ΔPeak Load$_{Y,r}$

The Peak Load factor measures the nameplate impact at the retail delivery or connection point. This factor should be measured consistently with the fixed reservation fee component of Peaking Services discussed above. For this factor, a positive value represents a reduction in peak load.

Peaking Services Commodity Cost$_{P,Y}$

The avoided commodity cost component of Peaking Services should be measured on a peak period basis. Avoided Commodity Cost benefits are calculated using a forecast of natural gas prices. NYISO's CARIS Natural Gas Price forecast ("CARIS") is used for the Gas BCA framework to create a blended gas price to reflect CECONY's commodity costs. To estimate peak day prices, a multiplier is applied to the blended average gas prices derived from the CARIS forecast. This multiplier is equal to the ratio of the top n-day prices to the average annual price. The top n-days corresponds to the number of days that the project or program provides peak load reduction.

4.2.2 Avoided Pipeline & Storage Capacity Costs

Much of CECONY's gas transportation portfolio includes firm contractual rights to interstate pipeline and storage that may be used to transport baseload gas from producing regions to CECONY's city-gate. For a fixed annual cost (i.e., the underlying reservation fee associated with the capacity contract) to hold firm capacity rights, these assets provide firm supply at CECONY's city gate.[11] The capacity portfolio of pipeline and storage contracts is designed to serve firm gas customers' peak day demand. The commodity component, associated with the physical molecules of natural gas that are delivered to CECONY's citygates by the pipeline and storage capacity, is covered in "Avoided Commodity Cost" below. As shown in Figure 1-3 above, Peaking Services is currently considered the marginal source of supply to serve firm gas customers' peak day demand. To the extent that the need for Peaking Services is reduced or eliminated and no longer considered the marginal

[11] Storage capacity also provide intra-day and day-ahead flexibility. To the extent that Gas BCA projects or programs reduce demand enough to potentially avoid fixed costs associated with storage capacity contracts, the flexibility and balancing needs of the system will also be need to be considered.

source of supply, then pipeline and storage based supplies may become the marginal source of supply to serve peak day demand.

This section discusses project/program specific benefits associated with avoiding financial commitments to maintaining contractual rights to off-system pipeline and storage capacity. These avoided costs, evaluated on a $/Dth/day basis, are only available after peak demand has been reduced such that the need for Peaking Services is eliminated. These can be calculated using the framework outlined in Equation 4-3 below. Location specific values can be used to the extent that they are known. The key consideration will be the project's ability to provide supply or reduce demand on coincident peak days, allowing CECONY to avoid costs associated with maintaining its portfolio of pipeline and storage capacity to meet peak-day requirements.

Estimating Project Specific Benefits

Equation 4-3. Avoided Pipeline & Storage Capacity Costs

$$\text{Benefit}_{Y+1} = \sum\left(\frac{\Delta\text{Peak Load}_{Y,r}}{(1\text{-CRG}_{Y})} * \text{Coincidence Factor}_{Y,r} * \text{Derating Factor}_{Y,r} * \text{Capacity Costs}_{Y}\right)$$

Where:

Y+1	The year when the benefit is recognized / realized through the actual avoidance of fixed reservation fees associated with off-system pipeline capacity.
ΔPeak Load$_Y$	The project's expected maximum demand reduction capability, or "nameplate" impact, measured in Dth/day.
CRG$_Y$	The Avoidable Loss for the system applicable to year Y.
R	The specific retail delivery location.
Coincidence Factor$_Y$	Factor used to adjust the nameplate capacity of the project or program to account for the relationship between the coincidence of overall system's peak day requirements and the asset's expected contribution at such time.
Derating Factor$_Y$	Factor used to de-rate the coincident peak load benefit of the resource based on its expected availability during peak days.
Capacity Costs$_Y$	The fixed reservation fee of the avoidable off-system supply under the applicable scenario, measured in $/Dth/day.

Considerations on Equation Components

Y+1

This benefit is assumed to be incurred in the year following the peak load reduction. This reflects the time differential between the contractual framework of pipeline and storage contracts and when peak load reduction is realized.

Peak Load$_Y$

The Peak Load factor measures the nameplate impact at the retail delivery or connection point. The nameplate capacity of a project is separate from its ability to impact coincident peak day requirements. The nameplate capacity is the underlying design capability of the asset or program, generally based on the associated underlying engineering principles. This input is project or program specific. For this factor, a positive value represents a reduction in peak load.

Coincidence Factor$_Y$

The coincidence factor quantifies a project's contribution to peak day supply (or demand reductions) relative to its nameplate impact. This factor should be used to adjust the nameplate capacity for various physical factors that affect the asset's ability to impact peak day and associated operational considerations that recognize how the program or asset impacts coincide with peak day requirements. For example, a project with a nameplate demand reduction capacity of 100 Dth with a system coincidence factor of 0.8 would reduce system peak demand by only 80 Dth. An asset's or program's performance may be negatively correlated with the factors that drive peak day demand (particularly temperature). The determination of the appropriate factor is project/program specific. However, consistent principles should be applied across all projects and programs.

Derating Factor$_Y$

The derating factor should be used to adjust for uncertainty-related factors that may affect the general availability of an asset, such as duration of service (e.g., one day or any day over the winter), or the likelihood that the asset or program will fail to perform, despite its physical capabilities. For example, an incremental supply may fail to perform because the facility is undergoing maintenance. The derating factor should also reflect distribution limitations that restrict the ability of an incremental supply (or demand reduction) at one point to fully reduce system requirements. Again, the specific factor adjustments will be project/program specific but should be consistently applied across all projects.

Capacity Costs$_Y$

This value is based on the fixed reservation fee component of the utility's existing portfolio of pipeline and storage capacity contracts. This is measured as the weighted average reservation fee of CECONY's pipeline and storage capacity portfolio, measured in $/Dth/day. The estimation of avoided fixed reservation fee should consider the projected load requirements (with and without the Gas BCA program/project) and the Utility's options for supplying incremental resource needs.

In establishing a specific avoided capacity costs, consideration should be given to the net cost of the associated off-system supply. For example, the residual value associated with reselling off-system capacity to the secondary market when not required for on-system loads (e.g., capacity release value). This offsetting capacity release value should be evaluated based on forward spreads for the associated contract path less applicable variable costs (e.g., fuel and commodity).

r

'r' represents the specific location of the Gas BCA program impact on the retail distribution system. To the extent that location specific information is available, portfolio analysis of Gas BCA programs will consider the location of the impact as it relates to specific off-system capacity commitments as not all locations will have the same impact. When either the data is not available or the program/portfolio is system-wide (e.g., energy efficiency programs), a system-average value will be used.

4.2.3 Avoided Commodity Costs

Variable avoided off-system supply costs are commodity in nature (i.e., $/Dth of consumption). The specific avoided commodity related benefits of a Gas BCA program or project are a result of the marginal commodity that can be avoided based on the supply portfolio at the time. Establishing the appropriate marginal supply cost is a function of the existing portfolio and the impact of the project on that portfolio (both the mix of assets acquired and use of the assets).

Project/program specific benefits associated with avoiding off-system commodity costs can be calculated using the framework outlined in Equation 4-4 below. As opposed to the calculation of avoided fixed reservation fees, which focuses on a project's ability to deliver supply or reduce demand on coincident peak days, the associated variable avoided commodity cost benefit may also be realized outside of the coincident peak period. For example, the addition of an energy efficiency program would generate avoidable commodity benefits all year round by reducing the need for the associated off-system supply throughout the year.

