**NPA Working Group: NPA Framework Comment Submission Due January 29**

**On behalf of (company/organization name):** Advanced Energy United

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Reference ID (to be filled in by Apex):

## High Level Comments

#### Key proposal strengths: Summary statement of high-level (executive summary-type) strengths of proposal

The directive from Order 20-80 requesting the local distribution companies (LDCs) to work with stakeholders to develop a framework for designing and deploying non-pipeline alternatives (NPAs) offers an important opportunity for Massachusetts to pro-actively plan for long-term gas system cost-containment. The proposed framework, presented to the Technical Subcommittee on January 22, 2025, is a strong start, and outlines key components and processes to determine appropriate NPA selections. Effective design of an NPA framework – from project screening through implementation and reporting – ensures that we avoid reinvesting in an expense and polluting system wherever possible and beneficial for customers.

#### Key proposal challenges: Summary statement of high-level (executive summary-type) challenges of proposal, including cross-cutting concerns

While we appreciate opportunity to review framework and offer comment, the limited time to review the draft framework and then write comments has limited everyone’s ability to engage deeply in the content. After the anticipated filing at the DPU, we hope the Companies will continue to invite stakeholder review and input to support useful iteration of the framework and successful NPA implementation.

## Project Identification

#### Key Point #1:

#### Advanced Energy United agrees that some project categories are not generally well-suited to NPA development, but the utility should not categorically exclude them.

Generally, Advanced Energy United (United) agrees with the project identification suitability categorization. However, projects in the “Emergent,” “Other Reliability,” “Metering,” “Facilities,” and “Information Technology” categories may at some point become suitable themselves for an NPA, or interact with investments that are otherwise suitable for an NPA. For example, a stub cut off project might not be necessary if the system in that area is being replaced with a thermal energy network within the next year or two. In this scenario (or one similar), the utility may be able to consider lower cost fixes or fixes with a shorter lifespan. If the project can be deferred until the NPA is implemented, or if the NPA might be reasonably accelerated to the timeline necessary for the project, ratepayers might save on that avoided investment.

Similarly, even though gas meters are required to be replaced every seven years by statute, the end of the seven-year cycle may be an opportunity to offer a customer electrification incentives to avoid the replacement altogether. In particular, if that meter replacement coincides with the need for a service line replacement (within several months to a years), both utility expenditures may be avoided with an individual-customer NPA. Though these NPAs are small, in the aggregate they may provide significant savings to ratepayers. Furthermore, customer offerings at these points in time can be standardized and systematized to make implementation routine.

#### Key Point #2:

#### LDCs can and should still work to minimize the costs from Emergent/Other Reliability/Metering/Facilities/IT, whether by classic NPA strategies or otherwise.

Although many of the projects within the “Emergent,” “Other Reliability,” “Metering,” “Facilities,” and “Information Technology” categories are not traditional gas infrastructure (e.g. pipelines, regulators, gates etc.), LDCs can still seek opportunities to find lower-cost solutions to address the need – especially where these projects overlap geographically with areas that are experiencing rapid electrification. Utilities can periodically review their standard approaches to the most common types of these projects every few years to ensure that they are not over-investing (in dollars or by building infrastructure meant to last longer than necessary).

#### Key Point #3:

#### United would like to see the utilities be more inclusive in its list of technologies and measures to consider as NPAs to maintain the ability to creatively link advanced energy resources.

On slide 8, the LDCs list out the technologies and measures that they will consider for an NPA analysis (i.e. air and ground source heat pumps, thermal network systems, energy efficiency and demand response, behavior change and market transformation, and supply side solutions), and then match those technologies to the program category. We do not disagree with any of the included technologies and measures, or pairings with program types, and believe that this is fine to use as a general guide or starting point. However, we recommend against making this a rigid list of NPA options.

