



## ENVIRONMENTAL LAW & POLICY CENTER

Protecting the Midwest's Environment and Natural Heritage

May 7, 2024

Ms. Lisa Felice  
Michigan Public Service Commission  
7109 W. Saginaw Hwy.  
P. O. Box 30221  
Lansing, MI 48909

RE: MPSC Case No. U-21291

Dear Ms. Felice:

**Direct Testimony of Brad Cebulko on Behalf of The Ecology Center, The  
Environmental Law & Policy Center, Union of Concerned Scientists, and Vote  
Solar**

**Proof of Service**

Sincerely,

Daniel H. Abrams  
Environmental Law & Policy Center  
[dabrams@elpc.org](mailto:dabrams@elpc.org)

cc: Service List, Case No. U-21291

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Minneapolis, MN • Madison, WI • North Dakota • South Dakota • Washington, D.C.

**STATE OF MICHIGAN  
MICHIGAN PUBLIC SERVICE COMMISSION**

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In the matter of the application of <b>DTE GAS</b>	)	
<b>COMPANY</b> for authority to increase its	)	
rates, amend its rate schedules and rules	)	Docket No. U-21291
governing the distribution and supply of	)	
natural gas, and for miscellaneous accounting	)	
authority	)	

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**DIRECT TESTIMONY OF**

**Bradley Cebulko**

**ON BEHALF OF**

**THE ECOLOGY CENTER, THE ENVIRONMENTAL  
LAW & POLICY CENTER, UNION OF CONCERNED SCIENTISTS, AND VOTE  
SOLAR**

**May 7, 2024**

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1 **I. Introduction and Summary**

2 **Q: Please state your name and business address.**

3 A: My name is Bradley Cebulko. My business address is 24125 47th Ave SW, Vashon,  
4 Washington, 98070.

5 **Q. By whom are you employed and in what capacity?**

6 A. I am the founder of CEB Energy Consulting. CEB Energy Consulting provides technical,  
7 economic, and policy analysis to public interest organizations who participate in public  
8 utility commission proceedings.

9 **Q. On whose behalf are you submitting this direct testimony?**

10 A. I am submitting testimony on behalf of The Ecology Center, The Environmental Law &  
11 Policy Center, Union of Concerned Scientists, and Vote Solar, collectively referred to as  
12 the Clean Energy Organizations or CEO.

13 **Q. Please summarize your qualifications, experience, and education.**

14 A. I founded CEB Energy Consulting in March 2024. Previously, I was a Senior Manager at  
15 Strategen Consulting from 2021 to 2024. At Strategen, I led the gas transition practice, as  
16 well as provided analysis on other utility regulatory issues including line extension  
17 allowances, gas utility capital investment plans, alternative fuels, electric and gas long-  
18 term planning, gas utility decarbonization plans, and new regulatory business models. Prior  
19 to joining Strategen, I worked at the Washington Utilities and Transportation Commission  
20 (“UTC”) for eight years. From 2013-2016, I was an analyst with the UTC Commission  
21 Staff focused on electric and natural gas integrated resource planning (“IRP”), electric and  
22 natural gas energy efficiency programs, and new program design and implementation.

1 From 2016-2021, I was an advisor to the Washington State Commissioners, where I led  
2 Commissioners’ review of major filings and adjudications, natural gas general rate cases,  
3 purchase gas adjustments, rulemakings, and natural gas IRPs. From 2019 through 2020, I  
4 led the UTC’s rulemakings to implement Washington state’s Clean Energy Transformation  
5 Act.

6 **Q. Have you testified before the Michigan Public Service Commission previously?**

7 A. Yes. I testified on behalf of Michigan Environmental Council, NRDC, and Sierra Club in  
8 U-21148, Consumers Energy’s 2021 gas rate case.

9 **Q: Have you testified or provided comments in similar state regulatory proceedings?**

10 A: Yes. I have testified and provided comments before several Public Utility Commissions  
11 including in Illinois, Minnesota, Colorado, Massachusetts, Oregon, Washington state, and  
12 Connecticut. My resume and summary of qualifications are attached as Ex. CEO-1 and  
13 provide additional detail.

14 **Q. Are you sponsoring any exhibits?**

15 A. Yes. I am sponsoring the following exhibits:

- 16 • Exhibit CEO-1: Resume of Bradley Cebulko
- 17 • Exhibit CEO-2: DTE Response to CEODG-2.4j
- 18 • Exhibit CEO-3: DTE Response to CEODG-1.16
- 19 • Exhibit CEO-4: DTE Response to MNSCDG-2.1b
- 20 • Exhibit CEO-5: DTE Response to CEODG-1.27a
- 21 • Exhibit CEO-6: DTE Response to CEODG-1.24a
- 22 • Exhibit CEO-7: Brattle, “The Future of Gas Series Utilities Series, Transitioning Gas  
23 Utilities to a Decarbonized Future.” Part 1 of 3. August 21.
- 24 • Exhibit CEO-8: DTE Response to CEODG-2.1
- 25 • Exhibit CEO-9: DTE Response to CEODG-1.15a
- 26 • Exhibit CEO-10: DTE Response to CEODG-2.1a
- 27 • Exhibit CEO-11: Modification to DTE Response to CEODG-2.1a
- 28 • Exhibit CEO-12: DTE Response to CEODG-1.30a
- 29 • Exhibit CEO-13: DTE Response to CEODG-1.30b

- 1 • Exhibit CEO-14: DTE Response to CEODG-1.30c
- 2 • Exhibit CEO-15: DTE Response to CEODG-1.30d
- 3 • Exhibit CEO-16: DTE Response to CEODG-2.6c
- 4 • Exhibit CEO-17: DTE Response to CEODG-2.6d
- 5 • Exhibit CEO-18: DTE Response to CEODG-2.7b
- 6 • Exhibit CEO-19: DTE Response to CEODG-2.7c
- 7 • Exhibit CEO-20: DTE response to CEODG-2.8a
- 8 • Exhibit CEO-21: DTE Response to CEODG-2.8b
- 9 • Exhibit CEO-22: DTE Response to CEODG-2.8c
- 10 • Exhibit CEO-23: DTE Response to CEODG-2.9a
- 11 • Exhibit CEO-24: B. Cebulko, *A Regulators Blueprint for 21st Century Gas Utility*
- 12 *Planning* (December 2023)
- 13 • Exhibit CEO-25: R. Nelson, *Non-Pipeline Alternatives to Natural Gas Utility*
- 14 *Infrastructure, An Examination of Existing Regulatory Approaches*
- 15 • Exhibit CEO-26: DTE Response to CEODG-1.3a
- 16 • Exhibit CEO-27: DTE Response to CEODG-1.8c
- 17 • Exhibit CEO-28: DTE Response to CEODG-3.7a
- 18 • Exhibit CEO-29: DTE Response to CEODG-3.7b
- 19 • Exhibit CEO-30: DTE Response to CEODG-3.7c
- 20 • Exhibit CEO-31: DTE Response to CEODG-3.7d
- 21 • Exhibit CEO-32: DTE Response to CEODG-3.7e
- 22 • Exhibit CEO-33: DTE Response to CEODG-3.7f
- 23 • Exhibit CEO-34: DTE Response to CEODG-3.8a
- 24 • Exhibit CEO-35: DTE Response to CEODG-3.8b
- 25 • Exhibit CEO-36: DTE Response to MNSCDG-2.6d Gas DR Pilot Results Season 2
- 26 • Exhibit CEO-37: DTE Response to CEODG-3.12
- 27 • Exhibit CEO-38: DTE Response to CEODG-1.4a
- 28 • Exhibit CEO-39: DTE Response to CEODG-1.5a
- 29 • Exhibit CEO-40: DTE Response to CEODG-1.3c
- 30 • Exhibit CEO-41: DTE Response to MNSCDG-2.6d
- 31 • Exhibit CEO-42: DTE Response to MNSCDG-2.6d, Gas Demand Response Results-
- 32 Year 1
- 33 • Exhibit CEO-43: DTE Response to CEODG-4.1bi
- 34 • Exhibit CEO-44: DTE Response to CEODG-4.1di
- 35

36 **Q: What is the purpose of your testimony?**

37 A: The purpose of my testimony is threefold. First, I discuss the unreasonableness of DTE  
38 Gas' business-as-usual rate case filing in which the Company fails to consider evolving  
39 public policy and market trends. My primary concern is that the Company is not planning

1 to meet the state’s emissions reduction goals nor is it accounting for emergent building  
2 electrification as a long-term risk to investments the Company is making today. The  
3 Company’s approach is both costly and risky for customers. Second, I discuss DTE’s  
4 failure to develop and properly evaluate its demand response pilots and why the  
5 Commission should require DTE to repropose new demand response programs. Finally, I  
6 discuss the need for DTE Gas to incorporate the MiEJScreen mapping tool into its  
7 programmatic and investment decision-making processes to ensure that environmental  
8 justice communities experience equitable outcomes.

9 **Q. What are your recommendations to the Commission?**

10 A. In my testimony I make the following recommendations:

11 **Mitigating Cost and Risk in Capital Investment and Programmatic Decisions**

- 12 • I recommend the Commission order the Company to use its Gas Delivery Plan  
13 to model specific emissions reductions pathways for meeting the state’s  
14 decarbonization goals, and report the potential costs, benefits, and risks of the  
15 various resources and investments used in each pathway. The Company must  
16 also consider electrification as an available decarbonization resource. As part  
17 of its analysis, the Company should identify the customer rate impact of each  
18 pathway.
- 19 • I recommend the Commission order the Company to develop an interim plan  
20 that examines the decarbonization pathways either by July 2025 or with its next  
21 general rate case, whichever comes first.
- 22 • I recommend that the Commission require DTE to work with stakeholders and  
23 Commission Staff to develop a Nonpipeline Alternative (“NPA”) framework

1           for analyzing capital investment projects. I recommend that this framework  
2           identify the types of projects that are eligible and threshold criteria using best  
3           practices from across the industry. The Company should complete this  
4           framework by July 2025 or prior to filing its next general rate case, whichever  
5           comes first,

- 6           • I recommend the Commission require DTE to work with stakeholders and  
7           Commission Staff to develop a framework for considering when pipeline repair  
8           is a suitable alternative to pipeline replacement projects. The Commission  
9           should require the Company to demonstrate that it conducted this analysis for  
10          all capital projects that meet the identified pipeline repair criteria when it seeks  
11          cost recovery of the eligible capital investment. The Company should complete  
12          this framework by July 2025 or prior to filing its next general rate case,  
13          whichever comes first.

- 14          • I recommend that going forward, the Commission require DTE Gas to  
15          demonstrate the consideration of nonpipeline alternatives (“NPA”) and pipeline  
16          repair as a condition of recovering additional investments in all pipeline  
17          infrastructure. The Commission should hold DTE to this standard even while  
18          the Company is developing its NPA and repair frameworks.

19           **Demand Response Programs and Pilots Cost Recovery**

- 20          • I recommend the Commission reject the Company’s request to recover the \$2.6  
21          million in deferred demand response costs as the Company did not identify clear

1 objectives, identify reasonable evaluation criteria, nor develop and implement  
2 a robust set of pilots that tested the effectiveness of demand response.<sup>1</sup>

- 3 • I recommend the Commission order DTE to work with Commission Staff and  
4 stakeholders to develop a more robust set of demand response programs. The  
5 Company and parties should establish clear objectives for each pilot, identify  
6 which costs and benefits will be evaluated, and undergo a thorough third-party  
7 evaluation. The Company and other stakeholders should consider the  
8 development of interruptible programs as part of this undertaking. The  
9 Company should complete this work by July 2025 or prior to filing its next  
10 general rate case, whichever comes first.

11 **MiEJScreen and Equity**

- 12 • I recommend that the Commission order DTE Gas to use the MiEJScreen tool  
13 to inform the impact of its capital investment decisions on low income and  
14 environmental justice communities in its next rate case. The Commission  
15 should require the Company to discuss how it used MiEJScreen to inform its  
16 investments in testimony.
- 17 • I recommend that the Commission order DTE gas to use the MiEJScreen tool  
18 to inform the design and implementation of its customer programs and policies,  
19 including the Company’s energy efficiency and demand response programs,  
20 low-income energy efficiency and heating assistance programs, arrearage  
21 management programs, and residential disconnection policy in its next rate

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<sup>1</sup> HJD-83, lines 18-20.

1 case. The Commission should require the Company to discuss how it used  
2 MiEJScreen to inform its investments in testimony.

3 • I recommend the Company integrate the six additional metrics discussed below  
4 as part of its use of the MiEJScreen tool. I identify the specific metrics  
5 beginning on page 49 of my testimony.

6 **II. The Company’s Business-As Usual Approach is Costly and Risky for Customers in**  
7 **a Rapidly Changing Energy Landscape**

8 **Q: Will you please describe the policy and economic landscape in which the Company**  
9 **is filing this rate case?**

10 A: Yes. Society is undergoing a fundamental energy transition in which we are shifting away  
11 from fossil fuels and towards renewable forms of energy. The shift is primarily being  
12 driven by two factors: changing policy and changing economics. Various levels of  
13 governments are enacting policies that restrict greenhouse gas emissions and incentivize  
14 renewable forms of energy. In 2020, Michigan set a goal to achieve economy-wide  
15 carbon neutrality by 2050 and achieve net negative emissions thereafter.<sup>2</sup> The state set  
16 interim targets to reduce GHG emissions by 28% by 2025 and 52% by 2030.<sup>3</sup> On an even  
17 more local level for DTE, the city of Ann Arbor is evaluating a plan to replace gas  
18 distribution infrastructure with lower emission technologies like highly efficient electric  
19 appliances.<sup>4</sup>

20 Concurrently, the cost to transition to less carbon-intensive energy has plummeted  
21 in recent decades, most notably in the power generation sector. As I will explain later in

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<sup>2</sup> BV-49, lines 7 – 10.

<sup>3</sup> *Id.*

<sup>4</sup> BV-49, 7 – 10.

1 my testimony, we are seeing the emergence of highly efficient electric appliances for  
2 space and water heating. In some jurisdictions, all-electric new residential homes are  
3 already less expensive than new residential homes that use gas.<sup>5</sup>

4 **Q: Does DTE’s rate case reflect this shifting political and economic reality?**

5 DTE’s rate case does not reflect the changing landscape much less propose  
6 actions that will direct the Company down a path towards meeting the state’s emissions  
7 reduction goals. In fact, the Company does not have a plan to achieve the state’s  
8 emissions reduction goals. Moreover, the Company continues to invest in its delivery  
9 system as if it does not need to meet the state’s emissions reduction targets or with due  
10 consideration for the coming energy transition. This is costly and risky for customers.  
11 The Company is making capital investments today in new pipes that will be in rates for  
12 the next 40 to 65 years. Whether and to what extent the Company’s proposed investments  
13 are necessary must be more carefully examined.

14 To respond to the changing environment, the Company must take a different  
15 approach, and that means looking for opportunities to reduce its capital investment  
16 spending. The Company must show the Commission how its spending, particularly its  
17 capital expenditures, are reasonable considering the state’s emissions reduction goals and  
18 the larger energy transition. For example, I would expect when considering how to  
19 remedy a segment of leaky pipe, the Company’s decision-making process would involve  
20 consideration of alternatives to replacements that are cheaper for customers and which

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<sup>5</sup> Tan, L. et al, “The Economics of Electrifying Buildings: Residential New Construction. Rocky Mountain Institute. 2022. Available at: <https://rmi.org/insight/the-economics-of-electrifying-buildings-residential-new-construction/>

1 better align with the state’s emissions reductions goals. Unfortunately, the Company does  
2 not make that showing in this case.

3 **A. *The Company’s Rate Case Application Does Not Account for Risk Posed by the***  
4 ***State’s Emissions Reduction Goals and Emergent Building Electrification Will***  
5 ***Further Erode Customer Demand***

6 **Q: Why does the Company say it is filing this rate case?**

7 A: The Company is filing this rate case because it is forecasting a revenue shortfall of \$266  
8 million for the projected 2025 test year.<sup>6</sup> The forecasted shortfall includes \$106 million  
9 associated with an Infrastructure Recovery Mechanism (“IRM”) surcharge, which is  
10 currently included in customers’ bill. The IRM is set to expire at the end of 2024 and the  
11 Company is seeking to renew the program for the next five years.

12 **Q: Does the Company provide a forecast of capital investments?**

13 A: Yes. The Company identifies its 10-year capital plan in its Gas Delivery Plan (“GDP”).<sup>7</sup>  
14 The Company plans to spend an incremental \$764 million per year for the next 10 years  
15 for a total of \$8,407,600,000 by 2033.<sup>8</sup> As can be seen in Figure 1, the Company’s 10-year  
16 capital expenditure plan shows that the Company continues to increase the pace of capital  
17 expenditure investments.

18 *Figure 1: DTE Gas 10-Year Capital Plan (\$M) Figure 65<sup>9</sup>*

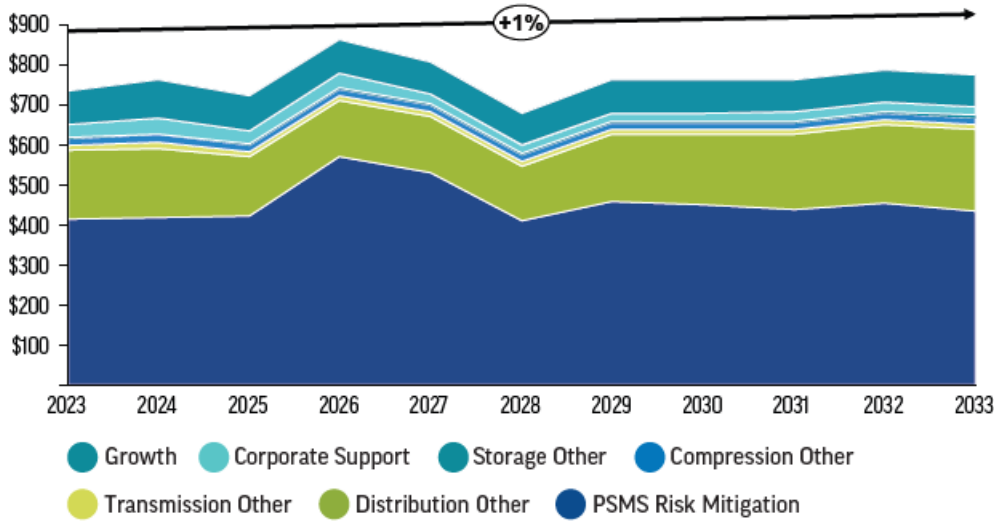
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<sup>6</sup> RMT-8, lines 1 – 11.

<sup>7</sup> Case No. U-21291, Exhibit A-12, Schedule B5.6, Page 68.

<sup>8</sup> CEO-2, DTE Response to CEODG-2.4j Figure 65 Data.

<sup>9</sup> Case No. U-21291, Exhibit A-12, Schedule B5.6, Page 68, Figure 65.



1

2 **Q: What is your concern with the Company’s pace and scope of its capital investment**  
 3 **plan?**

4 A: The Company’s capital investment plan is risky for three reasons. **First**, the Company’s  
 5 own projections, which do not account for any building electrification,<sup>10</sup> forecasts  
 6 declining customer demand.<sup>11</sup> All else equal, when capital investments increase but  
 7 demand decreases, customers rates will increase. **Second**, I am concerned that by not  
 8 considering the impact of building electrification on its future demand, customer rates will  
 9 increase more rapidly than anticipated. **Third**, the Company does not have a plan for  
 10 meeting the state’s emissions reduction targets. The Company’s case demonstrates that it  
 11 believes that it can continue to expand the gas delivery system indefinitely without making  
 12 any efforts towards meeting the state’s emissions reduction goals.

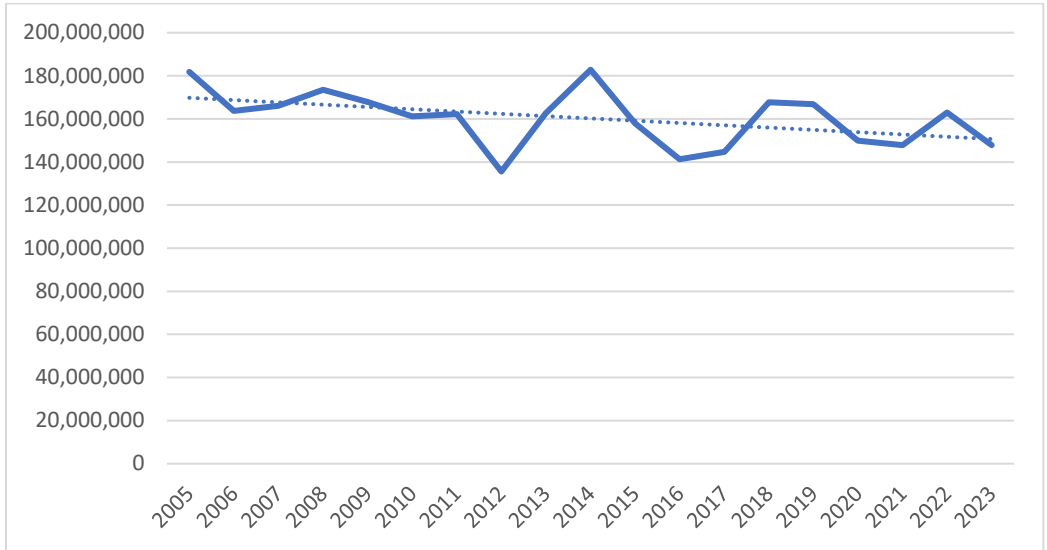
13 **Q: Let’s start with your first concern. Has customer demand increased or decreased in**  
 14 **the past 20 years?**

<sup>10</sup> CEO-3, DTE Response to CEODG-1.16.

<sup>11</sup> See Figure 2 below.

1 A: As shown in Figure 2 and 3 below, both the Company’s annual sales and peak demand  
2 have declined over the past 20 years.

3 *Figure 2: DTE Aggregate Gas Sales (MCF)<sup>12</sup>*

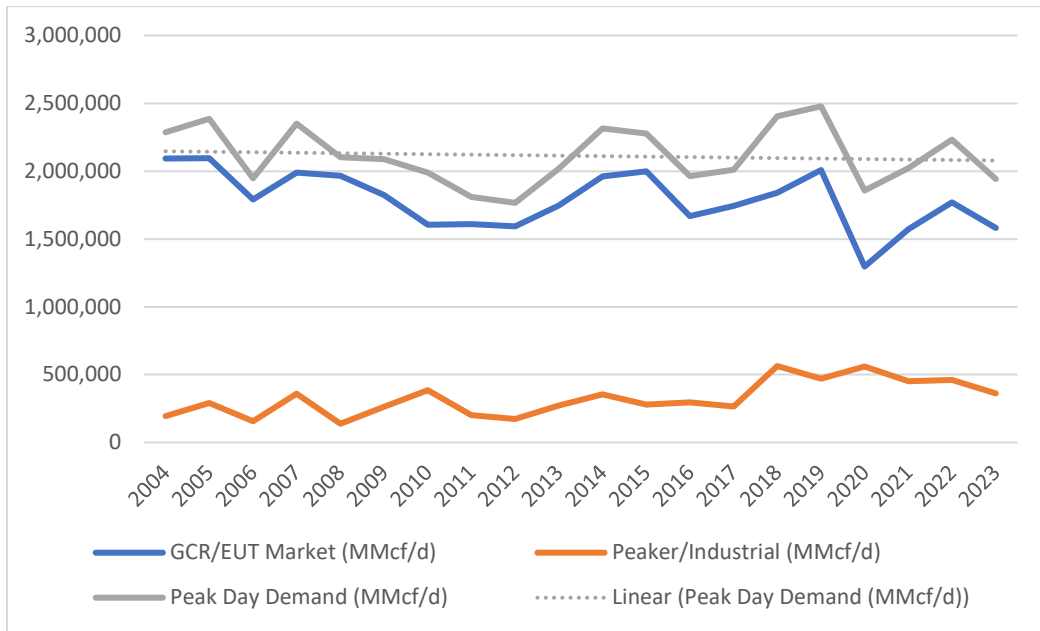


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<sup>12</sup> CEO-4, DTE Response to MNSCDG-2.1b.

1 *Figure 3: DTE's Actual Peak Demand 2004 – 2023 (MMcf/d)<sup>13</sup>*



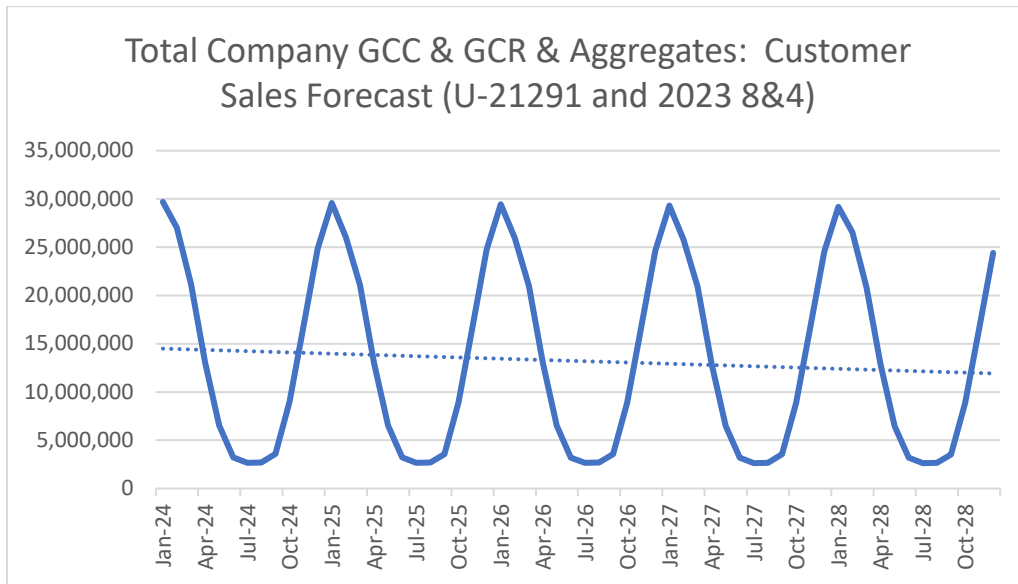
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3 **Q: Does the Company forecast increasing demand?**

4 A: No. As shown in Figure 4, the Company is forecasting annual demand decreases through  
 5 at least 2028. Although the Company is expecting to continue to add new customers to the  
 6 system, use-per-customer (“UPC”) is expected to continue to decrease. The net impact is a  
 7 decrease in annual and peak demand.

<sup>13</sup> CEO-5, DTE Response to CEODG-1.27a.

1 *Figure 4: Total Company (GCC & GCR) Customer Sales Forecast<sup>14</sup>*



2

3 **Q: Why is it relevant that the Company is forecasting declining demand?**

4 A: The Company is planning on investing hundreds of millions of dollars into its gas delivery  
5 system over the next 10 years. Concurrently, the Company is forecasting declining demand.  
6 All else equal, when the Company increases its investments in its delivery system, but  
7 demand declines, customer rates must increase. This is because a portion of the fixed costs  
8 of the gas delivery system is recovered through the variable charge. As fixed costs are  
9 spread over fewer and fewer therms, the cost per therm goes up. Ultimately, low-income  
10 customers bear a disproportionate burden of the increasing rates.

11 **Q: Why are low-income customers disproportionately impacted by increasing rates?**

12 A: By definition, low-income customers have less disposable income and therefore the impact  
13 of increasing gas bills is more acutely felt and experienced. Moreover, low-income  
14 customers are less capable of taking actions to reduce their energy bills. Low-income

<sup>14</sup> CEO-6, DTE Response to CEODG-1.24a.

1 customers have less access to capital to invest in weatherization or energy efficiency  
2 measures and are more likely to be renters<sup>15</sup> and therefore have less ability to, or control  
3 over decisions to, invest in weatherization or energy efficient appliances. Moreover,  
4 middle- and high-income customers, because they have more access to capital, are more  
5 likely to be able to afford high efficiency gas, or electric appliances As middle and high-  
6 income customers reduce their reliance on gas, the costs of operating the gas system will  
7 be disproportionately borne by those least likely to electrify: low-income customers.

8 **Q: Let’s turn to your second concern. Is there a risk that demand will further erode in**  
9 **the future?**

10 A: Yes, I expect gas demand will further erode primarily due to cost-effective building  
11 electrification and decarbonization policies. To start, there have been substantial  
12 improvements in heat pump technology and costs, particularly for cold climate heat pumps.  
13 In 2021, the US Department of Energy (“DOE”) launched a Residential Cold Climate Heat  
14 Pump Challenge to develop more efficient cold climate heat pumps. In November 2022,  
15 Trane, a heat pump manufacturer, announced that its newest prototype exceeded DOE  
16 targets by performing at temperatures as low as -23 degrees Fahrenheit.<sup>16</sup> A 2022 study

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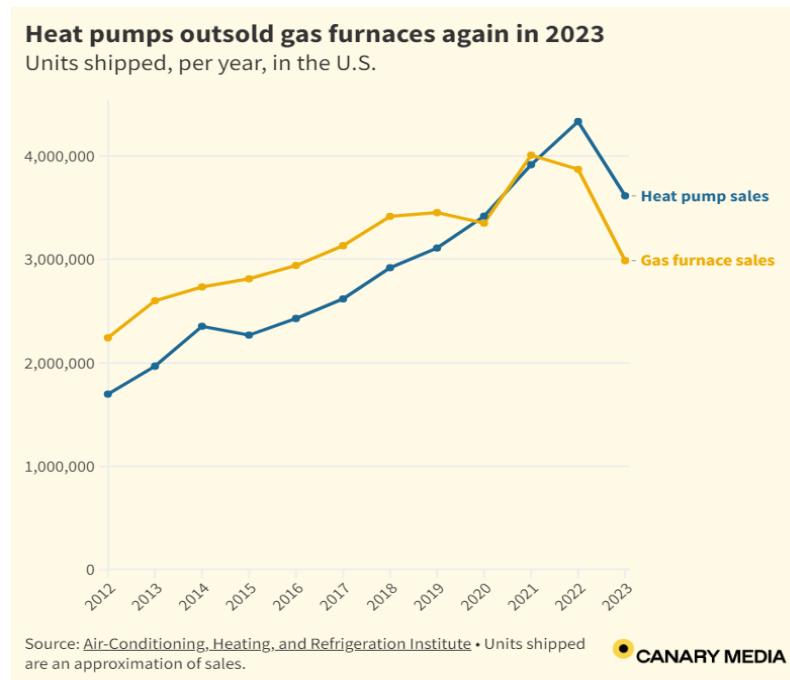
<sup>15</sup> United States Census Bureau, “Low-Income Renter Spent Larger Share of Income on Rent in 2021.” Available at: <https://www.census.gov/library/stories/2023/03/low-income-renters-spent-larger-share-of-income-on-rent.html#:~:text=Renters%20Household%20Incomes%20Lower%20Than%20Homeowners&text=Renter%20Occupied%20households%20made%20up,were%20in%20renter%20occupied%20units>.

<sup>16</sup> *Trane Passes Heat Pump Challenge*, Cooling Post (Nov. 4, 2022). Available at: <https://www.coolingpost.com/world-news/trane-passes-heat-pump-challenge/>.

1 found that all electric, single-family new construction is cheaper to build and operate than  
2 a home with gas appliances in all nine cities studied.<sup>17</sup>

3 Customers are taking notice. As shown in Figure 5, electric heat pumps have now  
4 outsold gas furnaces two years in a row. These data do not account for the impact of the  
5 Inflation Reduction Act, which should help further accelerate the adoption of electric  
6 appliances through the program’s generous appliance rebates and tax incentives.<sup>18</sup>

7 *Figure 5: Sales of Heat Pumps and Gas Furnaces from 2012 – 2023<sup>19</sup>*



8

9

<sup>17</sup> Tan, L. et al, “The Economics of Electrifying Buildings: Residential New Construction. Rocky Mountain Institute. 2022. Available at: <https://rmi.org/insight/the-economics-of-electrifying-buildings-residential-new-construction/>

<sup>18</sup> Beginning in 2023, state programs offer low- and moderate-income households’ rebates for heat pumps at the point-of-sale, cutting costs of purchase and installation up to \$8,000. If home electrical upgrades are needed to integrate new heat pumps, rebates of up to \$4,000 are available to households. See <https://www.whitehouse.gov/cleanenergy/>.

