MINNESOTA
PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	**September 12, 2024**	**Agenda Item 1****
Company	• CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas • Minnesota Energy Resources Corp • Northern States Power Co. d/b/a Xcel Energy	
Docket No.	G008,G002,G011/CI-23-117 G999/CI-21-565	

In the Matter of a Commission Investigation into Gas Utility Resource Planning

In the Matter of a Commission Evaluation of Changes to Natural Gas Utility Regulatory and Policy Structures to Meet State Greenhouse Gas Reduction Goals

Issues: What filing requirements should the Commission adopt for Xcel Energy, CenterPoint Energy, and Minnesota Energy Resource Corporation's natural gas integrated resource plans (IRPs)?

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✓ **Relevant Documents**	**Date**
Straw Proposal	
CenterPoint Energy Minnesota Gas	May 31, 2024
Minnesota Energy Resources Corporation	May 31, 2024
Xcel Energy	May 31, 2024
Initial Comments	
Building Decarbonization Coalition	June 28, 2024
Center for Energy and the Environment (CEE)	June 28, 2024

✓ **Relevant Documents**	**Date**
Citizens Utility Board of Minnesota (CUB)	June 28, 2024
Clean Energy Organizations (CEOs)	June 28, 2024
Minnesota Department of Commerce (Department)	June 28, 2024
Office of the Attorney General, Residential Utilities Division (OAG)	June 28, 2024
CenterPoint Energy Minnesota Gas (CPE)	June 28, 2024
Minnesota Energy Resources Corporation (MERC)	June 28, 2024
Xcel Energy	June 28, 2024
Reply Comments	
Ayada Leads, CURE, Minnesota Interfaith Power and Light, Midwest Building Decarbonization, and MN 350 Action (Ayada et al.)	July 19, 2024
Building Decarbonization Coalition	July 19, 2024
CEE	July 19, 2024
CEOs	July 19, 2024
CUB	July 19, 2024
Department of Commerce	July 19, 2024
LIUNA	July 22, 2024
IUOE Local 49	July 19, 2024
Local Governments	July 19, 2024
OAG	July 19, 2024
Public Comment	July 22, 2024
CPE	July 19, 2024
MERC	July 19, 2024
Xcel Energy	July 19, 2024
Additional Documents	
Gas Price Spike Order	February 17, 2023
Framework Order	March 27, 2024

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I. DOCKET HISTORY

A. Price Spike Order

On February 17, 2023, following a yearlong investigation initiated by the Minnesota Public Utilities Commission (Commission) regarding Winter Storm Uri and the impact of extreme weather events on gas utilities and their customers, the Commission expanded the use of resource planning to include gas utilities Northern States Power Co. d/b/a Xcel Energy (Xcel), CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas (CenterPoint or CPE), and Minnesota Energy Resources Corp. (MERC).[1] The Commission found natural gas resource planning to be in the public interest and delegated authority to the Executive Secretary to begin a proceeding to establish the timelines, content, and procedural requirements for natural gas resource plans for CenterPoint, Xcel, and MERC.

B. First Plan Proposals

The development of gas integrated resource plans (IRP) began with a proposal filed by the Citizen's Utility Board of Minnesota (CUB). Ultimately, stakeholders used the Great Plains Institute (GPI) workshops explained below and the Notice and Comment process to reach agreement on some aspects of CUB's proposal as well as subsequent proposals filed by CPE and Center for Energy and Environment (CEE).

C. Framework Order

Indeed, from those proposals and extensive stakeholder discussions, the Commission's March 27, 2024 Order Establishing Framework for Natural Gas Utility Integrated Resource Planning in docket numbers G-008,G-002,G-011/CI-23-117 and G-999/CI-21-565 (Framework Order) defined many aspects of the natural gas integrated resource planning <u>process</u>, including how often plans will be filed and the criteria by which the Commission will evaluate plans, as well as the <u>main components</u> of gas IRPs for Minnesota's three largest natural gas utilities.

D. Stakeholder Meetings

Great Plains Institute has facilitated monthly stakeholder workshops, titled the Gas Utility Innovation Roundtable, focused on the directives in the February 17, 2023 Order. Staff understood the first objective of the stakeholder meetings to be finding areas of stakeholder agreement on CUB's proposal.[2] Following the Commission's establishment of the main components of IRPs, the group continued to work to understand what analyses and data should be required for gas IRPs. Staff participated in these workshops to gain context for stakeholders' positions and to ask clarifying questions. Representatives from utilities, consumer advocates,

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[1] Order issued February 17, 2023 in Docket No. G999/CI-21-135 see pages 21-22 as well as Ordering paragraph 16.

[2] CUB's proposal was originally filed October 14, 2022 in docket no. docket no. G999/CI-21-135 and revised based on stakeholder feedback on October 24, 2023 in the instant docket.

clean energy organizations, and labor also participated while the Minnesota Department of Commerce, Division of Energy Resources (Department) attended as an observer. GPI has filed summaries in this docket.

E. Current Comment Period

The instant comment period asked for input on 1) whether the Commission should specify additional filing requirements for any of the main components of gas IRPs and 2) process details.

By May 31, 2024, CPE, MERC, and Xcel filed separate straw proposals regarding additional filing requirements.

By June 28, 2024, the Building Decarbonization Coalition, CEE, CUB, The Clean Energy Organizations (CEOs),[3] the Department, the Office of the Attorney General Residential Utilities Division (OAG), CPE, MERC, and Xcel filed initial comments.

By July 19, 2024, the following filed reply comments:

- one member of the public, a metro-area pediatrician,
- the Building Decarbonization Coalition,
- CEE,
- CEOs,
- CUB,
- the Department,
- LIUNA,
- IUOE Local 49,
- Local Governments,[4]
- OAG,
- CPE,
- MERC,
- Xcel,
- Ayada Leads, CURE, Minnesota Interfaith Power and Light, Midwest Building Decarbonization, and MN 350 Action (referred to as “Ayada et al.” in these briefing papers).

[3] In this docket, the CEOs consist of Fresh Energy, Minnesota Center for Environmental Advocacy, and Sierra Club.

[4] Bloomington Mayor Tim Busse; Edina Sustainability Manager Marisa Bayer; Hopkins Manager Mike Mornson; Richfield Manager Katie Rodriguez; Minneapolis Dept. Commissioner Patrick Hanlon; St. Paul Chief Resilience Officer Russ Stark; St. Louis Park Sustainability Manager Emily Ziring.

II. BRIEFING PAPER FOCUS AND STRUCTURE

A. Goal of Briefing Paper

This briefing paper will first talk about equity, noting that equity will be highlighted in participatory processes and the expansion alternatives analysis. Also, Staff will discuss equity in terms of workforce and decommissioning assets. Next the paper will discuss which utility files first and when. Last, the briefing paper will look at where stakeholders have requested clarifications of the existing the gas IRP filing requirements.

For many of the gas IRP filing requirements, stakeholders found the Framework Order offered enough specificity for utilities to file a resource plan. Staff will not discuss these components in the body of the briefing paper but notes that stakeholders have recommended that the Commission's final Order include a comprehensive list of all gas IRP requirements (**Decision Option 101**). Therefore, Staff will focus on IRP components for which stakeholders requested additional direction to the existing Framework Order.

First, Staff will present areas where there are many topics for the Commission to weigh in on: 1) the Expansion Alternatives Analysis, including its suitability to explicitly promote equity, 2) the quantification of the environmental impact of gas resources, and 3) utilities' demand forecast.

After, Staff presents areas where stakeholders focused less: 4) environmental efficiency, 5) scenarios and sensitivities, 6) MERC's request for deferred accounting, 7) the five-year action plan, 8) ordering paragraph text modifications, 9) "all-in costs" to compare resources, and 10) city climate policy and gas IRP alignment.

B. Outcome

This agenda meeting is another opportunity for the Commission, before the first gas IRPs are submitted, to establish details to ensure plans will meet the previously determined objective, scope, and definition of gas IRPs.[5] The agenda meeting may result in defining terms used in the Framework Order, providing details as to what data will be used for analyses, and aligning data and processes used across relevant dockets. More, the Commission can decide which utility will file its plan first and when it will be filed as well as decide how to deliberately imbed equity throughout gas IRPs.

C. Iterative Process

Staff understands that the gas IRP process is new to stakeholders and the Commission. While efforts are made to produce useful initial gas IRPs, additional information or clarifications can

[5] Order Establishing Framework for Natural Gas Utility Integrated Resource Planning issued March 27, 2024 in docket nos. G-008,G-002,G-011/CI-23-117 and G-999/CI-21-565 (Order Establishing Framework). See Ordering paragraphs 2-5.

be obtained through Information Requests (IRs).[6] More, with every successive IRP filed, the Commission and stakeholders will gain a firmer understanding of what makes an effective IRP, which can inform future modifications to the requirements, via Orders, as appropriate.

III. EQUITY

Staff issued two notices of comment to develop the gas IRP record. In each notice Staff prompted stakeholders to discuss how equity should be incorporated into gas IRPs as well as how members of the public want their utility to include the public in IRP development. **Decision Options 1 and 2** pose requirements to discuss how equity is considered broadly in the entire gas IRP and the planning process. However, equity will also be intentionally embedded into various components of the resource plan. At present, stakeholders focused on incorporating equity in a utility's expansion alternatives analysis as well as additional recommendations for procedural equity. Equity requirements may expand into other components over time, as stakeholders and the Commission gain experience with gas IRPs. Staff does note that some stakeholders were less emphatic about equity discussions, finding that equity could be in tension with other goals, like climate, and may be out of scope of the Framework Order.

A. Gas IRP Process

1. Stakeholder Recommendations

Stakeholders are depending on the public engagement process described in the Framework Order to incorporate public voices into draft resource plans before those plans come before the Commission.[7] In comment periods, Stakeholders identified additional procedural justice considerations to bolster the Framework Order. Stakeholders focused on:

- Continuing GPI-facilitated work sessions that include an equity component as well as focus on each utility's gas IRP.
- Building long-term trusting relationships with communities that have traditionally been underserved or underrepresented in the state-based energy conversation. Doing so would provide insights that reflect the diversity of utility customers.

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[6] Order Establishing Framework. See Ordering paragraph 22g.

[7] Order Establishing Framework for Natural Gas Utility Integrated Resource Planning issued March 27, 2024 in docket nos. G-008,G-002,G-011/CI-23-117 and G-999/CI-21-565. See, for example, Ordering Paragraphs:

24. Integrated resource planning proceedings will be conducted before the Commission in an uncontested proceeding whenever practicable, with the Commission issuing one or more notices of comment period to solicit comments from interested stakeholders and the public.
25. The Commission will ensure public meetings provide opportunities for Minnesota residents to verbally comment on the utilities' natural gas resource plans considering accessibility for individuals from or representing communities that are typically underrepresented in utility decision-making.
27. Resource plans must A) be updated on a regular basis, B) provide the opportunity for public participation and comment, C) provide for methods of validating predicted performance, and D) contain a requirement that the plan be implemented after approval of the state regulatory authority

- Sharing information and collaborating with local governments in utility service territories.
- Public meetings and comment processes that center participants' needs.[8] This includes offering food, space for dependent care, convenient hours, and proximity to transit.
- Following standards set out by the White House Environmental Justice Advisory Council in the context of other types of new infrastructure buildout.[9]

Ultimately, these procedural justice considerations are captured in **Decision Options 3-9.** Selecting from these options would result in discussions with impacted communities and stakeholders before finalizing IRPs or beginning work on the infrastructure projects selected in the final IRP.

Staff often relies on stakeholder groups' comments to represent the views of the broader public (see Staff Analysis, below). However, Ayada et al. offered an important reminder that "[e]ffective engagement with impacted communities must be a part of any planning process, and merely mapping folks or turning to 'stakeholders' to represent their interests is not a sufficient stand-in for talking to people themselves."[10]

2. Staff Analysis

Staff welcomes the new perspectives from commenters on this docket who perhaps were less vocal in, or unable to attend, stakeholder meetings. Staff is grateful for these new lenses through which to view IRPs, which have brought up new questions for the Commission to consider and new types of information that could help make plans more beneficial to gas customers.

The Commission and Utilities have been tasked with ensuring participation in the IRP process via the Framework Ordering paragraph 25:

> The Commission will ensure public meetings provide opportunities for Minnesota residents to verbally comment on the utilities' natural gas resource plans considering accessibility for individuals from or representing communities that are typically underrepresented in utility decision-making.

Thus, the additional recommendations gathered throughout the past two comment periods

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[8] Ayada et al. reply comments filed July 19, 2024 at 9 referenced specifically following the "CEQ" from Council on Environmental Quality, Environmental Justice Guidance Under the National Environmental Policy Act at 13 (1997), https://www.epa.gov/sites/default/files/201502/documents/ej_guidance_nepa_ceq1297.pdf.

[9] Ayada et al. at 10 with reference to WHITE HOUSE ENVIRONMENTAL JUSTICE ADVISORY COUNCIL, RECOMMENDATIONS: CARBON MANAGEMENT WORKGROUP, Nov. 17, 2023, at 23 https://www.epa.gov/system/files/documents/2023-11/final-carbon-managementrecommendations-report_11.17.2023_508.pdf (listing ten principles and subprinciples).

[10] Ayada et al. reply comments filed July 19, 2024 at 4

provide important practical advice as the Commission and Utilities embark on this work. More, Staff underscores the responsibility of stakeholders, who are often well-connected to diverse utility customer groups, to share participation opportunities with customers to whom they are connected and to build participatory capacity of those customers newer to Commission processes.

B. Additional Equity and Justice Considerations

1. Stakeholder Recommendations

Stakeholders also commented on other components of equity and justice. For the distribution of benefits and burdens, stakeholders recommended several mapping exercises, especially to inform the Expansion Alternatives Analysis (EAA). For example, the City of Minneapolis, Xcel, and CEOs explained that mapping in the EAA may help target energy efficiency and electrification efforts towards low-income households to lower bills and reduce pollution. The recommendations about the EAA from earlier comments are also reflected in **Decision Options 40-45**. Comments on distributional justice and equity also focused on the distribution of pollution impacts, including that of indoor air pollution related to burning gas. Indoor air pollution will be discussed further in Environmental Impacts (section VI).

To ensure the gas resource plans enacted match how people want to live their lives, recognition justice and equity were described as the need for participation and energy solutions that match how groups experience the world. Informal conversations with the Clean Heat Coalition, not included in this record, and Ayada et al.'s comments reminded Staff that not all groups, especially those living on tribal lands, have access to high-speed internet for virtual meetings. More, that some groups depend on gas or other types of fuel for cultural uses.

Stakeholders also discussed equity in terms of financial burdens, asking utilities to consider the bill impacts of various resource portfolios and equitable distribution of gas resource planning costs. To this point, Framework ordering paragraphs required utilities to include a "nontechnical summary of the likely effect of plan implementation on electric rates and bills" and "include the cost of each scenario and sensitivity presenting both the utility's revenue requirement and environmental costs and other externalities to the utility's revenue requirement." More, stakeholders will continue to consider rates structures needed to maintain affordable and equitable utility service through the Commission's Future of Gas proceeding in docket no. G999/CI-21-565.[11]

Equity was also framed in terms of access to and use of data. Maps, for example, can help to show how decisions may impact geographically distinct areas, like areas with high proportions of low-income people or tribal lands. Map data may be used in the expansion alternatives analysis (**Decision Option 40**) or more broadly throughout the entire IRP (**Decision Option 92**).

[11] Order Establishing Framework for Natural Gas Utility Integrated Resource Planning issued March 27, 2024 in docket nos. G-008,G-002,G-011/CI-23-117 and G-999/CI-21-565. Citing Ordering Paragraphs 36, 49, and 56.

CEOs also explained the importance of making data on utility service provision, rates, and customer demographics easily accessible. Doing so allows for accountability and helps identify areas in need of improvement.[12] Framework ordering paragraph 22 speaks to this point.

Finally, for redress for previous harms, stakeholders mentioned improved access to assistance programs in areas of historic inequity. Discussions of assistance programs take place in other dockets like annual Gas Affordability Program (GAP) proceedings and will not be explored in these briefing papers. MERC, Xcel, and labor unions also focused on workers and workforce transition with high-quality job opportunities for previously underrepresented communities (**Decision Options 10-11**). Last, Ayada et al. recommended a pathway to plan for the long-term treatment of gas infrastructure (**Decision Option 12**). These topics are expanded on below.

2. Workforce Options

a. Party Recommendations

Ayada Leads, CURE, Midwest Building Decarbonization, MNIPL, and MN350 Action (collectively, Ayada et al.) explained that, "As the industry evolves and employees are able to retrain into different industries, the Commission will need to view the issue of job impacts and workforce preparedness from the perspective of the employees and not just from the utility's vantage point." As such, this group recommended the Commission create a mechanism for existing employees of the utilities to provide input and have their voices heard without the intermediary of their employer. (Ayada et al.)[13]

Also acknowledging the importance of utility workforce, MERC recommended, and the Department supported, incorporating equity into gas IRPs via workforce development. MERC explained, "Equity via the Gas IRP process can also mean enhanced access to job opportunities in utility industry career areas that could become available due to implementing Gas IRPs."[14]

b. Staff Analysis

When similar work force transition questions arose in Xcel's electric integrated resource plan, those discussions were moved to a new docket focused on workforce transition related to retiring electricity generation facilities.[15] At the time of writing this briefing paper, no materials beyond the Commission's Notice of Docket Opening have been filed in the workforce transition docket. While that docket contemplates electric generation facilities specifically, it may be useful for questions of Xcel's gas workforce transition questions to be discussed alongside Xcel electric workforce questions, to share learnings and preserve stakeholder bandwidth. However,

[12] CEOs initial comments filed November 30, 2023 in docket no. G008, G002, G011/CI-23-117 at 10

[13] Ayada et al. comments at 6 filed July 19, 2024

[14] MERC straw proposal at 7

[15] Xcel Electric IRP docket no. E002/RP-19-368; new docket, no. E002/M-22-265, In the Matter of Workforce Transition Related to Retiring Electricity Generating Facilities.

discussing workforce questions in an Xcel-only docket would mean Xcel's workforce transition would be contemplated separately from other utilities. Alternatively, all gas utilities could contemplate workforce transition together in the Future of Gas proceedings in Docket No. G-999/CI-21-565.

Staff intends for The Future of Gas discussions to begin in Fall 2024 and focus on the topic required by Framework ordering paragraph 56:

> To consider changes to rates needed to maintain affordable and equitable utility service. Such discussions will consider recommendations from the G21 process, the potential for stranded costs on the natural gas system due to electrification, and the policy implications of electrification, including whether technological advances will allow complete electrification, given intermittency of renewables.