If an NPA that involves electrification would have an adverse impact on a neighborhood electric distribution system’s reliability or resilience, or on a customer’s combined utility bills, the utility may consider offering distributed energy resources such as distributed solar and storage and smart thermostats in combination with the heat pump. This may be strategic, and still save ratepayers money overall, if it minimizes the electric system upgrade costs or pencils out more favorably for the affected customer(s). The participating customers could also be enrolled (as a condition for receiving the incentive or on an opt-out basis) in load management programs or rates that best leverage those investments. Together, this system of advanced energy solutions might be an effective NPA.

We note that there are efforts already underway in Massachusetts to strategically integrate whole-home energy solutions, such as wi-fi enabled thermostats, batteries, and heat pumps, to provide grid services that benefit the electric system and the customer.[[1]](#footnote-2)

## Initial Viability Testing

#### Key Point #1:

#### Given experiences in other states, United urges caution around monetary project thresholds – they are arbitrary and may cause utilities to miss key opportunities.

Slide 9 suggests that each LDC will propose certain thresholds to help identify NPAs to prioritize. There are many ways to set thresholds, but United cautions against creating monetary minimums or maximums.

A significant amount of gas system spending is made up of small, individual or local projects that cost tens or hundreds of thousands of dollars. On their own, each of these opportunities looks negligible, but may become meaningful in the aggregate. We offer Public Service Company of Colorado (Xcel Colorado)’s first Gas Infrastructure Plan as a cautionary tale. In its 2023 filing, the company reported on projects above a $3 million threshold set by regulations. This included only 12 projects in the three year “action period” and another three in the “informational period,” as seen below in Table 1.[[2]](#footnote-3) These represented less than four percent of the utility’s planned capital expenditures within a five-year budget of 2.38 billion.[[3]](#footnote-4) Xcel Colorado wrote that it considers “most System Safety and Integrity investment is generally considered “programmatic” or “routine,” suggesting the expenditure is ongoing, impromptu, and small in dollar amount.”[[4]](#footnote-5) Of those, at the time, System Safety & Integrity and Mandatory Relocation projects were excluded from NPA analyses (although Xcel Colorado has been strongly encouraged to assess system safety and integrity projects in its 2025 Gas Infrastructure Plan[[5]](#footnote-6)).

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As a result of this experience, the Colorado Public Utilities Commission emphasized the need to consider the threshold relevant to “sets of inter-related facilities” and projects in earlier stages of development,[[6]](#footnote-7) though it is expected that they will revisit the threshold at some point in the future.

Importantly, United believes that NPAs can be successful on many scales – from an individual residential customer avoiding a service line replacement to avoiding capacity expansion for a whole portion of the system. Consolidated Edison is currently running two NPA programs in New York: the Electric Advantage Program and the Energy Exchange Program. The Electric Advantage Program eliminates the need to replace segments of leak-prone gas mains by providing customers with electric alternatives and facilitating disconnection from gas, with customers paying nothing. The Energy Exchange Program eliminates the need to replace existing gas services installed pre-1972 by providing electric alternatives for gas end-uses (except space heating, covered by a different Clean Heat Program) to facilitate disconnection from gas system. In a July, 2024 filing, the former found 22 projects to be feasible and cost-effective, saving customers $653,900, avoiding $4,035,412 in gas system costs, and avoiding 93,360 Dth of gas use and 114 Dth of peak day capacity.[[7]](#footnote-8) The latter identified 100 customers to serve, which would save those customers $135,056, avoid $2,804,904 in gas system costs, and avoid 33,202 Dth of gas use and 10.4 Dth of peak day capacity.[[8]](#footnote-9)

On the opposite end of the spectrum, Xcel Colorado has just filed its proposed “Mountain Energy Project” NPA, which will impact approximately 33,500 customers.[[9]](#footnote-10) This will make determining thresholds of any type difficult. At this early stage, we caution the LDCs against restricting themselves or narrowing their line of sight into valuable projects with arbitrary prioritizations, ceilings, or floors. Regardless, stakeholders must be able to review any proposed thresholds in the specific, and utilities must offer a process by which they plan to reassess those thresholds at regular intervals.