<sup>19</sup> Takemura, Alison. “Heat pumps outsold gas furnaces again last year – and the gas is growing” Canary Media. February 13, 2024. Available at :<https://www.canarymedia.com/articles/heat-pumps/heat-pumps-outsold-gas-furnaces-again-last-year-and-the-gap-is-growing>.

1 **Q: Now let’s turn to your third concern, that the Company does not have a plan for**  
2 **achieving the state’s emissions reduction goals. Please explain why you expect**  
3 **decarbonization policy to lead to a decline in demand for natural gas?**

4 A: Leading industry studies and state climate plans consistently identify building  
5 electrification as a critical component of a decarbonization pathway. In Michigan, the MI  
6 Healthy Climate Plan states that decarbonizing buildings will require evaluation and  
7 adoption of innovative home heating alternatives, including electrification.<sup>20</sup> The Plan  
8 further identifies a key strategy for meeting building decarbonization to include updates to  
9 building codes.

10 **Q: Is Michigan’s finding that building electrification will be a critical component of a**  
11 **decarbonization pathway consistent with findings from other states?**

12 A: Yes. The MI Healthy Climate Plan is consistent with other state decarbonization studies  
13 and investigations. In Illinois, Ameren hired the Electric Power Research Institute  
14 (“EPRI”) to study the impact of electrification on its system. As shown in Figure 6, the  
15 EPRI study found that in every scenario of the future it examined, efficient electrification  
16 would result in gas throughput declines from 18% to 40% from 2015 to 2050.<sup>21</sup> In  
17 particular, the study identified residential gas throughput in Ameren Illinois’s service  
18 territory declining between 38% and 56% from 2015 to 2050.<sup>22</sup>

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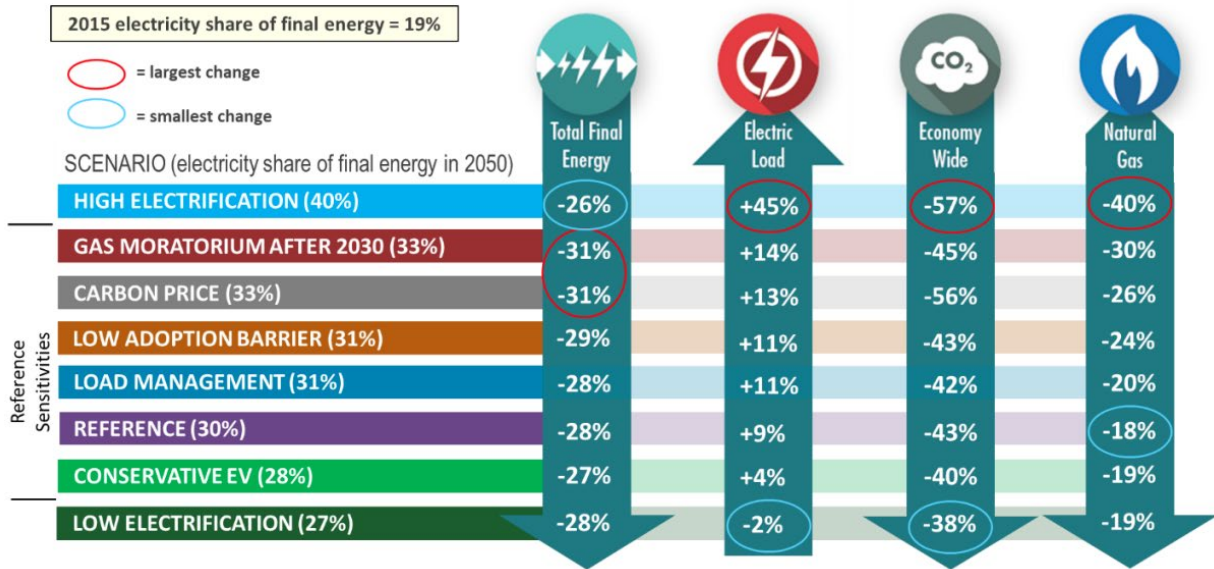
<sup>20</sup> MI Healthy Climate Plan at 41. <https://www.michigan.gov/egle/-/media/Project/Websites/egle/Documents/Offices/OCE/MI-Healthy-Climate-Plan.pdf?rev=d13f4adc2b1d45909bd708cafccbffa>

<sup>21</sup> Illinois Commerce Commission, Docket 23-0067, Ameren Illinois Company 2023 Gas Rate Case. PIO Exhibit 3.1REV. Available at: <https://www.icc.illinois.gov/docket/P2023-0067/documents/340150>

<sup>22</sup> *Id.* at 11.

1

Figure 6: EPRI Electrification Scenarios for Ameren Illinois<sup>23</sup>



2

3

4 In Massachusetts, the Massachusetts Department of Public Utilities (“DPU”)

5 issued its finding from its Investigation into the role of Gas Local Distribution

6 Companies for meeting the Commonwealth’s 2050 climate goals.<sup>24</sup> In its Order, the DPU

7 found that building electrification is necessary to achieve state policy goals, that gas

8 utilities have a role to play in facilitating building electrification, and that the state needs

9 to modify its line extension policy. In Connecticut, the Connecticut Department of

10 Energy & Environmental Protection (“DEEP”) stated that electrification must be the

11 dominant form of energy for building heat, writing that to “achieve the long-term vision

12 of a zero-carbon economy, widespread electrification of building thermal loads and the

13 transportation sector is required. By 2050 electricity must become the dominant form of

<sup>23</sup> *Id.*

<sup>24</sup> Ma. Dep’t of Public Utilities, Docket 20-80 (Dec. 6, 2023), available at: <https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/18297602> (last visited Apr. 17, 2024).

1 energy consumed in Connecticut, and the cornerstone of the state’s carbon-free economy  
2 will be decarbonization of the electric power sector.”<sup>25</sup>

3 **Q: Throughout this testimony you have discussed the risk that building electrification**  
4 **will lead to a decline in customer demand. Are you suggesting that building**  
5 **electrification will lead to full electrification of the building sector?**

6 A: Not necessarily, but more to the point, I think focusing on the end state – to what extent  
7 electrification will diminish gas demand – is misplaced. Even modest levels of building  
8 electrification would lead to a decline in customer demand and therefore substantial rate  
9 increases for remaining gas customers, which could lead to a cycle of further  
10 incentivizing additional electrification.

11 In 2021, Brattle published its “Future of Gas” series that identified the risks and  
12 opportunities of the energy transition for gas utilities. Brattle discussed its concern for a  
13 “death spiral” that results from gas utilities seeking to recover increasing capital  
14 expenditures from a shrinking customer base.<sup>26</sup> Brattle forecasted that “at the current  
15 pace, the number of homes with electric space heating could surpass homes with gas  
16 space heating by 2032.”<sup>27</sup> The Brattle report also found that “infrastructure is at risk of  
17 being stranded” and gas “utilities need to minimize stranded asset risk.”<sup>28</sup> The report then

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<sup>25</sup> Connecticut Department of Energy and Environment. Comprehensive Energy Strategy (2018). Page 10. Available at: <https://portal.ct.gov/-/media/DEEP/energy/CES/2018ComprehensiveEnergyStrategypdf.pdf>

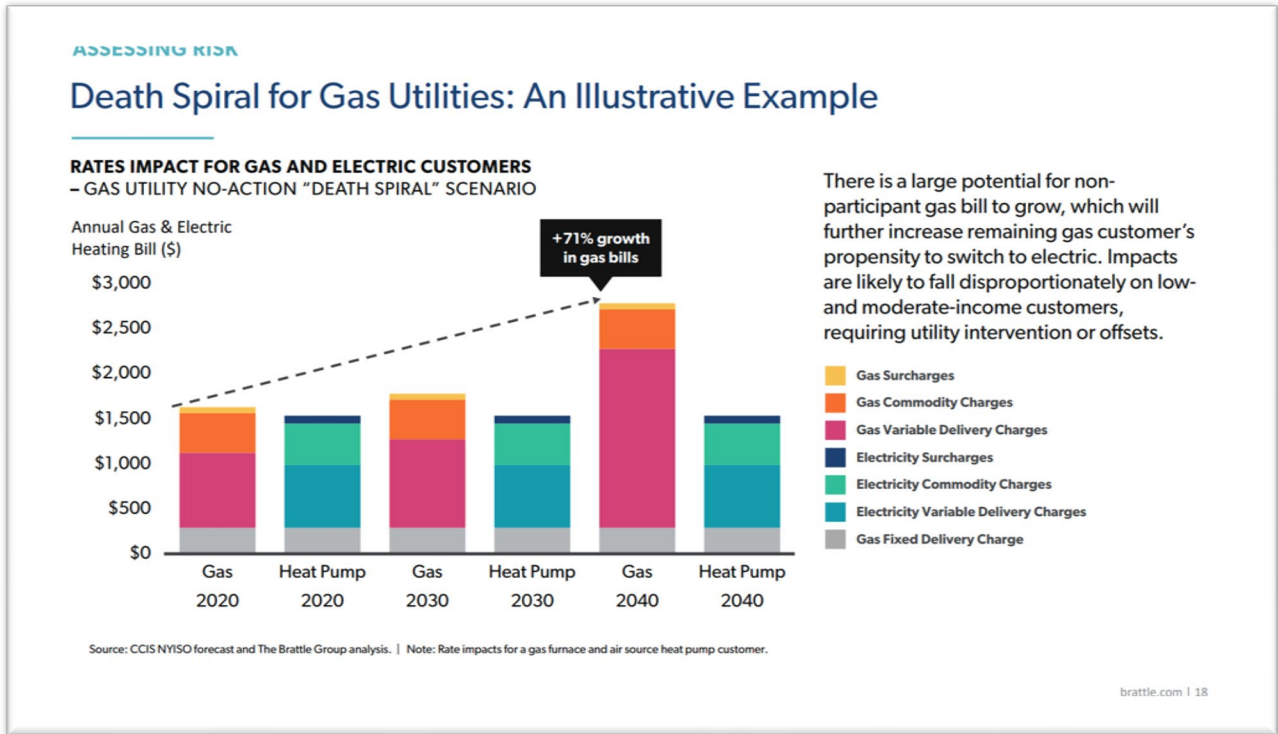
<sup>26</sup> CEO-7, Brattle, “The Future of Gas Series Utilities Series, Transitioning Gas Utilities to a Decarbonized Future.” Part 1 of 3. August 21. Available at: [https://www.brattle.com/wp-content/uploads/2022/01/The-Future-of-Gas-Utilities-Series\\_\\_Part-1.pdf](https://www.brattle.com/wp-content/uploads/2022/01/The-Future-of-Gas-Utilities-Series__Part-1.pdf).

<sup>27</sup> *Id.*

<sup>28</sup> *Id.*

1 suggested that commissions and utilities should be examining alternative depreciation  
2 schedules to ensure full recovery of gas investments.<sup>29</sup>

3 *Figure 7: Brattle The Future of Gas Utilities Series*



4  
5 The risk to DTE Gas and its customers, particularly low-income customers, is  
6 very real, and the Company should be assessing that risk in its decision making. Either  
7 increasing building electrification or emissions reduction requirements would have a  
8 substantial impact on the utility’s current business model. The utility should be adjusting  
9 its business decisions to reflect the present opportunities and risks.

10 **Q: Is DTE accounting for the risk of building electrification in its load forecast or**  
11 **capital investment decisions?**

<sup>29</sup> *Id.*

1 A: No. The Company states that it does not include the impacts of building electrification on  
2 its demand forecast as there is too much uncertainty related to the adoption of  
3 electrification technologies to accurately forecast.<sup>30</sup> Moreover, the Company has not  
4 conducted a study or analysis of the impacts of building electrification in its service  
5 territory.<sup>31</sup>

6 **Q: Is the Company’s position reasonable?**

7 A: No, the Company’s refusal to assess the potential impact of building electrification on its  
8 business is unreasonable and exposes its customers to too much risk. Although the  
9 Company recognizes building electrification may have an impact on its gas system, the  
10 Company argues that it is “premature to speculate” on what those impacts may be.<sup>32</sup> The  
11 Company continues that it is unwilling to consider building electrification in its demand  
12 forecast, writing, “[a]s stated previously, there is too much uncertainty related to the  
13 adoption of electrification technologies to accurately forecast. To date, the Company has  
14 not seen any impact of electrification and therefore does not include it in current  
15 forecasts.”<sup>33</sup> The Company’s position that it cannot assess the potential impact of building  
16 electrification due to uncertainty is not a neutral position – rather, it is an assumption that  
17 there will be no impact of building electrification. It is a failure to plan for the future and  
18 justifying that failure by arguing that planning is too difficult.

19 The Company is making decisions today about capital investments that customers  
20 will be paying for decades to come. The Company cannot wait for certainty about

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<sup>30</sup> CEO-3, DTE Response to CEODG-1.16.

<sup>31</sup> CEO-8, DTE Response to CEODG-2.1.

<sup>32</sup> CEO-9, DTE Response to CEODG-1.15a.

<sup>33</sup> CEO-3, DTE Response to CEODG-1.16.

1 building electrification to assess its potential impact as it is impossible to achieve  
2 certainty. It is necessary for any business, including a utility, to assess its uncertain  
3 planning environment and make decisions without complete knowledge of the future. No  
4 business can predict the future but every business, especially utilities with a captive  
5 customer base, must properly plan for the future using the best information available to it  
6 now.

7 In fact, the Company has developed processes for addressing uncertainty in other  
8 area of the business. For example, the Company mitigates the impact of commodity price  
9 volatility during the winter season by purchasing the bulk of its winter gas supply during  
10 the summer and making use of financial hedging.<sup>34</sup> Moreover, the Company has a  
11 planning process, the DTE Gas Delivery Plan, it could use to assess the potential impacts  
12 of building electrification on its system and to customer rates. Because the Company did  
13 not consider likely impacts of building electrification in its analysis, the load forecast and  
14 capital investment plan are likely inflated.

15 ***B. DTE Does Not Have a Plan for Achieving Emissions Reduction Goals***

16 **Q: What are Michigan’s emissions reductions goals?**

17 A: The State has a goal to achieve economy-wide carbon neutrality by no later than 2050,  
18 with interim targets to reduce greenhouse gas emissions by 28% by 2025 and 52% by  
19 2040.<sup>35</sup>

20 **Q: Does DTE have emissions reduction goals?**

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<sup>34</sup> Exhibit A-12, Schedule B5.6. DTE Gas Delivery Plan, p. 9 and 32.

<sup>35</sup> BV-49, lines 7- 10.

1 A: Yes. The Company issued a press release in 2020 stating its commitment to reduce  
2 greenhouse gas emissions from its own operations and its suppliers to “net zero by 2050,”  
3 as well as reduce greenhouse gas emissions from the combustion of gas at customer end-  
4 use by 35% by 2050 (from 2005).<sup>36</sup> However, despite this press release and the  
5 Company’s claim that “[d]ecarbonization and the reduction of greenhouse gas emissions  
6 is an increasing priority within the energy industry in totality and gaining momentum in  
7 the gas industry,” the Company has no plans for actually achieving these goals.<sup>37</sup>

8 **Q: What are DTE’s current level of emissions as compared to its baseline 2005**  
9 **emissions?**

10 A: DTE Gas reports that its gas consumption emissions were 7,969,415 metric tons of CO<sub>2</sub>e  
11 in 2023.<sup>38</sup> This is a 21% reduction from the Company’s 2005 emissions of 10,081,350  
12 metric tons of CO<sub>2</sub>e.<sup>39</sup> Based on the Company’s data, the decrease in emissions is  
13 entirely explained by the decline in demand for natural gas. In fact, the Company is  
14 already more than halfway to its goal without taking *any* proactive action. DTE Gas’s  
15 demand has declined by an average of 1.3% from 2005 to 2023. If demand were to  
16 continue to decline by 1.3% per year, the Company would achieve its goal to reduce  
17 emissions 35% by 2038 without taking any action at all.<sup>40</sup>

18 Moreover, as CEO witness Saad Siddique further explains, despite having a “net-  
19 zero by 2050” goal for upstream and operational emissions, the Company does not have

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<sup>36</sup> HJD-36, lines, 3 – 7.

<sup>37</sup> *Id.*

<sup>38</sup> CEO-10, DTE Response to CEODG-2.1a.

<sup>39</sup> *Id.*

<sup>40</sup> CEO-11, Modification to DTE Response to CEODG-2.1a.

1 baseline emissions for either sector. The Company’s “net zero by 2050” goal, at this time,  
2 is meaningless and incalculable.

3 **Q: You state that DTE may achieve its 35% emissions reduction goal for end-use**  
4 **combustion by 2038 without taking any action. Do you believe that the Company**  
5 **should set a more ambitious target?**

6 A: Yes. If DTE believes that “[c]limate change is one of the defining public policy issues of  
7 our time and it demands a bold response,”<sup>41</sup> as the Company testifies, then the Company  
8 should commit itself to a bold target and develop a public plan for achieving that target. At a  
9 minimum, the Company should commit itself to reduce end-use combustion emissions to net-  
10 zero by 2050, which is aligned with the state’s emissions reduction goals.

11 **Q: Why do you say that DTE does not have a plan for emissions reductions?**

12 A: Through discovery I asked the Company for reports, documents or other analysis that  
13 demonstrates the Company’s plans for meeting its commitment to reduce greenhouse gas  
14 emissions from its upstream suppliers, own operations, and customer end use. The  
15 Company responded in each case that it has not identified pathways to achieve the DTE  
16 Gas emission reduction goals and that the Company’s plans remain indeterminate due to  
17 the uncertainty, cost, and feasibility of technology deployment.<sup>42</sup> It seems the Company  
18 does not know how it will achieve its goal in part because the Company has not  
19 conducted basic analysis into key inputs and assumptions. For example, although the

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<sup>41</sup> HJD-36, lines 11 – 12.

<sup>42</sup> Ex. CEO-12, DTE Responses to CEODG-1.30a; Ex. CEO-13, DTE Responses to CEODG-1.30b; Ex. CEO-14, DTE Responses to CEODG-1.30c; Ex. CEO-15, DTE Responses to CEODG-1.30d

1 Company writes that it intends to use advanced technologies such as RNG, hydrogen, and  
2 gas heat pumps to reduce customer use emissions by 35% by 2040, the Company has not:

- 3 • performed a pricing analysis for the future price of RNG,<sup>43</sup>
- 4 • forecasted the percentage of the Company’s emissions reductions that can be  
5 achieved through the use of RNG,<sup>44</sup>
- 6 • performed a pricing analysis on the cost of green hydrogen,<sup>45</sup>
- 7 • forecasted what percentage of the Company’s emissions reductions can be  
8 achieved through the use of clean hydrogen,<sup>46</sup>
- 9 • forecasted annual gas heat pump deployment,<sup>47</sup>
- 10 • performed a pricing analysis of gas heat pumps,<sup>48</sup>
- 11 • forecasted the percentage of the Company’s emissions reduction that can be  
12 achieved through the use of gas heat pumps, and<sup>49</sup>
- 13 • established interim targets for reducing customer end-use emissions 35% by  
14 2040.<sup>50</sup>

15 DTE’s lack of a plan is problematic. The Company intends to continue its business-as  
16 usual pace of capital investments without considering the impact of achieving state  
17 emissions reduction goals, its own corporate goals, or how those investments will impact  
18 customer rates. The Company has not developed critical information for its own decision-

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<sup>43</sup> CEO-16, DTE Response to CEODG-2.6c.

<sup>44</sup> CEO-17, DTE Response to CEODG-2.6d.

<sup>45</sup> CEO-18, DTE Response to CEODG-2.7b.

<sup>46</sup> CEO-19, DTE Response to CEODG-2.7c.

<sup>47</sup> CEO-20, DTE Response to CEODG-2.8a.

<sup>48</sup> CEO-21, DTE Response to CEODG-2.8b.

<sup>49</sup> CEO-22, DTE Response to CEODG-2.8c.

<sup>50</sup> CEO-23, DTE Response to CEODG-2.9a.

1 making or for policymakers to understand how the Company can cost-effectively reduce  
2 its emissions and the future costs and risks it is imposing on customers from its  
3 investments today. The Company’s Gas Delivery Plan is an ideal place for the Company  
4 to consider potential pathways and future energy scenarios.

5 ***C. How DTE Can Better Use its Gas Delivery Plan for Emissions Reduction and***  
6 ***Capital Investment Planning***

7 **Q: What is the DTE Gas Delivery Plan?**

8 A: The DTE Gas Delivery Plan (“GDP”) is the Company’s 10-year demand and supply plan.<sup>51</sup>  
9 DTE writes that the purpose of the GDP is to “allow the Company to manage the top  
10 industry risks while meeting its objectives of providing safe, reliable, affordable, and  
11 environmentally responsible natural gas service.”<sup>52</sup> In its plan, DTE identifies the top  
12 industry risks as gas supply and deliverability, transmission pipeline failures, distribution  
13 gas leaks, system overpressure, storage well unintended gas release, cyber/physical  
14 security, and excavation damage.<sup>53</sup>

15 While I agree that each of those risks are important, the Company notably left out  
16 risks associated with two of its four objectives: affordability and environmentally  
17 responsible natural gas service. The Company does not use its GDP to explore how  
18 variables both within and outside its control could impact customer affordability and meet  
19 its emissions goals. Gas and electric utilities across the country use demand- and supply  
20 plans like the GDP to assess the optimal mix of resources and investments in various

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<sup>51</sup> Exhibit A-12, Schedule B5.6, DTE Gas Delivery Plan

<sup>52</sup> *Id.* at 6.

<sup>53</sup> *Id.* at 5.

1 futures using scenario and sensitivity analysis. Through its GDP, DTE should be exploring  
2 the potential impact of electrification on its demand through scenario and sensitivity  
3 analysis. No person or utility can predict the future. A scenario is a set of assumptions  
4 about variables within or outside the control of the utility about the future. A sensitivity is  
5 a modification of a single variable of a specific scenario to test the impact of that variable  
6 on the outcome of the future. Scenario and sensitivity analysis is important for helping the  
7 Company and policymakers understand the costs, emissions, and risks of various uncertain  
8 futures. For example, the Company could conduct analysis on the impacts to customer rates  
9 of various prices of alternative fuels, impacts of different levels of building electrification,  
10 as well as different levels of capital investment spending.<sup>54</sup>

11 **Q: Can you provide an example of a gas utility assessing the impact of electrification**  
12 **and decarbonization pathways in a demand- and supply-plan?**

13 A: Yes. Consumers Energy annually releases its own Natural Gas Delivery Plan. In its most  
14 recent Delivery plan, Consumers Energy explored the relative costs and benefits of various  
15 decarbonization pathways, as well as the potential pipeline composition in 2050 by  
16 scenario.<sup>55</sup> While I am not endorsing the specific inputs nor outcomes of Consumers  
17 Energy’s Natural Gas Delivery Plan, it is worth noting that Consumers Energy is using its  
18 Plan to better understand how it can manage customer costs and risks in an uncertain future.

19 **Q: What is your recommendation as it relates to using the Company’s Gas Delivery**  
20 **Plan for assessing costs and risks to customers?**

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<sup>54</sup> Ex. CEO-24, B. Cebulko, *A Regulators Blueprint for 21st Century Gas Utility Planning* (December 2023).

<sup>55</sup> <https://www.consumersenergy.com/-/media/CE/Documents/company/What%20We%20Do/consumers-energy-natural-gas-delivery-plan.pdf>

1 A: I recommend the Commission order the Company to use its Gas Delivery Plan to model  
2 specific emissions reductions pathways for meeting the state’s decarbonization goals, and  
3 report the potential costs, benefits, and risks of the various resources and investments used  
4 in each pathway. The Company must consider electrification as an available  
5 decarbonization resource. As part of its analysis, the Company should identify the customer  
6 rate impact of each pathway. I recommend the Commission order the Company to develop  
7 an interim plan by July 2025 that examines the decarbonization pathways or with its next  
8 general rate case, whichever comes first.

9 **Q: Where else, besides the Gas Delivery Plan, should DTE account for the risks of**  
10 **electrification?**

11 A: The Company should also account for the risks of the energy transition when making any  
12 capital investment decision, both investments that appear in the Gas Delivery Plan and  
13 those that emerge outside of the Gas Delivery Plan. As any business facing an uncertain  
14 future, the gas utility should account for risks outside its control when making business  
15 decisions. The Company should be examining alternatives when making capital  
16 investments, particularly for pipeline replacements and capacity expansions. The two most  
17 common types of alternatives are pipeline repairs and non-pipeline alternatives.

18 **Q: What are pipeline repairs?**

19 A: Cutting out and replacing a segment of pipe is expensive. Pipeline repair is the process by  
20 the gas utility repairs rather than replaces a segment of pipe. There are a variety of methods  
21 for repairing a natural gas pipeline. For example, one repair method is to wrap the leaking

1 segment of pipe with a “sleeve.”<sup>56</sup> Repairing, rather than replacing the segment of pipe,  
2 can be quite cost-effective. A 2023 study conducted by Gas Safety USA, submitted to the  
3 Public Service Commission of the District of Columbia on behalf of the District of  
4 Columbia Government, found that pipeline repair can cost between one tenth and one  
5 hundredth of the cost of pipeline replacement.<sup>57</sup> Repairs can safely extend the serviceable  
6 lives of the existing pipe without making an additional investment in new pipe that can  
7 have a depreciable life of 40 to 65 years.

8 **Q: What are nonpipeline alternatives?**

9 A: NPAs in the gas sector are the equivalent of the electric sector’s “non-wires alternatives”  
10 and refer to activities or investments that delay, reduce, or avoid the need to build or  
11 upgrade traditional gas system infrastructure such as pipelines, storage, and peaking  
12 resources.<sup>58</sup> An NPA can consist of a single demand- or supply-side resource, but more  
13 often it is a portfolio of resources. The specific costs and benefits of NPA opportunities  
14 depend on the nature of the utility’s pipeline system, capacity needs, types of customers,  
15 and policy goals. Typical NPA resources include demand response, energy efficiency,  
16 electrification of heat, behavioral programs, and on-system gas supply, such as compressed  
17 or liquified natural gas. NPAs can help achieve several policy goals including cost  
18 reductions, risk reductions, and emissions reduction.

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<sup>56</sup> <https://pgjonline.com/news/2020/12-december/appropriate-methods-for-repairing-pipelines>

<sup>57</sup> Ackley, B. et al, “Strategic Electrification in Washington, D.C.: neighborhood Case Studies of Transition from Gas to Electric-Based Building Heating. For the Washington, D.C., Department of Energy and Environment.” December 14, 2022. Available at: <https://edocket.dcpsec.org/apis/api/Filing/download?attachId=186471&guidFileName=a9254ec8-d08f-46ed-af0e-31b28d707139.pdf>

<sup>58</sup> Ex. CEO-25; Nelson, R. et al, “Part 1 | Non-Pipeline Alternatives to Natural Gas Utility Infrastructure, An Examination of Existing Regulatory Approaches” A Strategen Report prepared for the Lawrence Berkeley National Laboratory.

1 **Q: Are other states requiring gas utilities to examine nonpipeline alternatives to**  
2 **traditional capacity investments?**

3 A: Yes. Most recently, the Massachusetts Department of Public Utilities completed its Future  
4 of Gas investigation and identified NPA analysis as a requirement for all capital  
5 investments going forward. The DPU found that “[g]oing forward, [local distribution  
6 companies] will have the burden to demonstrate the consideration of NPAs as a condition  
7 of recovering additional investment in pipeline and distribution mains.”<sup>59</sup> Several other  
8 states have required NPA analysis for certain capital projects. For example, in Colorado,  
9 gas utilities are required to conduct NPA analysis for all capacity expansion and new  
10 business projects over \$3 million.<sup>60</sup> Rhode Island set a cost threshold at \$0.5 million.<sup>61</sup>  
11 New York did not set a specific threshold, rather it created separate small and large project  
12 thresholds for each gas distribution company (typically greater or less than \$2 million).<sup>62</sup>  
13 In Oregon, Avista agreed through a rate case settlement to conduct NPA analysis on all  
14 capital investment projects over \$1 million.<sup>63</sup>

15 **Q: What is your recommendation as it relates to alternatives analysis, namely pipeline**  
16 **repair and nonpipeline alternatives?**

17 A: I recommend that the Commission require DTE to work with stakeholders and Commission  
18 Staff to develop an NPA framework for analyzing capital investment projects going

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<sup>59</sup> DPU 20-80.

<sup>60</sup> Ex. CEO-25.

<sup>61</sup> *Id.*

<sup>62</sup> *Id.*

<sup>63</sup> Oregon Public Utilities Commission Docket No. UG 461, Order No. 23-384. October 26, 2023. Available at: <https://apps.puc.state.or.us/orders/2023ords/23-384.pdf>

1 forward. I recommend that this framework identify the types of projects that are eligible  
2 and threshold criteria using best practices from across the industry.<sup>64</sup> The Commission  
3 should require the Company to demonstrate that it conducted this analysis for all capital  
4 projects that meet the identified NPA criteria when it seeks cost recovery of that capital  
5 investment. The Company should complete this framework by July 2025 or prior to filing  
6 its next general rate case, whichever comes first.

7 I also recommend the Commission require DTE to work with stakeholders and  
8 Commission Staff to develop a framework for considering when pipeline repair is a suitable  
9 alternative to pipeline replacement projects. The Commission should require the Company  
10 to demonstrate that it conducted this analysis for all capital projects that met the identified  
11 pipeline repair criteria when it seeks cost recovery of capital investments that meet the  
12 criteria. The Company should complete this framework by July 2025 or prior to filing its  
13 next general rate case, whichever comes first.

14 **III. DTE Should Not Abandon Demand Response Programs**

15 ***A. DTE's Initial Pilots Did Not Have Clear Objectives.***

16 **Q: Will you please explain the Commission's 2019 Order directing the Company to**  
17 **develop demand response programs?**

18 **A:** In 2019, following an extreme cold weather event that contributed to an energy emergency,  
19 Governor Whitmer directed the Michigan Public Service Commission to conduct a  
20 Statewide Energy Assessment (SEA) with a goal to ensure safe, reliable energy for

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<sup>64</sup> Ex. CEO-25.

1 Michigan and to be prepared to mitigate impacts during potential future events.<sup>65</sup> The  
2 purpose of the assessment was to 1) evaluate whether the design of electric, natural gas,  
3 and propane delivery systems are adequate to account for changing conditions and extreme  
4 weather events, and 2) provide recommendations to mitigate risk.<sup>66</sup> In its Statewide Energy  
5 Assessment Report, the Commission identified the importance of demand response during  
6 energy emergencies and instructed gas utilities to develop demand response programs. The  
7 Commission wrote:

8           Given the pivotal role that DR can play during energy emergencies, the  
9           development or expansion of natural gas DR programs should be analyzed. The  
10          Commission recommends the utilities work with Staff and stakeholders to review  
11          the potential for natural gas DR programs and develop recommendations to  
12          encourage the development or expansion of natural gas DR programs.<sup>67</sup>

13 **Q: Is the Company proposing any demand response programs in this case?**

14 A: No. DTE is not proposing to maintain any demand response programs going forward. In  
15 2022, the Company developed three demand response pilots, which ended in 2023. The  
16 Company determined that the programs were not successful and do not wish to continue  
17 with the programs.

18 **Q: Please summarize the Company’s recently completed demand response pilots.**

19 A: The Company conducted three demand response pilots over a two-year period. The  
20 Company had two residential gas pilots, and one commercial pilot.<sup>68</sup> The residential

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<sup>65</sup> Michigan Public Service Commission, “Michigan Statewide Energy Assessment, Final Report,” September 11, 2019.

<sup>66</sup> *Id.* at i.

<sup>67</sup> *Id.* at 120.

<sup>68</sup> HJD-79, lines 7 – 8.

1 demand response pilots were referred to as the Smart Savers and Energy Action Days  
2 pilots.

3 **Q: Please describe the residential demand response pilots.**

4 A: The Smart Savers pilot was available to gas-only and dual-fuel customers who already had  
5 a Wi-Fi enabled smart thermostat. Customers who enrolled in the pilot received a \$50 up-  
6 front gift card upon enrollment and then another \$50 season ending gift card if the customer  
7 remain enrolled.<sup>69</sup> The customer did not receive a financial incentive or penalty for their  
8 actual participation in an event.<sup>70</sup>

9 The second program was the Energy Action Days program. The Company  
10 automatically enrolled customers in two regions, one dual-fuel and one gas-only, for  
11 participation in the program. Customers had to opt out of a program they did not voluntarily  
12 choose to enter into. The pilot participants received resources that encouraged energy  
13 efficient behavior and peak demand savings the day before an event. Participants did not  
14 receive a monetary incentive or penalty for participation/non-participation.