Workforce transition may be beyond the scope of the discussions as described in Framework ordering paragraph 56. If so, the Commission may consider finding the workforce topic suitable for stakeholders' next round of discussions. Alternatively, like treatment in Xcel Electric's IRP, a new docket may be opened to discuss the gas workforce but as it applies to all utilities.

Ayada et al. requested a separate channel for company employees to give input on gas IRPs. Staff agrees that hearing from workers is important to the Commission. However, Ayada et al. seemed to be advocating for the ability for workers to also comment anonymously. Staff underscores the importance of tying one's lived experience to a comment when building the record. Further, based on due process principles regarding an open public docket, the PUC has a public comment policy that anonymous comments will not be accepted into the record for a public comment period. Staff encourage those who wish to comment on the gas IRPs to submit comments through the online form on the Commission's website.

The Commission does recognize the need in certain circumstances for individuals to remain anonymous when reporting workplace wrongdoing separate from a matter that has a public open docket. Therefore, if a commenter has concerns about workplace wrongdoing and wishes to retain anonymity, the Commission offers an alternative process separate from the public comment process to accept input anonymously through the Consumer Affairs Office complaint process: https://mn.gov/puc/consumers/complaint/

Finally, with respect to considering workforce and supplier diversity, Staff acknowledges the Department's docket E,G999/PR-24-101 created to comply with Minn. Stat. § 216C.51. Reporting includes numerical data showing, "the utility's goals and efforts to increase diversity in the workplace, including current workforce representation numbers and percentages" as well as "an explanation of the plan to increase diversity in the utility's workforce and among the utility's suppliers during the next year." If there was interest, data could be referenced from this docket in gas IRPs or reporting from PR-24-101 could be included as an appendix to gas IRPs.

3. Decommission Gas Infrastructure

a. Ayada et al.'s Recommendation

Ayada et al. recommended the Commission require the gas utilities to plan for the future of gas infrastructure by establishing decommissioning trust funds that would hold sufficient funds for any future liabilities arising from abandonment.

b. Staff Analysis

Staff thanks the commenters for opening the discussion on decommissioning funds. If groups would like to pursue these topics further, the Future of Gas docket would likely be the best place for further record development. Staff notes one instance of a statutory decommissioning practice, outlined for Nuclear Plants and for storing used fuel in Minn. Stat. § 216B.2445.

IV. FILING CADENCE

Commenters largely agreed that Xcel should file the first gas IRP on October 1, 2026. Xcel was championed as the first utility to file based on its experience with filing IRPs for its electric service.[16] The Department noted that Xcel also has experience following its Clean Heat Plan for its Colorado service territory. The date of October 1st was proposed to avoid overlap, especially for stakeholders working across proceedings, with other dockets regularly filed on November 1, like utilities' integrated distribution plans.[17] Stakeholders then largely agreed that CPE should file the second IRP on October 1, 2027, followed by MERC on October 1, 2028 (**Decision Option 13**).

MERC was the only commenter to dispute this cadence, arguing that a two-year gap between the first and second plan would better allow the second utility to apply learnings from the first IRP (**Decision Option 14**). If the Commission were to decline this delay for the second utility, MERC recommended that the Commission delegate authority to the Executive Secretary revise the IRP filing schedule as needed (**Decision Option 13 A**).

V. EXPANSION ALTERNATIVES ANALYSIS

Stakeholders expressed confusion about the intention of the expansion alternatives analysis (EAA) section in the Framework Order, paragraphs 51-55. Through discussions facilitated by GPI as well as the notice and comment process, Staff believes stakeholders reached a broad common understanding. The EAA will not include a full distribution system planning exercise or analysis. Instead, the EAA should use an infrastructure cost threshold that will be established at this agenda meeting and applicable only to the EAA. All projects with a monetary value above

[16] Xcel straw proposal filed May 31, 2024 at 6-7

[17] This sentence and the previous, Department of Commerce comments filed June 28, 2024 at 9-10.

the threshold will form a pool of potential capacity expansion projects.[18] From that pool, a subset of two or three projects will be analyzed to learn if those projects would instead be suitable sites for an alternative energy source, rather than building extensive, new gas infrastructure.

Shared definitions were also part of the common understanding reached. Shared definitions were created for the words shown below in bold and quotation marks from the following Framework ordering paragraphs.

Distribution System Analysis

51. Utilities shall incorporate "**infrastructure costs"** related to resource expansion or new resources above an "**investment threshold**" to be established at a later date into the resource analysis and selection process.

52. The alternatives analysis shall be called "Expansion Alternatives Analysis."

53. Utilities shall incorporate targeted distribution system analysis into the integrated resource planning process to proactively identify areas of the natural gas system with upcoming capacity needs and analyze how to best serve those needs.

54. For initial utility resource plans, utilities shall identify two to three significant upcoming "**capacity expansion projects"** in each utility resource plan for a "**full alternatives evaluation**."

55. Distribution system investments related to routine maintenance, public works accommodation, integrity, reliability, and safety are not part of the integrated resource planning process or analysis.

A. Definitions of Infrastructure Costs and Capacity Expansion Projects

Utilities offered similar definitions for infrastructure costs which Staff summarizes as, "for the purposes of the natural gas integrated resource plan expansion alternatives analysis, infrastructure costs are capital costs the utility would incur to complete the project." MERC offered an example that, if a capacity expansion project were needed, and it required a CIAC to an Interstate Pipeline as well as supporting utility distribution system upgrades, all of these costs together would be considered.[19] See **Decision Option 15.**

Utilities also offered similar definitions for "Capacity Expansion Project, Resource Expansion, or New Resources" explaining that these would be considered individual projects, or a set of inter-related facilities needed to meet a specified capacity expansion need due to growth by existing or new customers and facilities. See **Decision Option 16** which would clarify the definition; alternatively, this definition is captured in Staff's **Decision Option 21**.

[18] In their initial comments at 12 CEE clarified that the EAA threshold will not apply to any projects outside the Expansion Alternatives Analysis. Indeed, the entire IRP will report full costs of resource portfolios as stated in Framework ordering paragraph 49, the utility's revenue requirement would include consideration of all costs, including related distribution system and capital costs, associated with the different resource options.

[19] MERC straw proposal at 2-3

In their clarification of framework ordering paragraph 54, utilities included the same language from Framework Ordering paragraph 55 which explains projects not included in the EAA. MERC, for example, reiterated that its definition "would exclude costs related to routine maintenance, public works accommodation, integrity, reliability, and safety, which are typically considered Gas Utility Infrastructure Cost (GUIC) eligible projects."[20] For this aspect of utilities' proposal, CEE found the utilities' emphasis on excluded projects and costs to be duplicative of ordering paragraph 55 and thus, unnecessary.

Stakeholders recommended additional text to utilities' definition of capacity expansion projects. CUB, with support from the Building Decarbonization Coalition, recommended that projects that meet the statutory definition of a natural gas extension project ("NGEP") should be eligible to be considered for an EEA (**Decision Option 18**).[21] More, CUB recommended that projects that are geographically related and/or interdependent on each other should be considered as a single capacity expansion project for the purposes of determining EAA eligibility above the cost threshold (**Decision Option 17**). Xcel did not support additional direction regarding geographically related projects explaining, "[i]t is possible to have multiple projects near each other with no relation, and they may not always address the same issue."[22]

B. Definition of Investment Threshold

Part of building common understanding also focused on threshold. After utilities provided historical values to inform the number of potential capacity expansion projects at various thresholds (**Table 1**), stakeholders explained their preferred thresholds such that eligibility for the EAA would include all projects valued at: $15 million or more (CPE), $10 million or more (LIUNA and CPE), $3 million or more (Xcel), and $1 million or more (the Building Decarbonization Coalition; MERC; CUB, CEE, CEOs, Dept, Xcel).

Table 1. Capacity Expansion Project Counts at Varying Thresholds, 2018-2023

Threshold	$1 Million	$3 Million	$5 Million	$10 Million	$15 Million
CPE	15 projects	5 projects	4 projects	4 projects	4 projects
MERC	6	2	2	2	1
Xcel	6	4	*Not included*	*Not included*	*Not included*

Some stakeholders believed that setting a value threshold would result in a burdensome number of potential projects being vetted for the eventual EAA. Thus, these commenters

[20] MERC straw proposal at 3

[21] Minnesota Statute § 216B.1638 defines "Natural gas extension project" or "project" means the construction of new infrastructure or upgrades to existing natural gas facilities necessary to serve currently unserved or inadequately served areas." And explains that "A public utility may petition the commission outside of a general rate case for a rider that shall include all of the utility's customers, including transport customers, to recover the revenue deficiency from a natural gas extension project."

[22] Xcel replies at 9

recommended capping the requirement at 5 or 10 projects if the Commission selects the $10 million or $1 million threshold, respectively. See **Decision Options 20-22.**

While the utilities each suggested that a different threshold was most appropriate for its own EAA, the Department recommended a single threshold for *all* utilities, for administrative efficiency. While the Commission may set a single threshold, Xcel included the caveat that it could evaluate and select projects below the threshold, if warranted.

C. Analysis of Alternatives

1. Moving from Pool of Projects to 2-3 Final Projects for Full EAA

Once a threshold had been used to create a pool of projects eligible for the EAA, the CEOs detailed a process to narrow down that pool to the 2-3 projects which would be subject to the full alternatives analysis, per Framework Ordering paragraph 54. The CEOs recommended:

> First, the preliminary screening of forecasted infrastructure investments identifies projects for alternatives analyses that are more likely to be feasible and executable based on safety, cost, and timing. Next, to assess whether an alternatives project is technically viable, a utility procures and assembles eligible resources into a portfolio. Finally, a utility evaluates the alternatives portfolio using a benefit-cost test, qualitative vendor criteria, and equity analysis.[23]

MERC and the Department did not support this recommendation as they found it too prescriptive. They believed stakeholders were still contemplating how the EAA would work in practice.

Additionally, CEE suggested that when selecting expansion projects for the EAA, utilities consider the potential for learning, equity impacts, and emissions reductions (**Decision Option 27**). CUB and CEOs requested that utilities consider the suitability of routine maintenance, public works accommodation, integrity, reliability, and safety projects for an EAA, though these types of projects are not part of the integrated resource planning process or analysis as explained in Framework Ordering paragraph 55 (**Decision Option 26**).[24]

2. Process for Full Alternatives Evaluation

The Framework Order called for a “full alternatives evaluation” at paragraph 54, but the Commission did not specify what that evaluation would be. In the instant comment period, stakeholders shared ideas about criteria to use to assess the feasibility of alternatives. The CEOs suggested a series of costs that should be quantified for each alternative project and compared to a gas expansion project (**Decision Option 28**). Xcel agreed to the CEOs’ recommendation.

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[23] CEOs initial comments at 8-10.

[24] CUB reply comments at 11; CEOs initial comments at 9.

CUB added an additional "cost" related to air quality impacts. CPE did not support; the Department did not support as it had not had enough time to review.

Commenters' recommendations also included requirements for preferred technological alternatives taken from Natural Gas Innovation Act (NGIA) guidance (**Decision Option 29**), which was not supported by CPE, and new business and capacity expansion projects as explained in Colorado's Gas Infrastructure Plans (**Decision Option 30**).

For transparency into the full alternatives evaluation process, Xcel offered to provide a discussion of the rationale for the projects selected for an EAA. The Department, CPE, CEOs, and CUB supported such a discussion. Expanding on Xcel's straw proposal, the CEOs recommended that for any project above the chosen investment threshold, utilities provide an explanation of why the projects selected for a full alternatives evaluation were prioritized over the projects that were not selected. This was supported by Ayada et al. but not by MERC, who said providing such explanations would be burdensome, especially if there were multiple projects in the pool of projects above the chosen threshold. However, Staff reasons that the project cap explained above could alleviate some of MERC's concern. See **Decision Options 31-32.**

D. Equity

Stakeholders recommended that EAAs use mapping tools to produce equitable outcomes. For example, mapping could show how capacity expansion projects or their alternatives could impact environmental justice and disadvantaged communities (see **Decision Options 40-41**). To this extent, maps could show the negative impacts by, for example, exploring the impacts of pollution on their communities. More, several stakeholders expressed desire for the EAA to prioritize investment of electrification for rural and low-income communities and perhaps even place a moratorium on expansion of gas assets into low-income communities ahead of a potential transition to greater electrification. Such prioritized investment would also recognize the unique conditions experienced by low income and rural customers. Also, targeted investment could protect against imposing the cost of expanding gas assets on the most vulnerable customers, who would remain dependent on the gas system if unable to afford to be among the first customers to electrify.

While many stakeholders supported use of such mapping, the Department wanted more time to evaluate the impact of maps and said the EAA should focus on established requirements.

Stakeholders also considered equity in the EAA as procedural justice, calling for inclusion of stakeholders as utilities developed their EAA, including which projects are ultimately suitable for that analysis. Stakeholders proposed that utilities be required to discuss EAAs with:

- diverse communities in their service territories,
- community leaders and elders,
- the Gas Utility Innovation Roundtable hosted by GPI, and
- local governments to align infrastructure projects with community capital improvement

plans as well as to minimize burden of stranded assets and a shrinking customer base (**Decision Options 33-38**).

Note, MERC reminded the Commission that regardless of collaboration, the utility should have ultimate authority over which projects it analyzes.[25]

E. Staff Discussion on EAA

1. Definitions

Staff believes the definition of cost would be appropriate for inclusion in the body of a new Order while the definition of infrastructure project could be put in a new Ordering Paragraph (as detailed in **Table 2** below). Staff agrees that a re-statement of excluded projects would be redundant, as this is already captured in Framework ordering paragraph 55, and thus is unnecessary.

2. Process

Staff finds it incredibly helpful that the instant comment period as well as CUB's initial proposal brought a wealth of information on the EAA process. However, as the EAA is a novel process and there is a committed group of stakeholders who can spend more time to discuss and try various EAA techniques, Staff cautions against selecting a detailed methodology for the EAA now. Staff believes it would be appropriate for the methodology to be worked out among stakeholders, utilities, and interested members of the public at further open meetings.

Therefore, Staff recommends the Commission consider the pared-down decision option that was created by CUB and CEE (final column in **Table 2**). CEOs and CEE's language was intended to replace Framework Ordering paragraph 51 and could be modified to include the Commission's chosen threshold and possibly project cap, inserted where the option currently reads "$1 million." Staff notes that while CUB and the CEOs' decision option contemplates *selection* of projects for the EAA, it does not mention performing the actual analysis. Therefore, Staff would modify CUB and CEE's decision option, shown with an underline.

3. Equity

Staff acknowledges the wide stakeholder support for use of maps in the EAA. Staff has previously studied the power that comes from visualizing the distribution of benefits and burdens. Importantly, Xcel has already demonstrated it can conduct complex geographic analyses, via its MN Electric Service Quality Interactive Map, and the positive impact of that map.[26] Therefore, Staff supports mapping exercises in the EAA.

[25] MERC reply comments filed July 19, 2024 at 6, referencing framework ordering paragraph 54, "utilities shall identify two to three significant...projects"

[26] https://xeago.maps.arcgis.com/apps/webappviewer/index.html?id=6b87f4d407864b939bcea05aad05bdd1

When it comes to explicitly including participation with stakeholders in the IRP process, the Framework Order explained how stakeholders should be involved in the broad IRP process but did not explicitly call out involvement in the EAA. Due to the novel nature of the process, Staff underscores the importance of stakeholder involvement per **Decision Options 31-36**.

More, city government officials explained how they would like to share data for synergies on project timing and funding (**Decision Options 37-38**). The local governments' proposed collaboration pertains only to where a utility's service territory aligns with the undersigned cities. The Commission has previously promoted work with city governments to achieve this synergy for Integrated Distribution Planning.[27] Therefore, Staff believes alignment with the IDP and collaboration with cities for the EAA would be beneficial. Note, the city governments also recommended collaboration with utilities throughout the entire gas IRP process (Section XIV).

4. EAA Conclusion

Ultimately, Staff recommends amending ordering paragraphs 51-54 and the accompanying heading of the March 27, 2024 Order in docket nos. G-008,G-002,G-011/CI-23-117 and G-999/CI-21-565 as follows, shown in the middle column of **Table 2** (**Decision Options 19, 21, 23, 31, and 39**). Doing so will preserve the essential components from the Framework Order but better convey common understandings of novel EAA analyses.

Table 2. Suggested Replacement Text for Framework Ordering Paragraphs 51-54

Framework Order Language	Staff Proposed New Language	CEE/CUB Proposal with Staff Addition of Underlined Text
51. Utilities shall incorporate "**infrastructure costs"** related to resource expansion or new resources above an "**investment threshold**" to be established at a later date into the resource analysis and selection process.	51. Integrated resource plans shall include an analysis of infrastructure projects related to individual projects, or a set of inter-related facilities needed to meet a specified capacity expansion need due to growth by existing or new customers and facilities at or above a $1 million threshold.	51. Integrated resource plans shall include infrastructure projects related to resource expansion or new resources at or above a $1 million threshold from which utilities select projects for
52. The alternatives analysis	52. From the pool of projects	

[27] Order Accepting 2021 Integrated Distribution System Plan and Certifying The Resilient Minneapolis Project issued July 26, 2022, in docket no. E002/M-21-694 at paragraph 6, requiring stakeholder meetings to provide transparency into the planning process and generate a shared vision for the distribution grid of the future, including how Xcel should consider and incorporate local clean energy goals in its planning processes, from which lessons learned would be incorporated into subsequent distribution plans.

shall be called "Expansion Alternatives Analysis."	above the threshold utilities shall select 2-3 projects for a full Expansion Alternatives Analysis. The Expansion Alternatives Analysis shall proactively identify areas of the natural gas system with upcoming capacity needs and analyze how to best serve those needs.	an Expansion Alternatives Analysis. Utility resource plans shall include a discussion of the rationale for the projects selected for an Expansion Alternatives Analysis, and summary of the utility's discussions with stakeholders throughout the selection process and the alternatives analysis.
53. Utilities shall incorporate targeted distribution system analysis into the integrated resource planning process to proactively identify areas of the natural gas system with upcoming capacity needs and analyze how to best serve those needs.	53. Utility resource plans shall include a discussion of the rationale for the projects selected for an Expansion Alternatives Analysis, and summary of the utility's discussions with stakeholders throughout the selection process and the alternatives analysis.	
54. For initial utility resource plans, utilities shall identify two to three significant upcoming "**capacity expansion projects"** in each utility resource plan for a "**full alternatives evaluation**."		

Staff does not recommend additional procedural specifications for the EAA, based on the understanding that stakeholders will be involved as the utilities select projects for the EAA and undertake the eventual full alternatives analysis. As such, stakeholders will give input on the selection criteria for projects and the analyses.