Estimating Project Specific Benefits

Equation 4-4 Avoided Commodity Cost

$$\text{Benefit}_{Y} = \sum_{P} \frac{\Delta\text{Commodity}_{P,Y,r}}{(1 - \text{CRG}_{Y})} * \text{Commodity Cost}_{P,Y,r}$$

Where:

Y	The year that the benefit is recognized / realized through the actual avoidance of commodity costs.
P	The period within a given year when commodity costs are avoided (e.g., peak day, peak winter, summer).
ΔCommodity$_{P,Y}$	The difference in the quantity of gas (measured in Dth/day) required at the applicable retail delivery point(s) (e.g., customer revenue meter) before and after the project or program is implemented, delineated by applicable years "Y" and periods "P" within each year.
CRG$_{Y}$	The Company Retained Gas for the system applicable to year Y.
r	The specific retail delivery location.
Commodity Cost$_{P,Y}$	The projected wholesale cost of gas delivered to CECONY's city-gate, measured in $/Dth.

Considerations on Equation Components

ΔCommodity$_{P,Y}$

The time differential for subscript P (period) will depend on the type of project, and could be winter, summer, or another time interval. The user must ensure that the time-differentiation is appropriate for the project being analyzed and consistent with when impacts are anticipated to occur within a year. For example, it may be appropriate to use an annual average price and impact for a Gas BCA proposal that has a consistent load reduction at all hours of the year. However, using the annual average may not be appropriate for evaluating a demand response program that only reduces load during a few peak days.

Commodity Cost$_{P,Y}$

Avoided Commodity Cost benefits are calculated using a forecast of natural gas prices. NYISO's CARIS Natural Gas Price forecast ("CARIS") is used for the Gas BCA framework to create a blended gas price to reflect CECONY's actual commodity costs. The blend is calculated using a volume weighted blend of the CARIS Zone J and Zones F-I natural gas price forecasts.

4.3 On-System Benefits

This section of the BCA methodology deals with on-system benefits, which are those that occur downstream of CECONY's city gates. The ability of specific Gas BCA projects or programs to defer or otherwise avoid on-system costs depends on a number of characteristics, including: timing of the proposed project; duration of the impact; location; relation to other Gas BCA projects/programs and their associated characteristics; and cumulative size of the impact of the whole portfolio of Gas BCA relative to any on-system requirements, such as those for safety and reliability. As such, Gas BCA proposals must be evaluated as a portfolio to assess the overall potential for cost avoidance.

4.3.1 Avoided On-System Capacity Infrastructure

Avoided On-System Capacity Infrastructure benefits result from on-system load reductions or supply resources that are valued at the marginal cost of transmission, regulator, or distribution system infrastructure that is avoided or deferred by a Gas BCA project or program. The project or program impact must be coincident with the on-system equipment peak or otherwise defer or avoid the need for incremental transmission, regulator, or distribution infrastructure based on the characteristics of the specific project or program. Project/program specific benefits associated with Avoided On-System Capacity Infrastructure are capacity related (i.e., $/Dth-peak day) and can be calculated using the framework outlined in Equation 4-5 below.

<u>**Estimating Project Specific Benefits**</u>

Equation 4-5: Avoided On-System Capacity Infrastructure

$$\text{Benefit}_{\text{Y}} = \sum_{\text{C}} \frac{\Delta\text{PeakLoad}_{\text{Y,r}}}{(1-\text{CRG}_{\text{Y}})} * \text{Coinc. Factor}_{\text{C,Y,r}} * \text{DeratingFactor}_{\text{Y}} * \text{Marginal Cost of Service}_{\text{C,Y,r}}$$

Where:

Y	The year that the benefit is recognized / realized through the actual avoidance of distribution system capacity infrastructure.
r	The retail delivery location (e.g. specific location or system-wide).
C	The specific distribution system constraint affected.
ΔPeak Load$_{Y,r}$	The project's expected maximum demand reduction capability, or "nameplate" impact, measured in Dth/day.
CRG$_{Y}$	The Company Retained Gas for the system applicable to year Y.
Coincidence Factor$_{C,Y,r}$	Factor used to adjust the nameplate capacity of the project or program to account for the relationship between the coincidence of the asset's expected contribution at the time the applicable section of distribution system experiences its peak load (this may differ from overall coincident system peak).
Derating Factor$_{Y}$	A generic factor used to de-rate the benefits of the program/project based on its anticipated availability during peak calls on the applicable section of on-system capacity.
Marginal Cost of Service$_{C,Y,r}$	The marginal cost of the on-system infrastructure that the project/program is relieving, measured in dollars per Dth-day. This variable is specific to the project/program location (r) and associated distribution system constraint (C).

<u>**Considerations on Equation Components**</u>

ΔPeak Load$_{Y,r}$

The timing of benefits realized from peak load reductions are project and/or program specific. It is assumed that a peak load reduction impact could produce benefits in the year of the impact. As with avoided supply costs, the impact of projects/programs should be evaluated on a 'with the program' and 'without the program' basis. A Gas BCA project or program may contribute to avoiding distribution system capacity costs temporarily, but not permanently. In that case, avoided distribution system costs would be reflected as a benefit for a limited period.

Coincidence Factor$_{C,Y,r}$ and Derating Factor$_{Y}$

These concepts are similar to the factors used for Avoided Supply costs Coincidence and derating factors could be determined by a project-specific engineering study, based on historical experience in CECONY's service territory or elsewhere, or based on engineering judgements about potential performance limitations. For the Coincidence Factor, the peak requirement for the applicable section of on-system infrastructure may differ from the overall coincident system peak. Both factors are project specific.

Marginal Cost of Service$_{C,Y,r}$

It is assumed that the marginal cost of service is based on the cost of expanding the applicable section of CECONY's transmission, regulator, and/or distribution system. Project- and location-specific avoided costs and deferral values should be used when and wherever possible. If the available marginal cost of service value is determined using a different basis, then this parameter should first be converted to represent load at the applicable system level prior to using in the equation above. In some circumstances, use of the system average marginal cost may be acceptable, for example, for evaluation of energy efficiency programs for which specific customer locations are not yet known. To the extent that a Gas BCA project can target or defer a specific infrastructure need then specific avoided costs values may be used while also using generic marginal cost to capture impacts to upstream infrastructure. Care should be taken to consider project specific dynamics when assessing which marginal cost values should be used.

Avoided or deferred on-system infrastructure benefits for a specific location are realized only if a Gas BCA project or portfolio of Gas BCA projects meets the engineering requirements for functional equivalence (i.e., a Gas BCA proposal's reliably reduces coincident load to a level that allows the deferral or avoidance of a distribution project).

4.3.2 Avoided O&M

Avoided O&M includes variable operation and maintenance benefits on the transmission, regulator, and/or distribution systems realized from a proposed program or project. Caution should be exercised in computing these benefits as O&M expenses related to on-system infrastructure expansions and upgrades are often incorporated into marginal cost studies and the associated avoided cost may already be captured as part of the Avoided On-System Capacity Infrastructure cost.

Project/program specific benefits associated with Avoided O&M costs are generally commodity related but can also have a capacity component. These can be calculated using the framework outlined in Equation 4-6 below.

Estimating Project Specific Benefits

Equation 4-6: Avoided O&M

$$\mathrm{Benefit}_{\mathrm{Y}} = \sum_{\mathrm{AT}} \Delta\mathrm{Expenses}_{\mathrm{AT,Y,}}$$

Where:

Y	The year that the benefit is recognized / realized through the actual avoidance of distribution system capacity infrastructure.
AT	The Activity Type or specific category of O&M expense (e.g., crews to replace equipment, inspection requirements, and other maintenance related expenses).
$\Delta\mathrm{Expenses}_{\mathrm{AT,Y}}$	Change in O&M expenses due to a project, including an appropriate allocation of administrative and common costs. In general, these costs would increase by inflation, where appropriate.