15 **Q: Please describe the commercial demand response pilot.**

16 A: For this program, the Company installed telemetry equipment on participating customers  
17 premises at no cost to the participant. Participants were asked to reduce their load during  
18 events, which were to last no longer than eight hours. The Company testifies that “due to  
19 delays on procuring and installing equipment” it only signed up 2 participating customers,

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<sup>69</sup> HJD-79, lines 9 – 11.

<sup>70</sup> CEO-26, DTE Response to CEODG-1.3a.

1 both high schools.<sup>71</sup> The Company’s testimony is not clear as to why procuring and  
2 installing the telemetry data was delayed. Participating customers did not have a source of  
3 backup heat<sup>72</sup> and were not provided a monetary incentive for participation.

4 **Q: What were the programmatic objectives of the Company’s demand response pilots?**

5 A: The Company failed to set clear objectives for its demand response pilots, which as I will  
6 explain later, is a significant driver as to why the Company concluded the programs were  
7 not successful. In the Company’s testimony, the stated purpose of the pilots was to  
8 “determine the effectiveness of gas demand response as a requirement of the Commission  
9 in its State Energy Assessment report” and “assist in understanding the opportunity that  
10 may exist within the gas demand response space and to determine whether future programs,  
11 if any, should be offered.” The Company does not identify or explain what “effectiveness  
12 of gas demand response as a requirement of the Commission” means. Nor did the Company  
13 explain what understanding it was seeking from the pilots. Through discovery, the  
14 Company provided an October 16, 2020, Gas Demand Response Pilots presentation, which  
15 identified a goal to “identify opportunities to reduce need for future investment.”<sup>73</sup> Thus,  
16 it is not surprising that the Company determined that the programs were not successful,  
17 writing, “At the conclusion of the second year of the demand response pilot, DTE Gas  
18 reviewed the results and determined the Demand Response program was not effective and  
19 determined not to request to extend the pilot or make the program permanent.”<sup>74</sup>

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<sup>71</sup> HJD-83, lines 6 – 8.

<sup>72</sup> Ex. CEO-27, DTE Response to CEODG-1.8c.

<sup>73</sup> Gas Demand Response Pilots, An overview of potential gas demand response pilots for residential and C&I Customers. October 16, 2020. Slide 2.

<sup>74</sup> RMT-28, lines 20-23.

1        ***B.     DTE Did Not Identify Evaluation Criteria***

2        **Q:     Did the Company conduct cost-benefit analyses for each of the pilots?**

3        A:     No, the Company did not conduct a cost-benefit analysis on any of the pilots either before  
4        starting the pilots nor after the conclusion of the pilots.<sup>75</sup>

5        **Q:     Did the Company identify the specific quantitative and qualitative benefits it would  
6        consider in its evaluation of the demand response pilots?**

7        A:     The Company did not identify any quantitative and qualitative benefits it would include  
8        in its evaluation of the success of the pilots. Through discovery, I asked the Company to  
9        identify the specific quantifiable and qualitative benefits that the Company evaluated. The  
10       Company response did not include a list of benefits; rather it responded with a list of  
11       “goals” for the program, such as to “[u]nderstand the capability of customers to reduce gas  
12       consumption following the notification of an event.”<sup>76</sup> Pilot goals are not the same as  
13       benefits of a pilot.

14       **Q:     What are common benefits that are considered in a demand response cost-benefits  
15       analysis?**

16       A:     Common quantifiable benefits included in a cost-benefit analysis are:

- 17                •     Avoided transmission pipeline capacity,  
18                •     Avoided distribution capacity,  
19                •     Avoided gas purchases, and

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<sup>75</sup> Ex. CEO-28, DTE Response to CEODG-3.7a; Ex. CEO-29, DTE Response to CEODG-3.7b; Ex. CEO-30, DTE Response to CEODG-3.7c; Ex. CEO-31, DTE Response to CEODG-3.7d; Ex. CEO-32, DTE Response to CEODG-3.7e; Ex. CEO-33, DTE Response to CEODG-3.7f

<sup>76</sup> Ex. CEO-34, DTE Response to CEODG-3.8a.

- 1           • Avoided emissions.

2   **Q: Did the Company track the cost per pilot?**

3   A: No, the Company did not track the costs of the individual pilot programs; rather it tracked  
4       the costs of the three programs in the aggregate. That is, the Company does not know the  
5       costs of any individual pilot.<sup>77</sup> Understanding the individual pilot program costs is  
6       necessary for determining if a pilot was successful.

7   **Q: Is it concerning to you that the Company did not conduct a cost-benefit analysis?**

8   A: Yes, it is concerning. In my more than 10 years working on utility pilots and programs, I  
9       have never seen a utility dismiss a program, much less a pilot, without conducting a cost-  
10       benefit analysis. As economic regulators, one of the most fundamental analyses relied upon  
11       by public utilities commissions is a quantitative assessment of a program's costs and  
12       benefits. A Commission may not rely entirely on quantitative analysis – I believe there is  
13       a role for qualitative analysis as well – but quantitative analysis is always the foundation  
14       of an evaluation. I do not understand how a Company could dismiss the efficacy of a  
15       program without undergoing this most basic of evaluations.

16   **Q: How did the Company evaluate the success of the pilots?**

17   A: The Company's testimony is not clear. The Company neither provided a detailed  
18       discussion in its testimony nor did it include an evaluation of the pilots with its testimony.  
19       In my experience, it is routine for utilities to conduct evaluations – typically third-party  
20       evaluations, of pilot programs. The objectives of the pilots were never clear, so it is not

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<sup>77</sup> Ex. CEO-35, DTE Response to CEODG-3.8b.

1 surprising the Company did not have clear criteria for evaluating the performance of the  
2 pilots.

3 Through discovery the Company provided two presentations titled “Gas Demand  
4 Response Results – Year 1” and “Gas Demand Response Winter 2022-23 Results.”<sup>78</sup> While  
5 the two presentations provided some observations of the programs, and the second  
6 presentation included a slide titled “Key Learnings and Next Steps” it would not be  
7 appropriate to call either of these presentations an evaluation. Typically, an evaluation  
8 would include an assessment of the costs and benefits of the programs, identify areas of  
9 success or problems with the pilots, identify the sufficiency of the data, and suggest options  
10 for improvement. The presentations, on the other hand, use vague generalized statements  
11 that lacked insight or critical analysis. For example, one presentation included a slide titled  
12 “Key Learnings and Next Steps” which stated the following:

- 13 • *“There is only so much large customers are willing to do to reduce gas consumption*  
14 *due to the comfort of customers and employees and the sensitivity around equipment*  
15 *and process specifications” and*
- 16 • *“Recruitment and installation of large customers is difficult.”<sup>79</sup>*

17 I would expect a proper evaluation to examine why recruitment and enrollment of large  
18 customers was difficult. In testimony, the Company writes that one (of the two total) large  
19 customers admitted to never reading the telemetry data.<sup>80</sup> I would expect an evaluator to  
20 have reached out to the only two customers who took part in the pilot and ask why the

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<sup>78</sup> Ex. CEO-36, DTE Response to MNSCDG-2.6d.

<sup>79</sup> *Id.* at slide 22.

<sup>80</sup> HJD-83.

1 program was not successful, why they did not read their telemetry reports, and gauge  
2 whether the program could be modified to be successful.

3 Finally, I think it is worth noting that the Company is dismissing a very large group  
4 of customers, nonresidential customers, based on the experience of two high schools when  
5 the Company had issues procuring necessary telemetry data. The Company’s dismissal  
6 based on such a small subset of customers is premature and I would have expected an  
7 evaluator to have noticed that issue as well. Moreover, the Company had at least three other  
8 commercial customers who wanted to participate in the program but were unable to  
9 participate because DTE did not procure and install the telemetry equipment. When I asked  
10 why the Company was “delayed” in procuring and installing the equipment, the Company  
11 responded that the employees responsible for researching and designing a solution had  
12 “competing priorities maintaining existing operational needs.”<sup>81</sup> My interpretation of the  
13 Company’s response is that it did not allocate sufficient resources and expertise to the  
14 commitments it made to conduct demand response pilots.

15 **Q: You mentioned that the Company did not offer a monetary or financial incentive to**  
16 **respond to a specific event for any of the three pilots. Did the Company perform an**  
17 **analysis that examined the impact of offering customers a monetary incentive?**

18 A: No. The Company responded to a discovery request that it did not perform an analysis on  
19 whether offering a monetary incentive is necessary to induce customers to participate.<sup>82</sup>

20 Through discovery, the Company stated that it did not conduct any analysis on whether a

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<sup>81</sup> Ex. CEO-37, DTE Response to CEODG-3.12.

<sup>82</sup> Ex. CEO-26, DTE Response to CEODG-1.3a; Ex. CEO-38, DTE Response to CEODG-1.4a; Ex. CEO-39, DTE Response to CEODG-1.5a

1 monetary incentive is necessary to induce customer participation.<sup>83</sup> The Company also  
2 responded that behavioral programs do not include a financial incentive,<sup>84</sup> however, that  
3 doesn't explain why the Company did not test if the other programs – particularly the  
4 nonresidential program – would perform better with a financial incentive. I do not know if  
5 offering a financial incentive would have changed the results of any of the pilots. But  
6 testing various programmatic designs is the very purpose of a pilot program. The Company  
7 had a terrific opportunity to explore a variety of approaches with the Commission's  
8 approval through the relative safety of pilots, and the Company chose not to explore using  
9 a financial incentive for active participation, one of the most common tools in demand  
10 response programs. Indeed, in the Company's own Year 1 results, the Company noted that  
11 one challenge is "lack of incentive for customer."<sup>85</sup> The Company recognizes the issue but  
12 is ignoring it.

13 **Q: Let's turn to the commercial pilot. Was there a problem with the design and**  
14 **implementation of the commercial program?**

15 A: Yes, there were several issues. First, the Company aimed to have 10 to 20 small and large  
16 commercial customers participate in the nonresidential pilot.<sup>86</sup> In the end, the Company  
17 only enlisted two customers, both high schools.<sup>87</sup> However, as mentioned previously, the  
18 Company did not assign sufficient resources to the demand response pilots and therefore

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<sup>83</sup> Ex. CEO-26, DTE Response to CEODG-1.3a.

<sup>84</sup> Ex. CEO-40, DTE Response to CEODG-1.3c.

<sup>85</sup> Ex. CEO-41, DTE Response to MNSDG-2.6d "Gas Demand Response Results – Year 1" May 11, 2022.

<sup>86</sup> DTE Response to MNSDG-2.6d "Gas Demand Response Results – Year 1" May 11, 2022. Slide 19.

<sup>87</sup> HJD-83, lines 7 – 9.

1 did not install telemetry data for three other customers who wished to participate in the  
2 program.<sup>88</sup>

3 Second, the Company only called two events during the winter of 2023 for two  
4 customers both of whom are high schools.<sup>89</sup> I would not agree that two events for two  
5 similarly situated customers is a robust data set for which it is reasonable to draw  
6 conclusions about a customer class as large and diverse and the commercial customer class.

7 Finally, neither participating received a financial incentive for active participation,  
8 nor did they have backup heat to rely on during the event.<sup>90</sup> It is not surprising to me that  
9 the two high schools chose not to cut off heat to their schools during a peaking event much  
10 less because it did not receive any financial remuneration for the action.

11 **Q: Now let’s turn back to the residential Smart Saver pilot. Is it clear that the results of**  
12 **the residential Smart Savers pilot were a failure, as the Company testifies?**

13 A: No. In fact, the limited data the Company evaluated in their presentation shows that the  
14 Smart Savers pilot successfully reduced customer usage during the events.<sup>91</sup> The Company  
15 called only 5 events during the two-year pilot.<sup>92</sup> The pilot grew from year one to year two.  
16 The Company’s slides show that customers decreased their use by 42%, 29%, 50%, 36%,  
17 and 36% during the events.<sup>93</sup> That appears to be quite a successful response. At the end of  
18 the event, the Company experienced “snapback.” Snapback is a well-known phenomenon  
19 whereby after the event, customer demand quickly rises. In one case for DTE, the snapback

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<sup>88</sup> Ex. CEO-38, DTE Response to CEODG-3.12.

<sup>89</sup> HJD-83, lines 7 – 9.

<sup>90</sup> Ex. CEO-27, DTE Response to CEODG-1.8c.

<sup>91</sup> Ex. CEO-42, DTE Response to MNSDG-2.6d “Gas Demand Response Results – Year 1” May 11, 2022.

<sup>92</sup> Ex. CEO-37, DTE Response to MNSDG-2.6d “Gas Demand Response Winter 2022-23 Results” June 16, 2023.

<sup>93</sup> Ex. CEO-42, DTE Response to MNSDG-2.6d “Gas Demand Response Results – Year 1” May 11, 2022, DTE Response to MNSDG-2.6d “Gas Demand Response Winter 2022-23 Results” June 16, 2023.

1 was sufficiently large that cumulative energy use actually increased. However, the  
2 Company does not evaluate the magnitude of this problem or if the snapback can be  
3 managed. If the snapback does not occur concurrent with the system peak, it may not  
4 actually be a problem for the utility and the benefits may still exceed the costs to the  
5 Company. The Company did not evaluate this issue because it did not evaluate the costs  
6 and benefits of the program. Nor did the Company demonstrate that it evaluated industry-  
7 known opportunities for mitigating snapback. For example, the Company could stagger  
8 customer reintegration or control the pace of a customer’s increase in demand. DTE is not  
9 the first utility to experience snapback and its lack of evaluation is concerning. Given that  
10 the purpose of a pilot is to provide a relatively safe place for a utility to experiment, it  
11 would have been reasonable for DTE to explore options for managing snapback through  
12 its pilots.

13 *C. The Commission Should Require DTE to Develop New Demand Response*  
14 *Programs*

15 **Q: The Company is choosing not to move forward with any demand response**  
16 **programs. Has the Commission’s fundamental concern, that gas demand response is**  
17 **necessary during extreme events, been alleviated?**

18 A: To the best of my knowledge, there continues to be a risk posed by extreme weather events  
19 and emergency situations. In its testimony the Company stated that it entered into a  
20 Memorandum of Understanding with Consumers Energy in April 2021 to provide each  
21 other mutual assistance in case of an emergency.<sup>94</sup> The Commission instructed the gas

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<sup>94</sup> KMF-76, lines 14 – 16.

1 utilities to develop demand response programs in lieu of broad emergency appeals (a  
2 behavioral program). The Company is proposing to walk away from the idea of creating  
3 demand response programs and is not proposing any program in its place.

4 **Q: Are there other demand response type programs for large customers common place**  
5 **in the industry?**

6 A: Yes. Many gas utilities across the country offer certain large, non-transport customers an  
7 interruptible tariff. An interruptible tariff is a schedule open to specific sizes of customers  
8 who, in exchange for a lower rate, agree to be curtailed during certain types of events. The  
9 most common type of event is a near-peak event when the system is maximized but some  
10 schedules also allow gas utilities to curtail these customers during gas price spike events.  
11 The benefit of an interruptible tariff to the utility and the rest of its customers is that the  
12 utility does not need to plan to meet interruptible customers' demand during peak periods  
13 thus lowering the design day costs for customers.

14 **Q: The Commission primarily focused on the role demand response can play during an**  
15 **energy emergency. Are there other potential benefits of demand response**  
16 **programs?**

17 A: Yes, there are several potential benefits of a demand response program. The SEA Report  
18 rightfully identified the benefits of gas demand response availability during energy  
19 emergencies and as an alternative to broad emergency appeals. The report also briefly  
20 mentioned several other demand response benefits, including avoided energy costs,  
21 reduced market price volatility, improved electric and gas system reliability, deferred or

1 avoided capital investments, and air emissions reductions.<sup>95</sup> That is a comprehensive list  
2 of potential demand response benefits. However, the benefits experienced by the utility  
3 and its customers from a demand response program are determined by the structure of the  
4 program. For example, a customer-wide demand response program may seek to maximize  
5 price risk mitigation and avoided transmission capacity, while a targeted demand response  
6 program focused on a specific neighborhood may seek to avoid the need for a specific  
7 distribution system investment.

8 **Q: Earlier you mentioned the need to conduct alternatives analysis, including**  
9 **nonpipeline alternatives. Can demand response be a component NPA portfolio of**  
10 **resources?**

11 A: Yes, demand response can be part of a portfolio of resources used to avoid a traditional  
12 pipeline investment. I would expect that demand response would feature most prominently  
13 in NPAs that are avoiding an expansion to gas utility delivery system to meet forecasted  
14 peak demand.

15 **Q: What are your demand response recommendations?**

16 A: First, I recommend the Commission reject the Company's request to recover the \$2.6  
17 million in deferred demand response costs.<sup>96</sup> The Company did not put forth a reasonable  
18 effort towards developing and evaluating demand response programs. The program lacked  
19 clear objectives, was limited in scope, and did not undergo a basic evaluation of success.

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<sup>95</sup> Michigan Public Service Commission, "Michigan Statewide Energy Assessment, Final Report," September 11, 2019, page 22.

<sup>96</sup> HJD-83, lines 18-20.

1           Second, I recommend the Commission order DTE to go back and work with  
2 Commission Staff and stakeholders to develop a more robust set of demand response  
3 programs that test multiple programs. The Company and parties should establish clear  
4 objectives for each pilot, identify which costs and benefits will be evaluated, and undergo  
5 a thorough third-party evaluation. The Company and parties should consider the  
6 development of interruptible programs as part of this undertaking. Demand response is a  
7 potentially important resource for mitigating peak demand and a properly designed demand  
8 response program is essential to the program’s success. Based on my review of DTE’s  
9 demand response pilot, I do not believe the Company allocated the necessary resources to  
10 designing and implementing this program. I recommend the Commission require DTE to  
11 commit the necessary resources to develop a robust demand response program. The  
12 Company should complete this work by July 2025 or prior to filing its next general rate  
13 case, whichever comes first.

14 **IV. Using Granular Data and Mapping to Ensure Equitable Gas Service**

15 **Q: What is the MI Healthy Climate Plan?**

16 **A:** In September 2020, Governor Whitmer signed Executive Directive 2020-10 (“ED 2020-  
17 10”) establishing an economy-wide goal of carbon neutrality by 2050 and to maintain net  
18 negative greenhouse gas emissions thereafter.<sup>97</sup> ED 2020-10 charged the Department of  
19 Environment, Great Lakes, and Energy (“EGLE”) to develop and issue a MI Healthy  
20 Climate Plan (“Plan”) to serve as the action plan for the state to reduce greenhouse gas

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<sup>97</sup> Office of Governor Gretchen Whitmer, Executive Directive 2020 – 10, September 23, 2020. Available at: <https://www.michigan.gov/whitmer/news/state-orders-and-directives/2020/09/23/executive-directive-2020-10>

1 emissions and transition toward economy-wide carbon neutrality. EGLE issued the MI  
2 Healthy Climate Plan in April 2022.<sup>98</sup> The Plan recognized that environmental justice  
3 communities, most often communities of color and/or low-income have experienced  
4 disproportionate negative impacts of society’s energy decisions.<sup>99</sup>

5 **Q: Is there any other relevant legislation that requires the minimization of harm and**  
6 **prioritization of benefits in certain communities?**

7 A: Yes. In 2023, the Michigan legislature passed SB 502, which authorizes the Commission to  
8 consider both climate and equity in its decision-making.<sup>100</sup> Specifically, the bill states the  
9 Commission shall prioritize certain goals including:

- 10 • “Equitable access to energy efficiency, weatherization, home electrification programs  
11 and services, and clean energy technologies,” and
- 12 • “Minimization of harm and prioritization of benefits in communities consisting  
13 predominately of minorities or households below the poverty line where factors,  
14 including socioeconomic stressors, disproportionate cost and environmental burdens,  
15 vulnerability to environmental degradation, and lack of accessibility in public  
16 participation, may act cumulatively to affect public health and the environment and  
17 contribute to persistent disparities.”

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<sup>98</sup> Department of Environment, Great Lakes, and Energy, “MI Healthy Climate Plan.” April 2022. Available at: <https://www.michigan.gov/egle/about/organization/climate-and-energy/mi-healthy-climate-plan>.

<sup>99</sup> *Id.* at 16.

<sup>100</sup> SB 502 (2023). Available at: <https://www.legislature.mi.gov/documents/2023-2024/billintroduced/Senate/htm/2023-SIB-0502.htm>

1 **Q: What specifically does the MI Healthy Climate Plan say about environmental justice**  
2 **communities?**

3 A: The Plan states that “[e]nvironmental justice considerations are a key component of  
4 equitable climate action and will continue to be a priority for the state as it works to  
5 eliminate racial disparities impacting the health and wellbeing of Michiganders.”<sup>101</sup> The  
6 Plan continues that “many disadvantaged communities live and work in subpar buildings,  
7 face higher energy burden, and are subject to health-related impacts from natural gas  
8 appliances, all while lacking access to the investments in energy efficiency and onsite  
9 renewable energy seen in other communities.”<sup>102</sup>

10 The Plan continues that to ensure that the state’s response to climate change does  
11 not reinforce challenges that historically disadvantaged communities, the state must  
12 proactively and intentionally plan for equity and environmental justice.

13 **Q: Are there tools to help the DTE identify historically disadvantaged communities?**

14 A: Yes. EGLE’s Office of the Environmental Justice Public Advocate, in cooperation with the  
15 Interagency Environmental Justice Response Team Data and Research Workgroup,  
16 developed an interactive mapping tool called MiEJScreen.<sup>103</sup> According to the Department,  
17 MiEJScreen is “an interactive mapping tool that identifies Michigan communities that may  
18 be disproportionately impacted by environmental hazards.”<sup>104</sup> Users can identify the

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<sup>101</sup> Department of Environment, Great Lakes, and Energy, “MI Healthy Climate Plan.” April 2022. Page 16.  
Available at: <https://www.michigan.gov/egle/about/organization/climate-and-energy/mi-healthy-climate-plan>.

<sup>102</sup> *Id.* at 17.

<sup>103</sup> <https://www.michigan.gov/egle/-/media/Project/Websites/egle/Documents/Maps-Data/MiEJScreen/MiEJScreen-Factsheet.pdf?rev=626af950b12349e499657e243b93af31>

<sup>104</sup> *Id.*

1 environmental, health, and socioeconomic conditions within a specific community or  
2 region.

3 **Q: How can an interactive mapping tool be useful to DTE Gas?**

4 A: A mapping tool can provide granular, geographic-specific information regarding aspects  
5 of the system and customer experience. For example, a mapping tool can be used to identify  
6 geographic areas where there are: high concentrations of poverty, high concentrations of  
7 people of color, higher levels of pollution, and parts of the system which may be older than  
8 other areas. DTE has an obligation to serve all its customers and part of that obligation  
9 requires it to serve all customers equitably. By identifying geographic areas that may be  
10 under-served in terms of investment and/or programs, the Company can better target capital  
11 investments or programming directly to these areas, thereby meeting its obligation to  
12 provide service equitably.

13 **Q: Why is it important to identify areas with high concentrations of poverty and/or high  
14 concentrations of people of color?**

15 A: To effectively reach communities with high concentrations of poverty and/or people of  
16 color, DTE may have to engage with its customers in these areas in a different way than it  
17 engages with its other customers. By identifying geographic areas with high concentrations  
18 of poverty and/or people of color, DTE can better understand how to be more culturally  
19 responsive to the challenges faced by these customers.

20 **Q: What indicators does the MiEJScreen tool measure?**

1 A: The tool measures 26 statewide indicators across four categories: Environmental exposure,  
2 environmental effects, sensitive populations, and socioeconomic factors.<sup>105</sup> In addition to  
3 individual indicator scores, the tool identifies a final composite score across the four  
4 categories to identify relative environmental risk factors in communities. A low composite  
5 score indicates that community, as a whole, has fewer environmental risk factors in the  
6 community as compared to other communities. A high composite score indicates that  
7 community experiences relatively more environmental risk. For example, the more  
8 affluent Grosse Pointe Farms census tract has a composite score of 12,<sup>106</sup> while a nearby  
9 census tract just south of Coleman A. Young International Airport has a composite score  
10 of 100.<sup>107</sup> The two census tracts are separated by about 6 miles.

11 **Q: Does DTE Gas use MiEJScreen or a similar mapping tool to inform its**  
12 **programmatic and capital planning decision making?**

13 A: No, the Company does not.<sup>108</sup> However, I recommend that the Commission order the  
14 Company to immediately start using the tool to plan, develop, and implement its programs  
15 and capital investment decisions.

16 **Q: Please explain how the Company should use MiEJScreen to inform its**  
17 **programmatic and capital planning decision making.**

18 A: The MiHealthy Climate Plan states that to ensure that Michigan’s response to climate  
19 change does not reinforce challenges faced by historically disadvantaged communities, the

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<sup>105</sup> <https://www.michigan.gov/egle/-/media/Project/Websites/egle/Documents/Maps-Data/MiEJScreen/MiEJScreen-Factsheet.pdf?rev=626af950b12349e499657e243b93af31>

<sup>106</sup> Census tract 26163550600

<sup>107</sup> Census tract 26163505500.

<sup>108</sup> Ex. CEO-43, DTE Response to CEODG4.1bi; and Ex. CEO-44, DTE Response to CEODG-4.1di.

1 state must proactively and intentionally plan for equity and environmental justice. The  
2 Michigan Public Service Commission, as a state agency, and DTE Gas, as a state-regulated  
3 monopoly, must take responsibility for proactively and intentionally ensuring that  
4 environmental justice communities are not disproportionately impacted for energy  
5 decisions.

6 I recommend that the Commission order DTE Gas to use MiEJScreen to inform its  
7 capital investment decisions going forward. When the Company is considering locations  
8 for significant capital investments, for example the need for a route of a new distribution  
9 main or transmission pipe, the Company would use the MiEJScreen to assess the potential  
10 impact to environmental justice communities, as well as the impact of alternatives  
11 proposals to meet the Company’s need. The Company would then be responsible for  
12 demonstrating that the preferred solution, either the original capital investment proposal or  
13 an alternative, does not disproportionately negatively impact environmental justice  
14 communities.

15 I also recommend that the Commission order DTE gas to use MiEJScreen to inform  
16 the design and implementation of its customer programs and policies going forward.  
17 Customer programs and policies include the Company’s energy efficiency and demand  
18 response programs, low-income energy efficiency and heating assistance programs,  
19 arrearage management programs, and residential disconnection policy.

20 **Q: How can an interactive mapping tool help DTE inform the design and implementation**  
21 **of its customer program, policies, and investments?**

22 A: The mapping tool can help to provide information on a program’s effectiveness by  
23 geography. For example, there may be certain geographic areas where energy efficiency

1 uptake is very low. By identifying those geographic areas, DTE can better understand  
2 where to target its spending on improving energy efficiency uptake.

3 **Q: Is there precedent for the Commission ordering DTE to use the MiEJScreen tool to**  
4 **inform its decision making?**

5 A: Yes. The Commission approved a rate increase for DTE Electric in December 2023. As  
6 part of its approval of DTE Electric’s plan to harden Detroit’s electric grid, the Commission  
7 directed the Company to provide a longer-term plan with benchmarks for performance and  
8 with an analysis of equity impacts, using MiEJScreen.<sup>109</sup>

9 **Q: Are there specific indicators and metrics the Company should be using in its**  
10 **program and capital investments decision making?**

11 A: Yes. The MiEJScreen tool includes several socioeconomic indicators including low-  
12 income populations, Black, Indigenous, People of Color Populations, and Housing  
13 Burden.<sup>110</sup> There are several indicators that are relevant to gas utilities that are not being  
14 measured in the state’s tool. I recommend that the Company measure several other  
15 indicators at the most granular level, census block. I recommend the Company begin  
16 tracking:

17 • The average energy burden of residential customers measured at the census block. This  
18 indicator is calculated by dividing the average annual residential bill by the average

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<sup>109</sup> Michigan Public Service Commission Press Release “MPSC approves \$368M rate increase for DTE Electric Co. to fund utility’s reliability upgrades.” December 1, 2023. Available at: <https://www.michigan.gov/mpsc/commission/news-releases/2023/12/01/mpsc-approves-368m-rate-increase-for-dte>.

<sup>110</sup> The MiEJScreen socioeconomic indicators are Low Income Population, Black, Indigenous, People of Color Population, Education Attainment, Linguistic Isolation, Population Under Age 5, Population Over Age 64, Unemployment, and Housing Burden.

1 area median income by census block. Previous work by the CEO have demonstrated  
2 that nearly 30 percent of DTE’s residential customers are energy burdened and that  
3 energy cost burdens are distributed unevenly across DTE’s territory.<sup>111</sup> Calculating  
4 energy burden at the census block group level will provide better insight as to where  
5 high energy burdened customers are located, and allow the Company to better target  
6 those areas for energy assistance.

- 7 • The percentage of residential customers disconnected per census block. This indicator  
8 is calculated as the number of disconnected premises in a census block divided by the  
9 total number of gas premises in the same census block.
- 10 • The percentage of low-income residential customers that participated in one or more  
11 energy assistance programs in a year, measured at the census block level. This indicator  
12 is calculated as the number of low-income households who participated in one or more  
13 energy assistance programs in a year divided by the total number of low-income  
14 households in the same census block. If the Company does not know the number of  
15 low-income households in a census block, the utility should develop a stakeholder-  
16 reviewed reasonable estimate.
- 17 • The percentage of low-income residential customers that participated in a payment plan  
18 in a year, measured at the census block level. This indicator is calculated as the number  
19 of low-income households who participated in a payment plan in a year divided by the  
20 total number of low-income households in the same census block. If the Company does

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<sup>111</sup> Docket No. U-21193, Direct Testimony of Boris Lukanov on Behalf of Environmental Law & Policy Center, The Ecology Center, Union of Concerned Scientists and Vote Solar. p. 3. Available at: <https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y00000789BIAAI>

1 not know the number of low-income households in a census block, the utility should  
2 develop a stakeholder-reviewed reasonable estimate.

- 3 • The percentage of residential customers enrolled in Shutoff Protection Plan<sup>112</sup> in a year,  
4 measured at the census block level. This indicator is calculated as the number of  
5 households in a census block enrolled in the Shutoff Protection Plan divided by the  
6 total number of households in that same census block.
- 7 • The percentage of low-income residential customers that participated in the Company’s  
8 energy efficiency program in a year, measured at the census block level. This indicator  
9 is calculated as the number of low-income households who participated in an energy  
10 efficiency program divided by the total number of low-income households in the same  
11 census block. If the Company does not know the number of low-income households in  
12 a census block, the utility should develop a stakeholder-reviewed reasonable estimate.

13 **Q: Why do you recommend calculating these indicators?**

14 **A:** Calculating and then analyzing these indicators at the census block level can help the  
15 utility, Commission, stakeholders, and policymakers identify where there may be  
16 discrepancies in the system and can help inform planning and investment decisions to  
17 better serve low-income communities and communities with high populations of Black,  
18 Indigenous and People of Color.

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<sup>112</sup> DTE Shutoff Protection Plan. Available at: <https://www.dteenergy.com/us/en/business/billing-and-payments/energy-assistance/shutoff-protection-plan.html>

1 **Q: The MiEJScreen tool measures indicators at the census tract level. You recommend**  
2 **measuring the additional indicators at the census block level. What is the value of**  
3 **the more granular measurement to DTE and the Commission?**

4 A: The census block is the smallest geographic area for which census data is available.  
5 Evaluating the Company’s service at the census block groups level allows the Company  
6 to be more precise when it considers program and investment level decisions. However, I  
7 understand the need to balance using the best information with minimizing administrative  
8 burden. To start, I recommend the Company use the existing MiEJScreen tool as it  
9 develops its own internal processes for using this type of mapping tool for planning,  
10 developing, and implementing programs and investments. At a later date, the Company  
11 may need to either work with the state to update the MiEJScreen tool to go to the census  
12 block level or develop its own mapping tool like Xcel Energy did in Minnesota. In the  
13 meantime, the census block level information can still be used as available additional  
14 information considered with the MiEJScreen tool that is available for refining Company  
15 decision making.