VI. QUANTIFYING ENVIRONMENTAL IMPACT OF GAS

A. Utilities' Straw Proposal

Framework ordering paragraph 4 states that, "[t]he scope of integrated resource planning considers the State's economy-wide greenhouse gas reduction statutory goals." To clarify how, in practice, the utilities would enact "consideration," Xcel proposed to, "[c]onsider the State's economy-wide greenhouse gas reduction statutory goals consistent with Minn. Stat. §§ 216H.01 and 216H.02 using 2020 as the baseline year. Lifecycle GHG emission factors from filed Natural Gas Innovation Act (NGIA) Plans can also be considered in resource analysis to ensure lower emissions on a lifecycle basis."[28] See **Decision Option 46.**

CPE supported the recommendation.[29] CEE, CUB, the OAG, and the Department also supported using Minn. Stat. §§ 216H.01 and 216H.02 as guideposts for the consideration of greenhouse gases. Though MERC also supported, it noted that the recommendation includes data from NGIA and MERC has not filed an NGIA plan and more, that the values listed in Minn. Stat. § 216H.02 are goals, not mandates.[30]

1. Baseline Year

Despite supporting the content of the proposal, several parties noticed the utilities' changed baseline year. Indeed, Minn. Stat. §§ 216H.01 and 216H.02 use 2005 as the baseline from which greenhouse gases should be reduced by 2025, 2030, and 2050. Xcel's decision option instead uses 2020 as the baseline year. The year 2020 aligns with Minn. Stat. § 216B.2427 subdivision 2(4), the NGIA statute, stating that NGIA plans will compare emissions to a 2020 baseline year.

In opposition to Xcel, the OAG recommended 2005 as the baseline year. OAG offered **Decision Options 47-48** and explained,

> Making the further clarification to set a 2005 baseline for Minnesota specific emissions is appropriate and will allow for comparison and consideration of projected reductions in the utilities' IRPs to those reported in the Biennial Plan and used in Minnesota's Climate Action Plan Framework. This will help the Commission assess the utilities resource plan in-line with overall progress on statewide GHG emissions reductions and allow for greater transparency for stakeholders and the public. This same comparison will not be as useful or straightforward if the 2020 NGIA baseline for lifecycle emissions are used.[31]

CEE did not take a position on which baseline year should be selected but underscored the importance of monitoring emissions. CEE offered the following description of emissions trends, which the CEOs and other groups echoed:

[28] Xcel straw proposal filed May 31, 2024 at 2

[29] CPE replies filed July 19, 2024 at 2

[30] MERC replies filed July 19, 2024 at 3

[31] OAG reply comments filed July 19, 2024 at 5-6 in which the OAG also explained how a framework is already in place to measure statewide greenhouse gas emissions as created in Minn. Stat. § 216H.07 Subd. 3.Biennial report. (a) By January 15 of each odd-numbered year, the commissioners of commerce and the Pollution Control Agency shall jointly report to the chairs and ranking minority members of the legislative committees with primary policy jurisdiction over energy and environmental issues the most recent and best available evidence identifying the level of reductions already achieved and the level necessary to achieve the reductions timetable in section 216H.02.

> [N]atural gas consumption and emissions have increased substantially in Minnesota since 2005. In fact, natural gas consumption and emissions in Minnesota increased 16.5% between 2005 and 2020, and by 32.5% from 2005 to 2022, an increase of 13.8% from 2020. As such Minnesota's natural gas utilities will need to reduce emissions by nearly 14% just to achieve the 2020 baseline, and by 32.5% to achieve the 2005 baseline.[32]

The Department was not concerned by which baseline year was chosen, reasoning that selection of a baseline would not impact the ultimate goal of reaching net zero by 2050.

2. Staff Analysis

This section is aimed at Framework Ordering paragraph 4 which requires consideration of state greenhouse gas emissions goals. Xcel's proposal offered concrete values on which to base the utilities' "consideration." Staff supports the Xcel proposal.

With respect to baseline year, Staff appreciates the insights shared by parties. Staff also acknowledges the Department's point that regardless of which year is chosen, the end goal remains the same. In the end, Staff does not have a strong opinion on which baseline to choose. Proceeding without a baseline would allow the Commission to only assess how much more a utility must decrease emissions to reach net zero. Proceeding with a baseline would also show progress from a starting point towards an eventual goal. This matter may be discussed further with parties during the agenda meeting.

B. Reporting Greenhouse Gas Emissions, Including Methane

1. Projected Emissions

The utilities' straw proposal explained the policy lens through which utilities would consider the State's greenhouse gas reduction statutory goals. To show how this consideration affects each utility's GHG emissions, the CEOs recommended that gas utilities include the emissions projected to result from their preferred plans and the other resource mixes considered. Supporting this recommendation were CUB, Ayada et al., and the Department, which stated that estimates should be consistent with the Commission's approved 10-year planning horizon (**Decision Option 49**).[33]

Further, Ayada et al. recommended utilities fully account for historic impacts on low-income communities and communities of color as a part of their plans but did not explain how to do this accounting (**Decision Option 50**).

[32] CEE initial comments filed June 28, 2024 at 5

[33] Note, Electric utilities currently include projected emissions in their IRPs.

2. Methane, A History

The record included additional focus on one specific greenhouse gas, methane. Indeed, in its January 26, 2024 Order the Commission moved, from Xcel's performance-based regulation (PBR) docket to gas IRP dockets, the reporting of methane emissions 1) from the Company's distribution system, 2) upstream, and 3) across the full fuel cycle.[34] To this extent, Staff's most recent notice of comment in this docket asked, "For Xcel Energy, what, if any, direction should the Commission give regarding Xcel's analysis and reporting on methane emissions?"

In Xcel's PBR filings, Xcel had explained actions taken to reduce methane emissions:

- Physical changes to its distribution system like replacing cast iron and unprotected steel distribution mains, avoiding natural gas releases during system construction work, increasing the frequency of leak surveys, and replacing existing high-bleed controllers.
- Xcel's net-zero vision for natural gas by 2050, with an interim goal to reduce greenhouse gas emissions 25% by 2030.[35]
- Working with other gas companies to keep methane emissions across the gas supply chain to 1% or less of throughput by 2025 and keep Xcel's distribution system emissions at or below 0.2%.[36]

Concerning reporting upstream emissions, Xcel stated that it did not have these data as sellers are not required to share methane data. More, Xcel buys gas from pooled resources so is unable to ascertain the individual supplier from which each gas molecule originated. Finally, certified natural gas had been purchased for Xcel's Colorado pilot project but most wells that are certified do not supply Minnesota.[37]

3. Methane in Gas IRPs- the Distribution System

In the instant proceeding, Xcel proposed to report methane emissions from natural gas distribution system operations using recognized reporting protocols, such as EPA 40 CFR Part

[34] Order Accepting 2021 and 2022 Reports, Suspending Decisions on Baselines and Targets, and Modifying Reporting Requirements issued January 26, 2024 in docket no. E002/CI-17-401 at Ordering Paragraph 9.

[35] Annual Report filed April 29, 2022 in docket no. E002/CI-17-401 at 17

[36] The Company joined ONE Future - Working to Reduce Methane Emissions as well as Methane Challenge- oil and natural gas companies publicly report actions taken to reduce emissions; to do so, join one or both ONE future, commitment to reduce their Company's emissions rate to 1%, or Best Management Practices (BMP), commitment to use commercially available technologies. Natural Gas STAR- resources and peer information sharing on best practices to reduce methane emissions; since 1993 report cumulative reductions of 1,719,307,246 Mcf since 2020 and $5,157,921,729 saved. STAR program ended in 2022 though EPA still facilitates informal information-sharing. In MN, Xcel (2008-2022) and CenterPoint Energy Minnesota Gas (1997 - 2022) participated. EPA.gov website accessed August 30, 2023.

[37] Xcel Energy annual PBR report filed April 29, 2022 in docket no. E002/CI-17-401 at 20

98, Subpart W,[38] in the natural gas IRP and annual updates (**Decision Option 51**). The Department supported this recommendation. While the Commission raised the question of methane emissions reporting only for Xcel, CEOs and CUB supported all utilities providing their methane emissions. (**Decision Option 52**)

4. Methane in Gas IRPs- Upstream and Lifecycle Emissions

To immediately report lifecycle emissions, CEOs and CUB suggested use of an additional greenhouse gas, including methane, reporting tool, M.J. Bradley & Associates methodologies (**Decision Option 56-57**). CEOs explained that the tool calculates lifecycle emissions using:

> [F]ugitive methane and combustion-related greenhouse gas emissions and relies on data publicly reported by local distribution companies to the U.S. Environmental Protection Agency (GHGRP; subpart W), as well as data from the National Energy Technology Laboratory, Energy Information Administration, Argonne National Laboratory's Greenhouse Gases and Energy Use in Transportation (GREET) model, Environmental Protection Agency Emissions and Generation Resource Integrated Database (eGRID), and the Environmental Defense Fund, Colorado State University, and other academic researchers.[39]

Xcel opposed this recommendation because accounting for upstream emissions using an alternative to NGIA and the GREET model could lead to confusion.[40] MERC does not have data on upstream emissions and believes these are a small percentage of emissions.[41]

Rather than immediate reporting, the Department and Xcel recommended pathways to learn more about upstream emissions. First, the Department recommended that Xcel work with gas suppliers to improve transparency in reporting of upstream methane emissions (**Decision Options 53-54**). CEOs supported this recommendation. Xcel is monitoring updates to the EPA's protocol which may give additional information on the reporting of upstream emissions.[42]

Second, Xcel, as explained previously, proposed to consider lifecycle GHG emission factors from

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[38] Per the Environmental Protection Agency's Title 40, Chapter I, Subch. C, Part 98, Subpart W defines industry segments that must report emissions; segments include the "distribution pipelines and metering and regulating equipment at metering-regulating stations that are operated by a Local Distribution Company (LDC) within a single state that is regulated as a separate operating company by a public utility commission or that is operated as an independent municipally-owned distribution system" but only if the facilities emit 25,000 metric tons of CO_2 equivalent or more per year. If that threshold is met, the LDC must report CO_2, CH_4, and N_2O emissions (leaks) from several system points. https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-98/subpart-W In replies at 12, Xcel noted that report revisions would go into effect on January 1, 2025.

[39] CEOs initial comments filed June 28, 2024 at 4-5

[40] Department replies at Xcel replies at 11-12

[41] MERC replies at 9

[42] Xcel replies filed July 19, 2024 at 12

filed Natural Gas Innovation Act (NGIA) Plans in resource analysis to ensure lower emissions on a lifecycle basis. As such, Xcel would "leverage lifecycle GHG emission factors from filed Natural Gas Innovation Act (NGIA) Plans in analysis to ensure resources result in lower emissions than conventional geologic natural gas on a lifecycle basis."[43] Staff notes that Xcel did not formally commit to making NGIA data available in eDockets.

5. Staff Analysis

This section focused on the data that could inform utilities' "consideration" of State greenhouse gas reduction goals. Staff believes that if an entity is aiming to reduce emissions, those emissions must be measured regularly and compared to a baseline and/or target to assess progress towards a reduction. In this docket, data could be reported on multiple greenhouse gases; additional discussion centered on whether all utilities would report methane data or just Xcel, following the Commission's Order in PBR. And more, whether reporting would include distribution system and/or upstream emissions.

If utilities were to enact Framework ordering paragraph 4 following Xcel's proposal, then the legislation referenced in that proposal would suggest the relevance of the following data:

- Minn. Stat. § 216H.01 Subd. 2. "Statewide greenhouse gas emissions" include emissions of carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride emitted by anthropogenic sources within the state and from the generation of electricity imported from outside the state and consumed in Minnesota.
- Minn. Stat. § 216H.02 Subd. 1. (a) It is the goal of the state to reduce statewide greenhouse gas emissions across all sectors producing greenhouse gas emissions by at least the following amounts, compared with the level of emissions in 2005:

  (1) 15 percent by 2015;

  (2) 30 percent by 2025;

  (3) 50 percent by 2030; and

  (4) to net zero by 2050.

- Minn. Stat. § 216B.2427 (NGIA) Lifecycle emissions of greenhouse gasses from innovative resources and a baseline, total emissions from natural gas use by utility customers in 2020.

Should Xcel provide information from the EPA's title 40 reporting, Commission and stakeholders would get data on CO2, nitrous oxide (N2O), and methane emissions from the distribution system, which would allow monitoring of the utility's consistency with Minn. Stat. § 216H.01 and 216H.02 for multiple gasses. Further, the methane data would fulfill the distribution system portion of the required methane reporting from PBR. With respect to CPE or MERC providing the EPA title 40 data, Staff does not have access to utility greenhouse gas

[43] NGIA uses the GREET model to account for lifecycle emissions. See Xcel straw proposal filed May 31, 2024 at 2 and Xcel's reply comments filed July 19, 2024 at 3.

emissions accounting data and therefore does not know if CPE or MERC would be required to report under the EPA guidelines.[44]

Because the protocol has already been vetted by the EPA and because Xcel—the utility that has volunteered to file the first IRP—is already familiar with this reporting protocol, Staff suggests that the Commission consider Xcel's recommendation to fulfill reporting on greenhouses gasses, including methane from the distribution system (**Decision Option 51**).

With respect to other utilities filing emissions information, as all three utilities are required to consider the State's economy-wide greenhouse gas reduction statutory goals under Framework Ordering paragraph 4, it seems reasonable that all utilities would report on greenhouse gasses emitted from their distribution system and to the extent possible, seek reliable data on emissions outside the distribution system (**Decision Options 52-54**).

The Commission may wish to contemplate whether to require reporting of projected emissions from preferred plans and the other resource mixes considered (**Decision Options 49**). Reporting required emissions could fulfill Framework ordering paragraph 50, which states, in part, "A natural gas utility's preferred plan should include both (1) a ten-year sales and emissions forecast [emphasis added]." In practice, utilities' approach could be modeled on electric utilities' emissions forecast methods.

Finally, with respect to emissions beyond the distribution system, NGIA would provide data on lifecycle emissions for natural gas and innovative resources the utilities may use to meet demand. Staff supports requiring utilities to include in their gas IRPs a discussion of the availability of reliable data on upstream greenhouse gas emissions. More, following a discussion with stakeholders, utilities should explain in their first gas IRPs or in a compliance filing, conceptually how they are measuring and defining distribution, upstream, and lifecycle emissions (**Decision Option 55**).

C. Justifying a Resource Plan in Terms of Emissions Reductions

1. Party Recommendations

CUB, supported by CEOs, the Department, and Ayada et al., recommended that utilities explain how their preferred resource plan would advance Minnesota's emissions reduction goals. CUB and CEOs added that, if the preferred plan would not advance those goals, the utility should explain why it nevertheless chose that plan (**Decision Option 58**).

LIUNA and Local 49 did not oppose requiring an explanation. Xcel disagreed, stating that "Requiring a narrative specifically targeted at greenhouse gas goals places one aspect of the

[44] See the Environmental Protection Agency's Title 40, Chapter I, Subch. C, Part 98, Subpart W that defines industry segments that must report emissions.

objective adopted by the Commission over the others."[45]

Ayada et al. suggested that utilities should also be required to select a preferred plan that advances climate goals (**Decision Option 60**).

CPE and MERC opposed these recommendations, asserting that the State has put forward only goals, not mandates, for greenhouse gas reductions, and that the goals are economy-wide and not specific to any given gas utility. LIUNA, supported by Local 49, agreed that "it would not be appropriate or useful to require utilities to demonstrate compliance pathways for a non-existent mandate, especially given the lack of proven and cost-effective alternatives to conventional delivery of gas."[46]

2. Staff Analysis

Groups' recommendations placed increasing emphasis on utilities demonstrating their proposed resource plan contributed to meeting Minnesota's greenhouse gas goals. Indeed, Framework ordering paragraph 4 found that the scope of gas resource planning "considers the State's economy-wide greenhouse gas reduction statutory goals." However, reducing greenhouse gas emissions, and more broadly environmental goals, is not the only requirement for a gas resource plan. When the Commission evaluates plans, per Framework ordering paragraph 20, it will consider the degree to which a plan yields safety, adequacy, and reliability of utility service; minimizes risk; promotes affordability and energy efficiency; and "Minimize[s] adverse socioeconomic effects and adverse effects upon the environment."

Therefore, if a narrative on a plan's ability to meet environmental objectives was required to assist in the Commission's evaluation of resource plans, explanatory narratives may then also be useful to aid in the evaluation of the other objectives of resource planning. Staff posits that the Commission could clarify that the existing requirement from Framework ordering paragraphs 35 or 36 includes a narrative on how a utility's plan advances each objective of gas resource planning, inclusive of greenhouse gas emissions reductions (**Decision Option 59**). Paragraphs 35 and 36, respectively, require:

> For the utility's preferred resource plan, the supporting information must include a narrative and quantitative discussion of why the plan would be in the public interest.
>
> A utility shall include in its resource plan filing a nontechnical summary, not exceeding 25 pages in length and describing the utility's resource needs, the resource plan created by the utility to meet those needs, the process and analytical techniques used to create the plan, activities required over the next five years to

[45] Xcel replies at 2

[46] LIUNA replies at 1

> implement the plan, and the likely effect of plan implementation on electric rates and bills.[47]

Alternatively, adopting the proposed emissions reporting would provide numerical data for the Commission to evaluate the environmental impact of gas IRPs.