Considerations on Equation Components

$\Delta\mathrm{Expenses}_{\mathrm{AT,Y}}$

Distribution O&M benefits from Gas BCA may be limited where the O&M costs are already embedded in the marginal cost of service values. Some secondary impacts may be identifiable and quantifiable. For example, to the degree incremental supply on-system lowers utilization of upstream assets (e.g., components of the distribution designed to maintain pressure or provide other benefits), the associated reduction in O&M expense may be attributable to the program/project and would not be reflected in the calculation of Avoided On-System Capacity Infrastructure costs. However, in general, these impacts are difficult to quantify and may be zero for most cases.

4.4 Cost Analysis

This section of the BCA methodology deals with utility, customer, or external costs imposed by NPS programs, either required as a result of program implementation or as a negative externality of the program itself. Costs are generally program-specific and depend on program incentives, investments, and fuel types. Note that certain costs (such as alternative fuel emissions costs) are treated as a negative benefit in the benefit-cost analysis.

4.4.1 Program Administration Costs

Program Administration Costs include the cost to administer and measure a Gas BCA program or project. This may include the cost of incentives, measurement and verification, and other program administration costs to start and maintain a specific program. These costs may include one-time or annual incentives such as rebates, one-time or annual payments to suppliers, and program administration costs related to marketing, evaluation, measurement and verification. These costs would increase by inflation, where appropriate. Program-specific details that are necessary to calculate the cost impact can include, but are not limited to, the scale of the activity, the types of participating technologies, and locational details.

Estimating Project Specific Costs

Equation 4-7: Program Administration Costs

$$\mathrm{Cost}_Y = \sum_M \Delta\mathrm{Program\ Administration\ Costs}_{M,Y,}$$

Where:

M	Measure
Y	The year that the cost is recognized / realized.

Considerations on Equation Components

ΔProgram Administration Cost$_{M,Y}$
This measures the change in program administration costs, which may include one-time or annual incentives such as, rebates, program, administration costs, measurement and verification, state incentives, and other costs. These costs would increase by inflation, where appropriate.

4.4.2 Incremental On-System Investments

Incremental On-System Investments include those costs incurred by the utility to support the Gas BCA project or program. These are distinct from Program Administration costs and can include incremental transmission, regulator, or distribution system infrastructure costs. In addition, this can include O&M, any capital or other direct expenses (e.g., special meters, monitoring systems, and/or upgrades), opportunity costs associated with any utility owned land or infrastructure granted or dedicated to the project, and indirect administrative costs related to the program (i.e., its impact on broader administrative costs).

4.4.3 Lost Utility Revenue

Lost Utility Revenue includes the distribution and other non-bypassable revenues that are shifted on to non-participating customers due to the normal process of establishing rates during a utility rate filing or the presence of revenue decoupling mechanisms. In both instances sales-related revenue shortfalls due to a decrease in natural gas sales or demand is recovered by marginally increasing delivery rates for all customers.

4.4.4 Shareholder Incentives

Shareholder Incentives include the annual costs to customers of utility shareholder incentives that are tied to the projects or programs being evaluated. Shareholder incentives are project or program specific and should be evaluated as such.

4.4.5 Incremental Participant Costs

Incremental Participant Costs are costs that would be incurred by providers of Gas BCA services, *less incentives recognized in Program Administration Costs with a floor of zero*. This includes the equipment and participation costs assumed by Gas BCA providers, which need to be considered when evaluating the societal costs of a project or program. For the purpose of performing the BCA, Incremental Participant Costs are applied net of rebates and incentives that have been accounted for under Program Administration costs.

In general, Incremental Participant Costs should be based on the incremental cost of the associated device or system relative to the costs the participant would have otherwise incurred. The Incremental Participant Costs includes the installed cost of the device or system, as well as any ongoing operations and maintenance expenses to provide the solution. Installed costs include the capital cost of the equipment, other capital investments required by the installation, and labor for the installation. Operating costs include ongoing maintenance expenses. These can also include costs borne by participants, particularly related to programs designed to incentivize or having an impact on customer behavior and/or real or perceived benefits from service (e.g., the purchase and installation price of a smart thermostat required to participate in temperature reduction programs).

4.4.6 Alternative Fuel Costs

Alternative Fuel Costs include the cost of using an energy source other than gas. For example, fuel switching in the form of consumers installing electric heat pumps in place of traditional natural gas boilers, is a measure to reduce the demand for natural gas. If fuel switching is selected as a viable Gas BCA solution, the cost of the alternative energy source should be considered in the BCA. The focus of the discussion here is on the use of electricity in place of natural gas. Although a variety of alternative energy sources can be considered, any analysis should consider the costs associated with the alternative (e.g., fuel costs, additional externalities).

The Electric BCA Handbook developed with the New York Joint Utilities discussed the calculation of Capacity, Energy, and associated transmission and distribution expenses on the electric system as a result of non-traditional programs like electric energy efficiency, demand response, and pursuing non-wire solutions to incremental load requirements. To the degree Gas BCA programs require an assessment of Alternative Fuel Costs, to the degree such costs are assessed to be substantive, they should be evaluated consistent with the framework and concepts established in the Electric BCA Handbook.

4.4.7 Alternative Fuel CO_2 Emissions

Alternative Fuel CO_2 Emissions include the emissions generated from the alternative fuel used by the consumer. For example, fuel switching in the form of consumers installing electric water heaters in place of traditional natural gas heaters is a measure to reduce the demand for natural gas. If the electricity is generated from a carbon emitting source, CO_2 emissions from the generation of the electricity needs to be accounted for. Equation 4-8 presents the cost equation for Alternative Fuel CO_2 Emissions:

Estimating Project Specific Costs

Equation 4-8. Alternative Fuel CO_2 Emissions

$$\text{Cost}_{\text{Y}} = \left(\frac{\Delta\text{Energy}_{\text{Y,r}}}{1 - \text{Loss\%}_{\text{Y,b}\rightarrow\text{r}}}\right) * \text{CO}_2\,\text{Intensity}_{\text{Y,Z}} * \text{Social Cost CO2}_{\text{Y}}$$

Where:

Y	The year that the cost is recognized / realized.
Z	The applicable NYISO load zone where the incremental energy use occurs in the case of electric usage.
r	The Retail Delivery or Connection Point.
b	The Bulk System.
Δ**Energy**$_{\mathbf{Y,r}}$	The change in energy purchased at the retail delivery or connection point ("r") as a result of the project. This parameter considers the impact at the project location, which is then grossed up to the bulk system level based on the $Loss\%_{b\rightarrow r}$ parameter. A positive value represents a reduction in energy.
Loss%$_{\mathbf{Y,t\rightarrow r}}$	The variable loss percent from the bulk system level ("t") to the retail delivery or connection point ("r").
CO_2 Intensity$_{\mathbf{Y}}$**, Z**	The CO_2 emissions rate of generation providing electricity to the applicable Zone.
Social Cost CO2$_{\mathbf{Y}}$	An estimate of the total impacts to society associated with an incremental increase in carbon dioxide emissions, measured in dollars per ton of CO_2 equivalent.

Any valuation of this benefit should be based on generally accepted methodologies and sources for assessing avoided costs, and should be consistent with the valuation of Avoided Greenhouse Gas Emissions.