16 **Q: Are you aware of any other states that use a similar mapping tool?**

17 A: Yes, I am aware of at least three other states: Minnesota,<sup>113</sup> Washington state,<sup>114</sup> and  
18 California.<sup>115</sup> Nationally, the U.S. Center for Disease Control maintains a national

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<sup>113</sup> Minnesota Department of Health, Minnesota Public Heat Data Access. Available at:  
[https://data.web.health.state.mn.us/equity\\_metadata](https://data.web.health.state.mn.us/equity_metadata)

<sup>114</sup> Washington State Department of Health, Washington Environmental Health Disparities Map. Available at:  
<https://doh.wa.gov/data-and-statistical-reports/washington-tracking-network-wtn/washington-environmental-health-disparities-map>

<sup>115</sup> California Office of Environmental Health Hazard Assessment. Available at:  
<https://oehha.ca.gov/calenviroscreen/report/calenviroscreen-30>

1 Environmental Justice Index which measures 36 social vulnerability, environmental, and  
2 health indicators for measuring cumulative environmental burden in communities. The  
3 CDC’s tool allows users to explore the indicators by census tract across the state of  
4 Michigan.

5 In Minnesota, Xcel Energy, a dual-fuel utility like DTE, created its own interactive  
6 map of its electric and gas service territories. Xcel Energy’s gas division tracks many of  
7 the same indicators I recommend DTE track and combined that data with demographic  
8 data from the US Census Bureau.

9 **Q: How does the Minnesota Public Utilities Commission and Xcel use the interactive**  
10 **mapping tool?**

11 A: The mapping tool is starting to be used by the Minnesota Public Utilities Commission, Xcel  
12 Energy, and stakeholders to design and implement programs. First, Xcel Energy’s mapping  
13 shows that energy assistance uptake in certain geographic areas is relatively low and is  
14 using this information to direct energy assistance to those areas. Furthermore, in Xcel  
15 Energy’s last rate case, interested parties used the mapping tool to posit that electric  
16 reliability is lower for communities of color and electric disconnections are higher, even  
17 when controlling for income. As a result, Xcel Energy evaluated that hypothesis and  
18 published results in March 2024, which confirmed there were some disparities in reliability  
19 and disconnections in certain areas with high concentrations of communities of color. The  
20 MPUC and stakeholders are now in the process of determining whether and how to address  
21 these disparities.

22 Second, after extensive work with the Company’s Equity Stakeholder Advisory  
23 Group, Xcel Energy recently unveiled a two-year pilot that would provide automatic bill

1 credits for customers in certain low-income areas.<sup>116</sup> The Company and the stakeholder`  
2 group utilized the mapping tool to identify the census block groups with the highest energy  
3 burdens and proposed to provide an automatic bill credit to all households in high-energy  
4 burdened census block groups. If approved, the automatic credit will bring the median  
5 energy burden in all census block groups in Xcel Energy’s service territory down to 4%;  
6 the bill credit will go to approximately 23,000 households in 77 census block groups. The  
7 automatic credit occurs without active enrollment from the household, eliminating the need  
8 for customers with high energy burdens to apply for energy assistance.

9 **Q: Please summarize your conclusions.**

10 **A:** My testimony discusses three separate issues, but there is a common thread that ties the  
11 three together. DTE Gas is not reasonably responding to shifting policy and economic  
12 trends.

13 As the Company acknowledges, there is a global energy transition occurring.<sup>117</sup>  
14 Despite recognizing that “decarbonization and the reduction of greenhouse gas emissions  
15 is an increasing priority within the energy industry in totality and gaining momentum in  
16 the gas industry”<sup>118</sup> the Company is not taking any meaningful action to meet the state’s  
17 emissions reduction targets. Nor is the Company incorporating the risk of the shifting  
18 policy and economics into its load forecasts and capital investment decisions. The  
19 Company’s business-as-usual approach is both costly and risky for customers and the  
20 Commission should order the Company to change its approach to mitigate future costs and  
21 risks for customers.

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<sup>116</sup> <https://m.startribune.com/xcel-energy-bill-credit-low-income-census-area-minnesota/600360958/>

<sup>117</sup> HJD-36, lines 23 – 25.

<sup>118</sup> HJD-36, 23 – 24.

1           The Company’s recalcitrance to effectively respond to changing conditions is  
2 highlighted by the Company’s lackadaisical approach to its demand response pilots.  
3 Despite the Commission identifying demand response as an important resource during  
4 emergency situations, the Company did not put sufficient effort into developing nor  
5 evaluating the pilots before proposing to abandon a valuable demand-side resource.

6           Finally, I conclude that the Company needs to incorporate more granular data and  
7 mapping tools to ensure equitable outcomes for its customers. In recent years, the state has  
8 passed legislation requiring the Commission to ensure equitable access to utility programs,  
9 minimize harms, and prioritize benefits to certain communities. The Commission can best  
10 achieve its state mandate by requiring the Company to use an interactive mapping tool and  
11 additional indicators to inform its program, policy, and capital investment proposals for  
12 Commission approval.

13 **Q: Does this conclude your testimony?**

14 **A:** Yes.

**STATE OF MICHIGAN  
MICHIGAN PUBLIC SERVICE COMMISSION**

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In the matter of the application of **DTE GAS** )  
**COMPANY** for authority to increase its )  
rates, amend its rate schedules and rules )                   Docket No. U-21291  
governing the distribution and supply of )  
natural gas, and for miscellaneous accounting )  
authority )

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**PROOF OF SERVICE**

I hereby certify that a true copy of the foregoing *Direct Testimony of Brad Cebulko on behalf of The Ecology Center, the Environmental Law & Policy Center, Union of Concerned Scientists, and Vote Solar* was served by electronic mail upon the following Parties of Record, this Tuesday, May 7, 2024.

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A handwritten signature in black ink, appearing to read "Daniel Abrams", written over a horizontal line.

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# Brad Cebulko

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## Professional Summary

Brad is an energy regulatory expert who specializes in gas and electric regulation before public utilities commission for clients who are committed to pursuing a just and equitable energy transition. Brad has submitted expert witness testimony and comments on a wide range of regulatory issues including rate allocation and rate design, low-income ratepayer issues, performance-based regulation, electric and gas long-term planning, capital investment planning, and gas utility decarbonization policy. Brad has prior experience at Strategen Consulting and the Washington Utilities and Transportation Commission.

## Education

### **Master of Public Administration**

University of Washington - Seattle, WA (2012)

### **Bachelor of Arts Political Science**

Colorado State University – Fort Collins, CO (2006)

## Work Experience

### **Founder, CEB Energy Consulting, (March 2024 – Present)**

- Works with consumer advocates and public interest organizations on gas and electric regulatory issues before state public utility commissions.

### **Senior Manager, Strategen Consulting, (2021 – March 2024)**

- Led Strategen’s gas transition practice, which included regulatory and legislative strategy, prudence reviews, and gas infrastructure planning.
- Worked with state regulatory commissions, consumer advocates, non-profits, and other clients to advance the public interest in regulatory decision-making.
- Developed testimony, comments, reports, and analysis on a subject matter including gas utility decarbonization strategies, performance-based regulation, electric and gas resource planning, fuel costs, energy efficiency, and low-income ratepayer issues.

### **Senior Policy Advisor for Energy Strategy, Washington Utilities and Transportation Commission (2016 – 2021)**

- Advised the Commissioners on electric and gas utility regulation and legislation.
- Led major Commission policy initiatives through Commission orders, policy statements, and rulemakings, including developing rules for the Clean Energy Transformation Act.
- Chair of the Staff Subcommittee on International Relations at NARUC.

### **Regulatory Analyst, Washington Utilities and Transportation Commission (2013 – 2016)**

- Testified before the commission in suspended utility filings and general rate case proceedings.
- Led Commission Staff’s review of natural gas integrated resource plans and energy efficiency filings.

## **Expert Testimony**

### **Northwest Natural Gas Company 2024 General Rate Case (DKT: UG 490) on Behalf of Coalition of Communities of Color, Climate Solutions, Verde, Columbia Riverkeeper, Oregon Environmental Council, Community Energy Project, and Sierra Club**

*Direct Testimony*

Filed testimony in opposition to the Company’s proposed gas line extension allowance policy, and the Company’s proposal for a 200% increase to the customer charge for new premise single-family and multi-family customers. Rebuttal Testimony will be filed in July 2024.

[Case Details](#) | [Direct Testimony](#)

### **Southern Connecticut Natural Gas Company and Connecticut Natural Gas Company 2024 Rate Case (DKT: 23-11-02) on Behalf of Sierra Club and Conservation Law Foundation**

*Direct and Rebuttal Testimony*

Filed testimony examining the Companies capital investments plans and decarbonization programs.

[Case Details](#) | [Direct Testimony](#) | [Rebuttal Testimony](#)

### **Public Service Company of Colorado 2024-2028 Clean Heat Plan (DKT: 23A-0392EG) on Behalf Western Resource Advocates and Rewiring America (2024)**

*Testimony and Report*

Filed a report and testimony examining the review the utility's capital investment plan, assessed the benefits of zonal electrification, assessed the capital and operation & maintenance (O&M) costs for blending hydrogen into the distribution system, and assessed the reasonableness of the Company's synthetic natural gas (SNG) assumptions.

[Case Details](#) | [Direct Testimony Report](#)

### **PacifiCorp 2023 Washington General Rate Case (DKT: UE-230172) on Behalf of The Energy Project (2023)**

*Response Testimony*

Filed testimony on the Company's proposed electric performance metrics on behalf of the state's low-income ratepayer advocate. Proposed a more comprehensive portfolio of metrics that measures the utility's performance to provide affordable, clean, equitable, and reliable power.

[Case Details](#) | [Direct Testimony](#)

### **Northern Illinois Gas Company Proposed General Increase in Rates and Revisions to Other Terms and Conditions of Service (DKT: 23-0066) on Behalf of Environmental Law & Policy Center, Environmental Defense Fund, Natural Resources Defense Council, and Illinois State Public Interest Research Group, Inc (2023)**

*Direct and Rebuttal Testimony*

Filed testimony on capital expenditures, line extension allowances, non-pipeline alternatives, gas system planning, performance metrics, and residential rate design.

[Case Details](#) | [Direct Testimony](#) | [Rebuttal Testimony](#)

### **The Peoples Gas Light and Coke Company 2023 Proposed General Increase in Rates and Revisions to Other Terms and Conditions of Service (DKT: 23-0068 and 23-0069) on Behalf of Environmental Law & Policy Center, Environmental Defense Fund, Natural Resources Defense Council, and Illinois State Public Interest Research Group, Inc. (2023)**

*Direct and Rebuttal testimony*

Filed testimony on capital expenditures, line extension allowances, non-pipeline alternatives, gas system planning, performance metrics, and residential rate design.

[Case Details](#) | [Direct Testimony](#) | [Rebuttal Testimony](#)

### **Avista 2023 Oregon Gas General Rate Case (DKT: UG-461) on Behalf of Sierra Club and Climate Solutions (2023)**

*Direct Testimony*

Filed testimony on Avista's compliance plan for meeting Climate Protection Program compliance, non- pipeline alternatives, and line extension policy. Through settlement, Avista agreed to initiate non- pipeline alternative analysis in its integrated resource plan,

phase out its line extension allowance policy by 2027, and delay seeking recovery of Climate Investment Cost Recovery.

[Case Details](#) | [Direct Testimony](#) | [Final Order](#)

### **Puget Sound Energy 2022 Electric and Gas General Rate Case (DKT: UE-220066, UG-220067, and UG- 210918) On Behalf of The Energy Project (2022)**

*Response Testimony*

Filed testimony on Gas and Electric Performance Metrics and Electric Time-of-Use Rate Pilot on behalf of the residential low-income advocate. Through settlement, PSE agreed to modify its Time of Use pilot and track performance metrics that closely aligned with The Energy Project's proposals.

[Case Details](#) | [Response Testimony](#) | [Settlement Testimony](#)

### **Avista 2022 Electric and Gas General Rate Case (DKT: UE-220053, UG-220054) On Behalf of The Energy Project (2022)**

*Settlement Testimony*

Developed a comprehensive set of performance metrics and negotiated with the utility and other parties on behalf of the client, low residential low-income advocate. Through settlement, Avista agreed to modify its performance metrics to closely align with The Energy Project's proposals.

[Case Details](#) | [Settlement Testimony](#)

### **Liberty Utilities RNG Program (DKT 22-32) On Behalf of Sierra Club (2022)**

*Direct Testimony*

Filed testimony recommending the Massachusetts Department of Public Utilities reject Liberty's proposed Voluntary Renewable Natural Gas Program because it was costly and the Company's proposal would have double counted the environmental attributes of the project. The Department of Public Utilities largely relied on Sierra Club's testimony when it reject the Company's proposed RNG program.

[Case Details](#) | [Direct](#)

### **PacifiCorp 2022 General Rate Case (DKT UE 399) On Behalf of Vitesse LLC (2022)**

*Direct and Rebuttal Testimony*

Filed testimony on behalf of Vitesse LLC, a wholly owned subsidiary of Meta, on the proposed design of PacifiCorp's voluntary green tariff program for large customers. The Oregon PUC approved a multi-party settlement that made several revisions to the program based on my testimony.

[Case Details](#) | [Direct](#) | [Rebuttal](#)

### **Consumers Energy 2022 Natural Gas General Rate Case (DKT U-21148) On Behalf of Michigan Environmental Council, NRDC, and Sierra Club (2022)**

#### *Direct Testimony*

Direct testimony on Company's proposal build and operate a RNG facility, and the Company's line extension allowance policy. Through settlement, the Company agreed not to seek recovery of the RNG facility and to update the utility's line extension allowance assumptions.

[Case Details](#) | [Direct](#)

### **Xcel Energy, Minnesota Energy Resources Corp, CenterPoint Energy (DKT: 21-138) On Behalf of Minnesota CUB (2021 – 2022)**

#### *Direct and Rebuttal Testimony*

Filed direct and rebuttal testimony on the prudence of the three gas utilities extraordinary gas costs during Winter Storm Uri in 2021. The Minnesota PUC relied, in part, on Strategen's testimony to find nearly \$60 million in imprudent costs for the gas utilities. The Commission also accepted Strategen's recommendation to initiate gas utility long-term planning.

[Case Details](#) | [Direct](#)

### **Puget Sound Energy Proposed Leasing Program (DKT: UE-151871/UG-151872) On Behalf of Washington UTC Staff (2016)**

Filed direct testimony opposing the Company's proposed end-use appliance leasing program for not being in the public interest. The Commission agreed that the program was poorly structured and was unlikely to benefit participants and non-participants

[Case Details](#) | [Direct](#)

### **Avista 2015 General Rate Case (Dockets UE-150204/UG-150205) On Behalf of Washington UTC Staff (2015)**

General Rate Case

[Case Details](#) | [Direct](#)

### **Avista 2014 General Rate Case (Dockets UE-140188/UG-140189) On Behalf of Washington UTC Staff (2014)**

General Rate Case

[Case Details](#) | [Direct](#)

## **Selection of Relevant Experience**

### **Tennessee Valley Authority 2024 Integrated Resource Plan on Behalf of GridLab and The Nature Conservancy (2024)**

*Technical and Policy Support*

Providing technical and policy assistance to The Nature Conservancy during its participation in the TVA IRP stakeholder work sessions.

**Nevada Public Utilities Commission Natural Gas Utility Integrated Resource Planning Rulemaking on Behalf of Western Resource Advocates (2024)**

*Technical and Policy Support*

Providing technical and policy assistance to Western Resource Advocates in its participation in the PUCN's rulemaking. Drafted proposed comprehensive rules and supporting arguments.

**A Regulator's Blueprint for 21st Century Gas Utility Planning, A Report for Advanced Energy United (2023)**

*Report*

Led the development of a report that provided a blueprint for state public utility commissions that are interested in developing gas utility planning requirements to improve transparency into gas utility resource and capital investment plans.

**New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation Initial Long-Term Gas System Plan on Behalf of Sierra Club and Earthjustice (2024)**

*A Review of the Initial Long-Term Plan*

Developed a report that analyzed the Companies' alternative fuel assumptions, electrification costs, capital forecast, technological assumptions for electrification technologies, benefit-cost analysis, and implementation of non-pipeline alternatives ("NPAs").

**Comments on CenterPoint Energy's Natural Gas Innovation Act (NGIA) Pilots in Minnesota on Behalf of Fresh Energy (2023)**

*Comments*

Provided technical support and comments to client on components of CenterPoint's filing including its proposed hydrogen blending facility, an RFP for renewable natural gas, and residential and commercial gas heat pump pilots.

**Minnesota Public Utilities Commission Investigation into Gas Utility Resource Planning on Behalf of the Citizen's Utility Board of Minnesota (2023)**

*Comments*

Providing technical support to client on the Minnesota Commission's consideration of natural gas utility long-term planning.

**Nonpipeline Alternative Analysis Framework for the Colorado Public Utilities Commission on Behalf of Lawrence Berkeley National Laboratory (2023)**

[\*Part 1 | Non-Pipeline Alternative to Natural Gas Utility Infrastructure Report\*](#)

[\*Part 2 | Non-Pipeline Alternatives: A Regulatory Framework and a Case Study of Colorado\*](#)

Through a collaboration with Lawrence Berkeley National Laboratory and the Colorado Public Utilities Commission, I led the development of two reports that first examined the existing regulatory approaches for non-pipeline alternatives, and then proposed a regulatory framework.

**Comments to the Oregon Public Utilities Commission on Northwest Natural Gas Company's 2022 Integrated Resource Plan on Behalf of Coalition of Climate Advocates (2023)**

[\*Natural Gas IRP\*](#)

Provided technical support to a coalition of climate-focused organizations, and frontline community organizations, on the gas utility's plans for meeting future customer demand while complying with Oregon and Washington emissions reductions requirements.

**Consolidated Edison and Orange & Rockland's 2023 Initial Long-Term Gas System Plan on Behalf of Sierra Club and Earthjustice (2023)**

[\*A Review of the Initial Long-Term Plan\*](#)

Provided a review of the gas utilities' initial Long-Term Plan with a focus on electrification assumptions, alignment of capital investment spending and load forecast, nonpipeline alternative analysis, and reasonableness of scenarios for meeting emissions reduction requirements.

**National Fuel Gas Distribution Corporation 2023 Long-Term Gas System Plan on Behalf of Sierra Club and Earthjustice (2023)**

[\*Comments on Electrification Assumptions\*](#)

Provided comments on NFG's technological and cost assumptions for various electrification technologies, cost basis for the crossover temperature for heat pumps, and electrification adoption curves. Strategen then proposed several recommendations for adjustments that NFG could make in this proceeding, or future LTPs, to better represent the technical capacity and emission reduction potential of electrified heating systems.

**Consumers Energy Gas Bill Impact Analysis: A Case Study of the Effects of Planned Capital Expenditures and Electrification Trends on Behalf of Advanced Energy United (2023)**

[\*White Paper\*](#)

Quantified the impact of gas utility capital improvement projects on customer rates Consumers Energy gas in Michigan. The paper found that Michigan residential customers

with Consumers Energy can expect to see their gas bills steadily increase over the next decade – up to 49% over 2021 levels – due to projected utility capital expenditures and electrification trends.

### **White Paper on the Relationship of Gas and Electricity Prices in New England on Behalf of Sierra Club (2023)**

[\*White Paper\*](#)

Co-authored a white paper that provides background and context on the implications of recent electricity price spikes in New England and the relationship between natural gas prices and electricity prices.

### **Nevada Gas Utility Decarbonization Planning 2022 Legislative Proposals on Behalf of GridLab and SWEEP (2023)**

*Technical and Policy Advice*

Providing a coalition of climate-focused advocates with technical and policy guidance on legislation for gas planning requirements

### **Presentations to Western States on Planning for Decarbonizing Gas Utilities on Behalf of Advanced Energy United (2022-2023)**

*Presentations*

Led Strategen's collaboration with AEU to develop a series of presentations for Western State Public Utility Commission commissioners on how to plan for the decarbonization transition of natural gas utilities.

### **Designing Building Electrification Incentives for Washington State on Behalf of Climate Solutions (2022)**

*Technical and Policy Advice*

Developed funding scenarios that would allow Washington State to meet building decarbonization targets. Solutions focused on rebates for high-efficiency electric appliance retrofits and community-centered weatherization programs.

### **Washington Utilities and Transportation Commission Proceeding to Develop a Policy Statement Addressing Alternatives to Traditional Cost of Service Rate Making, (DKT: U-210590) On Behalf of The Energy Project (2022)**

*Policy Statement*

Supported client, the low-income advocate in Washington, on comments on regulatory goals, outcomes, and performance metrics.

[Case Details](#) | [Comments](#)

### **Comments to the Minnesota Public Utilities Commission on Natural Gas Planning (DKT: 21-135) On Behalf of Citizens Utility Board of Minnesota (2022)**

### [Comments](#)

Provided technical and policy guidance to the Minnesota Commission on how gas planning, operational changes, and risk sharing can help protect customers from future natural gas price spikes like that occurred during February 2021.

### **Puget Sound Energy 2023 Natural Gas Integrated Resource Plan on Behalf of Climate Solutions (2023)**

#### *Natural Gas IRP*

Supported client's review of the Company's development of the inputs and assumptions used in the IRP.

### **Michigan Public Service Commission, Renewable Natural Gas Study Workgroup (DKT: U-21170) On Behalf of Michigan Environmental Council, NRDC, and Sierra Club (2022)**

#### *Workgroup*

Supported clients' review of the development of the study including submitting comments to the PSC.

### **Kentucky Utilities and Louisville Gas and Electric Company General Rate Case (DKT: 2020-00350) On Behalf of the Kentucky Public Service Commission (2021-2022)**

#### *General Rate Case*

Supported the Kentucky PSC evaluate testimonies on PURPA rates and set new rates for the utilities.

[Case Details](#) | [Final Order](#)

### **Minnesota Power 2021 Integrated Resource Plan (DKT: 21-33) On Behalf of Citizen Utility Board of Minnesota (2022)**

#### *Electric IRP*

Supported client's review of the Company's IRP.

[Case Details](#) | [Comments](#)

**MPSC Case No:** U-21291

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**Requester:** CEO

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**Question No.:** CEODG-2.4j

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**Respondent:** K. M. Fedele

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**Page:** 1 of 1

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**Question:** Please refer to Exhibit A-12, Schedule B5.6, DTE Gas Delivery Plan 2024 – 2033.

j. Please provide Figure 65 and the underlying data and analysis in an unlocked Excel workbook with all formulas intact.

**Answer:** See the data in file “U-21291 CEODG-2.4j Figure 65 Data”.

**Attachment:** U-21291 CEODG-2.4j Figure 65 Data

**Figure 65 Data (Dollars in \$M)**

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Growth	83.9	97.2	85.1	85.3	80.3	80.3	80.3	80.3	80.3	80.3	80.3
Corporate Support	31.5	37.1	34.7	35.1	24.0	21.1	21.1	21.1	21.1	21.1	21.1
Storage Other	2.8	3.1	3.4	3.8	4.2	4.7	5.1	5.6	6.1	6.6	7.3
Compression Other	18.7	18.4	14.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5
Transmission Other	12.9	16.7	11.6	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5
Distribution Other	169.6	171.8	147.7	140.0	140.0	136.0	166.8	176.8	186.8	196.8	206.8
PSMS Risk Mitigation	414.8	417.2	423.4	571.7	529.4	409.5	459.0	448.5	438.1	452.5	432.3
Total	734.2	761.5	720.4	863.9	806.0	679.6	760.3	760.3	760.4	785.3	775.8

**MPSC Case No:** U-21291

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**Requester:** CEO

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**Question No.:** CEODG-1.16

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**Respondent:** H. J. Decker

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**Page:** 1 of 1

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**Question:** 16. Does the Company's demand forecast include anticipated building electrification? If yes, please explain the impact on the utility's forecast. If not, please explain why not.

**Answer:** The Company's demand forecast does not include impacts of building electrification. As stated previously, there is too much uncertainty related to the adoption of electrification technologies to accurately forecast. To date, the Company has not seen any impact of electrification and therefore does not include it in current forecasts.

**Attachment:** None

**MPSC Case No:** U-21291

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**Requester:** MNSC

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**Question No.:** MNSCDG-2.1b

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**Respondent:** G. H. Chapel

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**Page:** 1 of 1

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- Question:**
1. Please refer to the following statement on page 5 of DTE's Gas Delivery Plan 2024-2033 (Exhibit A-12 Schedule B5.6): "DTE Gas has a 2050 net zero goal for upstream and internal emissions and a 2040 goal of a 35% reduction from 2005 levels in customer gas emissions."
  - b. Please provide DTE Gas' historical annual customer gas consumption from 2005 to 2023 in Excel format.

**Answer:** Please see attachment U-21291 MNSCDG-2.1b Annual Billed Sales Volumes.

**Attachment:** U-21291 MNSCDG-2.1b Annual Billed Sales Volumes

**Co-Respondent(s):** H. J. Decker

**MPSC Case No:** U-21291

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**Requester:** CEO

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**Question No.:** CEODG-1.27a

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**Respondent:** G. H. Chapel

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**Page:** 1 of 1

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**Question:** 27. Please provide the Company's actual peak day demand for each year of the previous twenty years of complete data.

a. Please separately identify the demand by customer class.

**Answer:** See attachment U-21291 CEOFG-1.27a Historical Peak Day Demand.

**Attachment:** U-21291 CEOFG-1.27a Historical Peak Day Demand

**MPSC Case No:** U-21291

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**Requester:** CEO

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**Question No.:** CEODG-1.24a

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**Respondent:** G. H. Chapel

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**Page:** 1 of 1

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**Question:** 24. Please provide the Company's annual demand forecast for each year for the next twenty years, or for as long as the utility develops a load forecast.

a. Please separately identify the forecast by customer class.

**Answer:** The Company's operating sales forecast is a five-year forecast. As such, it extends through December 2028. See attachment U-21291 CEODG-1.24a Five Year Forecast.

**Attachment:** U-21291 CEODG-1.24a Five Year Forecast

# The Future of Gas Utilities Series

TRANSITIONING GAS UTILITIES  
TO A DECARBONIZED FUTURE

Part 1 of 3

AUGUST 2021



## FUTURE OF GAS UTILITIES

# Agenda

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<b>I. Background on Industry and Landscape</b> .....	2–6
<b>II. Overview of Three-Part Future of Gas Utilities Series</b> .....	7
<b>III. Part 1: Assessing Risk</b> .....	8–20
A. Risk and opportunities for transition	
B. Regulatory and financial expectations	
C. Heating electrification	
D. Investor reactions	
E. Equity and energy justice	
<b>IV. How Brattle Can Help</b> .....	23–30



## SERIES INTRODUCTION

# Energy Sector's Changing Landscape Threatens Natural Gas Utilities

Natural gas utilities face **increased risk** related to decarbonizing the energy sector.



Pressure is increasing to ban new gas uses and gradually “electrify everything.”



However, as a countervailing force, a growing number of states have prohibited the enactment of bans on new gas connections.



Regardless of bans, cost declines related to innovation, as well as federal, state, and municipal support policy, will increase electrification (as is happening with renewable adoption in the electricity sector).

At the same time, there are **approximately \$150–180 billion of unrecovered gas distribution infrastructure**.

Utilities will need to consider how to **recover their costs from a shrinking customer base**, which could lead to higher rates and create a vicious cycle.

## SERIES INTRODUCTION

# Impact Will Differ for Pure-Play, Combination, and Electric Utilities

The natural gas transition will impact all three types of utilities:

- **Combination utilities** may be better positioned to transition business from gas to electricity investment and sales. Gas sale declines presents downside risk, but electrification can present upside potential.
- Electrification serves as a boon to **electric utilities**, which can increase electricity investments and sales.
- **Pure-play gas utilities** face the most downside risk, and will need to be innovative and proactive to grow business.

Regulation will fundamentally answer the question of “who pays” for the transition, highlighting the need for well-designed regulatory strategy.

### Who pays?

- Gas, electric, or combination utilities
- Shareholders or utility customers
- Gas or electric customers
- Current or future customers
- Advantaged vs. vulnerable populations

This series provides commentary on these issues and aims to help gas and combination utilities navigate the transition in a fiscally and socially responsible way.

## SERIES INTRODUCTION

# Waiting Passively Is Not a Sustainable Option for Utilities or Customers

If gas utilities defer building a long-term strategy, they risk not having a voice in the policy, planning, and regulation process.

### **Gas demand reduction and bill increases for remaining customers will come with or without utility involvement.**

However, the needed change is likely to be delayed or inefficient without utility involvement.

The scale of the transition is massive: displacing natural gas in the US would involve replacing nearly 150 million heating and cooking appliances, in addition to the gas distribution system infrastructure.

Proactive implementation of suitable solutions affords utilities the following benefits:

- Allows utilities to build a diversified and tailored strategy ahead of regulatory mandates
- Finding substitute capital deployments makes gas utilities part of the solution, not an obstacle
- Satisfy customers, reduce costs, and head off or offset probable customer defection
- Address investor concerns

The transition process will play out over many years, **but the planning must start now.**

## SERIES INTRODUCTION

# The Transition Presents Significant Growth Opportunities

**Natural gas utilities can create new business opportunities as an enabler of the energy transition**, through proactive and innovative approaches.

- Utilities' access to capital, capabilities in large-scale planning and execution, and experience in working with regulatory authorities make them uniquely positioned to help plan and implement large infrastructure transitions.
- Clean fuels, such as renewable natural gas (RNG) and hydrogen, can provide growth opportunities while re-utilizing gas utilities' existing infrastructure or right-of-ways.

**Gas utilities have options** to create and capture value and reduce customer costs.

- Utilities' pathways will depend on their characteristics (pure-play versus combination), location, customer base, and regulatory environment.

Natural gas utilities will need to work closely with legislators, regulators, and stakeholders to **design and pursue enabling regulatory mechanisms and policies** to navigate this transition.



## SERIES INTRODUCTION

# Building Blocks for a Successful Energy Transition



1

### Is it a real risk? How big is it, and how immediate?

- Policy risk
- Business strategy risks
- Cost of capital implications

2

### What strategies will enable solutions?

- Regulatory framework for transition
- New technologies and infrastructure
- Securing life of existing assets

3

### What steps can be taken to get there?

- Performance-based regulation
- Multi-year rate plan
- New programs

## SERIES INTRODUCTION

# The Brattle Group's Future of Gas Utilities Presentation Series

**The Brattle Group's Future of Gas Utilities** building blocks will be presented in a series of three presentations to be released in the summer and fall of 2021.

**The Brattle Group's Future of Gas Utilities Series** will culminate in a **Symposium**, where industry and Brattle experts will convene to debate key challenges and opportunities facing the gas industry.

The remainder of this slide deck will cover the first building block: **Assessing Risk**.



# Part 1: Assessing Risk

The Future of Gas Utilities Series



## ASSESSING RISK

# Risks and Opportunities of the Transition

**Traditional gas utility business models face increasing risks** as more states and locales challenge the long-run role natural gas could play in meeting climate and energy policy goals.

- Even though certain states are moving against this trend and enacting prohibitions on bans on new gas connections, cost declines related to technology innovation and federal, state, and municipal policy support will increase the deployment of lower-carbon alternatives to natural gas, as happened with renewables in the electricity sector.
- The transition is already underway: at the current rate, the number of homes with electric space heating could exceed the number of homes with gas space heating by 2032.

The transition will affect **gas companies' growth opportunities, cost recovery, and capital attraction.**

- In the past decade, gas utility capital expenditures have grown by around double the rate of water and electric utilities' spending, largely driven by safety and reliability.
- Utilities will need to recover their costs from a changing – and possibly shrinking – customer base.
- With energy and environmental policy targets rapidly approaching, gas utilities need to decide today how best to invest capital in long-lived assets and avoid stranded asset risks.
- Heightened perceptions of business risk are increasing financing costs for gas utilities. In early 2021, gas utilities traded at a ~20% discount relative to electric utilities.

**Any strategic plan (including electrification and alternative gas technologies) must address equity and energy justice by considering financial, health, and economic impacts to vulnerable communities.**

## ASSESSING RISK

# The Debate on the Future of Natural Gas Is Widespread

The **landscape for natural gas has shifted dramatically**, as states and cities across the country have passed natural gas bans and electrification mandates.

States are also launching proceedings on the role gas utilities will play in meeting the state's greenhouse gas (GHG) emissions and clean energy goals.

Proposed approaches include "electrify everything" or leveraging alternative gas technologies such as RNG, hydrogen, etc.