D. Environmental Externalities

1. Externality Cost Values

Framework ordering paragraph 17 states, "Utilities should estimate the environmental externality costs of resource options." Xcel and CPE's straw proposals recommended that utilities use the most recent externality values adopted by the Commission in docket no. E-999/CI-14-643 (**Decision Option 61**). Xcel and CPE proposed this to align externality values with those already used in Energy Conservation and Optimization Act (ECO) plans and NGIA. This recommendation is also supported by MERC, CUB, the Department, and CEE, which explained that a link to docket no. E-999/CI-14-643 would result in regular updates of values and that,

> While Minnesota Statute §216B.2422, Subdivision 3 only specifies electricity generation, we believe that the environmental costs established in Docket Number E999/CI-14-463 should be applied to emissions associated with resource options included in natural gas IRPs. There is no reason that the societal damages of greenhouse gas emissions from one energy resource would be valued differently from the societal damages of greenhouse gas emissions of another.[48]

While groups agreed to use the regularly updated values from docket no. E-999/CI-14-643, CPE's straw proposal suggested the need for a discussion on whether utilities should use a CO2 equivalency value as determined in ECO or NGIA.[49] The CEOs referenced CPE's straw proposal,

> CenterPoint points out that the equivalency factor to translate the social cost of carbon into a social cost of methane, for example, is different in Energy Conservation and Optimization (ECO) plans than it is in Natural Gas Innovation Act (NGIA) plans. CEOs recommend that the Commission clarify that the NGIA equivalence factor should be used in gas IRP dockets. The factor used in ECO is based only on combustion, whereas the factor in NGIA considers lifecycle emissions, which is a more accurate representation of global warming potential for a gas like methane, which is a potent greenhouse gas when leaked directly into the

[47] Framework ordering paragraphs 35 and 36

[48] CEE initial comments filed June 28, 2024 at 9

[49] CPE straw proposal filed May 31, 2024 at 3; CO2e is "CO2 equivalent" allowing any gas to be expressed as its equivalent units of CO2.

atmosphere, not just when combusted.[50] (See **Decision Option 62**)

Xcel responded that a clarification to use NGIA values was unnecessary as the Commission's chosen externality values include methane and its unique Global Warming Potential.[51]

In addition to which values should be used to quantify damages from resource options, stakeholders discussed how such values would be incorporated in the resource plan. The CEOs suggested that gas utilities incorporate environmental costs into IRP calculations using the same process electric utilities use. Xcel responded that it is still contemplating how it will do such analyses but, will "evaluate [its] revenue requirement on both a PVSC basis, which accounts for carbon and externality costs, and a PVRR basis, which excludes environmental cost adders, similar to our approach in electric IRPs" which, aligns with the Framework order.[52]

In contrast, CPE suggested environmental costs would only be utilized in the EAA. "CenterPoint Energy, proposes to use the $/short ton CO2e as addressed in the Commission's January 26, 2024, Notice and the December 19, 2023, Commission Order in Docket No. E999/CI-14-643 as additional costs considered <u>in the EAA</u> the Company provides within the IRP [emphasis added]."[53] See **Decision Option 63.**

2. Staff Analysis of Externality Cost Values

As groups largely agree with use of social cost values determined in docket no. E-999/CI-14-643 and because those same values are also used in NGIA and ECO, Staff finds it reasonable for values determined in docket no. E-999/CI-14-643 to inform costs used in gas IRPs.

a. Source of Environmental Cost Values

The social costs of greenhouse gases are derived by the EPA through a U.S. Government interagency working group (IWG) process. The IWG process began by defining only CO2 cost but in 2016, adopted methods to estimate the social costs of methane and nitrous oxide gases as well. The social costs of greenhouse gases (SC-GHG) provide "the monetary value of the future stream of net damages associated with adding one ton of that GHG to the atmosphere in a given year. The SC-GHG, therefore, also reflects the societal net benefit of reducing emissions

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[50] CEOs initial at 6

[51] Xcel reply comments at 4

[52] Xcel reply comments at 5. See also Order Addressing Environmental and Regulatory Costs issued December 19, 2023 in docket nos. E-999/CI-07-1199, E-999/DI-22-236, and E-999/CI-14-643 at 5, "In resource plan proceedings, a large electric utility proposes plans for meeting the forecasted energy needs of its customers, and analyze those plans under a variety of circumstances, to find the optimal mix of benefits and costs—including environmental costs and regulatory costs— summed up in the term Present Value of Social Cost." Last, see Framework ordering paragraph 49. "Natural gas resource plans shall include the cost of each scenario and sensitivity presenting both the utility's revenue requirement and environmental costs and other externalities to the utility's revenue requirement."

[53] CPE straw proposal at 2-3

of the gas by one ton."[54]

The Commission accepts the EPA's values for use in its policy decisions; most recently through its Notice[55] which was issued following provisional acceptance in its Order,

> The Commission provisionally adopts and applies the draft measurement of costs related to the emission of greenhouse gasses as set forth in the EPA's External Review Draft of Report on the Social Cost of Greenhouse Gases released in September 2022, and its successors. To this end, the Commission hereby revises its Order Updating Environmental Cost Values (January 3, 2018) in Docket No. E-999/CI-14-643, In the Matter of the Further Investigation into Environmental and Socioeconomic Costs Under Minnesota Statutes Section 216B.2422, Subdivision 3 accordingly.[56]

b. Values Used in ECO and NGIA

With respect to alignment with ECO, Staff emphasizes that "the IRP practices in Minnesota use the same primary cost-effectiveness tests used for energy efficiency resources."[57] In ECO investor-owned gas and electric utilities are required to use the Gas and Non-Gas Environmental Damage Factors for their 2024-2026 ECO cost-effectiveness analyses.[58] Per the Approved Inputs to Gas BENCOST for the 2024-2026 ECO Triennial period, environmental damage factors are calculated using criteria air emissions and greenhouse gases. The greenhouse gas portion is calculated using the values for carbon dioxide as determined by the Commission in its January 3, 2018 Order Updating Environmental Cost Values in docket no. E-999/CI-14-643.[59]

With respect to NGIA, social cost values from docket no. E-999/CI-14-643 are also used:

> The Commission establishes the baseline cost-effectiveness criteria against which an

[54] EPA Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances, Nov. 2023, at 5, https://www.epa.gov/system/files/documents/2023-12/epa_scghg_2023_report_final.pdf

[55] Notice of Final EPA Report on the Social Cost of Greenhouse Gases issued January 26, 2024 in docket nos. E-999/CI-07-1199, E-999/DI-22-236, and E-999/CI-14-643

[56] Order Addressing Environmental and Regulatory Costs issued December 19, 2023 in docket nos. E-999/CI-07-1199, E-999/DI-22-236, and E-999/CI-14-643

[57] Updating the Energy Efficiency Cost-Effectiveness Framework in Minnesota (mn.gov) issued August 8, 2018 Prepared for the Department of Commerce by Synapse Energy Economics, Inc. quoted text at 78

[58] These damage factors are the long-term "external" costs to society and the environment from generating gas and electricity, respectively.

[59] Decision in the Matter of 2024-2026 CIP Cost-Effectiveness Methodologies for Electric and Gas Investor-Owned Utilities issued March 31, 2023 in docket no. E,G999/CIP-23-46 at 266-267

> innovation plan should be compared pursuant to Minn. Stat. § 216B.2428(2)(iii)[60]… [In determining cost effectiveness], the Commission shall also consider environmental and socioeconomic costs and benefits that would result directly from the plan and the benefits of the plan for energy resource innovation in the state.[61]

In practice, the Commission's first NGIA filing calculated environmental costs using the GREET model. The GREET model relies on carbon dioxide equivalency values to derive environmental costs and benefits over the lifetime of an energy source.[62]

The EPA's environmental cost calculations developed through the IWG process include the costs for multiple greenhouse gases, like methane and CO2. However, docket no. 14-643 directs utilities to incorporate only the cost of C02 (**Table 3**). To this extent, ECO and the GREET model used in NGIA rely on CO2 and CO2 equivalents.

Table 3. Scenarios for Incorporating Environmental and Regulatory Costs[63]

Scenarios
A. Scenarios that incorporate, for all years, the low end of the range of environmental costs for carbon dioxide as approved by the Commission in its January 3, 2018 Order Updating Environmental Costs in Docket No. E-999/CI-14-643, In the Matter of the Further Investigation into Environmental and Socioeconomic Costs Under Minnesota Statutes Section 216B.2422, Subdivision 3, and set forth in Att. A.
B. Scenarios that incorporate, for all years, the high end of the range of environmental costs for CO2 as approved by the Commission in its January 3, 2018 order, and set forth in Att. A.
C. Scenarios that incorporate the low end of the range of environmental costs for CO2 but substituting, for planning years after 2024, the low end of the range of regulatory costs for CO2 regulations ($5 per short ton) in lieu of environmental costs.
D. Scenarios that incorporate the high end of the range of environmental costs for CO2 but substituting, for planning years after 2024, the high end of the range of regulatory costs for

[60] "To the maximum reasonable extent, the cost-benefit framework must be consistent with environmental cost values established under section 216B.2422, subdivision 3, and other calculations of the social value of greenhouse gas emissions reductions used by the commission." Values required under Minn. Stat. § 216B.2422 are developed in docket no. E-999/CI-14-643.

[61] Order Establishing Frameworks for Implementing Minnesota's Natural Gas Innovation Act issued June 1, 2022, in docket no. G-999/CI-21-566 at ordering paragraph 36

[62] "GREET was used to calculate conventional geologic natural gas's lifecycle GHG emissions in terms of kgCO2e/Dth. In GREET, fuel used as a "feedstock" is ANL's way of aggregating the fuel extraction, processing, and distribution emissions – essentially all relevant lifecycle emissions for a fuel up to the point of consumption/combustion – and this value (12.4 kgCO2e/Dth)8 was pulled from the GREET model for natural gas, and then added to GREET's combustion emissions metric for natural gas burned in a small industrial boiler (10-100 MMBtu/hour input), 53.74 kgCO2e/Dth." CPE NGIA initial petition June 28, 2023, Docket No. G-008/M-23-215 Exhibit F: Lifecycle GHG Calculation Details at 3

[63] Order Addressing Environmental and Regulatory Costs issued December 19, 2023, in docket nos. E-999/CI-07-1199, E-999/DI-22-236, and E-999/CI-14-643 at 14-15

CO2 regulations ($25 per short ton) in lieu of environmental costs.
E. A reference case scenario incorporating the Commission's middle or high values of the established environmental and regulatory cost ranges.

Therefore, while the Commission accepts guidance from the EPA regarding cost of multiple greenhouse gases, procedures have thus far been developed to include only the cost of CO2 and CO2 equivalency. The Commission will need to consider if it will:

- focus only on CO2 in gas IRPs,
- use an equivalency factor to consider other gases and their environmental cost, or
- develop a new process for including the cost of methane.

Xcel's comments suggested the potential to incorporate methane directly,

> The Commission adopted externality values, including those for methane, found in the U.S. Environmental Protection Agency's (EPA) Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances. That Report provides values for the Social Cost of Methane in $/metric ton of methane emitted, which already accounts for the greater Global Warming Potential of methane relative to carbon dioxide.[64]

To this extent, the Commission's most recent Order delegated authority to the Executive Secretary to open comment period(s) as needed in Docket No. E999/CI-14-643 to consider a process for applying the draft cost of greenhouse gas emissions valuations presented in the EPA's November 2023 report on the social cost of greenhouse gases.[65] If pursuing methane, the Commission may initiate such a proceeding or decide sufficient information on the cost of methane emissions exists to require methane costs directly to be included in gas IRPs.

i. Cost Over a Lifetime or at Combustion

In addition to considering whether to use cost of methane, the CO2 equivalent, and/or only CO2, the Commission will also need to consider whether to measure that environmental cost over a fuel's lifetime or consider only the "end point cost" of burning that fuel.

Indeed, as CPE and CEOs explained, environmental costs may differ between the lifecycle costs generated by the GREET model in the NGIA docket and environmental costs determined by the EPA for the net harm to society from emitting, suggesting combustion / end use, a metric ton of a greenhouse gas in a year. Therefore, calculating methane's cost or carbon equivalent would also require a choice of input value that captures either lifetime *or* end-use, combustion-only emissions.

[64] Xcel Replies July 19, 2024 at 4.

[65] Order Addressing Environmental and Regulatory Costs issued December 19, 2023, in docket nos. E-999/CI-07-1199, E-999/DI-22-236, and E-999/CI-14-643 at ordering paragraph 7(A).

The lifecycle NGIA GREET model could provide a more complete picture of the cost to society of a resource. However, as not all resources will be evaluated with the GREET model nor are utilities required to complete an NGIA plan, the values determined in ECO could estimate environmental costs if NGIA GREET model values were not available.

Finally, with respect to CPE's comment, Staff clarifies that environmental cost values would be provided for all proposed resource portfolios, in service of framework ordering paragraph 49. This paragraph states, "Natural gas resource plans shall include the cost of each scenario and sensitivity presenting both the utility's revenue requirement and <u>environmental costs</u> and other externalities to the utility's revenue requirement [emphasis added]." Details of how the EAA would account for impacts of alternatives remain to be determined, but commenters have proposed such details could be worked out in collaboration with stakeholders, see Section V.

E. Cost to Comply with Regulation of Greenhouse Gases

1. Party Recommendations

Framework ordering paragraph 15 states, "Utilities should address risk and uncertainty of demand, availability, and price for all resource options included in resource plans, and costs to comply with any regulation of greenhouse gas emissions." CEE offered two possible methods by which to quantify the cost of regulation; alternatively, CEE proposed further record development.

Xcel and CPE supported, and the Department and CEOs did not oppose, CEE's first method, to use values from the ECO cost-effectiveness framework which quantifies the environmental compliance cost of natural gas. Indeed, in March 2023, the Department of Commerce adopted the value of 1.40% of the $/MCF commodity cost for 2024 – 2045 to be used for natural gas environmental compliance impacts in ECO cost-effectiveness tests.[66] See **Decision Option 66.**

CEOs supported and the Department did not oppose CEE's second method, to use values required by Minnesota Statute § 216H.06[67] for all electricity generation resource proceedings, including electric IRPs, to inform the cost of regulating natural gas emissions (see **Decision Option 67**). Values were most recently updated in December 2023 and set the regulatory cost at $5 to $75 per short ton.[68] The CEOs defended use of these values stating:

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[66] CEE initial comments filed June 28, 2024 at 8 referencing Page 252 of the March 31, 2023 Department of Commerce Decision In the Matter of 2024-2026 CIP Cost-Effectiveness Methodologies for Electric and Gas Investor-Owned Utilities in Docket Number E,G999/CIP-23-46.

[67] "The Public Utilities Commission shall establish an estimate of the likely range of costs of future carbon dioxide regulation on electricity generation. The estimate, which may be made in a commission order, must be used in all electricity generation resource acquisition proceedings."

[68] Order Addressing Environmental and Regulatory Costs issued December 19, 2023 in docket nos. E-999/CI-07-1199; E-999/DI-22-236; and E-999/CI-14-643

> The recommendation to use an upper limit of $75 for the regulatory cost of carbon was based on the fact that this is the minimum amount of a carbon fee or tax that would be required to keep climate change to a 2-degree Celsius impact. This number is not based on carbon regulations specific to the electricity sector. It is based on the ambitious goals set by the Biden administration, the Walz administration, and the U.S. Nationally Determined Contribution under the Paris Agreement. The gas sector will need to be equally involved in decarbonization.[69]

Some stakeholders argued these values were created specifically for the electric sector and were not suitable for use by natural gas utilities. Because Minn. Stat. § 216H.06 was designed for electric utilities, CEOs recommended adding the 1.4% adder from ECO to make the 216H.06 values more suitable to gas utilities (**Decision Option 67 A**).

If neither of the methods it proposed were suitable, CEE posited that further record development could take place in the docket used to determine values for the cost of carbon regulation for electric generation, docket no. E999/CI-07-1199. The next revision is expected to take place in 2025, meaning updated values would be in place a year before Xcel has offered to file the first gas IRP (**Decision Option 68**).

Finally, LIUNA opposed using the regulatory cost of carbon, arguing that such an exercise is highly speculative and depends on legislative outcomes (**Decision Option 71**).

Regardless of what value may be selected, the CEOs recommended that gas utilities incorporate regulatory costs into IRP calculations using the same process electric utilities use (**Decision Option 70**).

2. Staff Analysis

The Framework Order tasked utilities with addressing “costs to comply with any regulation of greenhouse gas emissions.” Breaking this language down, regulatory costs are based on the need to account for pollution control equipment, fee and permit costs, and anticipated environmental requirements. Also, costs for all “greenhouse gases” must be accounted for, this includes methane but also carbon dioxide (CO2), nitrous oxide, and fluorinated gases.

Staff does not know if payment of regulatory costs would always cover both carbon dioxide and methane or if gases would be assessed separately and perhaps, differently, depending on the gas and methods needed to mitigate the emissions.

ECO is an existing proceeding from which values could be drawn for use in gas IRPs. ECO only

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[69] CEOs reply comments at 3

considers methane.[70] Alternatively, the Commission's most recent findings on regulatory costs made in accordance with Minn. Stat. § 216H.06, are only for electric generation and contemplate only costs of carbon dioxide regulation.[71]

CEE reasoned that the Commission will next decide the value of carbon dioxide regulation in 2025, but those values would not come into effect until much later, likely 2031. Until then, the first two utilities to file, recommended to be October of 2026 and 2027, would likely need to use the value determined for use until 2025 of $5–$25 per short ton of CO_2. The third would use the more recently determined value of $5-$75, effective in 2028.

Staff does not have enough information to determine whether electric generation is sufficiently different from gas generation as to require re-calculation of the cost of regulatory compliance. If so, it may be warranted to develop such a method docket no. E999/CI-07-1199 as suggested by CEE. Until, and if, a specific cost for regulation of greenhouse gases in the gas industry is contemplated (**Decision Option 68**), Staff suggests using the range of highest, mid-point, and lowest values determined through ECO and Minn. Stat. § 216H.06 to account for both methane and carbon dioxide regulation (**Decision Options 66-67**).

To LIUNA's point that the Commission should not incorporate the cost to comply with regulations, the Commission has already stated, in Framework ordering paragraph 15 that utilities should address costs to comply with any regulation of greenhouse gas emissions. While the verb "address" was not defined, Staff notes that this comment period has been focused on assigning values to concepts, like with respect to "considering" state greenhouse gas goals.

a. Considering the Interaction of Costs

In environmental and regulatory cost proceedings, stakeholders highlighted the uniqueness and importance of calculating regulatory and environmental costs in a thoughtful manner, not simply adding the costs together. Thus, the Commission required utilities, in their modeling scenarios, to consider environmental (that is, externality) costs in every year of the scenario to the extent that those costs exceed the regulatory (that is, internalized) costs for the same year (**Table 3**).[72] Utilities may contemplate this methodology for incorporating costs into their gas IRPs and work with stakeholders to finalize methods to appropriately include regulatory and

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[70] Page 252 of the March 31, 2023 Department of Commerce Decision In the Matter of 2024-2026 CIP Cost-Effectiveness Methodologies for Electric and Gas Investor-Owned Utilities in Docket Number E,G999/CIP-23-46. Quoted text, "The initial value [1.40% of the $/MCF commodity cost for 2024 – 2045] is based solely on proposed federal methane emissions standards that the EPA anticipates finalizing in 2024. All other gas environmental compliance factors are assumed to be 0 for this Triennial."

[71] Order Addressing Environmental and Regulatory Costs issued December 19, 2023, in docket nos. E-999/CI-07-1199; E-999/DI-22-236; and E-999/CI-14-643 see ordering paragraph 1 and page 6. New regulatory costs of $5 to $75 per short ton go into effect in 2028; until then, previous order language established a range of regulatory costs of $5–$25 per short ton of CO_2 emitted beginning in 2025.

[72] Order Addressing Environmental and Regulatory Costs issued December 19, 2023, in docket nos. E-999/CI-07-1199; E-999/DI-22-236; and E-999/CI-14-643 see ordering paragraph 3.

environmental costs.