4.4.8 Alternative Fuel Other Emissions

Alternative Fuel Other Emissions covers other emissions costs (other than CO_2) associated with using an energy source other than gas to replace the service provided by gas. These emissions will typically reflect on-system benefits; however, it may be extended to consider additional emissions if the emissions intensity differs materially. With respect to electric emissions, the wholesale market price includes compliance costs for these emissions, however this is not the case for natural gas or distillate fuels. Equation 4-9 provides a framework for evaluating these costs:

Estimating Project Specific Costs

Equation 4-9. Alternative Fuel Other Emissions

$$\text{Benefit}_Y = \sum_p \text{Onsite Energy}_{Y,r} * \text{Pollutant Intensity}_{p,Y,Z} * \text{Social Cost Pollutant}_{p,Y}$$

Where:

Y	The year that the cost is recognized / realized.
r	The Retail Delivery or connection point.
p	The applicable pollutant (e.g., SO2, NOx).
Z	The applicable NYISO load zone where the incremental energy use occurs.
Onsite Energy$_{Y,r}$	The electricity used by customer-sited equipment.
Pollutant Intensity$_{p,Y,Z}$	The pollutant emissions rate of the marginal generating unit providing electricity in the Zone.
Social Cost Pollutant$_{p,Y}$	An estimate of the cost to society associated with an incremental increase in pollutant 'p' emissions in a given year.

Any valuation of this benefit should be based on generally accepted methodologies and sources for assessing avoided costs, and should be consistent with the valuation of Other Avoided Emissions. To the degree these benefits exist but are not readily quantifiable, their impacts may be qualitatively assessed until such time the Commission provides guidance on how to quantitatively value these benefit streams.

4.4.9 Net Non-Energy Costs

Net Non-Energy Costs are other, non-commodity impacts on the utility's costs resulting from a Gas BCA project. Like Net Non-Energy Benefits, this can include the impacts to customer billing costs. To the degree these benefits exist but are not readily quantifiable, their impacts may be qualitatively assessed.

4.4.10 Other External Costs

This category covers external benefits not addressed in other categories, including land and water impacts associated with a Gas BCA program or project. To the degree these benefits exist but are not readily quantifiable, their impacts may be qualitatively assessed.

4.4.11 Cross-Fuel Market Price Effects

Cross-Fuel Market Price Effects refer to the cross-commodity price impacts of interlinked fuels. Because demand and therefore the price of electricity and gas markets are correlated, reduction in residential and commercial gas consumption might induce some downward pressure on electric prices.

In the NYISO power market, the locational marginal price of energy is set as the fuel cost of the marginal unit for the whole NYISO system with sophisticated price adjustments reflecting transmission constraints and system losses. Even a small downward shift in hourly electric price, mainly associated with a dual-fuel generation station switching from gas to fuel-oil, might create quantifiable regional or statewide benefits for the society as a whole under some circumstances.

In New England, where the locational marginal pricing of energy is similar to that of New York, a joint-utility sponsored independent study establishes the associated cross-fuel market price effects at multi-year intervals. [12] Should New York State decide to quantify such benefit streams on a statewide and regional level, those benefits could be included in program and project-level BCA calculations.

4.5 Reliability & Resiliency

Reliability & Resiliency benefits of Gas BCA projects and programs reflect how these programs and projects affect overall system reliability and ability to maintain system standards and recover from system outages. For example, on-system Gas BCA supply sources may provide pressure benefits depending on their location on the system. These can be leveraged to support system pressures during extreme events (increasing system reliability) and to provide faster recovery from disruption events.

Associated benefits are very program/project specific and highly influenced by the location of programs/projects on-system and their operational characteristics. Gas BCA options that can be dispatched (i.e., ability to call on supply or demand reduction without limitation) have the greater potential to provide such benefits. The specific benefits are very project/program specific. To the degree these benefits exist but are not readily quantifiable, their impacts may be qualitatively assessed.

4.6 Externalities

Externalities are benefit streams of Gas BCA projects not primarily paid for by the utility or its customers, to the degree such benefits are recognized in the broader market. Externalities include benefits such as avoided emissions on the system.

4.6.1 Avoided CO_2 Emissions

Avoided CO_2 Emissions accounts for avoided CO_2 emissions at the customer site due to a net reduction in natural gas use or replacement of gas normally delivered by pipeline with an alternative fuel. In the case of reductions in natural gas use, project/program specific benefits associated with Avoided CO_2 Emissions can be calculated using the framework outlined in Equation 4-10 below.

[12] Avoided Energy Supply Components in New England: 2018 Report; Prepared for AESC 2018 Study Group; *Synapse Energy Economics, Resource Insight, Les Deman Consulting, North Side Energy, and Sustainable Energy Advantage;* March 30, 2018

Estimating Project Specific Benefits

Equation 4-10. Avoided Greenhouse Gas Emissions

$$\text{Benefit}_Y = \Delta\text{Commodity}_Y * \text{GHG Intensity}_Y * \text{Social Cost CO2}_Y$$

Where:

Y	The year that the benefit is recognized / realized through the actual avoidance of distribution system capacity infrastructure.
ΔCommodity$_Y$	For demand-side measures, the change in natural gas used on-site as a result of the program or project. This is measured in Dth at the customer delivery point or revenue meter and accounts for the net change in use related to the program or project over the entire year. For RNG and other local supplies, the change in emissions attributable to the specific process used to provide the local gas supplies.
CRG$_Y$	The Company Retained Gas for the system applicable to year Y.
GHG Intensity$_Y$	The GHG emission rate of natural gas emissions (i.e., for demand-side measures, 117 lbs. /MMBtu or 0.0531 Metric Tons/Dt).
Social Cost CO2$_Y$	An estimate of the total impacts to society associated with an incremental increase in carbon dioxide emissions, measured in dollars per ton of CO2 equivalent.

Considerations on Equation Components

The net cost of CO_2 emissions will be taken into account with the intent to use a common cost of carbon across all aspects of the BCA. The SocialCostCO_2 is based on the Federal Environmental Protection Agency's Societal Cost of Carbon.[13] The benefit should be based on net changes in gas consumption at the customer site. Projects or programs that defer consumption to periods outside of the peak but do not otherwise reduce annual consumption will not realize benefits from reduction in CO_2 emissions.

4.6.2 Other Avoided Emissions

Other Avoided Emissions accounts for the value of avoided pollutant emissions (excluding greenhouse gases emissions). Project/program specific benefits associated with these emissions are commodity related (i.e., $/Dth) and can be calculated using the framework outlined in Equation 4-11 below.

[13] "Benefit-Cost Analysis Filing Requirement Guidance," New York Department of Public Service, Case 15-M-0252, May 15, 2018.

Estimating Project Specific Benefits

Equation 4-11. Other Avoided Emissions

$$\text{Benefit}_Y = \sum_p \frac{\Delta\text{Emissions}_Y}{1 - \text{CRG}_Y} * \text{Pollutant Intensity}_{p,Y} * \text{Social Cost Pollutant}_{p,Y}$$

Where:

Y	The year that the benefit is recognized / realized through the actual avoidance of distribution system capacity infrastructure.
p	Represents the applicable pollutant.
ΔEmissions$_Y$	Change in natural gas used on-site as a result of the program or project. This is measured in Dth at the customer delivery point or revenue meter and accounts for the net change in use related to the program or project over the entire year.
CRG$_Y$	The Company Retained Gas for the system applicable to year Y, if applicable.
Pollutant Intensity$_{p,Y}$	The average pollutant emission rate for pollutant p at the customer site, measured in tons/Dth. This is project and technology-specific.
Social Cost Pollutant$_{p,Y}$	An estimate of the cost to society associated with an incremental increase in pollutant p emissions in a given year.

Considerations on Equation Components

Pollutant impacts other than greenhouse gases emissions impacts are very project/program specific and may be zero depending on the project or program. Any valuation of this benefit should be based on generally accepted methodologies and sources for assessing avoided costs. To the degree these benefits exist but are not readily quantifiable, their impacts may be qualitatively assessed.