#### Key Point #2:

#### The matrix prepared by the utilities is useful; however, utilities have more NPA opportunity in the “new customer requests” category than the matrix suggests.

United finds the matrix on slide 10 to be a useful visualization of where the LDCs expect to find success with NPA projects. At this time, we only offer that “new customer requests” might be easier to serve with NPAs than indicated by the medium-low suitability rating in the matrix.

In the case of new customer requests (and equally for individual customer service line replacement), the LDCs may consider creating a program whereby a gas utility offers customers requesting new service a monetary incentive to opt-out of the request or replacement, set at some amount less than the avoided cost of the service line installation or replacement, so that nonparticipating customers continue to benefit. More details for the related case of service line replacements can be found in a proposal submitted by RMI to the Illinois Commerce Commission in their Future of Gas Proceeding.[[10]](#footnote-11)

Line extension allowance policy changes (a reduction in gas line extension allowances alone, or along with an increase in electric line extension allowances), paired with other electrification incentives offered by MassSave, municipalities, the federal government (e.g. the Home Electrification and Appliance Rebates or Home Efficiency Rebate programs), can make this new service NPA offer particularly appealing while minimizing ratepayer impact.

Over time, we hope the green area of the matrix can expand as the LDCs become comfortable with designing and implementing NPAs, and as downstream electrification impacts the upstream gas infrastructure currently out of reach by NPA programs.

## Gas System Feasibility Review and Electric System Feasibility Review

#### Key Point #1:

#### United urges caution with respect to the way that electric distribution system upgrades are attributed to NPAs.

If a NPA includes the electrification of some customers in a specific area, it seems intuitive to include the electric distribution system capacity or equipment upgrade costs to support that project. However, these costs may actually be inappropriate to assign to the NPA, and inclusion of them may tilt the analysis away from an electrification solution and towards the traditional gas system project.

At its core, identifying the appropriateness of including distribution system costs in the cost-benefit analysis (CBA) of an NPA is a challenge of timing and split planning across many different dockets. In order to achieve Massachusetts’ clean heat and transportation electrification goals (which include 2030 and 2032 interim goals), and the Commonwealth’s overarching target to reach net-zero greenhouse gas emissions by 2050, the electric distribution companies will have to significantly expand their distribution system capacity. Furthermore, to encourage adoption of distributed generation, distributed storage, community solar, virtual power plants, clean microgrids, and other localized resources that enhance reliability, resilience, affordability, and customer empowerment, additional investment in distribution system visibility, control, and management systems and customer-sited technologies will be needed.

That is, distribution system upgrades needed for an NPA may also be needed for a net-zero transportation, building, and power sector future. As such, if the upgrade was going to be needed for compliance with the Clean Heat Standard, Clean Energy and Climate Plan (CECP), electric sector modernization plans (ESMPs) or any other filing or policy, it may not be appropriate to include for the NPA in isolation, even if the NPA is driving the upgrade earlier than would have otherwise been necessary. If the distribution system upgrade costs are showing up across various filings, its costs might be double counted in a way that artificially inflates the cost of the clean energy investments.

The most appropriate way to assign a cost to the NPA may be to conduct a study of what a fully-electrified future looks like on various nodes of the distribution system, what the cost of the enabling upgrades and technologies are likely to be, and when the upgrade will be needed under various adoption scenarios. If the NPA does not require any upgrades above and beyond what is needed for that all-electric future, and is needed at the same time as upgrades are needed to enable other plans (Clean Heat Standard, CECP, or ESMP) there should be no electric distribution costs assigned to the NPA. If certain technology – like additional metering equipment – is required for the NPA but not the other plans under an all-electric future, the cost should be assigned to the NPA. If the NPA is accelerating the need for an investment which would otherwise be needed, and that investment will need to be replaced by the time the transportation- or other distribution system-related need materializes, the cost is appropriate to assign to the NPA. If the investment is only accelerated by several years, but otherwise necessary to comply with other goals, the LDCs may develop a methodology to assign the “accelerated value” to the NPA, which is in essence the opposite of the “deferral value” that may be assigned to a pipeline project for which an NPA is deferring, or a poles and wires project that a non-wires alternatives project may be deferring.