F. Indoor Air Impacts

1. Commenter Arguments

CUB and a pediatrician who commented on this matter wrote that indoor air pollution should be considered as utilities calculate the impacts of the combustion of natural gas. The pediatrician wrote on the relationship between gas stoves, air pollution, and childhood asthma[73] including a more recent study highlighting the relationship between gas stoves and childhood asthma.[74] Further, the comment highlighted work showing that Black and Hispanic folks have higher health burdens from indoor air pollution.[75]

In earlier comments, CPE dismissed other organizations' claims of indoor air pollution stating,

> More than twenty federal agencies in the Federal Interagency Committee on Indoor Air Quality, led by the Environmental Protection Agency ("EPA"), have studied natural gas use for cooking and have not identified using natural gas stoves as an important issue related to respiratory health conditions or asthma. Additionally, according to the peer-reviewed study "Cooking Fuels and Prevalence of Asthma: A Global Analysis of Phase Three of the International Study of Asthma and Allergies in Childhood (ISAAC)", there is no evidence of a link between using natural gas for cooking and asthma or asthma symptoms.[76]

If the Commission is interested in pursuing quantification of indoor air pollution, Ayada et al. suggested opening a docket to set indoor gas use externality values based on the current medical science reflecting the serious damage done to the most vulnerable members of our society by continued indoor gas combustion (**Decision Option 73**).

2. Staff Analysis

Air Quality Impacts are assessed in the ECO cost effectiveness tests. Impacts are included in both (1) the Minnesota Cost Test, which is the "primary" cost effectiveness test, and (2) the

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[73] Lebowitz, M. D., Collins, L., & Holberg, C. J. (1987). Time series analyses of respiratory responses to indoor and outdoor environmental phenomena. *Environmental research*, *43*(2), 332-341.

[74] Bédard, M. A., Reyna, M. E., Moraes, T. J., Simons, E., Turvey, S. E., Mandhane, P., ... & Subbarao, P. (2023). Association between gas stove use and childhood asthma in the Canadian CHILD Cohort Study. *Canadian Journal of Public Health*, *114*(4), 705-708.

[75] Buxton, M. A., Fleischer, N. L., Ro, A., & O'Neill, M. S. (2023). Structural racism, air pollution and the association with adverse birth outcomes in the United States: the value of examining intergenerational associations. *Frontiers in Epidemiology*, *3*, 1190407.

[76] CPE reply comments filed December 29, 2023 in docket no. G008,G002,G011/CI-23-117 at 2-3

secondary Participant Cost Test.[77] The primary Minnesota cost test measures air quality improvements as one societal impact of an ECO program. Air quality is measured via the following:

> **Input 28, Other Environmental:** Serves as a catch-all quantification of all other environmental impacts including other air emissions, solid waste, land, water, and other environmental impacts not accounted for in other criteria. The required value for the 2024-2026 Triennium for Other Environmental is zero (as yet unquantified).[78]

The Participant cost test also considers air quality improvements but is not included in the primary determinant of cost-effectiveness. Thus, air quality costs or benefits to individual participants will not be used to determine if a program is appropriate for inclusion in one of the segments of a utility's entire ECO portfolio.

Staff is unsure if individuals' home air quality would be quantified under the cost tests. The Societal component of the Minnesota test may be more focused on broad impacts that could be felt by anyone who goes outdoors or experiences larger climate phenomena, not just those who have, for example, a gas stove. Further, as shown in Input 28, below, presently there is no cost associated with "other environmental."

To this extent, new data collection strategies may be needed to capture indoor air impacts of various utility resource portfolios. One place to start may be the Commission's December 2023 order acted to "Provisionally directing utilities to incorporate the draft social cost of greenhouse gases as published by the federal Environmental Protection Agency (EPA) for purposes of measuring environmental and socioeconomic costs under Minnesota Statutes § 216B.2422, subdivision 3."[79] Staff is not completely familiar with the model, but as the model pulls atmospheric emissions data, doing so may only account for outdoor air pollution; the model may only capture indoor air pollution incidentally, if that pollution leaked outside. If so, a different strategy may be needed. For example, it may be reasonable to collect data on proliferation of gas stoves within a utility's service area and assign a value to each stove. Designing a methodology will take additional stakeholder input, perhaps during a notice and comment period accompanying environmental costs calculated in docket no. E-999/CI-14-643.

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[77] Decision in the Matter of 2024-2026 CIP Cost-Effectiveness Methodologies for Electric and Gas Investor-Owned Utilities issued March 31, 2023 in docket no. E,G999/CIP-23-46 at 34 citing "National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources (NSPM for DERs) – Overview", p. 15. The primary test shows which resources have benefits that exceed costs and therefore merit utility acquisition or support on behalf of their customers. Secondary cost tests are meant to answer different questions, for example the ability of a certain program to meet a specific goal, like lowering utility customers' bills.

[78] Decision in the Matter of 2024-2026 CIP Cost-Effectiveness Methodologies for Electric and Gas Investor-Owned Utilities issued March 31, 2023 in docket no. E,G999/CIP-23-46 at 263 (table) and Input 28 at 271

[79] Order Addressing Environmental and Regulatory Costs issued December 19, 2023, in docket nos. E-999/CI-07-1199, E-999/DI-22-236, and E-999/CI-14-643 at 3.

VII. FORECAST

A. IRP Forecasts and Use of Design Day and Rate Case Filings

Framework ordering paragraphs 40 and 41 explain utilities' forecast requirements and paragraph 50 sets the duration of that forecast:

> 40. Utilities shall provide a high, medium, and low load forecast, along with relevant assumptions, in their resource plans.
>
> 41. The utilities shall include in their resource plans information and assumptions used to develop the utility's design day criteria.
>
> 50. A natural gas utility's preferred plan should include both (1) a ten-year sales and emissions forecast, and (2) a five-year action plan of the specific steps that it will take to implement that plan over the next five years.

1. Stakeholder Recommendations

CPE's straw proposal offered clarification on forecasts. Stakeholders took issue with two aspects of CPE's straw proposal. First, CPE explained how it would use existing methods from its rate case and demand entitlement filings to produce forecasts in its gas IRP. To CPE's recommendation, the OAG offered the modifications shown with strikethrough and underline:

> Where the high load forecast may represent the ~~Company's~~ Commission-approved forecast for design day as provided in ~~their~~ the utilities' most recent demand entitlement filing, and the Commission-approved sales forecast as provided in the utilities' most recent rate case.

CUB wrote that it would not oppose the OAG's modified decision option (see **Decision Option 74**). However, the Department was concerned about the temporal mismatch of the 10-year forecast required in the gas IRP docket per framework ordering paragraph 50 and the near-term focus of the demand entitlement, "the design-day for an upcoming five-month heating season" and rate case filings, which "includes a one-year load forecast for the 12-month test year period. A multi-year rate case may include up to a five-year load forecast."[80]

2. Staff Analysis

Commenters argue whether the utilities' required 10-year gas IRP forecasts can draw on the forecasts used in rate cases and demand entitlement filings, because rate cases and demand entitlement plans are forecasted over a shorter time. Staff first briefly discusses how forecasts are made in rate cases and demand entitlement filings and then, the potential to leverage those filings for the 10-year forecast required in gas IRPs.

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[80] Department initial comments at 5

a. Rate Case Forecasts

Utilities create forecasts by studying several years of historic billing data, demographic data, and weather normalized data. The data are fit into a regression model to yield a single "test year" prediction of customer count and gas throughput (sales) to various customer classes. From the single test year, the utility generates its revenue requirement which will be recovered from customer rates. When the revenue requirement is deficient, meaning it can no longer sufficiently cover expenses, the utility files a new rate case with a new predicted test year. Staff notes that CenterPoint most recent rate case had a single "test year" forecast as well as a "plan year" forecast for the year after its test year.

While the test year is based on historic data, testimony in Xcel's most recent rate case explained how that year may be adjusted to account for current policies. For example, Xcel explained that test year forecast was adjusted for expected impacts of beneficial electrification. However, the test year was not adjusted for Demand-Side Management (DSM) because in the 2017 Gas Utility Infrastructure Costs (GUIC) filing (Docket No. G002/M-17-787), the Commission directed the Company to remove an adjustment for DSM energy impacts.[81]

b. Demand Entitlement Forecasts

A demand entitlement forecast serves an entirely different purpose from a rate case or a long-term gas IRP forecast. A demand entitlement forecast predicts the amount of gas that will be needed for customers during a single 24-hour period on the coldest day of a heating season. Thus, the demand entitlement forecast does not predict total demand for entire test year, like a rate case, nor 10 years, as the Commission instructed gas utilities to do in its Framework Order.

Per Minnesota Rule 7825.2910, subpart 2, gas utilities must request changes to their demand. For the past five years, CPE, Xcel, and MERC have requested changes to contract demand entitlements once each year. Staff notes that while utilities have made new filings annually, CPE's 2024 demand entitlement filing included a reserve margin forecast 5 years into the future (until 2028). Cost of the gas procured to serve customers is recovered in the Purchased Gas Adjustment (PGA).

Per Minnesota Rule 7825.2910, subpart 2, gas utilities' filing must describe the factors contributing to changing demand, design day demand, winter versus summer usage, and design day supply, including additional discussion of supply diversity.[82] Demand entitlement filings include information comparing the current and previous heating season in terms of customer counts, dekatherms needed, supply from pipeline capacity and storage, the utility's reserve

[81] Direct Testimony and Schedules, John Goodenough, November 1, 2023, Docket No. G002/GR-23-413 at 16-17

[82] Discussion of how changes to their pipeline capacity affect their supply diversity and, if pipeline capacity comes at a cost premium but increases supply diversity, provide a meaningful cost/benefit discussion of the tradeoff, including a comparison with the least-cost capacity option; this additional requirement was imposed by the Commission's Price Spike Order in docket no. 21-565 at ordering paragraph 9

margin, and cost and bill impacts. The utility may discuss the use of financial tools to mitigate price impacts. CPE also shared that its forecast methodology includes customer count and daily usage data for firm customers from all winter days from the six previous heating seasons, November – March. From those data, CPE builds a regression model to ensure enough capacity is available when temperatures near the Design Day.[83]

c. Potential to Leverage Existing Filings

Certain elements of the demand entitlement and rate case filings may be considered in gas IRP forecasting, like customer counts, dekatherms used, weather patterns, and demographic data. Further, the available resources catalogued in a demand entitlement filing will certainly be accounted for as resources available for IRP portfolios.

However, the short forecast time frames for both the rate case (one year) and demand entitlement (one 24-hour period during one heating season), as the Department observed, do not align with the 10-year forecast required for gas IRPs. Further, as Staff explained, the objective of the demand entitlement filing is different from that of the gas IRP.

Indeed, the forecast in a resource plan aims to ensure resources of the appropriate size and type are procured at the appropriate point in time to meet customer demand over the long-term forecast period.[84] As such, an electric utility's integrated resource plan filing, specifically its forecast, may provide a more appropriate model, *methodologically,* for how to make a forecast. Then, the data used in demand entitlement and rate case filings could be incorporated as the foundation on which, in part, long-term forecasts would be built.

Building longer-term forecasts on shorter-term forecasts is a current practice in Washington State. There, gas utility integrated resource plans rely on, "[t]he integration of the demand forecasts and resource evaluations into a long-range (e.g., at least ten years; longer if appropriate to the life of the resources considered) integrated resource plan describing the mix of resources that is designated to meet current and future needs at the lowest reasonable cost to the utility and its ratepayers."[85] More, Colorado's Gas Infrastructure Plans must include a forecast that aligns with already-approved forecasts. As such, forecasts are "consistent with the utility's approved portfolio of clean heat resources and in accordance with subparagraph

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[83] CPE Initial Filing April 1, 2024, in docket no. G008/M-24-146 at 6-7

[84] For electric utilities, Minn. R. 7843.0100 Subp. 9, "Resource plan" means a set of resource options that a utility could use to meet the service needs of its customers over the forecast period [15 years], including an explanation of the supply and demand circumstances under which, and the extent to which, each resource option would be used to meet those service needs. These resource options include using, modifying, and constructing utility plant and equipment; buying power generated by other entities; controlling customer loads; and implementing customer energy conservation." And per Framework Ordering paragraph 3, "Integrated resource planning for natural gas utilities includes analysis and evaluation of the appropriate resource mix, including supply-side and demand-side resources to serve customer end-use energy needs, and consideration of new infrastructure investments above a defined threshold necessary to meet existing or forecasted gas demand needs."

[85] Washington State Legislature- WAC 480-90-238 natural gas integrated resource planning, 3(g)

4731(b)(I), or any appropriate interim-year update to such forecasts."[86] Staff emphasizes that in practice, when moving from short- to longer-term forecasts, utilities must be transparent with and willing to modify their forecast assumptions as needed when moving towards a longer-term forecast.

Review of integrated resource plan forecasting methodologies from Minnesota and other states, in collaboration with the GPI-facilitated stakeholder workgroup, would be important to gauging the suitability of transferring methods to gas IRPs (**Decision Option 75**).

B. CPE's Request to Include Demand in Its Forecast

1. Party Recommendations

The second issue with CPE's forecast method centers on the narrative in CPE's straw proposal:

> For clarification, CenterPoint Energy envisions the current forecast methodology as providing the high range of results to ensure that reliability is met during the coldest winter days, and adequate supply is available year-round to meet customer requirements. These forecast methodologies have been reviewed in demand entitlement filings and rate cases and have provided the necessary guidance for CenterPoint Energy to secure the appropriate amount of <u>supply side</u> requirements. The Company envisions medium and low forecast ranges will take additional resources into consideration [emphasis added].[87]

In response, CEE explained that the CPE's decision option was discussed at the GPI-facilitated stakeholder roundtable on June 18, 2024. "Stakeholders clarified with CenterPoint Energy that the load forecast referred to in Order Point 40 should be a fuel-neutral forecast of energy loads served by the natural gas utility. Those energy loads could be served by a variety of energy resources, including electricity, energy efficiency, and gaseous fuels. The natural gas IRP process would provide options for how to serve the natural gas utilities' total energy load, considering a high, medium, and low load forecast scenario."[88]

CUB and the OAG offered decision options (**76 and 77**) that would underscore use of demand as a resource option, not a quantity to be included in forecasting.

2. Staff Analysis

Staff reiterates that the Commission repeatedly emphasized that demand-side resources are meant to be considered a resource; this requirement is included in Framework ordering paragraphs 3, 7, 14, and 44 which states, "Utilities shall examine all commercially available

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[86] Code of Colorado Regulations, Public Utilities Commission. Section 4553, subpart b(I).

[87] CPE straw proposal filed May 31, 2024 at 3

[88] CEE initial comments filed June 28, 2024 at 11

demand- and supply-side resources and determine a set of available resources." As the treatment of demand as a resource is emphasized in four existing Framework ordering paragraphs, Staff is not persuaded that additional clarification is needed.

C. Requirements for Additional Load Forecast Components

1. Stakeholder Recommendations

Stakeholders had additional recommendations for the preparation of utilities' forecasts. The OAG recommended that commenters may advocate for changes in or challenge a utility's forecast (**Decision Option 78**).

Ayada et al. recommended that utilities express demand as a function of heating needs.

CEOs offered a series of external factors for utilities to consider as they create load forecasts (**Decision Option 80**):[89]

- the effect of current or enacted state and local building codes and standards;
- building electrification, efficient fuel-switching, and energy efficiency programs or incentives offered by both the gas utility and the local electric utility or local, state, or federal entities that overlap with the utility's gas service territory;
- the effects of rate design and/or demand response programs;
- changes in the utility's line extension policies, and the associated impact on gas customer growth; and
- the price elasticity of demand (e.g., the impact of reduced throughput and rate increases on sales and peak demand requirements and impacts of commodity prices).

CUB supported the CEOs' recommendation.

The Department suggested moving contemplation of these factors, especially as they include rates and line extension policies, to the Future of Gas docket. The utilities opposed the CEOs' recommendation as they found it too prescriptive and believed that forecast considerations may evolve over time as stakeholders gain more experience with gas IRPs.

2. Staff Analysis

As forecasts depend on historical data, there will be a lag between the implementation of new policies and incentives for things like energy efficiency, demand response, and electrification (all of which may decrease gas use) and the reflection of impacts from those policies in forecasts *after* the policies have had time to impact demand. Staff understands the importance of having adequate resources to meet demand; however, Staff is concerned about a possible over-reliance on supply-side resources and the customer bill impact of purchases beyond what

[89] CEOs initial comments June 28, 2024 at 7, citing Colorado's Clean Heat Plan Code of Colorado Regulations, Public Utilities Commission. Section 4553, contents of a gas infrastructure plan, subpart b(II).

is needed. To this extent, Staff feels it is important to include new policy impacts on utility forecasts. Such impacts would likely be discussed in the "planning environment" section of gas IRPs, per Framework ordering paragraphs 37 and 38.

To include these contextual elements in the forecast, the Commission must decide how prescriptive to be. Pursuing the CEOs' pathway with **Decision Option 80** would ensure contextual elements were included in forecasts but would prescribe those elements before stakeholders and utilities began work on the initial IRP. Alternatively, the Commission could decline to prescribe forecasting requirements in its forthcoming order and put it upon stakeholders to discuss these elements in the roundtable.

To the OAG's point, Staff looks forward to robust discussion from the stakeholder group to bring insights to the forecast methodology proposed by utilities to identify any areas for improvement or of concern. To this extent, Staff highlights Framework ordering paragraphs 25, ensuring opportunities for making public comments on plans, and 33, which speaks to alternatives to a utility's resource plan:

> Parties and other interested persons may express support for the proposed resource plan filed by a utility. Alternatively, parties and other interested persons may file proposed resource plans different from the plan proposed by the utility. When a plan differs from that submitted by the utility, the plan must be accompanied by a narrative and quantitative discussion of why the proposed changes would be in the public interest, considering the evaluation criteria of gas plans.

Finally, Ayada et al.'s proposal for utilities to forecast "heating need" is indeed a thought-provoking exercise. However, it has not been developed fully for Staff to take a position. Staff invites the groups commenting under Ayada et al. to file additional comments, attend public meetings, or attend a stakeholder workshop to develop this idea further.

VIII. ENERGY EFFICIENCY

A. Party Recommendations

To explain how energy efficiency should be included in gas IRPs, Xcel proposed two clarifications, shown below, to existing Framework ordering paragraphs 11 and 12:

> 11. To treat energy efficiency alongside all other energy resource options, utility integrated resource plans should evaluate energy efficiency achievement scenarios including expected program achievement to maximum achievement (**Decision Option 81**).
>
> 12. The appropriate and cost-effective level of future energy efficiency procurement shall correspond to the maximum program spending level that remains cost-effective when compared to ~~supply-side~~ alternatives (**Decision Option 82**).

Xcel's proposal was supported by CEE, CUB, the Department, and CPE.

CUB modified Xcel's proposal for Framework ordering paragraph 12, emphasizing that energy efficiency should be compared to all resources (not just supply side). Above, Staff shows CUB's modification using a strike through. CPE supported CUB's proposed modification, and the Department did not oppose it.