4.6.3 Net Non-Energy Benefits Related to Utility Operations

This category covers other benefits (or reduced costs) accruing to the utility related to other non-commodity aspects of a proposed project or program. An example would be benefits from reduced costs to rendering a natural gas bill for a customer that switches to electric heat and terminates gas service entirely. To the degree these benefits exist but are not readily quantifiable, their impacts may be qualitatively assessed.

4.6.4 Other External Benefits

Other External Benefits may also include external benefits, such as land or water benefits associated with a project or program. In general, Other External Benefits would only apply to the Societal Cost Test. To the degree these benefits exist but are not readily quantifiable, their impacts may be qualitatively assessed.

5. HIGH-LEVEL EXAMPLES

As a means of illustrating the application of BCA to potential alternatives, this section provides a high-level overview of four potential Gas BCA programs and projects. These four examples cover a useful, illustrative range of impacts that Gas BCA can have on the various benefit and cost categories in the Interim BCA Handbook. Each Gas BCA technology has unique operating characteristics that allow it to accrue some benefits and costs but not others:

Table 5-1. Key Attributes of Selected Gas BCA Technologies

Energy Efficiency (EE)	EE reduces the energy consumption for delivery of a particular service use at customer premises.
Demand Response (DR)	DR reduces energy demand for a particular service (use) during specific hours or days. DR is typically available only for limited hours in a year (e.g., 5 days or 100 hours) and is dispatchable in nature. The operational objective of the DR determines how it may contribute to various benefit and cost categories.
Electrification	Electrification involves meeting a customer's natural gas requirements by converting to a technology that utilizes electricity instead to meet the customer's needs. The application could be a complete replacement or designed to cover resource needs during specific hours (ideally peak). The example presumes the technology is not dispatchable.
Compressed Natural Gas (CNG) Storage	CNG Storage (alternatively could be liquefied natural gas) can be distributed in different areas to be readily available to the distribution system during periods of peak demand. The resource is dispatchable in nature but utilizes on-site supply and storage.

Energy Efficiency

5.1.1 Example of an Energy Efficiency Program

An energy efficient furnace depicts a *load-reducing* project where the use of the technology decreases the customer's energy consumption as compared to what it would be without the technology or with the assumed alternative technology. As such, it represents a reduction in demand relative to a pre-existing load expectation.

5.1.2 Off-System Benefits

<u>**Avoided Peaking Services**</u>

Evaluation of avoidable Peaking Services costs related to an EE program requires assessment of the impacts of the specific technology under consideration and comparison of this technology to a base case (i.e., the current technology in place). Operational characteristics of both the before and after scenarios would be compared to provide the net impact from the energy efficiency program. Specific considerations in assessing their ability to avoid fixed and variable costs associated with off-system supply (based on the framework provided in Section 4) include:

ΔPeak Load

This would be set at the difference in the peak load expectation before and after the new technology. Caution should be exercised to confirm that the operational characteristics of the new technology or measure would generally result in peak demands at the same time the prior technology experienced these conditions. ΔPeak Load value must be normalized for the blended types and sizes of the entire population of buildings participating in the EE program, and accounts for the percentage unoccupied buildings, if applicable, or other behavioral considerations.

Coincidence Factor
The coincidence factor for an energy efficiency program depends on the nature of the technology being considered and the associated end use. For instance, a home furnace would tend to have a high coincidence factor as heating loads are a primary driver of peak demand. Coincidence factors should be determined based on evaluation, measurement and verification best practices.

Derating Factor
The derating factor will be a measure of the level of uncertainty associated with the ex-ante impact forecast. For instance, more hands-on take-to-market approaches, such as direct install and/or conventional EE measures with a large ex-post evaluation, measurement and verification literature would generally have Derating Factors closer to one. By contrast, innovative EE measures for which third-party evaluation is lacking, or for which delivery methods that are more hands-off, such as upstream or midstream rebate programs, will have a lower Derating Factor due to the higher uncertainty about impacts.

Avoided Commodity Costs

For most energy efficiency technologies the impact on volumetric demand will occur on more than peak day and generally throughout the year. As such, associated avoided commodity costs should be based on the broader cost of utility supply as opposed to just a peak day commodity price. In general, this price will reflect the utility's overall portfolio of gas supply options and consist of a combination of peak and non-peak prices.

5.1.3 On-System Benefits

Avoided On-System Capacity Infrastructure

Energy efficiency programs are not discrete projects with specific and known delivery locations on the distribution. Rather, their impacts tend to be distributed across many customer locations not identified at the time the BCA is performed. As such, they will not generally realize a specific avoided distribution cost, but may in aggregate benefit long-term utility planning. Any such aggregate benefit should be incorporated into the BCA and socialized across the pool of potential participants. This would generally be limited to the marginal cost of distribution capacity for the broad portfolio.

5.1.4 Reliability/Resiliency

Energy Efficiency programs are not generally anticipated to provide quantifiable reliability or resiliency benefits.

5.1.5 Cost Analysis

Program Administration Costs

Administrative costs for an energy efficiency program are an important consideration. These costs cover implementation costs associated with designing the program (including the cost to develop appropriate estimates of penetration rates and population specific characteristics), participant incentives designed to induce selection of alternative technologies, costs associated with marketing programs, costs to monitor participation rates (including costs to verify proper application of rebates with the HVAC sub-contractors that will generally represent the front-line of the program), and costs to measure and verify impacts.

Lost Utility Revenue

Volumes used for estimating avoided commodity costs represent reduced gas sales. These quantities should be used for estimating the impact on lost utility revenue and the associated impact on non-participant rates.

Incremental Participant Costs

Participant costs should be measured as a function of the incremental cost and not the gross cost of the technology. These should be measured net of rebates paid to the customer/participant, the cost of which is included in Program Administration Costs. This net cost should then be compared to the base case cost that would have otherwise been paid for the base technology. Given the program nature of this option, estimates of these differentials will need to be developed as part of the program design based on current market costs for technologies. Analysis should account for anticipated changes in costs over time (e.g., impact of technology improvements on relative costs of alternatives).

5.1.6 Externalities

Avoided Pollutant Emissions

Energy efficiency programs reduce the overall consumption of gas, which results in lower CO2 and other emissions. The estimated annual reduction in consumption (relative to the baseline) should be used for this calculation.

5.2 Example Demand Response Program

5.2.1 Example System Description

Demand Response depicts an example of a *dispatchable* Gas BCA solution where the resource can be called upon to respond to peak demand. For natural gas, the impact of a demand response program must be sustained for a period of time on the order of a few days to offset the load during a cold snap event, which might last for multiple days. Any such program would need to carefully address concerns regarding snap back effects (i.e., the tendency for a site to require more gas on the day following the day of interruption to make up for lost thermal benefits).

While this option does not provide incremental supply, the dispatchable nature of the asset creates parallels to CNG and Peaking Services. In particular, the benefit of the asset will depend on the duration of the impact that can be provided and the assets ability to sustain such impact over more than one peak period. Options capable of performing in multiple peak periods (after a specific recovery period) may have more value than options offering one single call. Considerations for addressing the duration and sustainability of calls are discussed in Section 5.7.

5.2.2 Off-System Benefits

Avoided Peaking Services

As with energy efficiency options, evaluation of avoidable off-system supply costs related to a demand response program requires assessment of the specific impact of the demand response resource relative to a base case (i.e., the customer's gas load if it had opted not to reduce demand). The key question is the difference between the quantity of gas required with and without the implementation of the demand response actions. Specific considerations in assessing their ability to avoid fixed reservation fees associated with Peaking Services (based on the framework provided in Section 4) include:

ΔPeak Load
This would be set at the difference in the peak load expectation with and without the demand response measure(s). ΔPeak Load value must be normalized for the blended types and sizes of the entire population of buildings participating in the DR program, account for snap back effect (if any), and also account for the percentage of unoccupied buildings, if applicable, or other behavioral considerations.