## Benefit Cost Analysis

#### Key Point #1:

#### The Gas Rate Impact Measure test is likely to tell a misleading story in the case of NPAs, and we caution against using it.

The National Standard Practice Manual[[11]](#footnote-12) (NSPM) asserts that the Rate Impact Measure (RIM) test is misleading because it accounts for historical costs and does not include a forward-looking analysis. A significant flaw with the RIM specific to this framework is that is includes “net revenue costs”, meaning it captures revenues lost due to the reduced sales caused by the NPA measure. That characterization conflicts with the intent of Order 20-80; the LDCs should not treat lost gas revenues from an NPA as a cost because it misses the purpose of performing NPAs. LDCs would lose revenue from its gas business anyway under the counterfactual scenario due to Massachusetts’ clean energy and climate mandates, as well as the anticipated Clean Heat Standard implementation. If state policies cause gas sales to decline enough, the LDCs could incur the costs of future stranded assets. Furthermore, the NSPM maintains that lost revenues are a sunk cost and therefore not appropriate for a benefit-cost analysis. We strongly advise against including the Gas Rate Impact Measure and the Electric Rate Impact Measure in the updated framework.

*Key Point #2*:

*There are qualitative factors that utilities and planners must take into account and be able to make executive judgements about if the BCA gets close to, but not quite at “1”.*

The Total Resource Cost (TRC) test is well understood due to its application in the Massachusetts energy efficiency programs, and it capably considers some qualitative issues. It makes sense to include the TRC test in the NPA analysis and adapt it as necessary to ensure that the values considered align with the broader goals of the Commonwealth. When there is a proposal that comes close to a BCA of “1”, careful consideration should be given before dismissing that project completely. We can look to the “Rhode Island Test[[12]](#footnote-13)” or to Colorado for examples of allowing projects to proceed that come to slightly below “1” in certain contexts; in the Colorado case study[[13]](#footnote-14), an NPA project that creates significant benefits for an EJ community may override the BCA if it meets certain equity criteria and safety requirements.

## Project Authorization and Prioritization

#### Key Point #1: In the prioritization order, consider swapping II and III so that avoided capital comes before net avoided GHG emission reductions.

On slide 16, the LDCs propose a prioritization order that first lists projects in Environmental Justice communities, second lists net avoided greenhouse gas emissions reductions, and third lists the amount of avoided capital on the local distribution company’s system.

While emission reductions are very important, we strongly recommend swapping priorities II and III so that avoided capital comes before emissions reductions. Massachusetts has many policies driving emissions reductions, including its Global Warming Solutions Act, Clean Heat Standard, and Municipal Fossil Fuel Free Building Demonstration Program. NPAs, at their core, are about cost containment and avoiding system costs that will exacerbate financial and ratepayer challenges as electrification accelerates. If this program does not prioritize avoided system costs, it is not clear that there are any others serving that specific purpose.

## Project Execution

#### Key Point #1:

#### LDCs should include a “post-execution” reporting process by which they report on progress, challenges, lessons learned, and key metrics.

#### United recommends that the LDCs be explicit in this framework about what they plan to report on during NPA implementation and after NPA project completion. We recommend that this includes narrative on progress, challenges, lessons learned, and key metrics determined collectively with stakeholders.