For further discussion of how to include energy efficiency as a resource in gas IRPs, CEE recommended natural gas utilities work through GPI's Gas Utility Innovation Roundtable to gather and incorporate input on the assumptions used for energy efficiency in their natural gas IRPs (**Decision Option 84**).

B. Staff Analysis

Based on the stakeholder support, the possibility of continued discussions through the GPI roundtable, and potential alignment with existing electric IPR dockets and ECO, Staff supports Xcel's proposed treatment of energy efficiency.

In ECO proceedings, utilities propose spending on and energy savings resulting from energy efficiency and demand response programs. Under the new ECO Act of 2021, efficient fuel switching can be considered under these efficiency and load management programs. For Xcel, ECO plans are then considered in electric integrated resource planning. Xcel proposes to leverage ECO triennial filings for gas resource planning purposes as well.

Indeed, the language Xcel used in its straw proposal suggests a process of "bundling" energy efficiency programs and comparing those to other resources in portfolio analyses. Staff will explain, at a high level, how this is accomplished in Xcel's electric IRP. First, Xcel creates three levels, or "bundles" of energy efficiency programming, each with an estimated cost and energy savings potential.

- The minimum bundle corresponds to the minimum amount of savings required under ECO, per Minn. Stat. § 216B.241. For electric utilities this is 1.75% of retail sales yearly; the Company operationalizes this value using weather normalized sales for the three years before a triennial is filed. For gas utilities the annual energy-savings goal equivalent to 1% of gross annual retail energy sales.
- The second bundle is the mid-achievement bundle in which the years 2024, 2025, and 2026 match the energy efficiency savings filed in Xcel's 2024-2026 ECO Triennial plan.
- The third bundle is the high-achievement, or "optimized bundle," based on experts' analyses and consideration of contextual variables including the 2018 Minnesota Energy Efficiency Potential Study findings, the Company's ECO Triennial Plan and IRP, and IRA policies and funding.

- Naturally occurring energy efficiency[90] is embedded in the load forecast.

If ECO plan values were used to develop "bundles" for gas IRPs, per Xcel's straw proposal, Staff provides **Table 4**. It shows "Minimum" energy savings per Minn. Stat. § 216B.241 and Programmatic Energy Savings, the proposed energy savings from each gas utility's most recent ECO triennial plan.

Table 4. Energy Savings as a Percent of Retail Sales

	Minimum	**Programmatic**			**Optimized**
		2024	**2025**	**2026**	
Xcel[91]	1%	1.57%	1.66%	1.77%	TBD
CPE[92]	1%	1.26%	1.28%	1.34%	TBD
MERC[93]	1%	1%	1%	1%	TBD

For Xcel, after creating three bundles, each is included in Encompass software, just like other supply-side resources. The first two bundles are required to be in the model as they were already committed to in the ECO dockets. Bundle three, optimized / high-achievement, is a selectable resource for the model during the optimization process.

As Staff understands,[94] Xcel's objective with the above recommendations was ensuring alignment between the IRP and ECO, especially as the existing ECO docket would likely function as the cost recovery mechanism for energy efficiency projects described in the IRP. During the GPI-facilitated meeting, stakeholders recounted that such alignment had not been the case in other dockets so introducing these modifications via Xcel's straw proposal had been done as a precaution. In sum, different levels of energy efficiency, as a resource, will be explored in both ECO and gas IRPs. While the levels need not be exactly the same across the filings, the filings should show *general* agreement in the levels of energy efficiency deemed reasonable to evaluate as part of ECO and gas IRPs.

IX. SCENARIOS AND SENSITIVITIES

At present, Framework ordering paragraphs 45-47 require utilities to analyze high, medium, and low load scenarios and high, medium, and low gas price sensitivities as well as a test

[90] "Naturally Occurring energy efficiency includes customers who take action without participating in energy efficiency programs and instances of equipment that currently may be influenced by energy efficiency programs, but in the future world would not be part of an energy efficiency program because an efficient technology is required to meet code or has become common practice." As explained in Xcel's February 1, 2024 filing in Docket No. E002/RP-24-67, Ch. 3 at 12.

[91] Xcel Energy 2024-2026 ECO Triennial Plan docket no. E,G002/CIP-23-92, June 29, 2023, at 8

[92] CenterPoint Energy 2024-2026 ECO Triennial Plan docket no. G008/CIP-23-95, June 30, 2023, at 6

[93] Minnesota Energy Resources 2024-2026 ECO Triennial Plan docket no. G011/CIP-23-98, June 30, 2023, at 6

[94] As explained during the GPI-facilitated stakeholder meeting held June 18, 2024

against a significant supply-disruption. Framework ordering paragraph 48 then states that, "Utilities shall include additional analyses of scenarios and sensitivities in their resource plans as directed by the Commission."

A. Party Recommendations

Xcel recommended modifying the Framework Order to bar analysis of any additional scenarios or sensitivities during the first resource plan filing (**Decision Option 85**). This modification was supported by CPE, CEE, and the Department.

CUB proposed a modified version of Xcel's recommendation: "In initial integrated resource plans, utilities shall, at minimum, analyze scenarios and sensitivities as specified in the March 27, 2024 Order in this docket" (**Decision Option 86**).

B. Staff Analysis

Staff interprets this modification as the utilities seeking certainty from the Commission that no additional portfolio analysis will be required, beyond those elements directly spelled out in framework ordering paragraphs 45-47. The Commission would thus commit to "no additional analyses" *before* the utilities' IRPs are filed, *before* the Commission has seen the utilities' analyses and results, and *before* the Commission has had a chance to evaluate the appropriateness of scenario and sensitivity analyses to test the ability of resource portfolios to meet customer demand. Staff welcomes clarification from commenters on this interpretation. If Staff's interpretation is correct, staff would not feel comfortable constraining the Commission's ability to seek additional information to serve its evaluation of initial gas IRPs.

X. DEFERRED ACCOUNTING

A. MERC's Request

MERC argued that the costs associated with preparing its gas IRP would be unforeseen and significant. To this extent, MERC proposed that utilities should be allowed deferred accounting treatment of costs associated with developing and implementing a gas IRP planning process, making a gas IRP, participating in the regulatory process for gas IRP filings including reporting, and implementing an approved gas IRP (**Decision Option 87)**.[95]

The OAG, CUB, and Department opposed MERC's request for deferred accounting (**Decision Option 88)**.

[95] MERC reply comments filed July 19, 2024 at 9-12.

XI. FIVE-YEAR ACTION PLAN

A. Party Recommendations

Framework ordering paragraph 50 states that a utility should include a “five-year action plan” but does not specify what that plan will include beyond “the specific steps that it [the utility] will take to implement that plan over the next five years.”

Xcel and the Department agreed upon a recommendation that explained some of the key components of the five-year action plan. CUB and CPE elaborated on their recommendation, recommending five-year action plans include (see **Decision Options 89-91**):

- justification of need,
- resource mix,
- project scope,
- construction timeline,
- cost estimates including any offsetting revenues and tax benefits, and
- a narrative discussion of any equity impacts the project may have.

Staff awaits the Department and Xcel’s response to these further modifications and notes that MERC does not support as it finds redundant the inclusion of equity discussions which could be included in other IRP requirements. Indeed, these briefing papers and **Decision Option 1** have already explored a requirement that each IRP discuss how equity was considered broadly.

Like the EAA, commenters specifically named the five-year action plan as a space for the gas IRPs to expressly focus on equity. To this extent, CPE, “looks to build on these learnings and looks to evaluate ways to incorporate public data and mapping tools for low-income residents or disadvantaged communities in this IRP process (see **Decision Option 92**).”

CUB and Xcel emphasized the importance of mapping to explain equity impacts of selected projects in the five-year action plan. The Department did not oppose this recommendation. MERC opposed the recommendation as too prescriptive.

Such mapping may honor the pediatrician’s recommendation that utilities delineate the extent to which gas IRPs will impact environmental justice communities, including the portion of project emissions that would be located within environmental justice communities.

B. Staff Analysis

Commenters have already presented recommendations for mapping to be utilized in the EAA. As described by CPE in this section, mapping would be used in the broader IRP. Such a map could show where existing supply-side, demand-side, or energy efficiency resources are currently being deployed or are planned. Such a map may contradict, in part, the Commission’s previous decision not to adopt the distribution analysis component of gas IRPs. The Commission may need further information from stakeholders during the agenda meeting about what such a mapping exercise, or use of other tools, would look like. Further, Staff notes the utilities' language that they would "evaluate ways" to incorporate tools, like maps, which does not appear to be a commitment to using those tools.

If the Commission wishes to see use of maps or other tools in utilities' five-year action plans, it may ask utilities to confirm their willingness to undertake mapping. Alternatively, the Commission may decline to decide this matter now, and ask that stakeholders address this issue during the GPI-facilitated workshops on utility-specific IRPs.

With respect to equity, the Commission may decide to circumscribe equity discussions to the five-year action plans (**Decision Option 91-93**). In addition, or as an alternative, equity may be incorporated in the EAA via discussions with stakeholders and project site selection (**Decision Options 31-45**) and/or emphasized in an overview of equity considerations throughout the gas IRP (**Decision Options 1-2**). Staff looks forward to expanding understanding of the gas IRP and, with experiencing creating and evaluating the plans, finding more ways in which equity can be deliberately incorporated in gas IRPs.

XII. TEXT CHANGE TO EXISTING ORDERING PARAGRAPHS

A. Stakeholder Recommendations

Framework ordering paragraph 36 appears to contain a relic from the electric IRP reporting requirements from which it was adapted. The text currently states, "A utility shall include in its resource plan filing a nontechnical summary, not exceeding 25 pages in length, describing the utility's resource needs, the resource plan created by the utility to meet those needs, the process and analytical techniques used to create the plan, activities required over the next five years to implement the plan, and the likely effect of plan implementation on electric rates and bills."

CPE, MERC, CEE, CUB, and the Department supported striking the word "electric" in the last line (**Decision Option 94**). However, CEE and CUB underscore that CPE and MERC should work with electric utilities in their service territories to understand, to the extent possible, the electric system impacts of resource options in the natural gas IRPs (**Decision Option 95**). CPE voiced hesitation about its ability to work with electric service providers.

MERC's straw proposal also discussed a clarification to a Framework Order point 28, based on language used in Framework ordering paragraph 50. Framework ordering paragraph 50 states:

> A natural gas utility's preferred plan should include both (1) a ten-year sales and emissions forecast, and (2) a <u>five-year</u> action plan of the specific steps that it will take to implement that plan over <u>the next five years</u> [emphasis added].

Indeed, echoing the language used in ordering paragraph 50, MERC proposed a clarification to framework ordering paragraph 28 which states, in part:

> Resources approved through the integrated resource planning process, within the defined, near-term action period, should be considered conditionally approved for acquisition or procurement [emphasis added].

MERC's clarification would define "near-term" as five years. MERC explained that "[p]lanning for capital investments over a time horizon beyond five years is preliminary and sufficient detail on costs, benefits and other aspects of the project are not typically available that far in advance. Attempting to include projects beyond a five-year time horizon would not provide meaningful insight with which the Commission could make decisions (**Decision Option 96**)."[96]

No other groups commented on MERC's definition of near-term.

B. Staff Analysis

Staff supports deleting the word electric as it does not apply to gas utilities and may have been left in by mistake. Staff is interested in contemplating how gas and electric utilities can work together and looks forward to doing this as the stakeholder meetings led by GPI continue, to the extent it is appropriate for Staff to attend those meetings.

Staff also highlights National Grid/ RMI's report which discusses project-specific application of integrated planning between gas and electric utilities.[97] Project-specific work could be an alternative to or addition to sharing load forecast data. Sharing such data has so far proven complicated as MERC, CPE, and Xcel have overlapping service territories with several electric providers. Further, Staff understands that during its February 22, 2024, agenda meeting the Commission declined to adopt decision options that would coordinate the planning of electric and gas utilities.

However, Staff encourages stakeholders to continue to think of ways to coordinate between gas and electric utilities. That might be in the creation of one of the load forecast scenarios or in coordinated projects in the EAA, as described in the RMI report. Proactive coordination could help to protect customers by making gas forecasts, and thus procurement choices, as closely aligned to as much relevant information, including electrification trends, as possible. For example, Xcel Electric's most recent IRP filing forecasted net energy requirements for which load growth was explained in part by beneficial electrification.[98]

With respect to MERC's prepared definition of "near-term" as five years, Staff does not find the clarification necessary as the use of the phrase "action plan" in Framework ordering paragraph

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[96] MERC straw proposal at 2

[97] RMI & National Grid May 2024 at 10. Non-Pipeline Alternatives: Emerging Opportunities in Planning for U.S. Gas System Decarbonization. https://www.nationalgridus.com/media/pdfs/other/CM9904-RMI_NG-May-2024.pdf

[98] Xcel Electric Resource Plan initial filing, Chapter 3 at 6. Docket no. E002/RP-24-67.

50 seems to overlap with the use of "action period" in Framework ordering paragraph 28. The use of the word "action" in both paragraphs seems to suggest that the action period will be the *time* that is discussed in the action plan and that *time* would be five years.

XIII. RESOURCE COMPARISON USING "ALL-IN COST"

A. Party Recommendations

Framework ordering paragraph 6 states, "All resources must be evaluated on a consistent and comparable basis." The CEOs recommended clarifying this paragraph stating, "The Commission should require utilities to use a consistent methodology to calculate the "all-in" costs of resources to allow for an apples-to-apples comparison (**Decision Option 97**)."

CEOs explained that a method is needed for all resource option types to be evaluated in the same way. Further, quoting an Environmental Defense Fund report, CEOs underscored that inclusion of variable costs in resource evaluations captures the ongoing expenses of different resources, ensuring that investments reflect their actual value and utility.[99] Indeed, CEOs shared the all-in cost calculation: fixed and variable costs of a resource divided by projected annual use to yield a dollars per dekatherm value. CUB supported this recommendation; the Department did not oppose.

In contrast, CPE and Xcel did not support and found the additional clarification unnecessary.

B. Staff Analysis

Staff interprets the CEO's recommendation as giving direction for *how* to conduct resource analysis, beyond what meaning utilities interpret from the phrase "consistent and comparable" in Framework ordering paragraph 6. Further, the CEOs recommendation would give direction beyond what has been required by Framework ordering paragraphs 5, 9, and 49:

> 5. The term "integrated resource planning" means, in the case of a gas utility, planning by the use of any standard, regulation, practice, or policy to undertake a systematic comparison between energy resource options to minimize the lifecycle costs of adequate and reliable utility services to consumers. Integrated resource planning shall take into account the necessary features for a system operation such as diversity, reliability, dispatchability, and other factors of risk and shall treat demand and supply to consumers on a consistent and integrated basis.
>
> 9. Consistent assumptions and methods should be used for evaluation of all

[99] CEOs initial comments at 5-6; Environmental Defense Fund, Aligning Gas Regulation and Climate Goals: A Road Map for State Regulators 19-20 (2021), https://blogs.edf.org/energyexchange/wpcontent/blogs.dir/38/files/2021/01/Aligning-Gas-Regulation-and-Climate-Goals.pdf.

resources.

49. Natural gas resource plans shall include the cost of each scenario and sensitivity presenting both the utility's revenue requirement and environmental costs and other externalities to the utility's revenue requirement.

To this extent, the CEO's recommendation seems to provide a method to consider the projected amount of use of a resource option which, would underscore the lifetime value of a resource, in terms of $/dekatherm. As such, the CEOs could be thought of as giving explicit direction to phrases like, "systematic comparison between energy resource options to minimize the lifecycle costs." In this context, lifecycle costs would perhaps be different than those explaining emissions via the GREET model.

Choosing **Decision Option 97** could bring transparency to *how* resources are evaluated by each utility. More, the CEOs' recommendation could promote consistency across utilities, in terms of resource evaluation. The GPI stakeholder roundtable group has discussed the benefits, in terms of stakeholder bandwidth, of standardizing some analytical methods across utilities' IRPs. Utilities however, reminded the group that their capabilities and staff capacities may be different and requiring the same analyses from each utility may not be practical. An option in this case may be for the utilities to continue to offer feedback as the first utility to file prepares its resource analysis and steer the process towards analyses that are feasible for all utilities to complete and comprehensible to stakeholders, if such an analytical compromise exists.

XIV. CITY CLIMATE POLICY

A. Cities' Recommendations

In reply comments, representatives from the cities of Bloomington, Edina, Hopkins, Richfield, Minneapolis, St. Paul, and St. Louis Park co-authored a letter recommending utilities incorporate local climate policies into gas IRPs. First, the cities recommended a narrative discussion of how the plans consider the climate goals of local governments within the utilities' service territories. The cities stated that such a discussion would include evaluating the impact of gas utility decisions on local emissions reduction targets, the impact of electrification targets on the gas supply, and supporting the transition to cleaner energy alternatives.

Beyond this narrative that would require only the utilities' review of existing government plans, the cities proposed an action, requiring consultation with cities. Cities would their data with utilities during the gas IRP planning process and then, as a result, ensure that utility resource plans reflect community-specific environmental priorities (**Decision Options 98-99**).

The cities argued that these proposals may allow the utility and city to synchronize timelines for projects in the same area and as such, avoid unnecessary costs. More, if a city were to have an aggressive electrification or carbon neutrality schedule, a gas utility may choose to prioritize projects there for its expansion alternatives analysis.[100]

Only LIUNA responded to these recommendations. LIUNA opposed the recommendations explaining that resource plans should not accommodate local goals or policy preferences in a manner that shifts costs or burdens to other communities and their ratepayers (**Decision Option 100**).

B. Staff Analysis

As mentioned in Staff's analysis of the EAA, the Commission has previously promoted work with city governments to achieve planning synergy as part of Integrated Distribution Planning.[101]

Staff has some concern about the number of cities within each utility's service territory. Review and incorporation of each city's unique climate policy could be time consuming for utilities and potentially, yield conflicting policy priorities for the utility to reconcile. More, if a city lacked a secure funding mechanism for its climate goals, the utility may be staking its plans on an uncertain future.

However, the cities' proposed collaboration could help avoid ratepayer financial burdens stemming from duplication of projects, delay, or gas system upgrades that would soon be rendered obsolete by electrification efforts. Ultimately, Staff believes alignment with the IDP and collaboration with cities would be beneficial in the instant docket as well. The cities' two broad decision options would yield different degrees of collaboration so the Commission may consider how much city-utility collaboration, if at all, would be beneficial.

XV. CONCLUSION

At its upcoming agenda meeting the Commission may give additional direction on the filing requirements for natural gas IRPs, decide which utility will file its plan first and when, and determine how to deliberately imbed equity in gas IRPs. Staff offers **Attachment A** showing which clarifications to the Commission's Framework order or additional requirements are available for the Commission's consideration. Upon the Commission's final decision, stakeholders have requested a Comprehensive Gas IRP Requirements document (**Decision Option 101**).