The outcomes being debated vary widely: while some states have banned the use of gas in new buildings, **others have prohibited the enactment of such bans.**

### STATES ENACTING GAS BANS | AS OF JULY 21, 2021

	STATE-WIDE	CITY			
	Proceeding on Future Role of Natural Gas	Proposed Gas Bans	Enacted Gas Bans	Implemented Moratoriums	Electrification "Reach" Codes
California	✓		✓		✓
Oregon	✓	✓			
Washington	✓	✓	✓		
New York	✓	✓		✓ PARTIALLY LIFTED	✓
Massachusetts	✓	✓	✓		
Colorado	✓	✓			✓
Washington, DC	✓				
Vermont					✓
<b>Proposed Prohibition on Gas Bans</b>		CO, MI, MN, NC, PA			
<b>Enacted Prohibition on Gas Bans</b>		AL, AR, AZ, FL, GA, IA, IN, KS, KY, LA, MO, MS, OH, OK, TN, TX, UT, WV, WY			

## ASSESSING RISK

# Gas Utilities Can Participate in a Decarbonized Future to Mitigate a Potential Death Spiral and Control Customer Costs

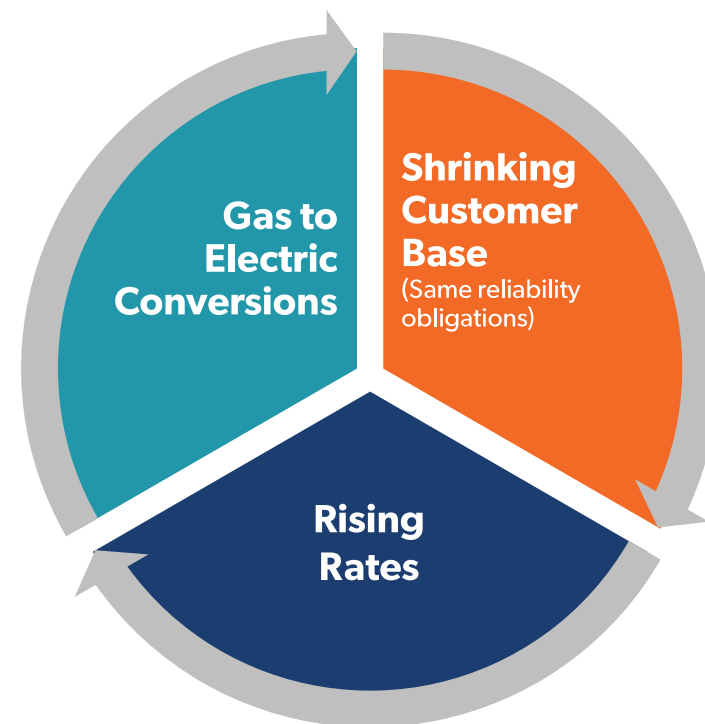
As states pursue degasification policies and homes convert to electric heating, **utilities risk losing customers and load.**

- Nationally, electric heating is outpacing gas heating adoption.
- Technology mandates and policy further accelerate the problem.

Utilities will likely **continue investing in their existing system for safety and reliability but need to recover those costs from a shrinking customer base.**

- This puts remaining customers at risk, a “death spiral” trend pushing more customers to electrification.
- Up to \$150–180 billion of gas distribution assets could be under-recovered as a result of the transition.

This spiral will increase customer costs and increase energy burdens, especially for low-income and vulnerable populations.



Gas utilities may reverse this problem if they quickly become part of the solution to a decarbonized future.

## ASSESSING RISK

# Gas Utilities' Risks and Opportunities with Decarbonization

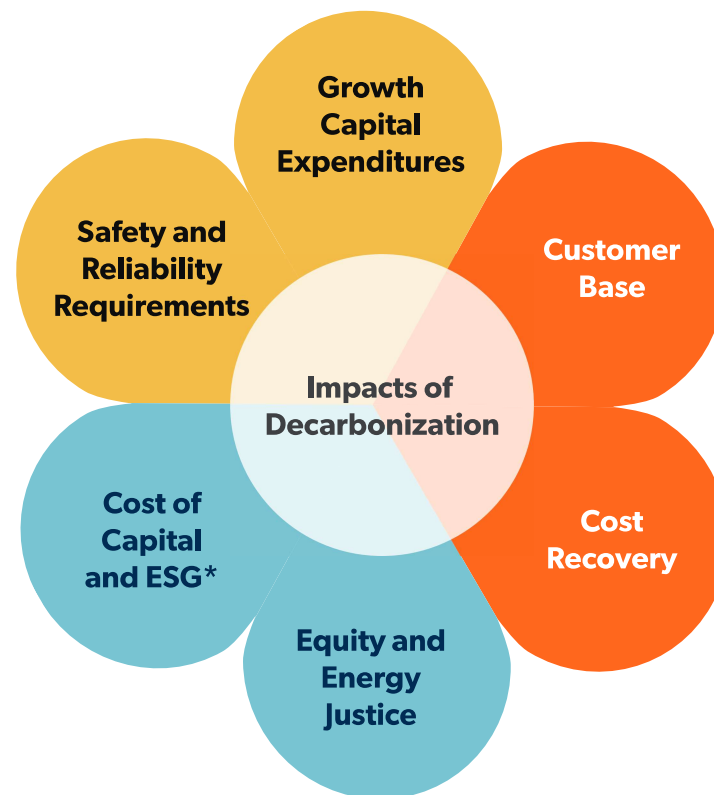
Proposed decarbonization pathways generally emphasize electrification, challenging the traditional business model of natural gas utilities.

Without proactive adjustments, utilities face increasing **cost recovery risks from capital investments** to grow the gas system or to maintain safety and reliability requirements.

There are **offsetting opportunities**, such as:

- Alternative fuels (RNG, hydrogen) are a viable alternative for end-uses that lack cost-effective electrification options.
- Long-run deep degasification may be expensive to achieve, requiring utilities to invest in clean performance of existing assets.
- Utilities could own and rate base gas replacement infrastructure, earning a return on these decarbonization assets.

The transition will take time and depends on factors such as costs, regulatory and legislative mandates, and customer adoption.



\*ESG stands for Environmental, Social, Governance investing

ASSESSING RISK

# Traditional Planning Faces Conflicting Regulatory and Financial Expectations

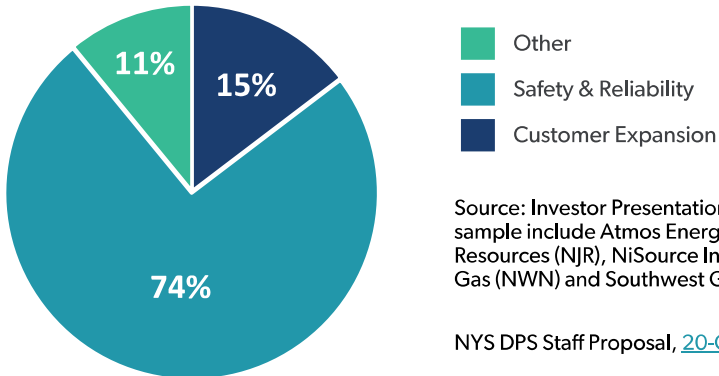
**New gas assets placed into service today have a useful life of ~40 years** – well beyond target dates for many decarbonization goals, creating cost-recovery risk.

- Gas utility capital expenditures have grown by around double the rate of water and electric utilities’ capital expenditures.

Regulators are requiring gas utilities to develop gas long-range capital investment plans that conform to state climate and energy policy goals. Gas utilities and regulators need to decide today how best to deploy capital and avoid cost recovery risks due to the transition.

- **Alternative depreciation schedules** may be required to fully recover traditional gas investments before policy target dates.
- **Diversifying into gas decarbonization technologies** can limit exposure to lost growth opportunities and reduce stranded asset risk.

## FORECASTED CAPITAL EXPENDITURES



Source: Investor Presentations, 2020. Utilities in the sample include Atmos Energy (ATO), New Jersey Resources (NJR), NiSource Inc. (NI), Northwest Natural Gas (NWN) and Southwest Gas (SWX).

NYS DPS Staff Proposal, [20-G-0131](#), February 12, 2021.

**NY GAS PLANNING PROCEEDING | STAFF PROPOSAL**

Utilities must incorporate demand-side solutions into their long-term planning to **reduce gas demand and the need for gas infrastructure investments.**

LDCs must **identify opportunities to avoid replacing leak prone pipe** and instead deploy “Non-Pipeline Alternative” investments.

## ASSESSING RISK

# Safety and Reliability Investments Will Remain a Priority

Utilities are under increasing pressure and are making **significant investments to meet new and existing safety and reliability requirements.**

- PHMSA's Mega Rule went into effect in 2020, mandating confirmation of Maximum Allowed Operating Pressures (MAOP), more frequent and regular pipeline integrity assessments, and new repair and leak detection requirements, amongst other requirements.
- This will require material investments, but increases the risk of obsolescence before the end of normal asset life (~40 years).

Utilities are also focused on replacing **leak-prone pipe**, which reduces methane emissions and helps meet state and corporate GHG emission targets.

- 32 natural gas utilities have pledged to reduce methane intensity to 1% by 2025.
- New York is asking utilities to identify opportunities to retire leak prone pipe and instead deploy non-pipeline alternatives, such as electrification of heating.
- Methane is a more potent GHG than CO<sub>2</sub> even though it is short-lived. Its 20-year warming potential is 80x – and its 100-year warming power is 25x – that of CO<sub>2</sub>, per ton emitted.

**Enabling regulatory mechanisms will need to be designed and implemented** to recover safety and reliability costs from a changing and/or declining customer base.

## ASSESSING RISK

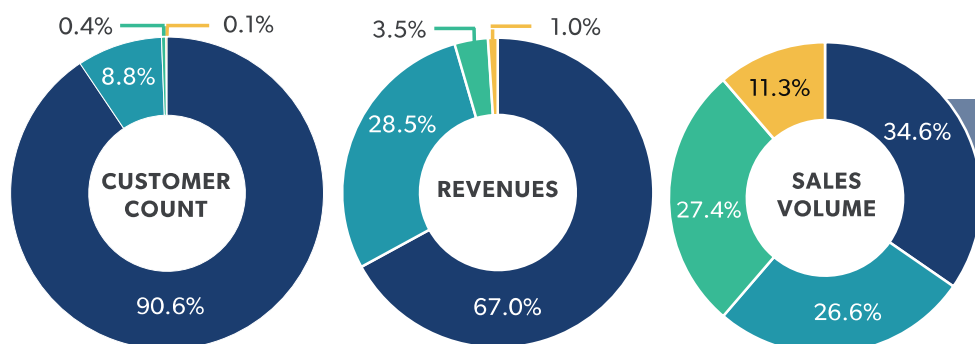
# Shifts in Customer Base Increase Cost Recovery Risks

The transition **will not occur at the same pace or magnitude across customer classes**, which compounds cost recovery risks (cost allocation, appropriate tariff designs, equity and energy justice).

- Residential customers, who are more likely to convert to electric alternatives, comprise 90% of total natural gas utility customers and 67% of revenues, but they account for only one-third of total system volumes.
- Harder to electrify industrial customers are a small portion of total customers but about 27% of total sales volumes.
- Differences in customer transition trends will impact the pace and feasibility of achieving state GHG emission targets.

Gas utilities can mitigate this risk by focusing on degasification solutions for commercial and industrial customers, which could most effectively help meet state and corporate decarbonization goals.

**Declines in customer base, starting with easy-to-electrify customers, will raise costs for remaining customers**, such as for low-income and other vulnerable customer populations.



### Gas Utility Customer Base



**68M**  
total customers

**\$67B**  
total revenues

**29.7B**  
MMBtu\*

Source: S&P Market Intelligence, data as of year-end 2019.

Note: Other revenues and sales volumes reflect electric power revenues and sales.

\*American Gas Association summary statistics

## ASSESSING RISK

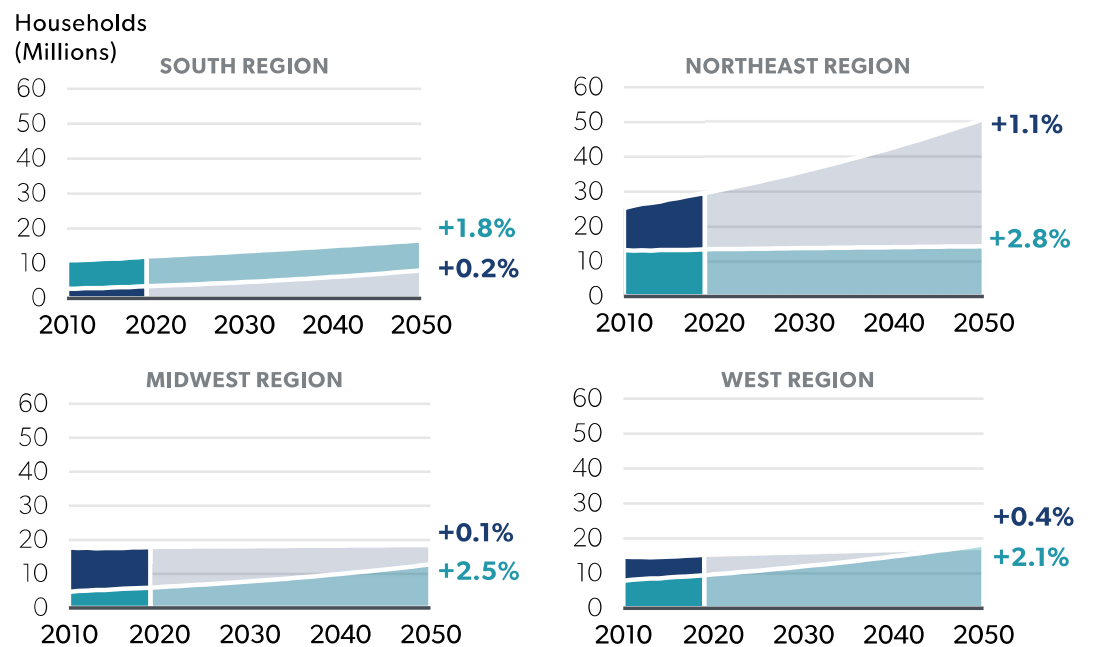
# Heating Electrification Will Accelerate Declines in Gas Customer Base

**Heating electrification is outpacing gas growth in some parts of the country.** At the current pace, the number of homes with electric space heating could surpass homes with gas space heating by 2032.

- Heat pumps remain more expensive than gas furnaces, but could become more competitive with technological improvements and financial incentives.
- Economics of heat pump water heaters (HPWH) can be more appealing because of lower upfront costs relative to heat pumps. HPWH also has a higher efficiency than its gas counterpart.

Electric utilities are promoting rebates for heat pumps and HPWHs to accelerate adoption. As heat pumps and other decarbonization technologies become more popular, **gas utilities need to think strategically about how to participate in this transition in order to remain viable.**

## US HOUSEHOLDS BY SPACE HEATING FUEL



Source: US Census Data, 2019. | Note: Electricity includes both heat pumps and electric resistance heating.

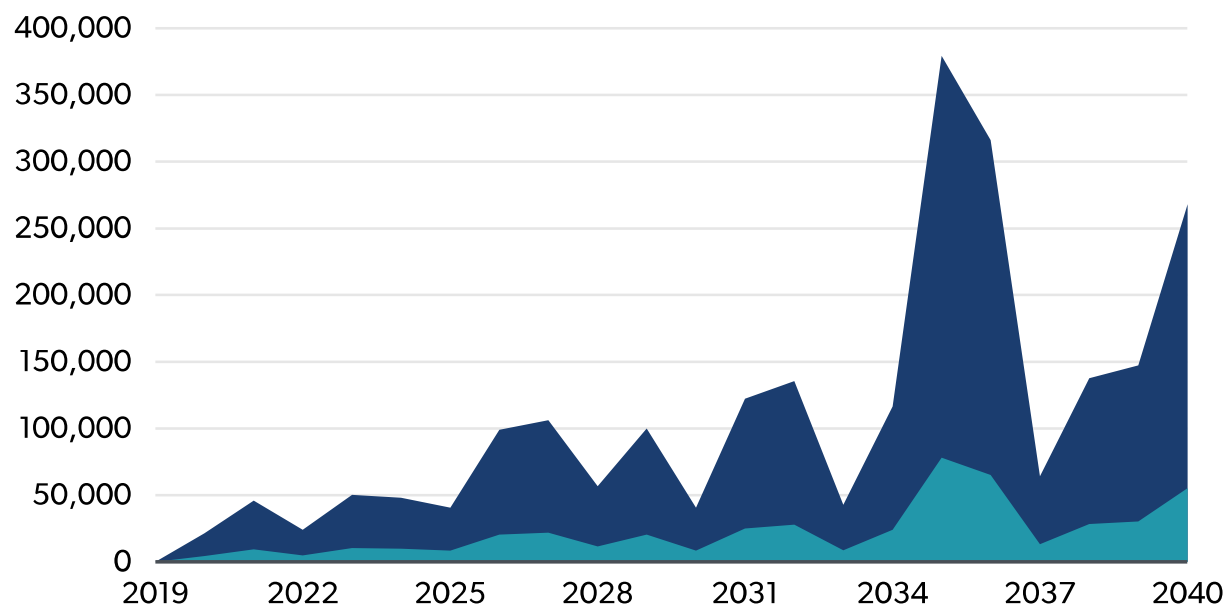
At current rates, homes with electric heating could surpass homes with gas heating by 2032 nationally.

## ASSESSING RISK

# Death Spiral for Gas Utilities: An Illustrative Example

### ELECTRIFICATION OF HEATING SECTOR CASE STUDY: NEW YORK GENERIC UTILITY

Forecasted Newly Electrified Load



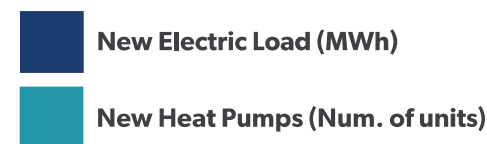
Source: CCIS NYISO forecast.

\*Assumed forecast of new heat pumps from CCIS forecast, calculated new load and related costs. We assume AHSP at \$12,800 and GHSP at \$35,700 in real dollars. Capital cost assumptions come from New Efficiency NY Analysis of Residential Heat Pumps.

The impact of increasing electrification will vary based on state and local regulations and decarbonization goals.

For example, up to **60% of New York's gas heating sector may be electrified by 2040.**

- This requires around **4 million additional heat pumps**, costing about **\$80 billion.\***
- Adds about 20% to residential electric consumption.



## ASSESSING RISK

# Death Spiral for Gas Utilities: An Illustrative Example

### RATES IMPACT FOR GAS AND ELECTRIC CUSTOMERS – GAS UTILITY NO-ACTION “DEATH SPIRAL” SCENARIO

Annual Gas & Electric  
 Heating Bill (\$)

\$3,000

\$2,500

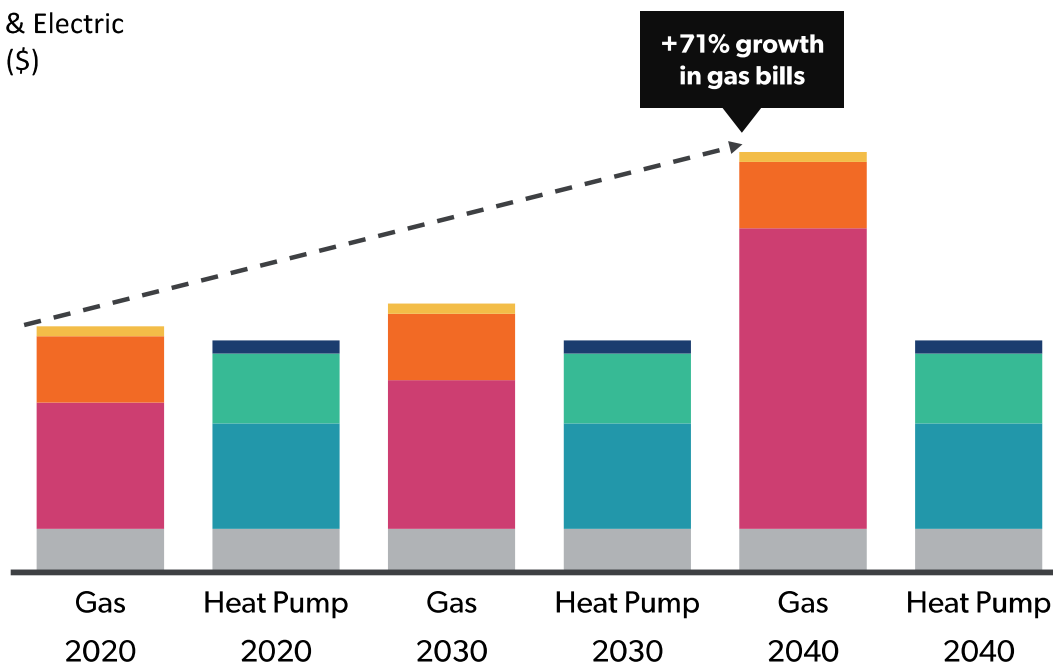
\$2,000

\$1,500

\$1,000

\$500

\$0



There is a large potential for non-participant gas bill to grow, which will further increase remaining gas customer’s propensity to switch to electric. Impacts are likely to fall disproportionately on low- and moderate-income customers, requiring utility intervention or offsets.

- Gas Surcharges
- Gas Commodity Charges
- Gas Variable Delivery Charges
- Electricity Surcharges
- Electricity Commodity Charges
- Electricity Variable Delivery Charges
- Gas Fixed Delivery Charge

Source: CCIS NYISO forecast and The Brattle Group analysis. | Note: Rate impacts for a gas furnace and air source heat pump customer.

## ASSESSING RISK

# Adverse Investor Reactions to Risks Are Emerging

Investors' **risk perceptions are shifting** as states and locales transition away from natural gas and reduce GHG emissions.

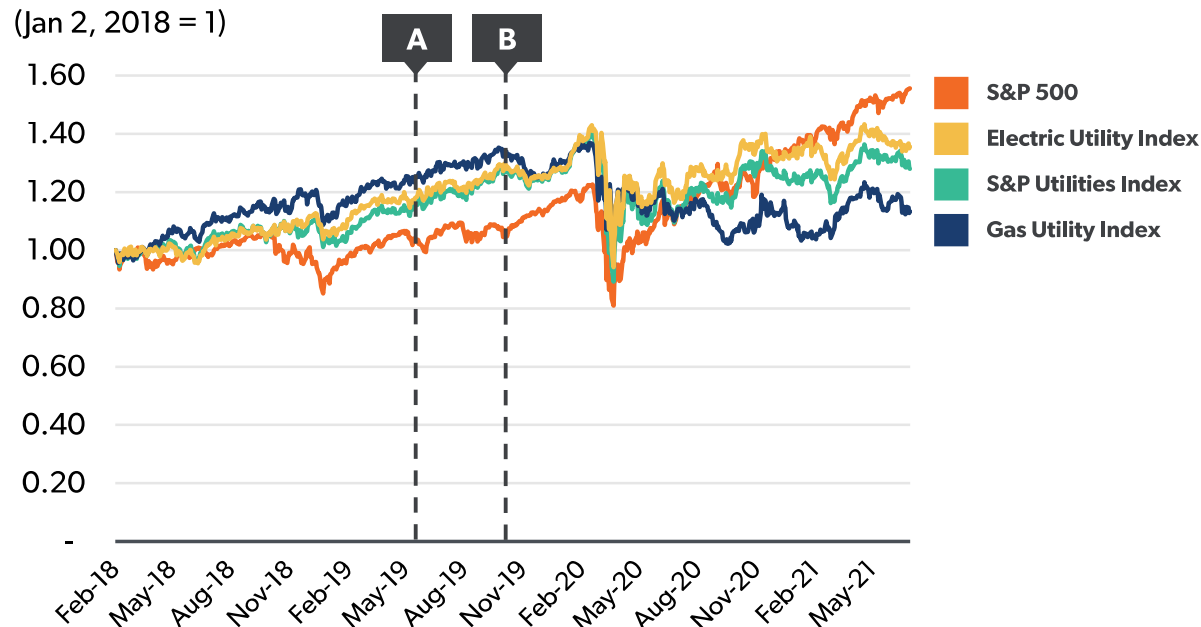
- A** Berkeley, CA passes the nation's first gas ban (July 2019)
- B** Brookline, MA passes first East Coast gas ban (Nov 2019)  
*Five additional CA municipalities have enacted gas bans*

All else equal, gas utilities have to **issue more shares to raise the same amount of equity capital**, relative to other utilities.

- Gas utilities currently trade at a ~20% discount relative to electric.
- However, P/E ratios for gas utilities remain elevated at approximately 18 (vs. 19 for electric utilities and 18.5 for S&P util.)

## UTILITY STOCK PERFORMANCE

(Jan 2, 2018 = 1)



Notes: **Gas Utility Index includes:** Atmos Energy, Chesapeake Utilities, New Jersey Resources, NiSource, NW Natural, ONE Gas, South Jersey Industries, Southwest Gas, Spire. **Electric Utility Index includes:** AEP, Southern, FirstEnergy, Exelon, Duke, Progress Energy, Evergy, NextEra, Edison International, Dominion. Electric Utility Index is currently trading 3% above S&P Utility Index and 20% above the Gas Utility Index. Data through June 30, 2021.

1: United Nations Environment Programme, [Net Zero Banking Alliance](#).

## ASSESSING RISK

# Investors Are Becoming Actively Involved in the Debate

**Environment, Social, and Governance (ESG) investors** are pressuring gas utilities to reduce GHG emissions and eliminate usage of fossil fuels.

43 banks across 23 countries announced a pledge to achieve “net-zero banking,” meaning their lending and investment portfolios are on track to reach net zero emissions by 2050.<sup>1</sup>

Utilities are increasingly highlighting RNG, hydrogen, and emission reduction efforts in their investor materials.

70 gas utilities across 31 states have set corporate carbon emission reduction targets.

1: United Nations Environment Programme, [Net Zero Banking Alliance](#).



## ASSESSING RISK

# Equity and Energy Justice Concerns Must Be Considered

Gas utilities and regulators will also need to **consider the risks and impact of the transition on low-income and less advantaged communities**, who may experience rising bills and longer exposure to emissions.

- Public policy is increasingly focused on fairness of service and equitable access to decarbonization technology.
- As more affluent customers adopt electric heating, low-income gas customers could disproportionately experience rate increases and/or be neglected by developers for obtaining new decarbonization technologies.
- For example, adverse effects from electrification on low-income communities can be observed in rooftop adoption, in which low-income communities subsidize delivery costs for homes with rooftop solar receiving net energy metering (NEM).



Emission  
Reductions

Physical and  
Mental Health

Environmental  
Justice

Equity

Affordability

Quality of  
Service

Community  
Citizenship

Job Creation

## ASSESSING RISK

# Turning Increasing Risk into Opportunity

Gas utilities need to **create an adaptive, long-term business plan that anticipates** the pathways, drivers, accelerators, and decelerators of the transition and identify the type and timing of impacts.

Long-term modeling tools can help

**Economy Decarbonization Model:** How different might the pace and means of decarbonization be? There are many enabling technologies and policy “knobs” yet to be turned or applied. What are these pathways, and how can they be realized or adjusted? When and how will gas utilities be affected under these different pathways?

**Distribution System Planning Model:** How can gas distribution investments, operations, pricing, and financing be altered so that utilities not only survive but grow in the face of the transition’s long-term effects?

By understanding the possible pathways, utilities can identify their comparative advantages, target market niches, and needed operational and regulatory adjustments.

- A “base case” would look at sales and profits with a passive response to trends in electrification.
- Responsive strategies are then developed for how to influence the path(s) that are likely to occur and how to prepare for their contingencies by selectively avoiding some risks and embracing others.

In Part 2 of this series, we will examine the solution elements available to gas utilities.

# How Brattle Can Help

Brattle's Unique Interdisciplinary Experience  
Provides a Holistic Skillset to Guide Transition



## Brattle's Expertise Can Tackle Analysis That Spans All Building Blocks



### Assess Transition Risks

Analyze how natural gas bans, electrification mandates, and ESG investment trends will impact business risk and cost of capital.

Estimate revenue loss to electrification under different future scenarios.

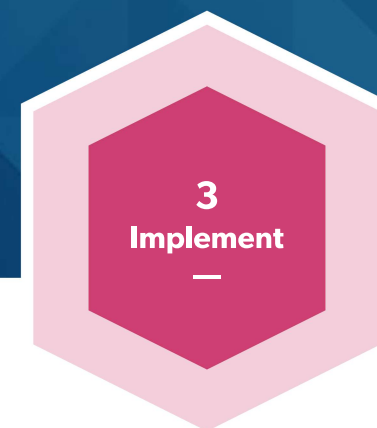
Use system dynamics to identify rate risks and customer feedback effects.



### Evaluate Strategy and Solutions

Facilitate strategy workshops to establish transition principles, identify potential business strategies, and determine near- and long-term action items.

Identify revenue potential from owning and rate-basing electrification infrastructure and evaluate rate impacts using system dynamics.



### Implement Regulatory Changes

Design and calculate tariffs to incentivize transition and protect customer costs.

## HOW BRATTLE CAN HELP

# DEEP Can Help Utilities Understand Risks and Evaluate Solutions

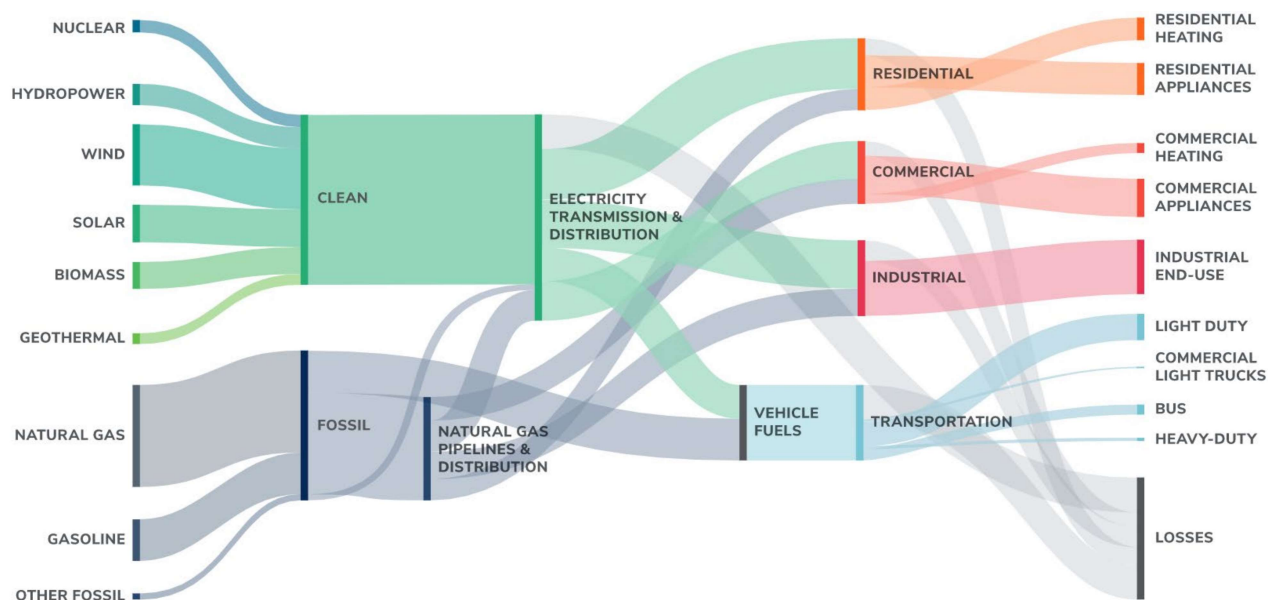
Brattle's **Decarbonization, Electrification & Economic Planning (DEEP) Model** is an energy economy modeling tool that can evaluate:

- The uptake of technologies and impact on gas consumption
- The roles of efficiency, electrification, and fuel-switching
- The utility and customer costs of specific technology pathways

DEEP can evaluate long-term planning impacts and the interactions of:

- Technology adoption
- Decarbonization policies
- Macroeconomic conditions
- Supply and demand

## DECARBONIZATION, ELECTRIFICATION & ECONOMIC PLANNING (DEEP) MODEL

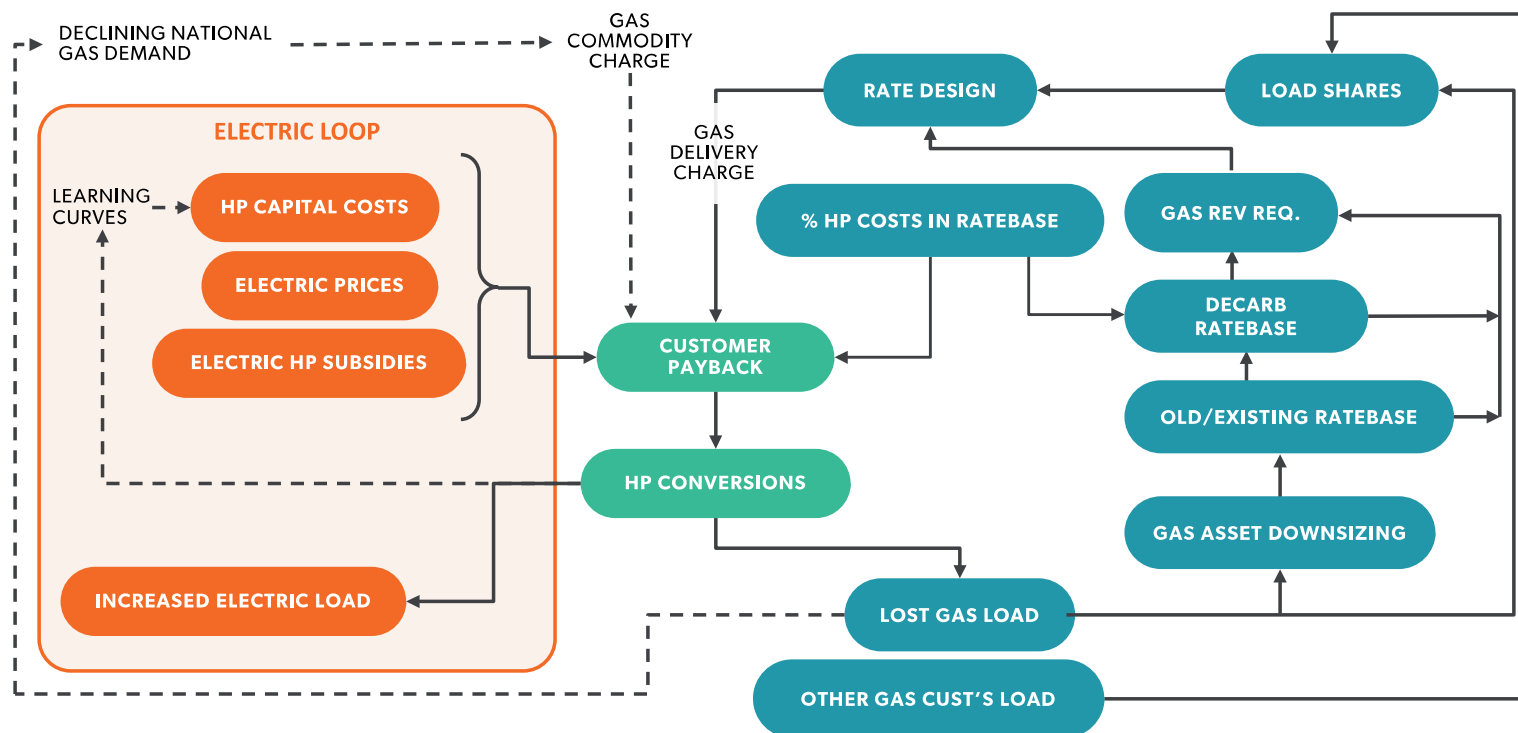


The model can be run in (1) **planning mode** and (2) **optimization mode** to meet client-specific needs.