Coincidence Factor
Given the dispatchable nature of the option, the coincidence factor will generally be one, assuming that ΔPeak Load accounts for any behavioral considerations.

Derating Factor
The derating factor will be a measure of the level of uncertainty associated with the ex-ante impact forecast. For instance, more hands-on take-to-market approaches, such as direct install and/or conventional DR measures with a large ex-post evaluation, measurement and verification literature would generally have Derating Factors closer to one. By contrast, more innovative DR measures for which third-party evaluation is lacking, or for delivery methods that are more hands-off, such as upstream or midstream rebate programs, a lower Derating Factor may be appropriate to reflect higher uncertainty of performance.

Avoided Peaking Commodity Costs

The starting point for assessing avoided commodity costs for a demand response asset or program will generally be the peak gas price of the marginal supply resource for the Utility. However, the net benefit associated with such technology should account for any snap back effects. To the degree the technology shifts demand from peak periods to other periods the net commodity benefit may be zero (or could be negative depending on how the technology operates and its impact on overall demand).

5.2.3 On-System Benefits

Avoided On-System Capacity Infrastructure

Demand response programs are typically not discrete projects with specific and known delivery locations on the distribution at the time the BCA is performed. Their impacts may be distributed across a wide area. As such, they will not generally realize a specific avoided distribution cost, but may in aggregate benefit long-term utility planning. Any such aggregate benefit should be recognized in the BCA. This would generally be limited to the marginal cost of distribution capacity for the broad portfolio. However, in the case of a single, large DR resource, it may be possible to determine a case-specific Avoided Distribution Cost.

5.2.4 Reliability/Resiliency

While demand response programs may be distributed across the utility, depending on the technology available for exercising the associated interruption right, there could be associated benefits with respect to reliability and resiliency. For example, if the technology permits the utility to direct activations to specific locations with sufficient aggregate participants, this may provide pressure stabilization benefits at times.

5.2.5 Cost Analysis

Program Administration Costs

Administrative costs for a demand response program will be similar to those associated with an energy efficiency program in many respects. Given the dispatchable nature of the asset, more effort and expense may be required with respect to validating impacts and/or pre-testing impacts on an annual or periodic basis.

Lost Utility Revenue

Volumes used for estimating avoided commodity costs represent reduced gas sales. These quantities should be used for estimating the impact on lost utility revenue and the associated impact on non-participant rates.

Incremental Participant Costs

Participant costs should be measured as a function of the incremental cost and not the gross cost of the technology or measures. Given the program nature of this option, estimates of these differentials will need to be developed as part of the program design based on current market costs for technologies. The analysis should account for anticipated increases in costs over time (generally inflation) but also projected reductions in spreads between base technologies and higher efficiency options based on technology improvements over time. CECONY may rely on the incentive payment or 'bid price' proposed by a respondent in a competitive solicitation process as the best estimate of incremental cost for assessing Participant Gas BCA Costs.

Alternative Fuel Costs

Demand response programs may involve usage of an alternative fuel. Analysis should include the costs associated with the alternative fuel, to the extent such costs exist.

Alternative Fuel Emissions

Analysis should also include the CO2 and other emissions costs associated with the alternative fuel, to the extent that such emission costs exist.

5.2.6 Externalities

Avoided Pollutant Emissions

Demand response programs reduce the overall consumption of gas, which results in lower CO2 and other emissions. The estimated annual reduction in consumption (relative to the baseline) should be used for this calculation.

5.3 Electrification Example

5.3.1 Example System Description

An electrification program involves the replacement of an existing gas application with a comparable resource powered by electricity. While this may completely eliminate the associated gas supply requirement, it creates an associated requirement on the power side that needs to be considered in the analysis.

5.3.2 Off-System Benefits

Avoided Peaking Services

Evaluation of avoidable Peaking Services costs related to electrification programs require assessment of the technology/ end-use being eliminated and also the details regarding the replacement technology with respect to associated power requirements. Specific considerations in assessing their ability to avoid fixed reservation fees associated with upstream supply (based on the framework provided in Section 4) include:

ΔPeak Load
This would be set at the peak load of the gas asset being displaced. ΔPeak Load value must be normalized for the blended types and sizes of the entire population of buildings participating in the G2E program.

Coincidence Factor
Coincidence factor shall be determined based on evaluation, measurement and verification best practices, which may entail computer-assisted building energy modeling or other approaches to establish the load profile of the gas usage (for instance space heating) being converted to electricity.

Derating Factor
The derating factor will be a measure of the level of uncertainty associated with the ex-ante impact forecast. For instance, more established approaches, such as measures with a large ex-post evaluation, measurement and verification literature would generally have Derating Factors closer to one. By contrast, more innovative approaches for which third-party evaluation is lacking, or delivery methods that are more hands-off, such as upstream or midstream rebate programs, may have a lower Derating Factor due to the higher uncertainty.

Avoided Commodity Costs

The commodity impact of an electrification program will depend on the associated end-use. In general, an electrification program will impact gas consumption throughout the winter season or year-round. As such, associated avoided commodity costs should be based on the broader cost of utility supply as opposed to a peak day commodity price. In general, this price will reflect the utility's overall portfolio of gas supply options and consist of a combination of peak and non-peak prices.

5.3.3 On-System Benefits

Avoided On-System Capacity Infrastructure

Electrification programs are not necessarily discrete projects with specific and known delivery locations on the distribution system. Rather, their impacts tend to be distributed across a wide area. As such, they will not generally realize a specific Avoided Distribution Cost, but may in aggregate benefit long-term utility planning. Any such aggregate benefit should be recognized in the BCA. This would generally be limited to the marginal cost of distribution capacity for the broad portfolio.

5.3.4 Reliability/Resiliency

Electrification programs are not generally anticipated to provide quantifiable reliability or resiliency benefits.

5.3.5 Cost Analysis

Program Administration Costs

Administrative costs for an electrification program would likely be similar to those associated with an energy efficiency program.

Lost Utility Revenue

Volumes used for estimating avoided commodity costs represent reduced gas sales service revenues. These quantities should be used for estimating the impact on lost utility revenue and the associated impact on non-participant rates. However, these should be netted against incremental revenues associated with the replacement electric technology for an overall impact.

Incremental Participant Costs

Administrative costs for an electrification program are consistent with those for an energy efficiency program.

Alternative Fuel Costs

Electrification programs involve usage of an alternative fuel. The costs of the alternative fuel should be included in the analysis. To the degree that such costs are assessed to be substantive, they should be evaluated consistent with the framework and concepts established in the Electric BCA Handbook.

Alternative Fuel Emissions

Analysis should also include the CO2 and other emissions costs associated with the alternative fuel.

5.3.6 Externalities

Avoided Pollutant Emissions

Net benefits should be computed for electrification programs. These programs reduce gas demand with associated emissions benefits, but increase electric demand and associated pollutant emissions costs. The external impacts associated with the incremental electric load should be netted against the gas demand benefits.

5.4 Compressed Natural Gas Storage Example

Compressed natural gas (CNG) storage is an example of a *dispatchable* Gas BCA solution, which is called upon to operate in response to system, pipeline, and distribution peaks.

5.4.1 Example System Description

Natural gas is compressed and stored in strategic locations where it can be re-introduced to the distribution system as required. Facilities can be constructed as full-cycle operations where gas is compressed on-site using supply directly from the distribution system and later re-injected into the system as required, or as satellite facilities where gas is compressed off-site (either at a separate full-cycle facility within the distribution system or from locations outside CECONY's service territory, and transported to the site in off-peak periods for storage and later sendout into the distribution system.