Next steps for the stakeholders involved in this process will be Future of Gas meetings to, "consider changes to rates needed to maintain affordable and equitable utility service," per Framework ordering paragraph 56. Stakeholders have also expressed interested in continuing

[100] Minnesota Local Governments comments filed July 19, 2024

[101] Order Accepting 2021 Integrated Distribution System Plan and Certifying The Resilient Minneapolis Project issued July 26, 2022, in docket no. E002/M-21-694 at paragraph 6, requiring stakeholder meetings to provide transparency into the planning process and generate a shared vision for the distribution grid of the future, including how Xcel should consider and incorporate local clean energy goals in its planning processes, from which lessons learned would be incorporated into subsequent distribution plans.

to work with utilities and GPI to craft utilities' first resource plans. After those initial plans are presented to the Commission, Staff expects a great deal of learning and opportunities for improvement. As such, Commission Orders can be used to update subsequent IRP iterations.

XVI. DECISION OPTIONS

Equity

1. Require gas utilities to include in their integrated resource plan a discussion of how equity was considered in the planning process. (Xcel, Dept, CUB, MERC)

2. Require gas utilities to include in their IRP a discussion of how changes to the distribution system will have upstream impacts on communities impacted by gas extraction and transportation. (Ayada et al.)

Equity- Participation

[*Any may be selected*]

3. Request that GPI incorporate an equity-focused component to the Gas Utility Innovation Roundtable to inform the development of natural gas utilities' IRPs. (CEE, CUB, Ayada et al., Dept, CPE; MERC does not oppose)

4. Require the natural gas utilities required to file gas IRPs to work through the Gas Utility Innovation Roundtable to engage and obtain input from stakeholders in the development of initial natural gas IRPs. (CEE; CUB, MERC, CPE does not oppose)

5. Require the gas utilities required to file gas IRPs to facilitate effective engagement with members of impacted communities throughout the integrated resource planning process. (Ayada et al.)

6. Encourage regular consultations between gas utilities required to file gas IRPs and local governments to discuss community-specific concerns and priorities throughout the planning process. (Local Gov)

7. Require gas utilities required to file IRPs to work with local governments to establish a process for utilities to provide periodic regulatory updates and educational opportunities to local governments in their service territories. Require each utility to file a narrative on the proposed process within 30 days of the issuance of this Order. (Local Gov, Staff modification regarding process)

8. Require Xcel, CenterPoint, and MERC each to develop a proposal for a structured process for local governments to provide input on proposed utility gas plans, including mechanisms to address how this input is or is not incorporated into final decisions. Require each utility to file a narrative on the proposed process within 30 days of the issuance of this Order. (Local Gov, Staff modification regarding process)

9. Adopt the following best practices for Community Engagement in the gas IRP process (Ayada et al.; Staff modification of formatting) [*The Commission may select any or all of the following*:]

   A. Provide healthy and appropriate food/beverages.
   B. Coordinate with local community leaders in advance to assure high attendance and awareness.
   C. Provide information during existing community events/meetings.
   D. When transit is available, choose locations with walkable access to major transit lines.
   E. Schedule during a reasonable time after typical working hours and school hours if planned during the week.
   F. Provide dependent-friendly spaces.
   G. Prioritize public meetings in areas designated as 'Green Zones' or in identified environmental justice areas.
   H. Designate space for community organizations or nonprofits to set up information and engage with attendees, equivalent in location and prominence to information provided by utilities
   I. Allow commenters to provide feedback over the phone or by other means.
   J. Contact government bodies and community groups before scheduling public meetings to provide input on scheduling.
   K. Incorporate explicit standards set out by the White House Environmental Justice Advisory Council in the context of other types of new infrastructure buildout
   L. Adopt best practices laid out in the CEQ guidance on environmental justice, which requires adaptive techniques for gathering information and / or for seeking comment from tribal members and low-income communities.

Equity- Focus on Workforce

[*Any may be selected*]

10. Delegate authority to the Executive Secretary to open a proceeding to create a mechanism for existing employees of the utilities to provide input and have their voices heard without the intermediary of their employer. (Ayada et al.)

11. Require utilities required to file gas IRPs to incorporate equity into workforce and supplier diversification as relates to gas IRPs by sharing relevant information filed in docket no. E,G999/PR-24-101 in the instant docket as part of annual updates (MERC, Dept; Staff modification as to where information should be filed)

Equity- Decommission Gas Infrastructure

12. Require the gas utilities required to file gas IRPs to plan for the establishment of decommissioning trust funds and maintain sufficient decommissioning funds to cover any future liabilities arising from abandonment of gas infrastructure. (Ayada et al.)

Filing Cadence

[*To give direction to utilities regarding filing, the Commission should select 13 or 14*]

13. Require Xcel to file its first gas IRP by October 1, 2026, and require the other two utilities to file their Plans on a 12-month cadence, beginning with CenterPoint on October 1, 2027, and MERC on October 1, 2028. (Dept, OAG, CUB, CEOs, CEE, Xcel, CPE; MERC with modification below)

[*With Decision Option 13, the Commission may also consider A*]

A. Delegate authority to the Executive Secretary to revise the filing schedule and cadence if the first Gas IRP filing takes longer than 12 months, shortly after the conclusion of the first Gas IRP. (MERC with staff modification)

OR

14. Adopt a two-year cadence between the filings of the Initial Gas IRPs of Xcel on October 1, 2026, and CenterPoint Energy on October 1, 2028, and a one-year cadence for MERC to file its Initial Gas IRP on October 1, 2029. After all of the Gas Utilities have filed their initial Gas IRPs, the filing cadence would then follow the Commission's Order Point 21 from the March 27, 2024 Order. (MERC)

Expansion Alternatives Analysis (EAA)

EAA- Clarifying Meaning

[*Any may be selected*]

15. Clarify that, as used in ordering paragraph 51 of the Commission's March 27, 2024 order in these dockets, "infrastructure costs" are the capital costs the utility would pay to do the project. (CPE, MERC, Xcel, CEE)

16. Clarify that, as used in ordering paragraphs 51 and 54 of the Commission's March 27, 2024 order in these dockets, "Capacity Expansion Project, Resource Expansion, or New Resources" are individual projects, or a set of inter-related facilities needed to meet a specified capacity expansion need due to growth by existing or new customers and facilities. (CPE, CEE; staff modified to remove duplicative last sentence)

17. Require that projects that are geographically related and/or interdependent on each other be considered as a single capacity expansion project for the purposes of determining EAA eligibility above the cost threshold. (CUB)

18. Find that projects that meet the statutory definition of a natural gas extension project ("NGEP") are eligible to be considered for an EEA if above the investment threshold. (CUB, Building Decarbonization)

EAA- Replacing Framework Ordering Paragraphs

19. Replace the section title immediately preceding ordering paragraph 51 of the Commission's March 27, 2024 Order in these dockets with the following: Expansion Alternatives Analysis. (Staff)

[To give direction on Investment Threshold, the Commission should consider selecting one from 20-22]

20. Replace ordering paragraph 51 of the Commission's March 27, 2024 Order in these dockets with the following: Gas integrated resource plans shall include infrastructure projects related to resource expansion or new resources at or above a [$1 million] threshold from which utilities select projects for an Expansion Alternatives Analysis. Utility resource plans shall include a discussion of the rationale for the projects selected for an Expansion Alternatives Analysis, and summary of the utility's discussions with stakeholders throughout the selection process. (CEE and CUB)

OR

21. Replace ordering paragraph 51 of the Commission's March 27, 2024 Order in these dockets with the following: Integrated resource plans shall include an analysis of infrastructure projects related to individual projects, or a set of inter-related facilities needed to meet a specified capacity expansion need due to growth by existing or new customers and facilities at or above a threshold of [$_____]. (Staff)

[*If selecting Decision Options 20 or 21, Commission should choose either utility-specific thresholds (A-C) or one universal threshold from D–H to put inside the brackets*]

A. $15 million for CenterPoint Energy, adjusted for inflation. (CPE)
B. $3 million for Xcel (Xcel, preferred)
C. $1 million for MERC (MERC)
D. $10 million (LIUNA)
E. $10 million, but no more than five total projects must be considered for the EAA (CPE)
F. $10 million, but no more than ten total projects must be considered for the EAA (CPE)
G. $1 million (CUB, CEE, Building Decarbonization, MERC, CEOs)
H. $1 million, but no more than ten total projects must be considered for the EAA (Xcel, Dept.)

OR

22. Replace ordering paragraph 51 of the Commission's March 27, 2024 Order in these dockets with the following: Integrated resource plans shall include an analysis of the largest [two or three or four] infrastructure projects related to individual projects, or a set of inter-related facilities needed to meet a specified capacity expansion need due to growth by existing or new customers and facilities. (LIUNA) [*If selected, Commission should choose one of the numbers in brackets*]

[To give direction on the creation of the pool from which some projects will be selected for a full EAA, the Commission should consider selecting 23 and any from 24-27]

23. Replace ordering paragraph 52 of the Commission's March 27, 2024 Order in these dockets with the following: From the pool of projects above the threshold, utilities shall select 2-3 projects for a full Expansion Alternatives Analysis. The Expansion Alternatives Analysis shall proactively identify areas of the natural gas system with upcoming capacity needs and analyze how to best serve those needs. (Staff)

24. Require each utility to follow the following process to create a project pool for its EAA (CEOs):

    A. First, the preliminary screening of forecasted infrastructure investments identifies projects for alternatives analyses that are more likely to be feasible and executable based on safety, cost, and timing.
    B. Next, to assess whether an alternatives project is technically viable, a utility procures and assembles eligible resources into a portfolio.
    C. Finally, a utility evaluates the alternatives portfolio using a benefit-cost test, qualitative vendor criteria, and equity analysis.

25. Allow utilities to evaluate and select projects for an Expansion Alternatives Analysis below the established cost threshold. (Xcel; staff modified to show CEO's suggestion to include all utilities)

26. Encourage utilities to consider expansion alternatives for projects related to safety and reliability, public works accommodation, routine maintenance, and integrity. (CEOs, CUB)

27. Require utilities to consider additional factors when selecting expansion projects for the EAA, including the potential for learning, equity impacts, and emissions reductions. (CEE)

[To give direction on the full Expansion Alternatives Analysis, the Commission should consider selecting any from 28-30]

28. Require that a full alternatives evaluation, as required by Order Point 54 of the Commission's March 27, 2024 Order, include: (CEO, Xcel, CUB)

    A. non-pipeline alternatives and/or non-natural-gas alternatives;
    B. costs and benefits of those alternatives including the costs of direct investment, variable costs, and the social costs of carbon and methane for emissions due to or avoided by the alternative;
    C. air quality impacts; (CUB only)
    D. a thorough and transparent explanation of the criteria used to rank or eliminate such alternatives; and an explanation of how equity was considered.

29. Require utilities to consider zero on-site combustions technologies like electrification, geothermal district energy, and thermal energy networks in their expansion alternatives analysis. (Building Decarb)

30. Require that an expansion alternatives analysis consider the following, adapted from requirements for new business and capacity expansion projects in Colorado's Gas Infrastructure Plans (CEOs; Ayada et al.; staff modified to avoid Colorado-specific references):

A. one or more applicable clean heat resources;
B. a cost-benefit analysis including the costs of direct investment and the social costs of carbon and methane for emissions due to or avoided by the alternative, and other costs determined appropriate by the Commission; and
C. available employment metrics associated with each alternative, including a projection of gas distribution jobs affected by the alternative and jobs made available through the alternative, opportunities to transition any affected gas distribution jobs to the alternative, pay and benefit levels of the affected gas distribution.

[To give direction on decision-making in the EAA, including stakeholder meetings, the Commission should consider selecting 31 and any from 32-38]

31. Replace ordering paragraph 53 of the Commission's March 27, 2024 Order in these dockets with the following: Utility resource plans shall include a discussion of the rationale for the projects selected for an Expansion Alternatives Analysis, and summary of the utility's discussions with stakeholders throughout the selection process and the alternatives analysis. (Staff)

32. For projects above the investment threshold for the expansion alternatives analysis, require the utility to explain why the projects selected for a full alternatives evaluation were prioritized over the projects that were not selected for a full alternatives evaluation. (CEOs; Ayada et al.)

33. Require each utility to engage diverse communities within its service territory in the process of identifying potential projects for EAAs and the selection of the projects on which EAAs will be conducted. (CUB)

34. Require each utility to include in each gas IRP a summary of its discussions with stakeholders, including all members of the impacted community, including community leaders (e.g. local government or tribal leaders) and other important leaders such as elders. (Ayada et al.)

35. Require that the alternatives analysis under the overall planning structure or within an EAA be done at the discretion of impacted communities. (Ayada et al.)

36. For the initial natural gas IRPs, require natural gas utilities to present possible expansion projects to the Gas Utility Innovation Roundtable stakeholders and work collaboratively with stakeholders to select projects for Expansion Alternatives Analyses. (CEE, CUB, CEOs)

37. Encourage coordinated planning among gas utilities required to file gas IRPs and local governments to align infrastructure projects with community capital improvement plans and climate objectives, prioritizing city timelines to the extent possible to help avoid redundant investments and leverage opportunities for integrated solutions. (Local Gov)

38. Require utilities required to file gas IRPs to include local government representatives in stakeholder engagement, and request local governments' participation to gather input from their communities and provide feedback on ways to minimize the cost burden of stranded assets

and a shrinking customer base, especially on those who can least afford to shoulder them. (Local Gov)

[*Decision Option 39 can be paired with any other decision options.]*

39. Rescind ordering paragraph 54 of the Commission's March 27, 2024 Order in these dockets. (Staff)

EAA- Equity, Mapping, and Geographic Specificity

[*To give direction on equity, maps, and project sites in the EAA, the Commission may choose any from 40-43 but only one from 44-45*]

40. To integrate equity into alternatives analyses, require utilities to evaluate ways to overlay maps of proposed capital projects and resource acquisitions across maps of environmental justice and disadvantaged communities in the utilities' service areas. (CEO, Building Decarbonization, CUB, Xcel, CPE, MERC, Ayada et al.)

41. Require utilities to select capacity expansion projects for expansion alternatives analysis using equity criteria and Environmental Justice Areas as defined in Minn. Stat. § 116.065, subd. 1(e) (2023). (Building Decarbonization, CPE)

42. Require utilities when selecting projects for EAAs to consider the disparate impacts of gas system emissions on various communities, and whether low- and moderate-income households will benefit from an alternative through bill savings, air quality improvements, or other direct benefits. (CUB)

43. Require utilities required to file gas IRPs to prioritize rural low-income communities for clean heating options when replacing propane, fuel oil, or wood heating. (Ayada et al.)

44. Instate a moratorium on expansion into low-income communities. (Ayada et al.)

OR

45. Require an EAA for each expansion project proposed in an environmental justice community with significant numbers of BIPOC residents, low-income residents, or any expansion in Indian Country or indigenous communities. (Ayada et al.)

Quantifying the Environmental Impact of Gas

Considering Greenhouse Gas (GHG) Emissions

[*To decide a method for considering GHGs, the Commission should choose **EITHER** Decision Option 46, with this the Commission may also consider A **OR** the Commission should select 47 and 48]*

46. Require utilities in their gas IRPs to consider the State's economy-wide greenhouse gas reduction statutory goals consistent with Minn. Stat. § 216H.01 and 216H.02 using 2020 as the baseline year. Lifecycle GHG emission factors from filed Natural Gas Innovation Act (NGIA) Plans can also

be considered in resource analysis to ensure lower emissions on a lifecycle basis. (Xcel, CPE, MERC, CEE, CUB, Dept.)

A. Require utilities to calculate out-of-state emissions using NGIA GREET for purposes of gas IRPs. (Xcel, CEE, CPE CEOs, CUB; Ayada et al.)

OR

47. Clarify that the scope of gas integrated resource planning considers Minnesota's economywide greenhouse gas reduction statutory goals, which consider state-specific emissions, and may also consider lifecycle greenhouse gas emissions where appropriate. (OAG)

AND

48. Require the utilities in their gas IRPs to report and forecast "statewide greenhouse gas emissions," as defined in Minn. Stat. § 216H.01, using a 2005 baseline. (OAG)

Reporting on GHG including Methane

Projected Emissions

[*Any may be selected*]

49. Require each utility to include in each gas integrated resource plan the emissions projected to result from its preferred plan and from the other resource mixes considered. Projected emissions shall include all emissions from distribution system operations and upstream emissions associated with purchased gas using recognized reporting protocols and available tools. (CEO, CUB, Ayada et al., Dept)

50. Require utilities to fully account for historic impacts on low-income communities and communities of color as a part of their gas IRPs. (Ayada et al.)