## HOW BRATTLE CAN HELP

# Dynamic Modeling Can Help Utilities Understand Risk and Evaluate Potential Strategies

Brattle’s technical and analytical abilities can model pathways for decarbonization and the complex interdependencies both within and between the gas and electric sectors, many of which have not yet been thoroughly studied.



Brattle’s **System Dynamics Model** can help utilities analyze the complex feedbacks and interdependencies associated with the transition.

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# Clarity in the face of complexity

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**MPSC Case No:** U-21291

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**Requester:** CEO

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**Question No.:** CEODG-2.1

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**Respondent:** H. J. Decker

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**Page:** 1 of 1

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**Question:** Has DTE Gas or DTE Electric conducted a study or analysis that examines or forecasts the impact of building electrification in its service territory? If yes, please provide the study and its associated analysis in their native formats. If the Company's analysis includes Excel workbooks, please provide the workbooks in an unlocked file with all formulas intact.

**Answer:** The Company has not conducted a study or analysis that forecasts the impact of building electrification.

**Attachment:** None

**MPSC Case No:** U-21291

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**Requester:** CEO

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**Question No.:** CEODG-1.15a

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**Respondent:** H. J. Decker

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**Page:** 1 of 1

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**Question:** 15. Does the Company believe there will be an increase in building electrification over the next 30 years?

a. Please provide all sources and documents relevant to the Company's response.

**Answer:** The Company recognizes there are nascent efforts to increase building electrification. At this point, it is premature to speculate on the impact these efforts will have on building electrification in our service territory. Examples of electrification efforts:

<https://www.energy.gov/eere/buildings/residential-cold-climate-heat-pump-challenge>

<https://www.whitehouse.gov/ostp/news-updates/2022/12/14/fact-sheet-new-innovation-agenda-will-electrify-homes-businesses-and-transportation-to-lower-energy-bills-and-achieve-climate-goals/>

**Attachment:** None

**MPSC Case No:** U-21291

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**Requester:** MNSC

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**Question No.:** MNSCDG-2.1a

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**Respondent:** K. M. Fedele

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**Page:** 1 of 1

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**Question:** 1. Please refer to the following statement on page 5 of DTE's Gas Delivery Plan 2024-2033 (Exhibit A-12 Schedule B5.6): "DTE Gas has a 2050 net zero goal for upstream and internal emissions and a 2040 goal of a 35% reduction from 2005 levels in customer gas emissions."

a. Please provide DTE Gas' historical annual customer gas emissions from 2005 to 2023 in Excel format. Please provide all supporting workpapers with formulas intact and sources, methodologies, and assumptions clearly stated.

**Answer:** The Company's customer gas emissions reduction target was developed using customer natural gas usage excluding "end user transport" (EUT) customers. The annual customer gas consumption and emissions associated with that consumption from 2005-2023 for non-EUT customers can be found in the attachment named "U-21291 MNSCDG-2.1a Annual Emissions from Customer Gas Consumption".

**Attachment:** U-21291 MNSCDG-2.1a Annual Emissions from Customer Gas Consumption

## DTE Gas Customer Natural Gas Consumption and Emissions

Year	2005
Natural Gas Consumption (MCF) <sup>1</sup>	184,993,211
CO2 Emissions (metric tons)	10,070,949
CH4 Emissions (metric tons)	190
N2O Emissions (metric tons)	19
CO2e Emissions (metric tons)	10,081,350

### Information Used in Calculations (from EPA GHG Reporting Rule; 40CFR, Part 98)

Natural Gas Heat Content	1.026
CO2 Emission Factor	53.06
CH4 Emission Factor	0.001
N2O Emission Factor	0.0001
CH4 Global Warming Potential	25
N2O Global Warming Potential	298

#### Notes:

1 - Excludes EUT customer natural gas use

	2006	2007	2008	2009	2010	2011	2012	2013
	162,189,835	164,655,785	171,405,936	165,964,381	146,825,979	160,198,508	133,881,417	160,700,819
	8,829,543	8,963,788	9,331,264	9,035,028	7,993,142	8,721,136	7,288,445	8,748,482
	166	169	176	170	151	164	137	165
	17	17	18	17	15	16	14	16
	8,838,662	8,973,046	9,340,901	9,044,359	8,001,397	8,730,143	7,295,973	8,757,517

mmbtu/mscf

kg/mmbtu

kg/mmbtu

kg/mmbtu

-1.30%

0.987

2014	2015	2016	2017	2018	2019	2020	2021
180,259,832	155,854,353	139,591,594	142,909,649	165,764,729	164,935,554	148,174,120	146,102,094
9,813,266	8,484,642	7,599,305	7,779,938	9,024,159	8,979,019	8,066,534	7,953,734
185	160	143	147	170	169	152	150
18	16	14	15	17	17	15	15
9,823,401	8,493,405	7,607,153	7,787,973	9,033,479	8,988,292	8,074,865	7,961,948

2022	2023	2024	2025	2026	2027	2028	2029
161,209,331	146,239,111	144,338,003	142,461,609	140,609,608	138,781,683	136,977,521	135,196,813
8,776,165	7,961,193						
165	150						
17	15						
8,785,229	7,969,415	7,865,813	7,763,557	7,662,631	7,563,017	7,464,697	7,367,656
	21%	22%	23%	24%	25%	26%	27%

2030	2031	2032	2033	2034	2035	2036	2037
133,439,254	131,704,544	129,992,385	128,302,484	126,634,552	124,988,303	123,363,455	121,759,730
7,271,877	7,177,342	7,084,037	6,991,945	6,901,049	6,811,336	6,722,788	6,635,392
28%	29%	30%	31%	32%	32%	33%	34%

2038	2039	2040	2041	2042	2043	2044	2045
120,176,853	118,614,554	117,072,565	115,550,622	114,048,464	112,565,834	111,102,478	109,658,146
6,549,132	6,463,993	6,379,961	6,297,022	6,215,161	6,134,363	6,054,617	5,975,907
35%	36%	37%	38%	38%	39%	40%	41%

2046	2047	2048	2049	2050
108,232,590	106,825,566	105,436,834	104,066,155	102,713,295

5,898,220	5,821,543	5,745,863	5,671,167	5,597,442
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41%	42%	43%	44%	44%
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**MPSC Case No:** U-21291

**Requester:** CEO

**Question No.:** CEODG-1.30a

**Respondent:** H. J. Decker

**Page:** 1 of 1

**Question:** 30. Please refer to RMT-30, lines 17 – 21, where the witness writes that “The Company issued a press release on June 24, 2020, announcing the Company’s commitment to reduce greenhouse gas emissions from the Company’s own operations and from the Company’s suppliers of natural gas to net zero by 2050 as well as help to reduce our customers’ greenhouse gas emissions 35% by 2050 (from 2005).

a. Please provide all reports, documents, and analysis that demonstrate the Company’s plans for meeting its commitment to reduce greenhouse gas emissions from its own operations to net zero by 2050. If the response includes Excel workbooks, please ensure that the workbooks are unlocked with all formulas intact.

**Answer:** Pathways to achieve the DTE Gas emission reduction goals remain indeterminate due to the uncertainty associated with the cost and feasibility of technology development. DTE has identified solutions that, in some combination, can be used to meet its goals. The below graphic highlights these solutions.

DTE Gas decarbonization goals



**Attachment:** None

**MPSC Case No:** U-21291

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**Requester:** CEO

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**Question No.:** CEODG-1.30b

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**Respondent:** H. J. Decker

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**Page:** 1 of 1

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**Question:** 30. Please refer to RMT-30, lines 17 – 21, where the witness writes that “The Company issued a press release on June 24, 2020, announcing the Company’s commitment to reduce greenhouse gas emissions from the Company’s own operations and from the Company’s suppliers of natural gas to net zero by 2050 as well as help to reduce our customers’ greenhouse gas emissions 35% by 2050 (from 2005).

b. Has the Company conducted a customer bill impacts analysis associated with the Company’s plan for meeting its commitment to reduce greenhouse gas emissions from its own operations to net zero by 2050? If yes, please provide the response in an unlocked Excel workbook with all formulas intact. If not, please explain why not.

**Answer:** The Company has not conducted a bill impacts analysis associated with the Company’s emission reduction plan because DTE has not defined a specific plan to meet the current emission reduction commitments. After technology matures and DTE is able to determine a specific pathway for emission reductions, then further analysis will be completed.

**Attachment:** None

**MPSC Case No:** U-21291

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**Requester:** CEO

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**Question No.:** CEODG-1.30c

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**Respondent:** H. J. Decker

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**Page:** 1 of 1

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- Question:** 30. Please refer to RMT-30, lines 17 – 21, where the witness writes that “The Company issued a press release on June 24, 2020, announcing the Company’s commitment to reduce greenhouse gas emissions from the Company’s own operations and from the Company’s suppliers of natural gas to net zero by 2050 as well as help to reduce our customers’ greenhouse gas emissions 35% by 2050 (from 2005).
- c. Please provide all reports, documents, and analysis that demonstrate the Company’s plans for reducing its customers’ greenhouse gas emissions 35% by 2050 (from 2005). If the response includes Excel workbooks, please ensure that the workbooks are unlocked with all formulas intact.

**Answer:** DTE does not have a specific plan associated with meeting our emission reduction goals. DTE has identified likely solutions that can support our emission reduction goals as provided in response 30.a.

**Attachment:** None

**MPSC Case No:** U-21291

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**Requester:** CEO

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**Question No.:** CEODG-1.30d

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**Respondent:** H. J. Decker

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**Page:** 1 of 1

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**Question:** 30. Please refer to RMT-30, lines 17 – 21, where the witness writes that “The Company issued a press release on June 24, 2020, announcing the Company’s commitment to reduce greenhouse gas emissions from the Company’s own operations and from the Company’s suppliers of natural gas to net zero by 2050 as well as help to reduce our customers’ greenhouse gas emissions 35% by 2050 (from 2005).

d. Has the Company conducted a customer bill impacts analysis associated with the Company’s plan for meeting its commitment to reduce its customers’ greenhouse gas emissions 35% by 2050 (from 2005).? If yes, please provide the response in an unlocked Excel workbook with all formulas intact. If not, please explain why not.

**Answer:** DTE Gas has not conducted a bill impact study associated with the Company’s plan for reducing customers’ emissions 35% by 2040 because the Company has not defined a specific plan to meet its commitments. After technology matures and DTE is able to determine a specific pathway for emission reductions, then further analysis will be completed.

**Attachment:** None

**MPSC Case No:** U-21291

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**Requester:** CEO

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**Question No.:** CEODG-2.6c

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**Respondent:** H. J. Decker

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**Page:** 1 of 1

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**Question:** Please refer to Exhibit A-12, Schedule B5.6, DTE Gas Delivery Plan 2024 – 2033, Page 34. The Company writes, “[d]ownstream, through a combination of strategic initiatives such as a new voluntary carbon offset program, EWR efforts, and advanced technologies (e.g., RNG, Hydrogen, Gas Heat Pumps), the Company aims to reduce customer use emissions by approximately 35% by 2040 (from 2005 levels).”

c. Has the Company conducted an analysis of the price of RNG by source for each year of the Gas Delivery Plan (2023-2033)? If yes, please provide the analysis and please specify if price forecast includes the value of environmental attribute or not. Please provide response in an unlocked Excel workbook with all formulas intact.

**Answer:** The Company has not performed a pricing analysis for RNG for the years 2023-2033.

**Attachment:** None

**MPSC Case No:** U-21291

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**Requester:** CEO

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**Question No.:** CEODG-2.6d

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**Respondent:** H. J. Decker

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**Page:** 1 of 1

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**Question:** Please refer to Exhibit A-12, Schedule B5.6, DTE Gas Delivery Plan 2024 – 2033, Page 34. The Company writes, “[d]ownstream, through a combination of strategic initiatives such as a new voluntary carbon offset program, EWR efforts, and advanced technologies (e.g., RNG, Hydrogen, Gas Heat Pumps), the Company aims to reduce customer use emissions by approximately 35% by 2040 (from 2005 levels).”

d. What is the Company’s estimate of the percentage of emissions reductions the Company can achieve through deploying RNG for meeting its 35% reduction by 2040 target?

**Answer:** The Company does not currently have a prescribed percentage reduction attributable to the use of RNG.

**Attachment:** None

**MPSC Case No:** U-21291

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**Requester:** CEO

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**Question No.:** CEODG-2.7b

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**Respondent:** H. J. Decker

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**Page:** 1 of 1

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**Question:** Please refer to Exhibit A-12, Schedule B5.6, DTE Gas Delivery Plan 2024 – 2033, Page 34. The Company writes, “[d]ownstream, through a combination of strategic initiatives such as a new voluntary carbon offset program, EWR efforts, and advanced technologies (e.g., RNG, Hydrogen, Gas Heat Pumps), the Company aims to reduce customer use emissions by approximately 35% by 2040 (from 2005 levels).”

b. Has the Company conducted an analysis of the price of green hydrogen? If yes, please provide the Company’s analysis.

**Answer:** The Company has not conducted specific analysis on the cost of green hydrogen but has conducted preliminary analysis on blending green hydrogen into the natural gas supply at Blue Water Energy Center (see attachment U-21291 CEODG-2.7b BWEC Hydrogen Blending Pilot) and blending in a portion of the distribution system (see response U-21291 MNSCDG-2.4b&e for the full blending analysis).

**Attachment:** U-21291 CEODG-2.7b BWEC Hydrogen Blending Pilot

**MPSC Case No:** U-21291

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**Requester:** CEO

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**Question No.:** CEODG-2.7c

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**Respondent:** H. J. Decker

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**Page:** 1 of 1

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**Question:** Please refer to Exhibit A-12, Schedule B5.6, DTE Gas Delivery Plan 2024 – 2033, Page 34. The Company writes, “[d]ownstream, through a combination of strategic initiatives such as a new voluntary carbon offset program, EWR efforts, and advanced technologies (e.g., RNG, Hydrogen, Gas Heat Pumps), the Company aims to reduce customer use emissions by approximately 35% by 2040 (from 2005 levels).”

c. What is the Company’s estimate of the percentage of emissions reductions the Company can achieve through deploying hydrogen for meeting its 35% reduction by 2040 target?

**Answer:** The Company does not currently have a prescribed percentage reduction attributable to the use of hydrogen.

**Attachment:** None

**MPSC Case No:** U-21291

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**Requester:** CEO

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**Question No.:** CEODG-2.8a

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**Respondent:** H. J. Decker

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**Page:** 1 of 1

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**Question:** Please refer to Exhibit A-12, Schedule B5.6, DTE Gas Delivery Plan 2024 – 2033, Page 34. The Company writes, “[d]ownstream, through a combination of strategic initiatives such as a new voluntary carbon offset program, EWR efforts, and advanced technologies (e.g., RNG, Hydrogen, Gas Heat Pumps), the Company aims to reduce customer use emissions by approximately 35% by 2040 (from 2005 levels).”

a. Please provide the Company’s annual forecast gas heat pump installations for each year from 2024 – 2033.

**Answer:** The Company does not have an annual forecast for gas heat pumps at this time.

**Attachment:** None

**MPSC Case No:** U-21291

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**Requester:** CEO

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**Question No.:** CEODG-2.8b

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**Respondent:** H. J. Decker

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**Page:** 1 of 1

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**Question:** Please refer to Exhibit A-12, Schedule B5.6, DTE Gas Delivery Plan 2024 – 2033, Page 34. The Company writes, “[d]ownstream, through a combination of strategic initiatives such as a new voluntary carbon offset program, EWR efforts, and advanced technologies (e.g., RNG, Hydrogen, Gas Heat Pumps), the Company aims to reduce customer use emissions by approximately 35% by 2040 (from 2005 levels).”

b. Please provide the Company’s assumed price of a gas heat pump for each year 2024-2033.

**Answer:** The Company does not have an assumed price of gas heat pumps for the years 2024-2033.

**Attachment:** None

**MPSC Case No:** U-21291

---

**Requester:** CEO

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**Question No.:** CEODG-2.8c

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**Respondent:** H. J. Decker

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**Page:** 1 of 1

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**Question:** Please refer to Exhibit A-12, Schedule B5.6, DTE Gas Delivery Plan 2024 – 2033, Page 34. The Company writes, “[d]ownstream, through a combination of strategic initiatives such as a new voluntary carbon offset program, EWR efforts, and advanced technologies (e.g., RNG, Hydrogen, Gas Heat Pumps), the Company aims to reduce customer use emissions by approximately 35% by 2040 (from 2005 levels).”

c. What is the Company’s estimate of the percentage of emissions reductions the Company can achieve through deploying gas heat pumps for meeting its 35% reduction by 2040 target?

**Answer:** The Company does not currently have a prescribed percentage reduction attributable to the adoption of gas heat pumps.

**Attachment:** None

**MPSC Case No:** U-21291

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**Requester:** CEO

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**Question No.:** CEODG-2.9a

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**Respondent:** H. J. Decker

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**Page:** 1 of 1

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**Question:** Please refer to Exhibit A-12, Schedule B5.6, DTE Gas Delivery Plan 2024 – 2033, Page 34. The Company writes, “[d]ownstream, through a combination of strategic initiatives such as a new voluntary carbon offset program, EWR efforts, and advanced technologies (e.g., RNG, Hydrogen, Gas Heat Pumps), the Company aims to reduce customer use emissions by approximately 35% by 2040 (from 2005 levels).”

a. Please provide the Company’s forecast of annual customer use emission reductions for each from 2024 through 2040. Please disaggregate the data to show the number and percentage of emissions reductions from each “strategic initiative.”

**Answer:** The Company does not forecast customer use emissions on an annual basis. As stated, DTE Gas is targeting a 35% reduction in customer use emissions by 2040 but does not have interim targets at this time.

**Attachment:** None

# A Regulator's Blueprint for 21<sup>st</sup> Century Gas Utility Planning

Prepared by Strategen for Advanced Energy United  
December 2023

# Acknowledgments

## Lead Authors:

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**Erin Mettler**, Consultant at Strategen



## Executive Summary

The energy sector is in the midst of a profound transition as it shifts away from fossil fuels to renewable energy and a decarbonized economy. Natural gas utilities are not immune to this transition as their main product is a fossil fuel. Unlike electricity, where either fossil fuels, nuclear energy, or renewable resources can generate an electron, there is not a commercially available, zero-carbon substitute resource that can be used in the existing gas distribution system at the scale that would be needed to replace natural gas at current usage levels. Gas utilities in certain regions, such as New York and Washington state, are beginning to see stagnating customer growth, declining demand per customer, and competition from the electric sector due to decarbonization policies and increasingly cost-effective electrification solutions.<sup>1</sup>

Despite these major changes, ratepayers, stakeholders, and public utility commissions (PUCs) have little insight into gas utility capital investments and resource supply plans. Unlike electric utilities, only a handful of states require natural gas utilities to file long-term plans. Given the rapidly changing energy landscape, regulatory oversight of gas utility spending is more important than ever. Without detailed analysis and evaluation of utility forecasts and plans, it is challenging for the public to determine if utility spending is reasonable. Ultimately, unwise utility investment decisions are most likely to be borne by the customers through higher rates.

**It is against this backdrop that this paper has been prepared: to introduce gas planning, lay out the key components of a gas plan, and discuss different types of gas plans. The paper also provides specific state examples of these concepts in action through short case studies. In total, this paper reviews five existing methods of gas planning, highlighting the strengths and drawbacks of each. It then makes some recommendations for states looking to create new, modern gas plans or strengthen existing plans, based on experiences and challenges with existing gas and electric planning processes.**

**Gas system planning delivers four primary benefits: cost and risk mitigation, transparency, compliance with climate goals, and intra utility coordination.**

---

<sup>1</sup> Consolidated Edison, Inc. *Long-Range Plan*. January 2022. Available at: <https://www.coned.com/-/media/files/coned/documents/our-energy-future/our-energy-projects/gas-long-range-plan.pdf>; Puget Sound Energy, *2023 Gas Utility IRP and Electric Progress Report*. March 2023. Available at: <https://www.pse.com/en/IRP/Past-IRPs/2023-IRP>



A gas system planning exercise forces utilities to coordinate internally to consider a range of scenarios that meet customer demand. The utility then tests the impact of technological, economic, and policy changes, and confronts resource and investment tradeoffs. The resource, throughput, weather, and capital forecasts amassed during gas planning form a single repository of information useful to the utility, regulators, stakeholders, and the general public. Rather than having key pieces of data scattered across several proceedings, the information compiled during planning proceedings allows for a transparent forum in which stakeholders can better understand a utility's strategic direction and compliance with policy goals, such as emissions targets.

There are two main components to modern gas planning: process requirements and analytical features, described below and summarized in the accompanying Table 1.

- **Process requirements** are the basic structural components of a gas planning process beneficial to customers. Requirements include a set filing cadence and planning horizon, robust stakeholder involvement, and a PUC review process. The involvement of the public in gas planning is essential and results in a diversity of voices that help to refine utility strategy, ultimately benefiting ratepayers.
- **Analytical features** are the tools and analyses used to assemble a portfolio of resources and capital investments deemed to best balance cost and risk. By accounting for technological, economic, and policy variables, utilities can better identify risks associated with specific investment approaches and construct a portfolio of resources that mitigates unnecessary spending and ensures compliance with state laws, including emissions reduction targets. Analytical features also enable utilities to quantify impacts on disadvantaged populations and society in general.

Overall recommendations, process requirement recommendations, and analytical feature recommendations are included in the Conclusion.



Table 1 – Process Requirements and Analytical Features of a Modern Gas Plan

Process Requirements	Analytical Features
Filing cadence	Short-term action plan
Planning horizon	Load forecasting
Stakeholder involvement	Scenario and sensitivity analysis
Draft and final plans	Non-pipeline alternatives
PUC review	Identification of preferred portfolio
	Capital investment forecast
	Bill impact analysis
	Equity analysis
	Coordination with the electric sector
	Mapping



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## List of Case Studies

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2. Oregon Gas Integrated Resource Plan Stakeholder Engagement Process
3. New York State Electric & Gas Non-Pipeline Alternative in Lansing, NY
4. Northwest Natural System Maps
5. National Fuel Gas Distribution Corporation's Initial Long-Term Plan
6. Northwest Natural 2022 Integrated Resource Plan
7. Consumers 2021-2031 and 2023-2033 Delivery Plans
8. Xcel Energy Initial Gas Infrastructure Plan and Clean Heat Plan
9. Illinois' Long-Term Gas Infrastructure Plan
10. Coordinated Planning in Practice in British Columbia



## Introduction

Gas and electric utilities are always planning for their future investments and expenditures to ensure that they are providing safe and reliable service. Internal utility investment planning is standard practice. Although public-facing resource planning, often called integrated resource planning (IRP), gained traction among electric utilities in the 1980s after changes in global economic conditions and a series of expensive utility planning mistakes in the 1970s, gas utility planning did not receive a similar focus. Still, the reasons that made electric integrated resource planning attractive, such as the need to better integrate demand-side resources, like energy efficiency, into utility planning, are present on the gas side as well.

### An Energy Transition is Underway

The use of natural gas in the United States has reached an inflection point. For the past several decades, natural gas has been considered an affordable and environmentally friendly fuel. Other fuels like heating oil produce greater emissions (and are typically more expensive than natural gas), while electric heating (using electric resistance technology) has historically been considerably more expensive. However, the energy transition has brought forth a new, energy efficient and increasingly cost-competitive competing technology: electric heat pumps. Meanwhile, large sectors of the global economy are undergoing a parallel transformation: the fleet of electric generators that power electric heating technologies is rapidly converting from fossil fuels to renewable electricity, the transportation sector is electrifying, and industrial sectors are looking to decarbonize with electrification and alternative fuels. The concern to natural gas distribution utilities that deliver gas to end-use customers is not theoretical – natural gas use in residential and commercial buildings has stagnated<sup>2</sup> and gas prices are rising and becoming more volatile than electricity.<sup>3</sup>

#### **Gas utilities are experiencing four primary headwinds:**

1. The lifetime costs of electric appliances are comparable to gas appliances;
2. States, cities, and the federal government are adopting decarbonization policies;
3. Gas prices are increasingly volatile and are more heavily influenced by global supply and demand dynamics; and
4. Utility delivery system investments are outpacing load growth.

<sup>2</sup> U.S. Energy Information Administration. *Natural gas explained*. November 7, 2022. Available at: <https://www.eia.gov/energyexplained/natural-gas/use-of-natural-gas.php>

<sup>3</sup> Talor Gruenwald, Rocky Mountain Institute. *Reality Check: The Myth of Stable and Affordable Natural Gas Prices*. November 17, 2021. Available at: <https://rmi.org/the-myth-of-stable-and-affordable-natural-gas-prices/>



The first two headwinds are closely related. Efficient electric appliances – such as electric heat pumps and induction stoves – are emerging as cost-competitive alternatives to their gas counterparts. This is in-part due to government decarbonization policies, such as state-level emissions reduction requirements driving market growth and customer adoption, and federal incentives through the Inflation Reduction Act.<sup>4</sup>

State climate goals are catalyzing the energy transition and ramping up pressure on businesses to decarbonize. Twenty-five states and the District of Columbia have established economy-wide greenhouse gas reduction goals, as shown in Figure 1.<sup>5</sup> For example, Rhode Island passed a law requiring a state-wide emissions reduction of 45% in 2030 and 80% in 2040, with a requirement to achieve net zero emissions statewide by 2050.<sup>6</sup> Meeting such targets requires immediate action from all sectors of the economy, including commercial and residential buildings. The United States Energy Information Administration (EIA) estimates that, in 2021, natural gas combustion (including electricity generation) accounted for 34% of US CO<sub>2</sub> emissions.<sup>7</sup> Additionally, the EIA estimated that methane leaks during natural gas extraction, processing, and transportation accounted for 4% of total US greenhouse gas emissions, based on carbon-dioxide equivalents, in 2020.<sup>8</sup> Since gas system end users account for about 58% of natural gas consumption,<sup>9</sup> addressing the direct use of gas in buildings and industry is critical in meeting economy-wide decarbonization goals.

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<sup>4</sup> Advanced Energy United. *Making the Most of the Federal Home Energy Rebates*. September, 2023. Available at: [https://blog.advancedenergyunited.org/reports/homes\\_eehra\\_guide\\_2023](https://blog.advancedenergyunited.org/reports/homes_eehra_guide_2023)

<sup>5</sup> Center for Climate and Energy Solutions. *U.S. State Greenhouse Gas Emissions Target*. September 2023. Available at: <https://www.c2es.org/document/greenhouse-gas-emissions-targets/>

<sup>6</sup> Rhode Island General Laws § 42-6.2-2 (2021 Act on Climate). <http://webserver.rilin.state.ri.us/Statutes/TITLE42/42-6.2/42-6.2-2.HTM>

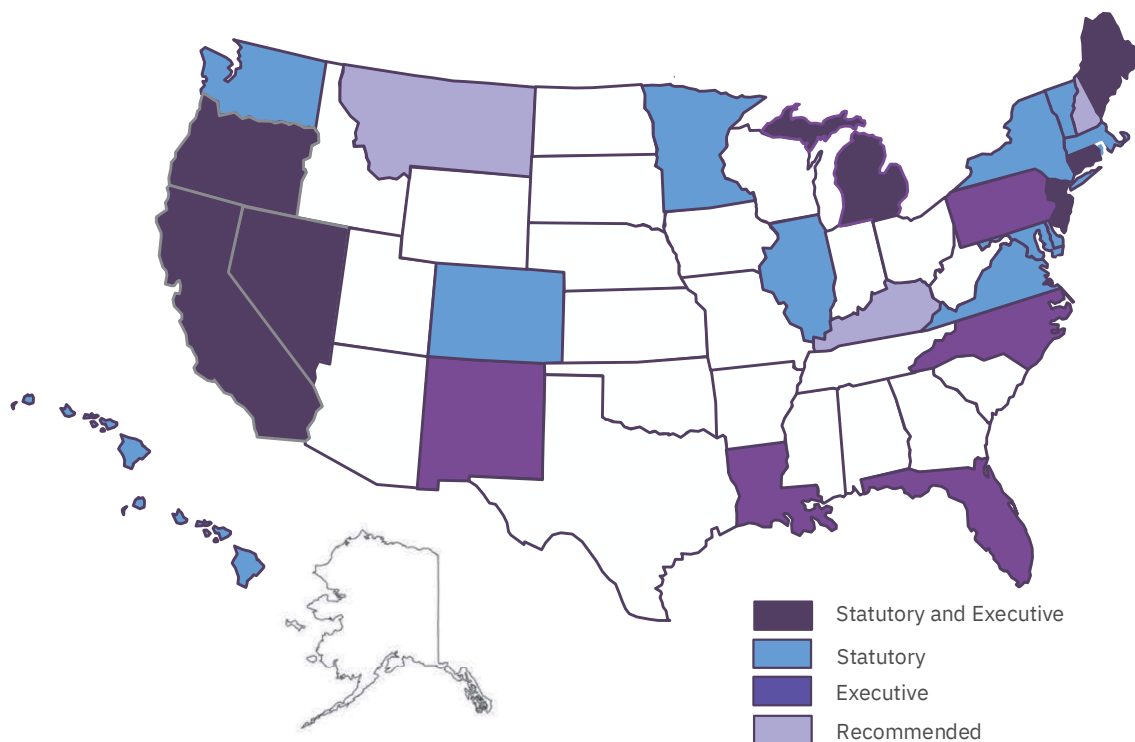
<sup>7</sup> U.S. Energy Information Administration. *Natural gas explained*. November 7, 2022. Available at: <https://www.eia.gov/energyexplained/natural-gas/natural-gas-and-the-environment.php>

<sup>8</sup> *Id.*

<sup>9</sup> U.S. Energy Information Administration. *Natural Gas Consumption by End Use*, September 29, 2023. Available at: [https://www.eia.gov/dnav/ng/ng\\_cons\\_sum\\_dcu\\_nus\\_a.htm](https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm)



Figure 1 – States with Economy-Wide Emissions Goals<sup>10</sup>



While renewable resources and emerging battery technologies, combined with energy efficiency and other distributed and demand-side resources offer promising pathways to achieving carbon neutrality in the electricity sector, there are no clearcut solutions for the natural gas sector. Historically, gas utility efforts to reduce emissions have centered on energy efficiency measures and avoiding methane leaks primarily through pipeline replacements. Although these measures reduce emissions, gas systems remain primarily fossil-based sources of energy. Therefore, climate goals challenge gas utilities to develop new solutions to reduce fossil fuel usage.