The physical footprint of CNG facilities varies based on size and design. Full-cycle facilities require room for compression, storage, and regasification. While avoiding the need for compression facilities, satellite facilities require sufficient footprints to permit delivery of off-site supply (typically via tanker trucks). In general, CNG facilities will require a smaller footprint than LNG facilities (due to set back and dispersion requirements). At any given point, a facility will have a limited number of days of deliverability based on the on-site storage capacity and on-site truck injection/replacement capacity.

Facilities can also be designed with secondary purposes, such as a refueling station for CNG vehicles. This creates additional societal benefits but may complicate call rights.

5.4.2 Off-System Benefits

<u>Avoided Peaking Supplies</u>

While CNG is dispatchable, these projects would generally have a limited number of days of operation or availability (limited by the on-site storage capacity of the facility). This has implications for derating factors affecting both avoidable upstream supply costs, such fixed reservation fees associated with Peaking Services, and distribution costs. Specific considerations in assessing their ability to avoid fixed reservation fees associated with upstream supply (based on the framework provided in Section 4) include:

> ***ΔPeak Load***
> This would generally be set at the facility's peak sendout or nameplate capacity, net of any on-site uses of natural gas.
>
> **Coincidence Factor**
> The coincidence factor for a CNG project is anticipated to be at or near one. These projects provide equivalent commodity on-system as dispatched. The name plate capacity should reflect the full capability of the facility to deliver during design conditions.
>
> **Derating Factor**
> Minimal 'on the day' operating conditions should impact the derating factor for a CNG facility. However, this factor should also be used to adjust the deliverability of the project to account for limitations related to on-site storage durations and refill/replacement considerations. Specifically, a facility capable of providing multiple contiguous days of full deliverability prior to refilling on-site supply has less value than a facility with many days of supply on-site.
>
> Refill choices also affect the value of the asset to avoiding upstream capacity. A facility that can refill from off-site resources (e.g., via trucked supply) may have more value than a facility that requires solely on on-system supply to refill the facility as this increases loads and reduces availability during peak periods.

<u>Avoided Commodity Costs</u>

The utility may negotiate a specific commodity rate for purchases of gas from a CNG facility. Any such rate should be compared to the cost the utility would otherwise pay for supply on the days it anticipates calling on the CNG facility in order to assess the net avoided commodity cost associated with the project.

5.4.3 On-System Benefits

Avoided On-System Capacity Infrastructure

CNG projects are discrete projects with specific and known delivery locations on the distribution system. If sufficient information is available, the BCA should assess the value of deferral or avoidance of distribution system investment as a result of the CNG Project.

5.4.4 Cost Analysis

Lost Utility Revenue

As an alternative supply source, CNG projects do not create Lost Utility Revenue.

Incremental Participant Costs

Incremental Participant Costs will be estimated based on any amount paid to the CNG developer by the utility in excess of the price of natural gas supplied by the CNG plant.

Incremental Distribution System Investments/Costs

Utility costs related to a CNG facility may include the cost to connect such facility to the distribution system and any downstream improvements of the distribution system to allow full delivery of the associated supply.

5.4.5 Reliability/Resiliency

CNG projects have the potential to provide reliability/resiliency benefits. While this is location specific, the on-system location and dispatchability of the projects is particularly attractive as a means of preserving systems pressures and overall stability. However, in assessing such benefits consideration should be made of any limitations on operations. For example, a project may have a minimum run time that exceeds the anticipated need for pressure stabilization at a given location. Each discrete use of the facility may have an associated fixed start-up cost that would need to be incorporated into an assessment of the associated reliability/resiliency benefits. The net value of the asset will depend on its merits and costs relative to the alternative resources the utility would otherwise be installed.

5.4.6 Externalities

Incremental Greenhouse Gas or Other Emissions associated with the operation of the facility, may be incorporated into the assessment to the degree they are substantive in nature. This would include incremental emissions associated with compressions of the natural gas (or liquefaction in the case of LNG).

Attachment B: Illustrative Example of Performance Incentive Calculations

Attachment B
Illustrative

Non-traditional Solution (NTS) Quantity: No Change in Quantity Needed During Implementation

Forecast Costs and Benefits	$ (000s)	
Forecast benefits*	$ 1,000,000	(1)
Forecast utility cost of utility solution peak reduction (dth)	$ 50,000	(2a)
Forecast utility cost of non-traditional solution Dth	$ 550,000	(2b)
Forecast customer cost of non-traditional solution**	$ 350,000	(2c)
Forecast # Dth load reduction needed to achieve deferral/elimination	150	(3a)
Forecast $ per dth utility NTS costs	$ 3,667	(4)=(2b)/(3a)
Initial Net Benefits	$ 100,000	(5a)=(1)-[(2b)+(2c)]
Development of Share-the-Net Benefits Incentive		
Company % Share of Net Benefits	30%	(6)
Initial Incentive	$ 30,000	(7)=(5a)*(6)
Customer % Share of Net Benefits	70%	(8)=100%-(6)
Forecast Customer Benefits	$ 70,000	(9)=(5a)*(8)
Actual Program Results and Costs		
Actual # peak dth load reduction necessary to achieve deferral/elimination	150	(3b)
Actual utility costs of NTS Dths when known with reasonable certainty	$ 550,000	(10a)
Actual # Dth Load Reduction Achieved	150	(11)
Actual $ utility cost per Dth non-traditional solution	$ 3,667	(12)=(10a)/(11)
Difference in Utility NTS Costs*****	$ -	(13)=(2b)-(10a)
Final Net Benefits****	$ 100,000	(5b)=(5a)+(13)
Incentives Tied to Reducing Costs to Achieve Reduction		
Company Percent of cost delta	50%	(14)
Program Cost Delta Share Incentive (Penalty)	$ -	(15)=(14)*(13)
Check Against # Dth Procured		
Minimum percent of Forecast Load Reduction Required	70%	(16)
Minimum amount of Load Reduction Required	105	(17) = (16)*(3b)
Actual Load Reduction Achieved greater than Minimum?	TRUE	(18)=IF[(11)>(17)]
Check Against Incentive Hard-Cap		
Total Incentive Achieved	$ 30,000	(19)=[(7)+(15)]*(18)
Hard Cap Percentage of Initial Forecast Benefits	50%	(20)
Hard Cap on Incentive Amount	$ 50,000	(21)=(20)*(5a)
Check Against Incentive Floor		
Total Incentive Achieved	$ 30,000	(19)
Floor on Incentive Amount	$ 0	(22)
Final Company Incentives and Customer Savings		
Final Pretax Incentive Awarded to Company	$ 30,000	(23)=MIN[(19),(21)] or (22) if MIN[(19),(21)] is negative
Company effective income tax rate	26%	(24)
Government taxes collected	$ 7,842	(25)=(24)*(23)
Company Share of Adjusted Net Benefits Dollars	$ 22,158	(26)=(23)-(25)
Customer Share of Adjusted Net Benefits Dollars	$ 70,000	(27)=(5b)-(23)
Government share (%) of Final Net Benefits	8%	(28)=(25)/(5b)
Company share (%) of Final Net Benefits	22%	(29)=(26)/(5b)
Customer share (%) of Final Net Benefits	70%	(30)=(27)/(5b)

Non-traditional Solution Quantity: Material Reduction (>30% over 3 years) in Dths Needed During Implementation