Distribution System

[*The Commission should clarify whether only Xcel or all utilities should report on distribution system emissions by selecting one of the following. Staff bolded terms to emphasize differences*]

51. Require **Xcel** to report methane emissions from natural gas distribution system operations using recognized reporting protocols, such as 40 CFR Part 98, Subpart W, in the natural gas integrated resource plan and annual updates. (Xcel, Dept)

OR

52. Require **Xcel, MERC, and CPE** to report methane emissions from natural gas distribution system operations using recognized reporting protocols, such as 40 CFR Part 98, Subpart W, in the natural gas integrated resource plan and annual updates. (CEOs, CUB)

Upstream Emissions

[*The Commission may select any of 53-55 to learn about upstream emissions. For reporting on upstream emissions, it may also select either 56 or 57. Staff bolded terms to emphasize differences*]

53. Require gas utilities required to file gas IRPs to work with gas suppliers to improve transparency in reporting of upstream methane emissions. (Dept, CEOs)

54. Require utilities to include in their gas IRPs additional information about upstream emissions data availability. (CUB, CEOs; Dept)

55. After discussing with stakeholders, utilities required to file gas IRPs shall explain how they are measuring and defining distribution, upstream, and lifecycle emissions. Utilities shall provide this information in a compliance filing made within 90 days of the issuance of this Order. (Staff)

56. Require **Xcel** to report estimates of the full fuel cycle methane emissions associated with its gas system using both the EPA and M.J. Bradley & Associates methodologies, along with any other appropriate tools Xcel identifies, in its first natural gas resource plan filing. (CEE)

OR

57. Require **each utility** in its gas IRP to report on all emissions from distribution system operations and upstream emissions using recognized reporting protocols and available tools, including the EPA's protocol Subpart W referenced by Xcel and the Department, as well as additional data from the National Energy Technology Laboratory, Energy Information Administration, GREET model, and other sources. (CEOs, CUB)

Justifying GHG Reductions

[*For an explanation of a gas IRP's GHG reductions specifically, the Commission may select 58 and may also include A. Decision Options 59 and 60 may be selected regardless of other options chosen*]

58. Require each utility to include in each gas integrated resource plan a narrative description of how its preferred plan will support and serve Minnesota's greenhouse-gas-emission-reduction goals. (CEOs, CUB, Dept., Ayada et al., LIUNA)

    A. If the preferred plan chosen by the utility is not estimated to be on track for achieving the 2050 net zero goals, require the utility to provide a justification of why the plan was nevertheless chosen as its preferred plan (CUB, CEOs)

59. Clarify that, as used in ordering paragraph 35 of the Commission's March 27, 2024 order in these dockets, "a narrative and quantitative discussion of why the plan would be in the public interest" includes a narrative description of how a utility's preferred plan will support and serve to maintain or improve the safety, adequacy, and reliability of utility service; keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints; minimize adverse socioeconomic effects and adverse effects upon the environment; enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations; limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control; and include cost-effective energy savings as the preferred energy resource. (Staff)

60. Require utilities required to file gas IRPs to select a preferred plan that advances climate goals. (Ayada et al.)

Environmental Costs

[*Any may be selected*]

61. To estimate the environmental externality costs of resources options in gas IRPs, require utilities to use the most recent externality values adopted by the Commission in Docket No. E-999/CI-14-643. (CPE, Xcel, CEE, CUB; MERC, Dept)

62. Clarify that the NGIA equivalence factor shall be used in gas IRP dockets. (CPE, CEOs)

63. Require utilities to use the $/short ton CO2e as addressed in the Commission's January 26, 2024, Notice and the December 19, 2023, Commission Order in Docket No. E999/CI-14-643 as additional costs considered in the EAA the utility provides within the IRP. (CPE)

Process

[*Any may be selected*]

64. Clarify that utilities shall include externalities in scenarios in the same manner that electric utilities do in integrated resource planning to the greatest extent possible. (CEO 4; CUB; Ayada et al.; Dept does not oppose)

65. Require utilities to share information on how and to what extent they will incorporate externality costs in their gas IRP analysis. (CUB, CEOs)

Regulatory Costs

[To give direction on regulatory costs, the Commission should select one of 66-68. In addition, decision option 69 could accompany any of 66-68; if selecting 67, consider also selecting A]

66. Require utilities required to file gas IRPs to apply the ECO cost-effectiveness framework, which considers environmental compliance costs related to natural gas, by utilizing the most recent factor adopted by the Deputy Commissioner of the Department of Commerce.[102] (CEE, Xcel, CPE, Dept does not oppose; CEOs could support)

OR

67. Require utilities required to file gas IRPs to use the regulatory cost of carbon emissions established in response to Minn. Stat. § 216H.06 to account for future regulation of carbon emissions. (CEE, CEOs, Dept does not oppose)

[102] A March 31, 2023 Decision, adopted a factor of 1.40 percent of the commodity costs of natural gas for 2024-2025 to be used for natural gas environmental compliance impacts in ECO cost-effectiveness testing. This value is based on the EPA's Regulatory Impact Analysis for the proposed federal methane emission standards, anticipated to be finalized by the EPA in 2024.

[*If selected, the Commission may also choose the following:*]

A. Utilities required to file gas IRPs shall also add 1.4% to the commodity cost of gas to account for methane regulatory costs. (CEOs 11)

OR

68. Delegate authority to the Executive Secretary to open a comment period in Docket Number E999/CI-07-1199 to consider and determine the appropriate data source and values for the regulatory cost of greenhouse gas emissions for natural gas resource planning through the upcoming docket to update the regulatory cost of carbon for electric resource planning. (CEE, CPE)

69. Require utilities required to file gas IRPs to incorporate factors that reflect the full range of potential outcomes, including increasingly common policy swings against decarbonization that effectively produce negative cost factors for GHG emissions. (LIUNA)

Process

70. Clarify that utilities shall include the regulatory cost of greenhouse gases in scenarios in the same manner that electric utilities do in integrated resource planning to the greatest extent possible. (CEO)

[*If the Commission choses decision option 71, do not select any from 66-70*]

71. Deny inclusion of a regulatory cost of carbon in gas IRPs. (LIUNA, preferred)

Indoor Air

[*Any may be selected*]

72. Require utilities to include in each gas IRP an analysis of the mortality and morbidity caused by continued gas use in residences and businesses. (Ayada et al.; Pediatrician)

73. Delegate authority to the Executive Secretary to issue a Notice of Comment to set indoor gas use externality values based on the current medical science reflecting the serious damage done to the most vulnerable members of our society by continued indoor gas combustion. (Ayada et al.)

Forecast

[*The Commission may select any of the following, but consider choosing only one from 76-77*]

74. Clarify that, for purposes of ordering paragraph 40 of the March 27, 2024 Order in these dockets, the high load forecast may represent the Commission-approved forecast for design day as provided in the utilities' most recent demand entitlement filing, and the Commission-approved sales forecast as provided in the utilities' most recent rate case. (OAG; CUB would not oppose, CPE)

75. Require utilities required to file gas IRPs to collaboratively develop forecast methodologies with stakeholders through Great Plains Institute's Gas Utility Innovation Roundtable. (Staff)

76. Clarify that utilities required to file gas IRPs must consider all commercially available supply-side, demand-side, and infrastructure resources for meeting high, medium and low load forecasts. (CUB)

    OR

77. Find that while utilities required to file gas IRPs may use various levels of energy efficiency and demand response to inform load-forecasting scenarios, this does not relieve the obligation to also consider energy efficiency and demand response as resources on par with other options for meeting energy and capacity needs. (OAG)

78. Find that gas integrated-resource-planning participants are free to advocate for changes to the filed forecasts in a utility's plan or otherwise challenge the forecast's reasonableness or accuracy. (OAG)

79. Require utilities to express demand as a function of heating needs in their gas IRPs. (Ayada et al.)

80. Require utilities, in each gas integrated resource plan, to indicate how the utility load and customer forecasts incorporate, to the extent practicable, relevant external factors including, but not limited to (CEO, CUB):

    A. the effect of current or enacted state and local building codes and standards;
    B. building electrification, efficient fuel-switching, and energy efficiency programs or incentives offered by both the gas utility and the local electric utility or local, state, or federal entities that overlap with the utility's gas service territory;
    C. the effects of rate design and/or demand response programs;
    D. changes in the utility's line extension policies, and the associated impact on gas customer growth; and
    E. the price elasticity of demand (e.g., the impact of reduced throughput and rate increases on sales and peak demand requirements and impacts of commodity prices).

Energy Efficiency

[*To give additional direction on energy efficiency, the Commission may consider 81 and then either 82 or 83. Regardless of the Commission's choice, 84 may be selected.*]

81. Replace ordering paragraph 11 of the Commission's March 27, 2024 Order in these dockets with the following: To treat energy efficiency alongside all other energy resource options, utilities shall evaluate energy efficiency achievement scenarios including expected program achievement to maximum achievement in their gas IRPs. (Xcel, CEE, CUB; Dept; CPE)

82. Replace ordering paragraph 12 of the Commission's March 27, 2024 Order in these dockets with the following: The appropriate and cost-effective level of future energy efficiency procurement for gas IRPs shall correspond to the maximum program spending level that remains cost-effective when compared to alternatives. (CUB, Xcel, CPE; Dept not opposed; Staff added "for gas IRPs")

OR

83. Replace ordering paragraph 12 of the Commission's March 27, 2024 Order in these dockets with the following: The appropriate and cost-effective level of future energy efficiency procurement shall correspond to the maximum program spending level that remains cost-effective when compared to supply-side alternatives. (CEE)

84. Require natural gas utilities to work through the Gas Utility Innovation Roundtable to gather and incorporate input on the assumptions used for energy efficiency in their natural gas IRPs. (CEE)

Additional Scenarios and Sensitivities

[*Select neither OR only one of the following; Staff bolded language to emphasize difference*]

85. In initial integrated resource plans, require utilities to analyze scenarios and sensitivities as specified in the March 27, 2024 Order in this docket. The Commission may later order additional scenarios and sensitivities. (CPE, Dept., CEE does not oppose)

OR

86. In initial integrated resource plans, require utilities to**, at minimum,** analyze scenarios and sensitivities as specified in the March 27, 2024 Order in this docket. The Commission may later order additional scenarios and sensitivities. (CUB, Xcel; Dept does not oppose)

MERC Deferred Accounting

[*Select one of the following*]

87. Allow utilities deferred accounting treatment of costs associated with developing and implementing a Gas IRP process for reporting, conducting a Gas IRP, the costs associated with the regulatory process for the Gas IRP filings, and implementing a Gas IRP once approved by the Commission. (MERC)

OR

88. Deny MERC's request for deferred accounting. (OAG, CUB, Dept)

Five-Year Action Plan

[*To give more direction on the Action Plan, select one from the following. Staff bolded text to emphasize difference.*]

89. Require each utility to include in its preferred five-year action plan justification of need, resource mix, project scope, construction timeline, and cost estimates. (CEE)

OR

90. Require each utility to include in its preferred five-year action plan justification of need, resource mix, project scope, construction timeline, and cost estimates **with any offsetting revenues and tax benefits**. (Xcel, Dept)

OR

91. **For each project proposed** in its preferred five-year action plan, require the utility to include justification of need, resource mix, project scope, construction timeline, cost estimates **including**

any offsetting revenues and tax benefits, and a narrative discussion of any equity impacts the project may have. (CUB, CPE)

Mapping

[*Select any of the following*]

92. Require each utility, in its first gas IRP, to evaluate ways to incorporate public data and mapping tools for low-income residents or disadvantaged communities in this IRP process. (Staff interpretation of CPE; CUB, Xcel; Dept does not oppose)

93. Require utilities to delineate the extent to which their resource plans will impact environmental justice communities, including the portion of project emissions that would be located within environmental justice communities. (Pediatrician)

Clarifying Ordering Paragraphs

[*Select any of the following*]

94. Modify ordering paragraph 36 of the March 27, 2024 Order in these dockets as follows:
    A utility shall include in its resource plan filing a nontechnical summary, not exceeding 25 pages in length, describing the utility's resource needs, the resource plan created by the utility to meet those needs, the process and analytical techniques used to create the plan, activities required over the next five years to implement the plan, and the likely effect of plan implementation on ~~electric~~ rates and bills. (CPE, MERC, CEE, CUB, Dept)

95. Require Xcel, CenterPoint Energy, and MERC to work with electric utilities in their service territories to understand, to the extent possible, the electric system impacts on resource options in the natural gas IRPs. (CEE, CUB, staff inclusion of Xcel)

96. Clarify that for purposes of gas IRPs, "<u>near-term</u>" means within five years. (MERC)

Resource Comparison Using All-In Costs

97. Require each utility to use a consistent methodology in its gas IRPs to calculate the "all-in" costs of resources to allow for an apples-to-apples comparison. (CEO; CUB; Dept does not oppose)

City Climate Policy

[*Select any of 98-99 OR select 100*]

98. Require utilities, in their gas IRPs, to include a narrative discussion of how the plans consider the climate goals of local governments within the utilities' service territories. This includes evaluating the impact of gas utility decisions on local emissions reduction targets, the impact of electrification targets on the gas supply, and supporting the transition to cleaner energy alternatives. (Local Gov)

99. Require utilities required to file gas IRPs to consult with local governments in their service territories in the gas resource planning process so that cities may contribute data and insights on local climate initiatives, ensuring that utility resource plans reflect community-specific

environmental priorities. Require utilities to include a narrative of how local policies are reflected in gas IRPs, or if not, why policies were not included in gas IRPs. (Local Gov, staff modification for process)

OR

100. Determine that resource plans should not accommodate local goals or policy preferences in a manner that shifts costs or burdens to other communities and their ratepayers. (LIUNA)

Comprehensive Gas IRP Requirements Document

101. Authorize the Executive Secretary to create a "Comprehensive Gas IRP Requirements" document which reconciles the gas IRP requirements established in the Framework Order filed March 27, 2024, and the additions and modifications to those requirements made above, and issue the document as an attachment to the Order. Delegate continuing authority to the Executive Secretary to update the Comprehensive Gas IRP Requirements document to reflect any future modifications or additions to the gas IRP requirements established in future Commission decisions, to be filed as an attachment to future orders establishing such changes. (Staff)

XVII. ATTACHMENT A. Framework Ordering Paragraphs and Proposed Clarifications

Para.	Framework Order	Stakeholder Recommendations
	OBJECTIVES AND SCOPE	
1	Name of proceeding (IRP)	
2	Objective of IRPs	
3	Resources considered in IRPs	
4	Scope of gas IRPs considers GHG reduction goals	• Consider consistent with Minn. Stat. §§ 216H.01 and 216H.02. • Use 2020 OR 2005 as the baseline year. • Consider lifecycle GHG emission factors from filed Natural Gas Innovation Act (NGIA) Plans.
	Xcel shall report on methane in gas IRP, not PBR	• All utilities report projected emissions from all resource portfolios. • Xcel report methane from distribution system using EPA protocol- would also give data on other GHGs. File with Annual Reports. • Xcel report upstream emissions- MJ Bradley or keep working on getting good data. • All utilities provide methane data. • Justify a chosen plan in terms of ability to reduce emissions.
5	Definition of gas IRP	
	GUIDELINES	
6	Gas IRP resources must be comparable.	Use a consistent methodology to calculate the “all-in” costs of resources to allow for an apples-to-apples comparison.
7	Gas IRP resources must include supply, demand, & infrastructure.	Recognize that some groups depend on gas or other types of fuel for cultural uses.
8	Factors used to compare resources in scenario analyses	
9	Use consistent methods to compare resources.	
10	Evaluate resources using US dollar and appropriate discount rates.	
11	Energy Efficiency must be included in resource analysis.	Utility integrated resource plans should evaluate energy efficiency achievement scenarios including expected program achievement to maximum achievement.

12	Clarify cost-effective level of Energy Efficiency procurement.	The appropriate and cost-effective level of future energy efficiency procurement shall correspond to the maximum program spending level that remains cost-effective when compared to [ALL] alternatives.
13	Energy Efficiency must be coordinated with ECO and NGIA.	Also coordinate with stakeholders, via GPI process, on the assumptions used for energy efficiency in natural gas IRPs.
14	Demand Response must be included in resource analysis.	Consider the role of demand in forecasts.
15	Utilities must address risk, price of all resources, and cost to comply with any regulation of greenhouse gas emissions.	• Use ECO values. • Use Minnesota Statute § 216H.06 values. • Include ECO adder 1.4% to Minnesota Statute § 216H.06 value. • Determine new values. • Process follows electric IRPs.
16	Address additional risk and uncertainty.	
17	Estimate environmental externality costs of resources.	• Use values established in Docket Number E999/CI-14-463. • Use CO2, CO2 equivalency factor from NGIA, or methane. • Consider lifetime or combustion values. • Include indoor air quality impacts. • Process follows electric IRPs.
18	Analyze all resources on integrated basis.	
19	Show chosen portfolio meets reliability objectives.	
20	Criteria Commission uses to evaluate IRPs	
	PROCEDURAL REQUIREMENTS (*includes new equity recommendations*)	
21	Utilities shall file gas IRPs every 3 years.	• Xcel files first, then CPE, and then MERC. • Plans are filed on October 1st. • Xcel files in 2026, CPE files in 2027 or 2028, MERC files one year later.
22	Gas IRPs must be publicly available.	• Build relationships with impacted communities. • Collaborate with local governments.
23	Stakeholders need not formally request intervention.	
24	IRPs will be an uncontested proceeding.	

25	Commission will ensure useful public meetings.	• Create a special comment process for impacted workers. • GPI facilitates an equity process and utility-specific work sessions. • Adopt public comment and meeting practices that center participants' needs.
26	Commission will approve, modify, and/or reject IRPs.	
27	Plans will be updated regularly, include public comment, allow validation, and be implemented.	
28	Commission gives plans conditional approval.	Clarify that "near-term" means next 5 years.
29	Utilities use existing cost recovery proceedings.	Grant utilities deferred accounting for IRP preparation costs.
30	Give annual update on any plan changes.	*Also listed above*- Xcel report methane from distribution system using EPA protocol- would also give data on other GHGs. File with Annual Reports.
31	Annual updates are informational only.	
32	Typical discovery procedures via Minn. R. 7843.0300.	
33	Parties may support a gas IRP or offer an alternative plan.	
34	File details of process and analysis.	
35	Explain why plan is in public interest.	
36	Provide a non-technical summary.	• Strike the word "electric." • Encourage gas-electric coordination.
RESOURCE PLAN COMPONENTS		
37	Describe the planning environment.	City climate policy collaboration and consideration.
38	Description of planning environment includes narrative review of past plan.	
39	Provide utility load and customer forecast.	• Involve stakeholders in forecasting. • Consider heating need.
40	Provide high, medium, and low load forecasts and assumptions.	• Align forecast with rate case sales forecast. • Include additional considerations in forecasts.
41	Disclose Design Day methodology.	Align forecast with design day forecast used in demand entitlement.
42	Give full resource list with characteristics, cost, environmental	

	impacts, and duration.	
43	Use existing cost recovery proceedings.	
44	Determine available resources by examining all supply & demand resources.	
45	Use High Med Low load scenarios.	
46	Use High Med Low price sensitivities.	
47	Include a significant supply-side disruption scenario.	
48	Provide additional scenarios/sensitivities as Commission requests.	Do not require analysis of any additional scenarios or sensitivities in the first resource plan filing.
49	Provide cost of scenarios & sensitivities as PVRR, environmental cost, & externalities.	
50	Each gas IRP should include a 10-year sales + emissions forecast; 5-year action plan	• Include justification of need, resource mix, project scope, construction timeline, cost estimates including any offsetting revenues and tax benefits, and a narrative discussion of any equity impacts the project may have. • Develop equity mapping component. • Show emissions in EJ communities.
	~~DISTRIBUTION SYSTEM~~ EXPANSION ALTERNATIVES ANALYSIS	
51	Incorporate infrastructure costs related to resource expansion or new resources above an investment threshold.	• Define infrastructure cost. • Set threshold & possible project cap. • Process for project "pool" and full analysis. • Include NGEP and co-located projects.
52	Analysis is named 'Expansion Alternatives Analysis (EAA).'	• Include a mapping component. • Prioritize the most vulnerable customers.
53	Gas IRPs include an alternatives analysis.	Work with impacted cities and community leaders to consider projects and do EAA.
54	Pick 2-3 projects for full EAA.	• Define capacity expansion project. • Give rationale for selecting projects. • Explain why projects were not chosen.
55	Investments to exclude from EAA.	
	ADDITIONAL EQUITY TOPICS	
NEW	*Equity throughout the IRP*	• Narrative on centering equity in the IRP • Impacts of distribution infrastructure changes.
NEW	*Workforce*	Equity should be enacted via workforce

		development and transition.
NEW	*Decommissioning Infrastructure*	Decommissioning trust funds should be established.
56	Next, work on rates in Future of Gas.	