The third headwind is the increasingly volatile price of natural gas. After a decade of relatively low gas prices spurred by the development of shale gas, there has been an increase in both the price and volatility of natural gas (see Figure 2). In that time, the United States switched from being a net importer of liquefied natural gas (LNG) to a net exporter, and in 2022, the US became the world's largest LNG exporter.<sup>11</sup> This occurred as overall global trade of LNG increased, meaning that the US domestic market for gas is now more closely tied to global demand and prices, and thus the volatility of the market. For example, there was a substantial

<sup>10</sup> Center for Climate and Energy Solutions. *U.S. State Greenhouse Gas Emissions Target*. September 2023. Available at: <https://www.c2es.org/document/greenhouse-gas-emissions-targets/>

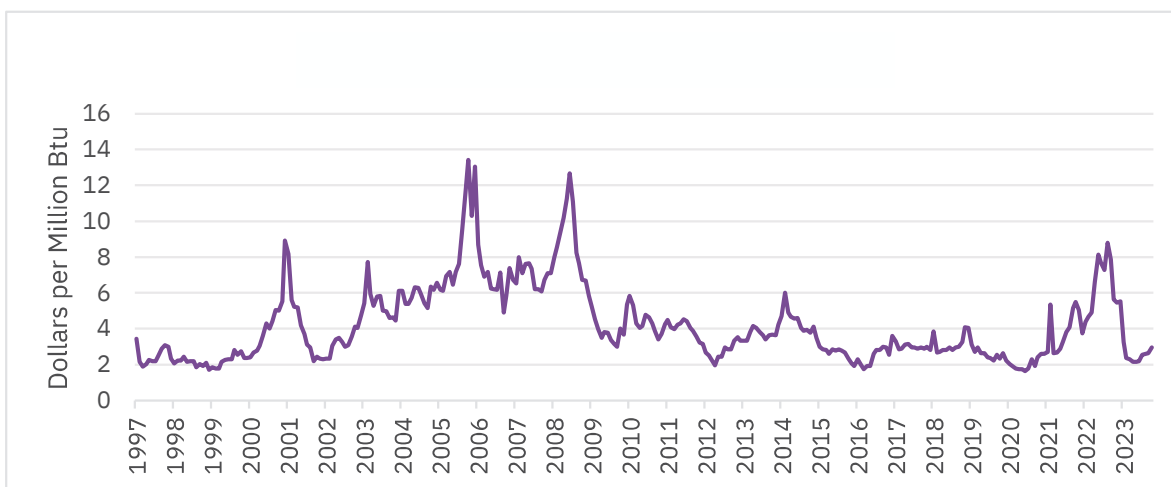
<sup>11</sup> U.S. Energy Information Administration. *The United States became the world's largest LNG exporter in the first half of 2022*. July 25, 2022. Available at: <https://www.eia.gov/todayinenergy/detail.php?id=53159>



increase in gas prices after Russia’s invasion of Ukraine and European nations reduced their import of gas from Russia.

Extreme weather events are also disrupting gas commodity markets, which supply both gas-powered electric generation facilities and gas distribution utilities. During the five-day Winter Storm Uri in 2021 in Texas, natural gas prices increased up to \$400/per million Btu (MMBtu) (where they are normally “much less than \$10/MMBtu”).<sup>12</sup> Electric utilities across the middle of the country using gas for electricity generation incurred billions of dollars of incremental costs that customers will be paying off for years.<sup>13</sup> More generally, the rise and volatility in natural gas prices in the 2021-2023 period had significant impacts on both gas utility customers and on the cost of electricity generation, which is influenced heavily by natural gas prices.

Figure 2 – Henry Hub Natural Gas Spot Price<sup>14</sup>



The fourth headwind is the mismatch between utility infrastructure investments and load. Gas utilities are increasing investments in their delivery systems, far exceeding what would be expected to meet demand. As shown in Figure 3 below, residential, commercial, and industrial customer demand has remained relatively flat over the last twenty-five years<sup>15</sup> while construction spending has increased nearly sixfold.<sup>16</sup> Without a new approach to the gas

<sup>12</sup> University of Texas at Austin. *The Timeline and Events of the February 2021 Texas Electric Grid Blackouts*. July 2021. Available at: <https://energy.utexas.edu/sites/default/files/UTAustin%20%282021%29%20EventsFebruary2021TexasBlackout%2020210714.pdf>.

<sup>13</sup> American Public Power Association. *Winter Storm Uri, Extreme Winter Events, And Natural Gas Reforms*. January 2022. Available at: <https://www.publicpower.org/system/files/documents/January%202022%20-%20Winter%20Storm%20Uri.pdf>

<sup>14</sup> U.S. Energy Information Administration. *Henry Hub Natural Gas Spot Price*. Available at: <https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm>

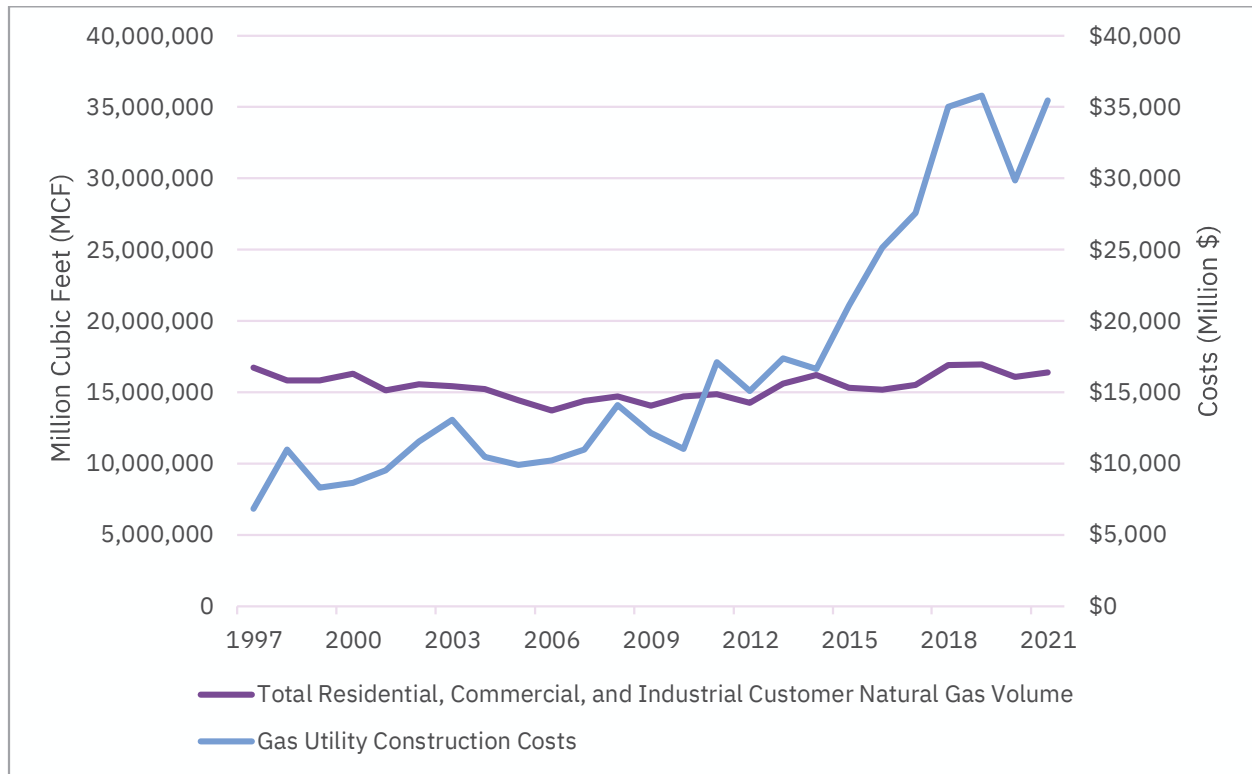
<sup>15</sup> U.S. Energy Information Administration. *Natural Gas Consumption by End Use*. Available at: [https://www.eia.gov/dnav/ng/ng\\_cons\\_sum\\_dcu\\_nus\\_a.htm](https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm)

<sup>16</sup> American Gas Association. *Gas Utility Construction Expenditures by Type of Facility*. 2023. Available at: <https://www.aga.org/wp-content/uploads/2023/01/Table12-1.pdf>



planning process, customers, stakeholders, and PUCs face challenges in understanding the reasonableness of this dramatic increase in gas utility infrastructure investments.

**Figure 3 – Gas Consumption and Gas Utility Construction Expenses (1997-2021)**



## Overview of Paper

The remainder of this paper is organized into two halves. The next three sections describe the need for, and key elements of a modern gas plan, with deeper dives into several of those key elements and case studies embedded throughout. The latter two sections then explore existing gas plans in the Pacific Northwest, New York, Colorado, Michigan, and British Columbia, and compare their features with that of the comprehensive set of best practices outlined in the first half of this paper. Specifically:

- **Section II** provides a general overview of the benefits of modern, public gas planning.
- **Section III** provides an overview of the process requirements, analytical features, and tools that enable robust modern gas plans.
- **Section IV** offers a deeper dive into Public Engagement, Non-Pipeline Alternatives, Embedding Equity, Evaluating RNG and Hydrogen Proposals, and System Mapping.
- **Section V** provides an overview of existing gas planning requirements and, through case studies, highlights the strengths of various State planning requirements.
- **Section VI** compares existing gas plans and provides recommendations to establish a comprehensive, modern gas plan.



# Part I: A Framework for Modern Gas Planning

## Benefits of Modern Gas Planning

A more transparent, and public modern gas planning process offers a myriad of benefits to the utility, to the PUC, and to the public. First and foremost, a gas plan identifies the “least cost, least risk”<sup>17</sup> set of investments for meeting the utility’s needs via a comprehensive assessment of resource costs, availability, state policy alignment, and technological barriers in combination with demand forecasts.

Modern gas planning should result in a portfolio of resources and investments for each year of the planning period. For example, an alternative fuel scenario may forecast the quantities of supply-side resources, such as green hydrogen and renewable natural gas, as well as measures aimed at reducing demand, such as energy efficiency. The cost of each resource and measure becomes part of a larger portfolio that is compared to other portfolios that use a different mix of resources and measures across a planning period. In assembling resource portfolios, utilities weigh the cost against less tangible factors, such as technology and availability risks. Utilities must also model changes to assumptions, such as demand reductions due to climate change, state clean energy policies, or customer reductions due to a forthcoming reduction in gas line extension allowances. Utilities then typically select a “preferred” portfolio of resources and measures that best aligns with a least-cost, least-risk investment approach.

Gas plans are also iterative – a utility files a plan every two to three years – to enable utilities to revise assumptions and analyze new portfolios in response to economic, technological, and policy changes. For example, changing commodity prices for natural gas can result in energy efficiency measures becoming comparatively more cost-effective and major infrastructure upgrades becoming less useful for customers. Technological changes, such as innovations and cost reductions in heat pump technologies, can lead to a reduction in gas demand and usage patterns. Policy changes, such as the establishment of firm emissions reduction targets, can dramatically alter future demand such that revising a previous gas plan does not sufficiently account for the impact of the change. The short duration between plans allows for forecasting to remain current and roughly aligns with the frequency of general rate cases, allowing investment plans, also referred to as a “preferred portfolios” or “short-term action plans,” to translate directly into utility spending decisions.

Ultimately, gas customers bear the risks of inadequate system planning, and utility regulators have a responsibility to understand and mitigate those risks. Utilities recover the cost of gas

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<sup>17</sup> Also known as “lowest reasonable cost.”



and capital investments from ratepayers, who may have little knowledge or influence over the direction of the utility's investments. Planning shortcomings, especially those that obscure the bigger picture via fragmented data and decision-making, significantly increase the risk that a utility unwisely invests in – and regulators approve – infrastructure that requires significant capital investments in assets that will be recovered over a shrinking customer base and sales volume. In particular, low-income gas customers, who are the least likely to be able to afford the capital costs to exit the gas system via electrification, are the most exposed to the risk of the resulting bill increases.

Although there are a range of benefits to modern gas planning, this paper focuses on four: risk mitigation, transparency, compliance with state policy goals, and intra-utility coordination.

### **Risk Mitigation**

The two overarching risks for the utility and customers are cost and reliability. Inaccurate forecasts can lead to over-investment in the system, the wrong mix of resources, or a system unable to meet the demands of customers. The already difficult forecasting process is rendered far more challenging due to rapidly changing energy sector dynamics. Gas utilities must consider the appropriate role for alternative fuels, like hydrogen and renewable natural gas, new demand-side resources, including gas demand response and electrification, and decarbonization policies. In particular, given the long-lived nature of traditional gas system infrastructure, there is both path dependency, an investment opportunity cost, and stranded asset risk for investing now in one type of decarbonization pathway over another.

Robust modern gas planning can reduce cost and reliability risks. Gas planning considers a range of scenarios, tests the impact of technological, economic, and policy changes, and then analyzes resource and investment tradeoffs. The results of this process can expose risks associated with a particular portfolio and help ensure that short-term investments benefit ratepayers while being compatible with a long-term vision.

### **Transparency**

A more transparent, modern gas planning process helps shed light on a utility's plans and operations by serving as a central repository of information and allowing the public to weigh in. In the absence of such transparency, PUCs, the public, and other stakeholders are not typically privy to the utility's long-term forecasts and capital plans. A PUC might only see the utility's annual or short-term demand forecast in regulatory filings. In contrast, a modern gas plan as described here requires the utility to walk through its analysis and provide accompanying narrative details of its business, including data on customer base, customer demand, state of the distribution system, existing resource supplies, and future investments into system upgrades and resource acquisitions. Furthermore, gas plans often provide an overview of how



the utility leverages storage, interruptible tariffs, and peaking facilities to meet demand. Utilities bear the burden of demonstrating that their actions and investments are prudent, but, without this data, it is challenging for PUCs and stakeholders to adequately evaluate utility decision-making.

The public process also allows stakeholders and ratepayers an opportunity to provide direction and feedback on the utility's future. In designing gas plans, PUCs can pursue various approaches to data sharing, as detailed below in the Issue Spotlight. Examples of these approaches in action are included in the Appendix.

### Issue Spotlight: Data Access

Improving access to data and modeling is a key strategy to make utility regulatory processes on both the gas and electric side more effective and more equitable. To make decisions, PUCs rely on the information that is submitted into the record during a proceeding. Notably, utilities have the most resources for data collection, modeling, and analysis – and the most intimate knowledge of their systems. Other stakeholders, including regulators, may not have access to utilities' modeling tools and assumptions, nor to all the data used in their planning decisions, reports, and proposals. This creates an information asymmetry that many states are trying to address.<sup>18</sup>

Ultimately, the addition of different perspectives allows for more comprehensive and robust gas planning. The challenges associated with the energy transition only increase the complexity of gas planning and therefore reinforce the need for the involvement of the public.

#### **Options for Commissioners to increase access to data for regulatory decisions:**

- Commissioners can require utilities to provide modeling licenses or remote access to the software to stakeholders, Commission staff, and/or consumer advocates
- Commissions can require the utility to provide scenario development opportunities to stakeholders
- Commissioners can require utilities to run specific scenarios

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<sup>18</sup> All processes can be tailored to comply with local privacy and confidentiality requirements.



## **Compliance with State Policy Goals: Emissions Reductions and Energy Equity**

Gas utilities are subject to state regulation and with it the policies and preferences articulated by the state legislature and PUC. Although state legislatures have always been involved in energy policy, the last few years have seen an uptick in focus on emission reductions and equity. Emission standards significantly increase the complexity of utility modeling exercises since status quo operations are typically insufficient for compliance with state and local laws. Modern gas planning is necessary for modeling emissions reduction pathways because utility investments can differ radically based on the preferred portfolio. For example, futures that rely upon alternative fuels versus electrification require very different types of investments to transform the utility's system. However, a utility cannot easily, cheaply, or quickly pivot from one pathway to another if circumstances change without burdening customers with rate increases. Gas planning is therefore paramount in helping utilities chart a long-term, least-cost, least-risk approach to decarbonization and avoiding path dependency that is incompatible with state policy. Additionally, each iteration of a utility's gas plan provides a checkpoint at which the utility can adjust its plans if confronted with new information, and at which a PUC and stakeholders can assess a utility's accountability and progress toward goals.

Several states, including Washington, New York, Colorado, California, and Nevada, have passed legislation requiring utilities to examine their investments' impacts on disadvantaged communities.<sup>19</sup> In recognition that past energy decisions have disproportionately impacted certain communities, these states are requiring the utilities to identify those communities and design programs so that residents within them are also benefiting from the energy transition. Through modern gas planning, utilities can identify where investments will occur and who will be impacted in both positive and negative ways and provide quantitative and qualitative analysis of the impacts to disadvantaged communities.

## **Intra-Utility Coordination**

One of the least discussed benefits of gas planning is the coordination it requires from within a utility. A gas planning process requires multiple departments of a gas utility, such as distribution planning, transmission planning, storage and reservoir engineering, gas supply and procurement, demand-side management, and gas operations staff to discuss their internal department plans, learn from each other and coordinate. Gas utilities, like their electric counterparts, tend to be siloed, and departments often do not interact more than is required for day-to-day operations and occasional business needs. Gas planning provides the broader enterprise with a regular opportunity to discuss planned projects, iterate and improve coordination, and offer suggestions for improvement that might not otherwise be made.

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<sup>19</sup> Nevada Senate Bill 281 (2023); Colorado Senate Bill 264 (2021); New York Senate Bill 6599 and Assembly Bill 8429 (2019); Washington House Bill 1181 (2023); California Senate Bill 350 (2015).



## Core Elements of Modern Gas Planning

Designing a modern gas planning regulatory process is complex, though several PUCs have already developed a variety of analytical and procedural requirements to guide utility filings. Furthermore, decades of experience with electric utility integrated resource planning and distribution system planning processes can be drawn upon where relevant. The most comprehensive gas plans are the result of regulations that ensure that filings are a single repository of key utility data and assumptions. As will be shown in Section V, there are a variety of types of existing gas plans, and although the best approach for a state will depend on the needs and goals of the state, there are several common features. In this section, those key features are identified and divided into two categories: Process Requirements and Analytical Features.

### Process Requirements

Process requirements describe the rules and actions for developing a modern gas plan.

- **Filing cadence:** Filing cadence refers to the period of time between required gas plan filings. Gas plans are iterative because the forecasts and assumptions inherent to a gas plan will change as economic, technological, and policy conditions change. A longer filing period may reduce the responsiveness of utility planning strategy to changes in forecasts and stakeholder concerns. However, a longer filing period also reduces the administrative burden of developing, participating in, and reviewing a gas plan. Existing gas plans are typically filed every two to three years.
- **Planning horizon:** Planning horizons refer to the period of time evaluated in gas plans. Gas plans typically have a planning horizon of 15-20 years. The planning horizon is broken down into a short-term period, for which an “action plan” is developed that details specific investments within the next three to six years, and a long-term period outlining broad utility strategies.
- **Stakeholder involvement:** Gas planning offers fewer benefits without robust stakeholder involvement, including that of both the more frequent participants and those representing vulnerable populations. The inclusion of the public throughout the entire process – from the initial plan design to the evaluation of the end product – results in the discussion of different viewpoints and more robust feedback to the utility.

A gas plan should be public, and the people on whose behalf decisions are being made should have a role in its development. Common stakeholders include members of the public, including those residing in environmental justice or low-income communities,



PUC staff, consumer advocates, representatives of the business community, environmental advocates, and large consumers.

- **Draft and final plans:** The utility should present (or file) a draft plan before submitting the final plan, with a defined period for stakeholders to submit comments (with sufficient time for stakeholders to conduct their own analysis). Although a utility may present segments of its analytical approach during stakeholder meetings, the utility’s methodological approach or analysis may change during the development of the plan. Moreover, the draft plan is the first opportunity stakeholders have to see the comprehensive plan. By filing a draft, utilities can amend the plan based on stakeholder feedback and minimize the number of disputes left unresolved when it files its final plan with the PUC.
- **Evaluating gas plans with a PUC review process:** Ultimately, PUCs pass judgment on the utility’s plan, but the manner in which they do so varies from state to state.

Final plans should be adjudicated whenever the process leads to a formal “green light” to proceed with a given investment plan, though a utility must still demonstrate prudent investment activity in its next rate case to receive approval for cost recovery. Furthermore, states can look to the manner in which they litigate or review electric utility resource or distribution plans for guidance on whether or not their gas planning process should also be litigated.

In the Pacific Northwest, the PUCs have decided to either “acknowledge” or “not to acknowledge” gas utility plans after a stakeholder process.<sup>20</sup> In New York, the Public Service Commission can either approve, approve with modifications, or reject a utility’s long-term plan.<sup>21</sup> While a non-acknowledgment or rejection does not directly or immediately impact return on equity or the revenue requirement, the utility is generally expected to modify its gas planning per the PUC decision, or else it faces a significant challenge when it seeks cost recovery during a rate proceeding. For example, this could mean avoiding, delaying, or providing further assessments of planned investments that the PUC deemed inconsistent with the utility’s long-term planning approach. The failure of the utility to align infrastructure investments with a PUC order on its gas plan threatens the recovery of assets in a general rate case and could lead to a reduction in utility profits. Therefore, PUC acknowledgment or approval of gas plans is highly

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<sup>20</sup> Oregon Public Utility Commission. Docket UM 1056, *Order No. 07-002*, page 2. January, 2007. Available at: <https://apps.puc.state.or.us/orders/2007ords/07-002.pdf>

<sup>21</sup> New York Public Service Commission. Docket No. 20-G-0131, *Order Adopting Gas System Planning Process*, page 25. May 12, 2022. Available at: [https://app.insightengine.org/dockets/ny-20-00652-20-g-0131/filings/16815248?version=beta&filing\\_search\\_id=1615753&document\\_id=165777211](https://app.insightengine.org/dockets/ny-20-00652-20-g-0131/filings/16815248?version=beta&filing_search_id=1615753&document_id=165777211)



consequential, and utilities are incentivized to work with stakeholders to determine the best path forward.

## Analytical Features

For gas planning to provide the greatest benefits, public stakeholders and PUCs must understand the utility's strategy and its impacts on customers. This requires the utility to model the evolution of its business by integrating internal investment strategies with forecasts of customer growth, fuel costs, policy changes, and other factors. The following analytical features provide participants with adequate information to evaluate a utility's strategy.

- **Load forecast:** The first analytical task of a gas plan is to develop a load, or demand, forecast for the planning horizon. It is paramount that a utility can accurately predict its demand so that it can meet demand on even the coldest days but is not so conservative that the utility spends unnecessarily on capital investments, such as pipeline capacity. Consequently, long-term load forecasting should be performed on a regular cadence to allow ample time to address potential future constraints driven by changes to load.

There are two primary components of a load forecast: energy demand (also called throughput) and peak demand. Energy demand is typically calculated as the total demand for all customers throughout the year. Peak demand is the amount of gas needed to serve customers on the coldest day of the year. The gas utility's demand forecasts should explicitly identify the utility's design day criteria and planning standard used for developing the load forecast. It should also explicitly consider and identify how it incorporates the impacts of climate change and federal, state, and local policy. Importantly, load forecasting must also be conducted on more granular levels, including climate zones and neighborhoods/localities, which may be experiencing different trends in gas use than other parts of the system. As future demand is uncertain, typically a utility will develop several demand forecast scenarios.

- **Short-term action plan:** The utility proposes specific capital investments that address short-term needs over a period of three to six years that align with its long-term vision. Few projects that are planned for four or five years in the future are likely to be finalized upon submission of the short-term action plan, but it is nonetheless important that utilities reflect investment opportunities in the short-term action plan such that they may be evaluated in advance – especially if the project is a candidate for a “Non-Pipeline Alternative” (NPA) as described further below.
- **Comparative evaluation of demand- and supply-side investments:** A modern gas plan, regardless of the name, should consider commercially available demand- and



supply-side investments as solutions for meeting customer needs in the short-term, though the solutions should be compatible with an approved pathway towards the state and utility's long-term goal. Typically, gas utilities develop demand-side portfolios and then apply the impact as a load reduction. Like their electric counterparts, the best gas plans also allow the model that determines the utility's capacity expansion needs to select additional demand-side management resources rather than only allowing supply-side investments to meet customer needs.

- **Scenario and sensitivity analysis:** Scenario and sensitivity analysis are critical for testing the robustness of the utility's investments under various futures. A scenario is a set of assumptions about variables not entirely controlled by the utility (including energy prices, customer demand, and resource costs) that will have a significant impact on the utility's decision-making. A sensitivity analysis isolates one variable for cost and risk assessment, such as a policy change impacting customer growth or commodity prices. Such analysis is especially helpful in evaluating risk to the preferred portfolio. Portfolios are then compared to one another to determine the least-cost, least-risk set of investments that meet customer demand.



## Case Study: Puget Sound Energy's IRP Scenarios and Sensitivities

Figure 4 below displays the sensitivity analysis Puget Sound Energy (PSE) conducted in its 2023 Natural Gas Integrated Resource Plan in Washington.<sup>22</sup> PSE's sensitivities analyzed technological, economic, and policy changes. The "High Gas Price" scenario models the impact of changing economic conditions that result in a long-term increase in gas prices. The "Floor Price" and "Ceiling Price" sensitivities, which measure the impact of variable emissions allowance costs under Washington's cap-and-invest policy called the Climate Commitment Act (CCA),<sup>23</sup> also capture economic uncertainty. A high allowance price indicates state-wide decarbonization challenges, while a low allowance price suggests that other businesses can cut emissions more cost-effectively. The "RNG NA" sensitivity assumes that Renewable Natural Gas (RNG) can only be acquired regionally, as opposed to nationally.

Several factors are relevant in this sensitivity, such as slow technological development that could limit the cost-effective adoption of RNG, significant competition for RNG that could lead to less available supply and higher costs, and policy changes limiting PSE from acquiring RNG from outside its service territory. Finally, the "Electrification" scenario and "HHP Policy" (hybrid heat pump policy) sensitivities modeled electrification adoption to meet the Washington State Energy Strategy, and a policy where gas heating appliances would be replaced with hybrid heat pumps at the end of their life, with all other gas end-uses electrified, respectively. The sensitivity analysis allowed PSE to determine the quantity of allowances needed – and therefore purchased with an additional cost to customers – to meet compliance with state climate goals and the associated costs in each scenario.

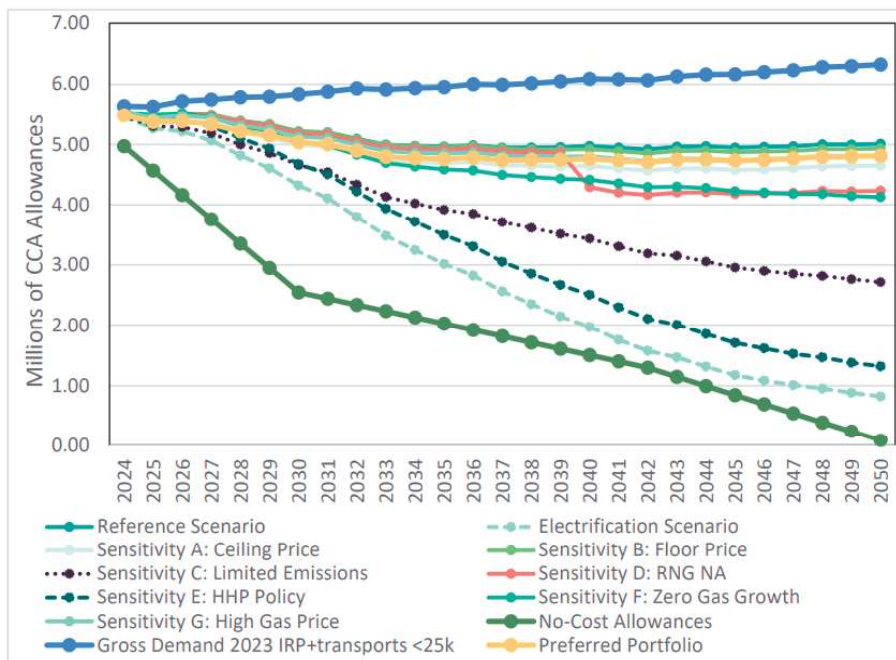
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<sup>22</sup> Puget Sound Energy. *2023 Puget Sound Energy Integrated Resource Plan*, Chapter 4. March 31, 2023. Available here: <https://www.pse.com/en/IRP/Past-IRPs/2023-IRP>

<sup>23</sup> Washington Department of Ecology. *Climate Commitment Act*. <https://ecology.wa.gov/air-climate/climate-commitment-act#:~:text=In%20the%20CCA%2C%20the%20Legislature,commitments%20set%20in%20state%20law>



Figure 4 – Puget Sound Energy Natural Gas IRP Sensitivity Analysis<sup>24</sup>



### Capital Investment Forecast

A gas plan categorizes a utility’s proposed capital investments by investment type (e.g., capacity expansion, new business, mandatory relocation, safety and reliability). A capital forecast should accompany each of the scenarios modeled in order for the utility to provide stakeholders with a complete understanding of portfolio costs. This is necessary to include alongside a scenario analysis because a scenario analysis on its own only covers resource acquisition costs and does not quantify distribution costs such as pipeline replacements and asset repairs. Infrastructure investments are a significant portion of customer bills and may vary substantially by scenario. Gas planning analysis is incomplete if regulations do not require comprehensive capital investment forecasts.

- Non-Pipeline Alternative assessment:** These analyses compare traditional utility investments to non-pipeline alternatives, described in Table 2. NPAs can reduce costs, reduce the likelihood of stranded assets, provide options value over traditional investments, and avoid emissions. Gas planning regulations in New York and Colorado have recently included NPA assessment requirements, and examples are provided in the NPA spotlight in Section IV.

<sup>24</sup> Puget Sound Energy. 2023 Puget Sound Energy Integrated Resource Plan. Chapter 2.20. March 31, 2023. Available here: <https://www.pse.com/en/IRP/Past-IRPs/2023-IRP>



Table 2 – Examples of Non-Pipeline Alternatives

Demand-Side Solutions	Supply-Side Solutions
Targeted Demand Response	On-system Renewable Natural Gas
Targeted Energy Efficiency	On-system Liquefied Natural Gas (LNG) Peaking Storage
Heat Pumps	Compressed and Liquefied Natural Gas Trucking (Virtual Pipelines)
Thermal Storage	
Other Electrification & Fuel Switching	LNG Liquefaction Port Terminals
Behavior Change & Market Transformation	

Source: What can we learn from New York's non-pipeline solutions ruling? ICF International, March 18, 2019

- **Identification of “short term action plan” or “preferred portfolio”:** The utility selects the portfolio it assesses as the least-cost, least-risk among the ensemble of portfolios analyzed. The identified short-term investments are expected to align with the preferred portfolio.
- **Bill impact analysis:** This analysis measures changes in customer bills based on the utility’s preferred portfolio and capital forecast. This is an analysis aimed at evaluating the short-term implications of all utility spending, including capital spending, operations and maintenance, and fuel costs.
- **Equity impact analysis:** Traditional bill impact analysis can hide inequities through averages, such as distributional impacts and transfers of wealth. Specifically measuring costs and benefits to disadvantaged populations provides an assessment of portfolio equity impacts. This analysis can be done qualitatively and quantitatively and is improved by involving local stakeholders from impacted communities.
- **Coordination with electric sector:** Gas utilities – whether gas-only utilities or part of a combined gas and electric utility – do not operate in a silo. Customers that electrify will increase the load on the electric sector, impacting electric distribution, transmission, and generation capacity needs. Coordination is especially critical in evaluating these impacts, which may otherwise go unquantified. We discuss this further in Spotlight on Gas Planning Elements.
- **System mapping:** Gas distribution and transmission maps allow PUCs and stakeholders to understand system constraints and possible resolutions, especially where they overlay with disadvantaged communities. Northwest Natural’s 2022 Gas IRP provides one such example, detailed below.