As a starting place, we offer the following metrics used by Consolidated Edison in its Benefit-Cost Analyses filings for its Electric Advantage and Energy Exchange Programs.[[14]](#footnote-15) This includes:

* + Number of customers affected/participating
  + Money saved – avoided costs
  + Money saved – customer savings
  + Money saved – social cost of carbon/methane
  + Gas avoided
  + Peak day capacity avoided
  + Total benefits/total costs
  + Emissions avoided

## Customer Education, Engagement and Commitment

#### Key Point #1: N/a

## Impacts to Project Implementation

#### Key Point #1: N/a

## Framework Updating

#### Key Point #1: N/a

## Other (please specify)

#### Key Point #1: N/a

1. PR Newswire. U.S. Department of Energy Selects Generac for $50 Million in Federal Funding to Increase Power Grid Resilience in Massachusetts. October 27, 2023. Available at: <https://www.prnewswire.com/news-releases/us-department-of-energy-selects-generac-for-50-million-in-federal-funding-to-increase-power-grid-resilience-in-massachusetts-301970329.html> [↑](#footnote-ref-2)
2. Public Service Company of Colorado. Initial 2023-2028 Gas Infrastructure Plan. Docket No. 23M-0234G. May 18. 2023, p. 7. [↑](#footnote-ref-3)
3. Colorado Public Utilities Commission. Commission Decision Addressing Adequacy of Gas Infrastructure Plan and Providing Guidance for Future Gas Infrastructure Plan Filings. Docket No. 23M-0234G. February 23, 2024, p. 25. [↑](#footnote-ref-4)
4. Colorado Public Utilities Commission. Commission Decision Addressing Adequacy of Gas Infrastructure Plan and Providing Guidance for Future Gas Infrastructure Plan Filings. Docket No. 23M-0234G. February 23, 2024, p. 24. [↑](#footnote-ref-5)
5. Colorado Public Utilities Commission. Commission Decision Granting, In Part, and Denying, In Part, Application for Rehearing, Reargument, or Reconsideration of Commission Decision No. C24-0092. Docket No. 23M-0234G. April 15, 2024, p. 4. [↑](#footnote-ref-6)
6. Colorado Public Utilities Commission. Commission Decision Addressing Adequacy of Gas Infrastructure Plan and Providing Guidance for Future Gas Infrastructure Plan Filings. Docket No. 23M-0234G. February 23, 2024, p. 31. [↑](#footnote-ref-7)
7. Consolidated Edison. Electric Advantage Benefit Cost Analysis: Non-Pipes Alternative to Gas Service Replacements. Docket No. 22-G-0065. July 2024 [↑](#footnote-ref-8)
8. Consolidated Edison. Energy Exchange Benefit Cost Analysis: Non-Pipes Alternative to Gas Service Replacements. Docket No. 22-G-0065.July 2024. [↑](#footnote-ref-9)
9. Public Service Company of Colorado. Direct Testimony and Attachments of Grace K. Jones. Docket No. 25A-0044EG. January 16, 2025, p. 3. [↑](#footnote-ref-10)
10. Joe Dammel, RMI. Service Line Non-Pipeline Alternative*.* December, 2024. Available at: <https://icc.illinois.gov/api/web-management/documents/downloads/public/future-of-gas/Service%20Line%20Non-Pipeline%20Alternative_RMI.pdf> [↑](#footnote-ref-11)
11. NESP. National Standards Practice Manual. August 2020. Available at: https://www.nationalenergyscreeningproject.org/wp-content/uploads/2020/08/NSPM-DERs\_08-24-2020.pdf [↑](#footnote-ref-12)
12. State of Rhode Island Division of Public Utilities & Carriers. The Rhode Island Cost-Effectiveness Framework: Methodologies for Developing Inputs for Distributed Energy Resources. October 29, 2018. Available at: <https://ripuc.ri.gov/sites/g/files/xkgbur841/files/eventsactions/docket/4600A-DIV-DraftRept-FrameworkMethodology%2810-3-18%29.pdf> [↑](#footnote-ref-13)
13. Non-Pipeline Alternatives: A Regulatory Framework and a Case Study of Colorado. October 2023. Available at: <https://eta-publications.lbl.gov/sites/default/files/non-pipeline_alternatives_to_natural_gas_utility_infrastructure_2_final.pdf> [↑](#footnote-ref-14)
14. Consolidated Edison Company of New York. Benefit-Cost Analysis: Non-Pipes Alternative to Gas Infrastructure Replacement. Docket No. 22-G-0065. July 23, 2024. [↑](#footnote-ref-15)