Forecast Costs and Benefits	$ (000s)		Change from column B-D
Forecast benefits*	$ 1,000,000	(1)	
Forecast utility cost of utility solution peak reduction (dth)	$ 50,000	(2a)	
Forecast utility cost of non-traditional solution Dth	$ 550,000	(2b)	
Forecast customer cost of non-traditional solution**	$ 350,000	(2c)	
Forecast # Dth load reduction needed to achieve deferral/elimination	150	(3a)	
Forecast $ per dth utility NTS costs	$ 3,667	(4)=(2b)/(3a)	
Initial Net Benefits	$ 100,000	(5a)=(1)-[(2b)+(2c)]	
Development of Share-the-Net Benefits Incentive			
Company % Share of Net Benefits	30%	(6)	
Initial Incentive	$ 30,000	(7)=(5a)*(6)	
Initial Unit Incentive	$ 200.00	(7a)=(7)/(3a)	Needed for Adjusted Incentive Achieved calculation below
Customer % Share of Net Benefits	70%	(8)=100%-(6)	
Forecast Customer Benefits	$ 70,000	(9)=(5a)*(8)	
Actual Program Results and Costs			
Actual # dth load reduction necessary to achieve deferral/elimination	100	(3b)	Change per utility reliability assessment
Actual utility costs of NTS Dths when known with reasonable certainty	$ 360,000	(10a)	Because fewer Dths procured
Actual # Dth Load Reduction Achieved	105	(11)	
Actual $ utility cost per Dth non-traditional solution	$ 3,429	(12)=(10a)/(11)	
Difference in Utility NTS Costs	$ 190,000	(13)=(2b)-(10a)	
Unit Difference Utility NTS Costs	$ 238	(13a)=(4)-(12)	Needed for Adjusted Incentive Achieved calculation below
Final Net Benefits****	$ 290,000	(5b)=(5a)+(13)	
Incentives Tied to Reducing Costs to Achieve Reduction			
Company Percent of cost delta	50%	(14)	
Program Unit Cost Delta Share Incentive (Penalty)	$ 119	(15)=(14)*(13a)	Needed for Adjusted Incentive Achieved calculation below
Check Against # Dth Procured			
Minimum percent of Forecast Load Reduction Required	70%	(16)	
Minimum amount of Load Reduction Required	70	(17) = (16)*(3b)	Calculation off of lower Dths needed
Actual Load Reduction Achieved greater than Minimum?	TRUE	(18)=IF[(11)>(17)]	
Check Against Incentive Hard-Cap			
Nominal Incentive Achieved	$ 47,857	(19)=[(7a)+(15)]*(3a)*(18)	
Adjusted Incentive Achieved	$ 33,500	(19a)=[(7a)+(15)]*(11)*(18)	Incentive adjusted down to reflect reduced Dth needed
Hard Cap Percentage of Initial Forecast Benefits	50%	(20)	
Hard Cap on Incentive Amount	$ 50,000	(21)=(20)*(5a)	
Check Against Incentive Floor			
Total Incentive Achieved	$ 33,500	(19a)	
Floor on Incentive Amount	$ 0	(22)	
Final Company Incentives and Customer Savings			
Final Incentive Awarded to Company	$ 33,500	(23)=MIN[(19a),(21)] or (22) if MIN[(19a),(21)] is negative	
Company effective income tax rate	26.1%	(24)	
Government taxes collected	$ 8,757	(25)=(24)*(23)	
Company Share of Adjusted Net Benefits Dollars	$ 24,743	(26)=(23)-(25)	
Customer Share of Adjusted Net Benefits Dollars	$ 256,500	(27)=(5b)-(23)	Does not include reduced societal benefits from less dth reduced
Government share (%) of Final Net Benefits	3%	(28)=(25)/(5b)	
Company share (%) of Final Net Benefits	9%	(29)=(26)/(5b)	
Customer share (%) of Final Net Benefits	88%	(30)=(27)/(5b)	

Non-traditional Solution Quantity: Increase in DTh Needed During Implementation

Forecast Costs and Benefits	$ (000s)		Change from column B-D
Forecast benefits*	$ 1,000,000	(1)	
Forecast utility cost of utility solution peak reduction (dth)	$ 50,000	(2a)	
Forecast utility cost of non-traditional solution Dth	$ 550,000	(2b)	
Forecast customer cost of non-traditional solution **	$ 350,000	(2c)	
Forecast # Dth load reduction needed to achieve deferral/elimination	150	(3a)	
Forecast $ per dth utility NTS costs	$ 3,667	(4)=(2b)/(3a)	
Initial Net Benefits	$ 100,000	(5a)=(1)-[(2b)+(2c)]	
Development of Share-the-Net Benefits Incentive			
Company % Share of Net Benefits	30%	(6)	
Initial Incentive	$ 30,000	(7)=(5a)*(6)	
Customer % Share of Net Benefits	70%	(8)=100%-(6)	
Forecast Customer Benefits	$ 70,000	(9)=(5a)*(8)	
Actual Program Results and Costs			
Actual # Dth load reduction necessary to achieve deferral/elimination	200	(3b)	Increase per annual utility reliability assessment
Actual utility costs of NTS Dths when known with reasonable certainty	$ 550,000	(10a)	
Actual utility costs of additional non-traditional solution Dths	$ 185,000	(10b)	Due to more Dths procured
Actual # Dth Load Reduction Achieved (up to original forecast)	150	(11)	
NTS needed in original forecast: Actual $ utility cost per Dth when known with reasonable certainty	$ 3,667	(12)=(10a)/(11)	
NTS added to original forecast: Actual $ utility cost per Dth when known with reasonable certainty ***	$ 3,700	(12a)=(10b)/[(3b)-(11)]	For added Dths procured
Difference in Utility NTS Costs (only originally-planned Dths)	$ -	(13)=(2b)-(10a)	
Final Net Benefits****	$ 100,000	(5b)=(5a)+(13)	
Incentives Tied to Reducing Costs to Achieve Reduction			
Company Percent of cost delta	50%	(14)	
Program Cost Delta Share Incentive (Penalty)	$ -	(15)=(14)*(13)	
Check Against # Dth Procured			
Minimum percent of Forecast Load Reduction Required	70%	(16)	
Minimum amount of Load Reduction Required	105	(17) = (16)*(3a)	Additional Dth procured not included for Incentive
Actual Load Reduction Achieved greater than Minimum?	TRUE	(18)=IF[(11)>(17)]	
Check Against Incentive Hard-Cap			
Total Incentive Achieved	$ 30,000	(19)=[(7)+(15)]*(18)	
Hard Cap Percentage of Initial Forecast Benefits	50%	(20)	
Hard Cap on Incentive Amount	$ 50,000	(21)=(20)*(5a)	
Check Against Incentive Floor			
Total Incentive Achieved	$ 30,000	(19)	
Floor on Incentive Amount	$ 0	(22)	
Final Company Incentives and Customer Savings			
Final Incentive Awarded to Company	$ 30,000	(23)=MIN[(19),(21)] or (22) if MIN[(19),(21)] is negative	
Company effective income tax rate	26.1%	(24)	
Government taxes collected	$ 7,842	(25)=(24)*(23)	
Company Share of Adjusted Net Benefits Dollars	$ 22,158	(26)=(23)-(25)	
Customer Share of Adjusted Net Benefits Dollars	$ 70,000	(27)=(5b)-(23)	Does not include increased societal benefits from greater dth reduced
Government share (%) of Final Net Benefits	8%	(28)=(25)/(5b)	
Company share (%) of Final Net Benefits	22%	(29)=(26)/(5b)	
Customer share (%) of Final Net Benefits	70%	(30)=(27)/(5b)	

Input cells are highlighted in light green
* Per publication of BCA handbook.
** Included per the Societal Cost Test
*** Additional non-traditional solution Dth will not be counted towards an incentive and will only receive regulated cost recovery
**** Initial net benefits adjusted up or down for Utility NTS cost underruns or overruns
***** NTS- Non-traditional solution

CERTIFICATE OF SERVICE

I hereby certify that on this 23rd day of February 2021, a copy of the foregoing was served on the following parties by electronically mail:

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