## Spotlight on Gas Planning Elements

### Fostering Stakeholder Engagement

Robust stakeholder engagement is a critical element of a successful gas planning process. The public should be involved throughout the entirety of the planning period from the plan's development to public meetings, technical working groups, and formal comments on the final plan.

There are two primary opportunities to strengthen stakeholder feedback in addition to hosting public comment hearings and allowing formal comments/testimony, technical working groups, and third-party evaluations.

- **Technical working groups** are formed in the early stages of the planning process and are the initial voice of stakeholders. Utilities disseminate gas plan details, including initial forecasts and portfolios, and collect feedback in technical working groups. The best stakeholder processes are built to have sufficient time to incorporate stakeholder suggestions, feedback, and suggested analysis before the utility completes its analysis for the draft plan. Technical working groups are most commonly open to any interested participant but require technical skills to meaningfully participate. **Example: Oregon's Gas Planning Technical Advisory Group, detailed below.**
- **Third-party evaluation** of gas plans allows for a neutral party to assess gas plans in a way that supports stakeholder participation. The PUC hires a consultant to provide an initial and revised analysis of the utility's initial and final gas plans, respectively. While not common, the involvement of third parties through independent assessments can elevate public discourse. **Example: Third-party evaluations of New York's Long-Term Plans, detailed in Part II.**

### Evaluating RNG and Hydrogen in Modern Gas Plans

A PUC's scrutiny of a gas plan is a critical component of the process. While many of the same principles that apply to electric resource plans also apply to gas resource plans, there are some potentially unique features including the assessment of new supply-side resources such as RNG and hydrogen.

When a utility proposes an RNG or hydrogen pilot project or a gas plan that relies heavily on the future use of RNG and/or hydrogen for decarbonization, PUCs should confirm that the alternative fuels are feasible and cost-effective options at scale and in the timeframe proposed.



### Checklist for Evaluating Utility RNG/Hydrogen Proposals

- Does modeling acknowledge and evaluate limitations to RNG supply and pricing, including competition from other sectors?
- Does the cost assessment include system and end-use equipment retrofits/replacements needed to accommodate high hydrogen blends?
- Does the plan direct RNG and hydrogen to the highest-value use cases?
- Are the costs of decarbonizing industrial customers included in the modeling scope?
- Is there a plan to meet gaps between RNG/hydrogen supply and total gas demand with cost-effective, zero-emission resources through other means (e.g., efficiency, electrification)?
- Does the plan confirm a firm, long-term supply of the RNG and hydrogen fuels that will be used to meet projected demand?
- Do overall plan costs include the costs of any required carbon offsets?
- Are interconnection points for RNG and hydrogen focused on areas of the system that minimize stranded asset risk (e.g. near hard-to-electrify end users or self-contained distribution systems that can be disconnected from the main system)?

### Case Study: Oregon's Non-Acknowledgement of RNG investments

In Northwest Natural's (NWN) 2022 gas IRP, the Oregon Public Utilities Commission (OPUC) elected not to acknowledge specific RNG investments in the short-term action plan. In its acknowledgment letter, the OPUC explained its decision stating, "Without an analysis that demonstrates that the level of RNG procurement proposed is the least-cost, least-risk way to meet the company's compliance needs, we cannot acknowledge [the RNG Procurements]" (OR Order 23-281, page 11). The OPUC Order identified utility shortcomings and provided a standard for the utility to meet in order to recover RNG investments in a general rate case.



## Non-Pipeline Alternatives

Non-pipeline alternatives (NPAs) are critical for avoiding unnecessary gas system investments. NPAs in the gas sector are the equivalent of the electric sector’s “non-wires alternatives” and refer to activities or investments that delay, reduce, or avoid the need to build or upgrade traditional gas system infrastructure such as pipelines, storage, and peaking resources. Best developed via competitive solicitation, NPA solutions are composed of a variety of strategies, programs, and technologies on both the demand side and supply side,<sup>27</sup> including demand response, energy efficiency, electrification, thermal storage, behavioral changes, liquefied natural gas (LNG) peaking storage, and mobile pipeline injection, as illustrated above in Table 2. In practice, NPAs are typically a portfolio of solutions that offset pipeline gas demand in a defined geographic area.

## The primary benefits of NPAs: cost reduction, risk reduction, emissions reductions

NPAs can be less expensive than traditional utility capital investments (e.g. pipeline replacements). This is especially pertinent if new pipelines are at risk of being stranded or recovered through a dwindling customer base, a risk that is increasing with ongoing building electrification. Implementing NPAs instead of pipeline solutions can therefore reduce the risk of asset under-recovery and customer rate shocks. Additionally, demand-side NPAs reduce gas consumption, thus enabling emissions reductions and compliance with a state’s climate goals.

A robust regulatory NPA process consists of three steps: a preliminary screening, the development of NPA resource portfolios, and the evaluation of portfolios.<sup>25</sup>

- **PRELIMINARY SCREENING:** This first step filters out potential NPA projects that are not technically feasible. Screening criteria include safety, time required for NPA assessment and project implementation, and capital cost.
  - a. **Safety:** Capital project types that cannot be delayed for safety reasons are not suitable for NPAs. For example, emergency investment projects, sometimes referred to as “Failed Plant and Operations,” require immediate remediation.

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<sup>25</sup> Ron Nelson, et al., Strategen Consulting. *Non-Pipeline Alternatives: A Regulatory Framework and a Case Study of Colorado*. 2023. Available at: <https://www.strategen.com/strategen-blog/non-pipeline-alternatives-framework>



- b. **Timeline:** There must be ample time for the utility to perform an NPA analysis and implement a solution. A timeline threshold filters out projects with insufficient lead time before the required implementation of the solution. Generally, a utility should be working early and often to identify NPA opportunities well in advance of the need so that as many viable NPAs as possible can be pursued.
  - c. **Cost:** Evaluating small capital projects for NPAs may not be cost-effective due to the cost of the NPA evaluation. By setting a cost threshold, a utility can efficiently identify suitable capital projects for NPA evaluation. The cost threshold should reflect the size of the utility.
- **PORTFOLIO DEVELOPMENT:** Upon completion of the preliminary screening, a utility must assemble NPA resources into a portfolio that addresses the technical needs of the project.
  - a. **Eligible Resources:** Demand-side resources, such as energy efficiency and electrification, and supply-side resources, such as mobile liquified natural gas injections, are potential NPA resources. Regulations should indicate a preference for demand-side solutions since such resources typically provide more customer benefits and lead to greater emissions reductions than supply-side resources.
  - b. **Project Solicitation:** For larger projects, utilities should acquire NPA resources through Requests for Proposals (“RFPs”). Competitive procurements, such as RFPs, drive down prices and provide a range of options from qualified vendors. Competitive solicitations also provide the utilities with the essential flexibility to target specific locations, sizes, and durations based on the local distribution need, and to expect contracts with creditworthy and reliable counterparties with viable projects. Such needs-based solicitations would not presuppose the exact technology solution but instead leverage the competitive market to come forward with solutions, or portfolios of solutions, based on needs identified by the utility. For smaller NPA projects undergoing a streamlined assessment (e.g., confined to one or several streets), internal utility estimates may be a viable option.
  - c. **Confirmation of Portfolio Requirements:** Once the utility has amassed information on NPA resources, it must determine if a set of resources can meet technical project criteria. For example, if a project requires a reduction of 100 million cubic feet per hour, a portfolio is only viable if it can reduce demand by such an amount. If possible, a utility should develop more than one portfolio to



weigh different policy goals, such as cost-effectiveness and emissions reductions.

- **PORTFOLIO EVALUATION:** Once the utility has assessed a portfolio of resources that can meet the technical project requirements, the utility needs to assess the portfolio for cost-effectiveness, vendor qualifications, and equity. Evaluating the portfolio as a whole is important because not all measures may individually lower costs compared to the traditional capital solution required, but the sum of the portfolio's parts may save ratepayers money over the business-as-usual option.
  - a. **Benefit-Cost Analysis (BCA):** A BCA determines if the NPA portfolio provides greater net benefits (or fewer net costs) than the traditional capital solution. The Societal Cost Test, which measures benefits and costs incurred by individuals and by society as a whole, including emissions, should be the primary BCA test used in the evaluation of portfolios. The utility should be transparent with its BCA framework by detailing data inputs, assumptions, variables, and methods for quantifying cost-benefit analyses impacts, ensure that the test is symmetrical, and include the value of deferral or avoidance of the traditional gas infrastructure project and the social cost of methane in its NPA analyses.
  - b. **Vendor Evaluation:** Utilities should assess third-party vendors for qualitative and quantitative measures such as vendor experience, technical reliability, environmental impacts, and safety.
  - c. **Equity:** NPA impacts on disadvantaged communities should be quantified. The results of an equity analysis can override BCA results. For example, an NPA project that provides significant equity benefits but produces greater net costs than the traditional solution may be approved.

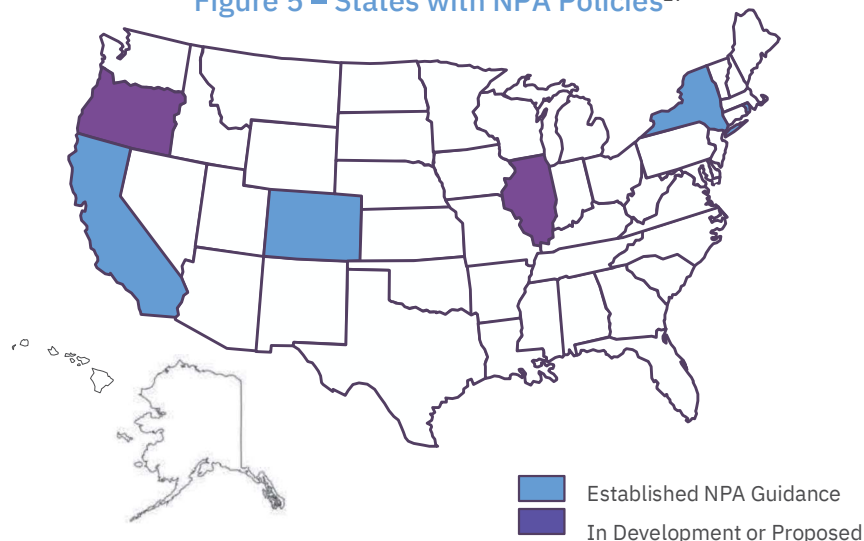
Finally, complementary policy changes, such as a **shared savings mechanism**, can help reduce the utility's inherent financial preference for traditional capital solutions over NPAs. While utilities typically do not receive a rate of return on demand-side NPA implementations, a shared savings mechanism allows utilities to earn a financial reward for successful NPA projects. Shared saving mechanisms typically allocate to the utility a fixed percentage of net benefits produced by the project but can take several forms. For example, New York allows utilities to earn up to 30% of an NPA project's net benefits through an incentive mechanism.<sup>26</sup>

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<sup>26</sup> New York Public Service Commission. Docket No. 19-E-0378. *Order Approving Electric and Gas Rate Plans in Accord with Joint Proposal, With Modification, Appendix HH*. November 19, 2020. Available at: [https://app.insightengine.org/dockets/ny-19-01236-19-e-0378/filings/15514210?version=beta&filing\\_search\\_id=1615769&document\\_id=163555515](https://app.insightengine.org/dockets/ny-19-01236-19-e-0378/filings/15514210?version=beta&filing_search_id=1615769&document_id=163555515)



Figure 5 – States with NPA Policies<sup>27</sup>



### State Example: NPAs in New York’s Long-Term Gas Planning Framework

As part of its gas planning order, the New York Public Service Commission (NY PSC) required each utility to assess NPAs in its long-term plan filings. The regulations require that the gas utilities include information that would allow clean heat developers to target programs toward areas with leak-prone pipes or areas in need of infrastructure improvements to maintain reliable service.<sup>28</sup> Specifically in addressing leak-prone pipes, the NY PSC encourages gas utilities to take a “neighborhood approach” and work with local groups and state agencies on a comprehensive program that simultaneously removes the leaking infrastructure and employs programs such as weatherization and demand response along with electrification.<sup>29</sup>

The New York rules allow utilities to form portfolios of demand- and supply-side resources as NPAs, since individual measures may not entirely resolve capacity issues. Demand-side resources must provide permanent reductions through measures that include electrification, energy efficiency, and weatherization.<sup>30</sup> Notably, solutions that result in a switch to other fossil fuels, such as propane, are not viable.<sup>31</sup>

<sup>27</sup> Ron Nelson, et al., Strategen Consulting. *Non-Pipeline Alternatives: A Regulatory Framework and a Case Study of Colorado*. 2023. Available at: <https://www.strategen.com/strategen-blog/non-pipeline-alternatives-framework>

<sup>28</sup> New York Public Service Commission. Docket No. 20-G-0131, *Order Adopting Gas System Planning Process*, page 21-22. May 12, 2022. Available at: [https://app.insightengine.org/dockets/ny-20-00652-20-g-0131/filings/16815248?version=beta&filing\\_search\\_id=1615753&document\\_id=165777211](https://app.insightengine.org/dockets/ny-20-00652-20-g-0131/filings/16815248?version=beta&filing_search_id=1615753&document_id=165777211)

<sup>29</sup> New York Public Service Commission. Docket No. 20-G-0131, *Order Adopting Gas System Planning Process*, page 39. May 12, 2022. Available at: [https://app.insightengine.org/dockets/ny-20-00652-20-g-0131/filings/16815248?version=beta&filing\\_search\\_id=1615753&document\\_id=165777211](https://app.insightengine.org/dockets/ny-20-00652-20-g-0131/filings/16815248?version=beta&filing_search_id=1615753&document_id=165777211).

<sup>30</sup> New York Public Service Commission. Docket No. 17-G-0606, *Petition of Consolidate Edison Company of New York, Inc. for Approval of the Smart Solutions for Natural Gas Customers Program. Request for Proposals of Non-Pipeline Solutions to Provide Peak Period Natural Gas System Relief*. December 21, 2017. Available at: [https://app.insightengine.org/dockets/ny-17-02100-17-g-0606/filings/7998384?version=beta&filing\\_search\\_id=1615796&document\\_id=163612284](https://app.insightengine.org/dockets/ny-17-02100-17-g-0606/filings/7998384?version=beta&filing_search_id=1615796&document_id=163612284)

<sup>31</sup> *Id* at p. 8.



NPAs in practice are not new to New York; several utilities have implemented NPA solutions before the promulgation of the 2022 gas planning regulation, as illustrated in the NYSEG case study below.

### Case Study: NYSEG's Non Pipeline Alternative Analysis in Lansing, NY

In 2020, the NY Public Service Commission approved NYSEG's NPA project in the Town of Lansing in Tompkins County. A growth in natural gas demand caused a decrease in in system operating pressure, leading to a reliability concern on very cold days.<sup>32</sup> The traditional solution to such an issue would have been the addition of a compressor, but instead, NYSEG issued an RFP for NPAs. NYSEG received sixteen proposals that included electrification via heat pumps, energy efficiency, community ground source heat pump loops, industrial waste heat recovery, demand response, smart thermostats, Compressed Natural Gas (CNG) injection, LNG, and a rebate program to incent heat pump adoption.<sup>33</sup> The Commission ultimately approved a portfolio of six resources, including residential air source and ground source heat pumps plus energy efficiency, new efficient gas boilers, a waste heat recovery system for an industrial customer, demand response, and education and outreach with heat pump incentives for space or water heating fuel switching. Together, these measures sufficiently reduced peak day demand and thereby avoided traditional infrastructure investments.<sup>34</sup> While not all resources individually produced a net benefit as measured by a societal cost test, collectively, the portfolio of resources did.

The rise of electrification of building heating is likely to lead to more cost-competitive demand-side NPA portfolios. The Lansing NPA is an example of avoiding gas capacity expansion investments, but NPAs can also be beneficial when infrastructure investments are needed in an area with decreasing throughput. Those NPAs can prevent capital projects that may become stranded or underused if trends continue, producing benefits for both the customers who are fuel switching and the remaining gas customers. NPAs are a nascent, but critical tool in avoiding infrastructure investments to prevent gas rate increases.

<sup>32</sup> New York Public Service Commission. Docket No. 17-G-0432, *Order Approving Petition for Non-Pipe Alternative Projects, With Modifications*. June 21, 2021. Available at: [https://app.insightengine.org/dockets/ny-17-01528-17-g-0432/filings/15506679?version=beta&filing\\_search\\_id=1615810&document\\_id=163588518](https://app.insightengine.org/dockets/ny-17-01528-17-g-0432/filings/15506679?version=beta&filing_search_id=1615810&document_id=163588518)

<sup>33</sup> *Id.* at p. 6-9.

<sup>34</sup> *Id.*



## Embedding Equity

Disadvantaged populations generally face high rates of energy insecurity,<sup>35</sup> with some having to forgo necessities to pay energy bills. Fewer financial resources also prevent disadvantaged populations from investing in energy efficiency and fuel-switching in response to high or volatile energy prices. Thus far equity analysis has not played much of a role in gas planning regulations and without explicit PUC guidance, existing planning tools are unlikely to factor in impacts on disadvantaged communities. For example, a reduction in average energy consumption and residential customer bills does not indicate that all customers are benefiting since a subset of high-income customers could be driving the trend and receiving the majority of benefits. Similarly, not all communities are equally impacted by infrastructure projects and the impact of gas emissions, including pollutants such as nitrous oxide that lead to adverse health consequences.<sup>36</sup> There are several dimensions of equity analysis, but this paper largely focuses on distributional equity, which examines how impacts or benefits are distributed among target populations. For more information on recognition, procedural, distributional and restorative equity, see the Energy Equity Project.<sup>37</sup>

Both the federal government and states are increasingly interested in embedding equity into clean energy policies. For example, a new Pipeline and Hazardous Materials Safety Administration Gas Distribution Safety Requirements proposed rule, created in August of 2023, proposes a requirement for gas distribution utilities to “[promote] environmental justice for minority populations, low-income populations, or other underserved and disadvantaged communities, or others who are particularly likely to live and work near higher-risk gas distribution pipeline systems.”<sup>38</sup> If this rule is formally published, distribution operators will have to consider the effect that certain programs, including their distribution integrity management programs (DIMP) and asset condition remediation programs, potentially including NPAs, will have on disadvantaged communities. The implementation of this rule will help create additional justification to prioritize historically disadvantaged and low-income groups.

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<sup>35</sup> U.S. Energy Information Administration. *One in three U.S. households faced challenges in paying energy bills in 2015*. Available at:

<https://www.eia.gov/consumption/residential/reports/2015/energybills/#:~:text=Transportation-.One%20in%20three%20U.S.%20households%20faced%20challenges%20in%20paying%20energy,in%20their%20home%20in%202015>

<sup>36</sup> Jeffrey Kluger, Time. *Your gas stove may be leaking benzene into your kitchen*. October 20, 2022. Available at:

<https://time.com/6223219/gas-stove-leaking-benzene/>

<sup>37</sup> University of Michigan School of Environment and Sustainability, Energy Equity Project. *Energy Equity Framework: Combining data and qualitative approaches to ensure equity in the energy transition*. 2022. Available at:

[https://energyequityproject.com/wp-content/uploads/2022/08/220174\\_EEP\\_Report\\_8302022.pdf](https://energyequityproject.com/wp-content/uploads/2022/08/220174_EEP_Report_8302022.pdf)

<sup>38</sup> Pipeline and Hazardous Materials Safety Administration, Federal Register. *Pipeline Safety: Safety of Gas Distribution Pipelines and Other Pipeline Safety Initiatives*. September 7, 2023. Available at:

<https://www.federalregister.gov/documents/2023/09/07/2023-18585/pipeline-safety-safety-of-gas-distribution-pipelines-and-other-pipeline-safety-initiatives>



The US Department of Energy also recommends creating several Distributional Energy Analysis (DEA) metrics for every Distributed Energy Resource (DER) project and evaluating these metrics for both disadvantaged populations and other customers.<sup>39</sup> The DEA metrics utilize pass/fail criteria to determine if the DEA has an equal or larger positive impact on disadvantaged customers compared to other customers. The pass/fail criteria are established by stakeholders before the analysis of a specific project and should align with equity goals set by the operating utility and PUC.

States are similarly beginning to incorporate aspects of equity into their planning process,<sup>40</sup> however, the requirements appear to be largely focused on electric resource planning at this time. New York's Climate Leadership and Community Protection Act (CLCPA) requires at least 35% of benefits from energy program spending, including gas energy efficiency and electrification, to be directed towards disadvantaged communities.<sup>41</sup> New York's gas utilities are recognizing this requirement in their long-term plans, but the implementation, like in other states, is still in its infancy. NYSEG and Rochester Gas & Electric (RGE), gas utilities owned by Avangrid, mapped disadvantaged communities in their initial joint Long-Term Plan and noted that they are developing a "Just Transition" framework for future use.<sup>42</sup>

Incorporating impacts on disadvantaged populations will require iterations and improvements in each subsequent gas plan. How states incorporate the various aspects of equity, including recognition, procedural, distributional, and restorative equity into the policies and procedures is a question much larger than gas planning. As a starting point for modern gas planning, PUCs should leverage national and state work to define and map disadvantaged communities for use in the gas plans. PUCs should also consider requiring gas utilities to overlay a map of proposed capital projects and resource acquisitions in the short-term action plan across a map of all disadvantaged populations in the utility's service area. Through this process, decision-makers will have a greater understanding of areas that are likely to be impacted by utility investments.

## Mapping

Maps serve as an important tool in creating comprehensive, modern gas plans that effectively communicates system capacities, constraints, needs, and potential solutions to address issues and provide useful information to stakeholders. Where a state has mapped environmental justice or

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<sup>39</sup> U.S. Department of Energy and Lawrence Berkeley National Lab. *Distributional Equity Analysis for Energy Efficiency and Other Distributed Energy Resource Programs: A Practical Guide*. May, 2023. Available at: <https://www.energy.gov/sites/default/files/2023-05/bto-peer-2023-dea-frick.pdf>

<sup>40</sup> Berkeley Lab and Pacific Northwest National Laboratory. *22 States + D.C. are Advancing Energy Equity through Executive, Legislative, and Regulatory Actions*. February 21, 2023. Available at: <https://emp.lbl.gov/news/22-states-dc-are-advancing-energy-equity>

<sup>41</sup> New York Senate Bill 6599 and Assembly Bill 8429 (2019)

<sup>42</sup> New York Public Service Commission, Docket No. 23-G-0437. *NYSEG and RG&E Initial Gas Long-Term Plan*. October 2, 2023. Available at: <https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=23-G-0437>



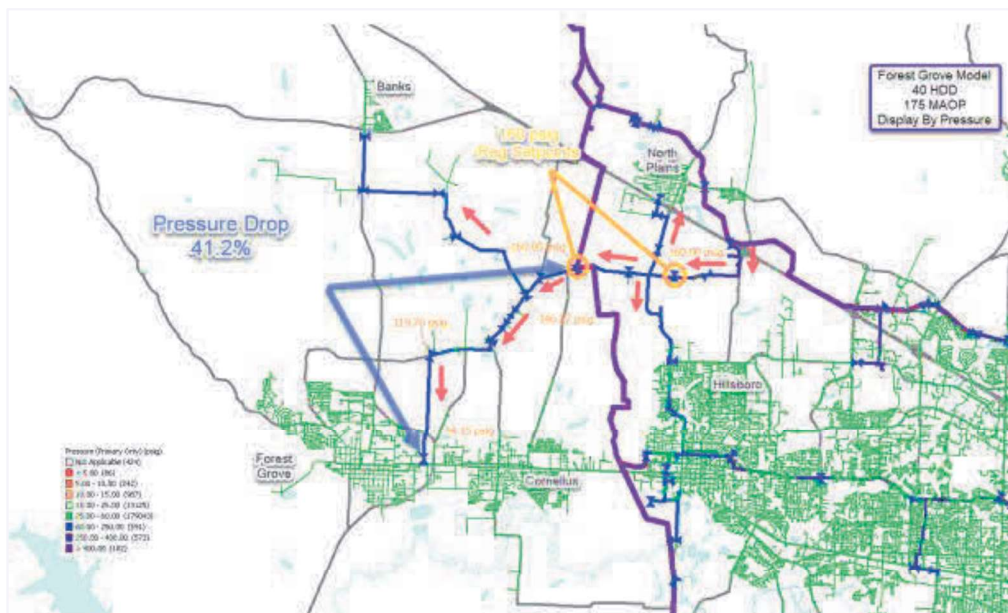
disadvantaged communities, gas systems can be overlaid with those geographies to uncover environmental hazards or injustices and to better shape solutions that address historical inequities. The inclusion of maps allows stakeholders to better understand the system constraints that utilities must address as well as be better equipped to determine whether the solutions utilities identify are reasonable and appropriate.

### Case Study: Northwest Natural’s System Maps

A recent example of a utility effectively including maps in its gas IRP is Northwest Natural’s (NWN) 2022 IRP, shown in Figure 6. The maps served as an important visual guide in discussions, creating a more comprehensive narrative, illustrating the current state of the system, and better describing the plans the utility has for its system.

NWN first provided a map that shows all existing natural gas pipelines and storage infrastructure in the region, including total pipeline capacities. NWN utilized maps to illustrate which pipelines and natural gas sources would serve the NWN’s service territory in the case that certain LNG facilities were decommissioned, to demonstrate possible routes identified for a pipeline that NWN’s modeling determined was necessary, and to illustrate the interchangeability of certain LNG facilities via a gas flow diagram. The maps supplemented the utility’s discussion of its exploration of options for the sizing of pipelines to address constraints and potential decommissioning of LNG facilities.

Figure 6 – NWN Gas IRP Map Denoting Pressure Drop<sup>43</sup>



<sup>43</sup> Oregon Public Utility Commission. Docket No. LC 79. *NW Natural’s 2022 Integrated Resource Plan*, p. 388. September 2022. Available at: [https://app.insightengine.org/dockets/or-lc-79?version=beta&docket\\_search\\_id=1615821](https://app.insightengine.org/dockets/or-lc-79?version=beta&docket_search_id=1615821)



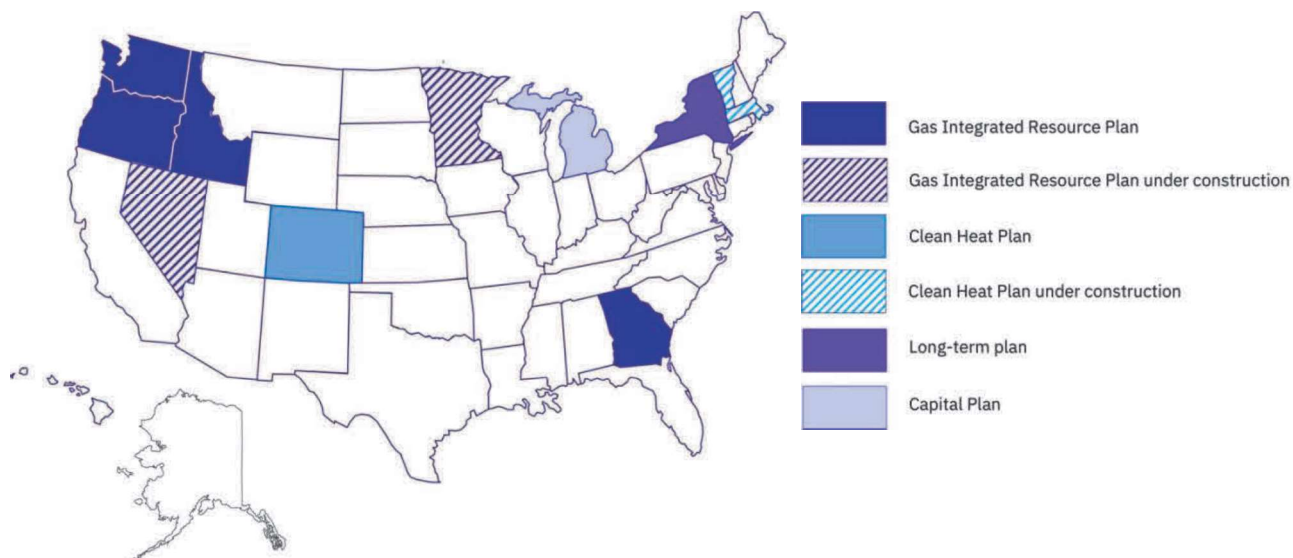
## Part II: An Overview and Comparison of Existing Gas Plans

### Types of Gas Plans

This section provides a detailed review of four different approaches to gas system planning. **New York long-term plans (LTPs), Colorado Gas Infrastructure Plans (GIPs) and Clean Heat Plans, and Pacific Northwest Gas Integrated Resource Plans (IRPs)** are gas planning requirements that identify the optimal portfolio of resources that meet customer needs and account for state policy goals, including climate goals. In Michigan **Consumers Energy voluntarily produces Capital Plans**. This section also provides an overview of the Canadian Province of **British Columbia's Coordination between Gas and Electric Utilities' Plans**, to illustrate a novel approach to coordination.

Emissions considerations are recent additions to gas planning and, as such, utilities in New York, Colorado, and the Pacific Northwest are, as of 2023, submitting their first iterations of gas plans that include climate targets.

Figure 7 – 2023 Gas Planning Landscape in the United States



Each of the state's gas planning regulations requires several analytical elements, however, no state mandates all the analytics features detailed above. In general, utilities produce more robust gas plans in states with more extensive analytical requirements.

### **New York Long-Term Plans (LTPs)**

In May 2022, an NY PSC order established a gas system planning process that requires gas utilities to file long-term plans every three years, detailing demand and supply forecasts over a 20-year horizon.<sup>44</sup> Each utility must provide a "no-infrastructure option" in which the utility models a scenario that does not rely on traditional capital spending for meeting system reliability needs and forecasted gas demand. As part of the planning requirement, the utilities must develop a framework for the acquisition and assessment of NPAs. Additionally, the Order requires utilities to provide bill and emissions impacts and identify a preferred portfolio.

Stakeholder engagement is a core part of the NY LTP process. The Order stipulates that utilities must hold a technical conference within a few weeks of the initial LTP filing. Stakeholders are granted the opportunity to submit comments and engage with utilities in additional meetings. The Commission also recommends that an independent third-party consultant evaluate the utility plans. Following the submission of stakeholder comments, utilities must then provide a revised long-term plan. Stakeholders have an additional opportunity to submit a second set of comments in response to the revised LTP and engage with the utility at another stakeholder meeting. Finally, the Commission decides whether to adopt, reject, or modify the revised long-term plan.

A driving factor for the establishment of gas planning is the CLCPA, which specifies emissions reduction targets across the state's economy. Although the CLCPA does not specifically identify emissions reduction goals for gas utilities, the NY Climate Action Council (CAC) recently submitted its Final Scoping Plan that sets targets for building decarbonization, including a goal of electrifying 85% of home and commercial building space by 2050.<sup>45</sup> Although the utilities are not legally required to adhere to the Final Scoping Plan, they will likely need to decarbonize rapidly to meet future policy requirements. As such, the Commission ordered utilities' LTPs to be consistent with the CAC's Scoping Plan.<sup>46</sup>

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<sup>44</sup> New York Public Service Commission. Docket No. 20-G-0131, *Order Adopting Gas System Planning Process*. May 12, 2022. Available at: [https://app.insightengine.org/dockets/ny-20-00652-20-g-0131/filings/16815248?version=beta&filing\\_search\\_id=1615753&document\\_id=165777211](https://app.insightengine.org/dockets/ny-20-00652-20-g-0131/filings/16815248?version=beta&filing_search_id=1615753&document_id=165777211)

<sup>45</sup> New York State Climate Action Council. *New York State Climate Action Council Scoping Plan*, p 180. 2022. Available at: <https://climate.ny.gov/resources/scoping-plan/>

<sup>46</sup> New York Public Service Commission. Docket No. 20-G-0131, *Order Adopting Gas System Planning Process*. May 12, 2022. Available at: [https://app.insightengine.org/dockets/ny-20-00652-20-g-0131/filings/16815248?version=beta&filing\\_search\\_id=1615753&document\\_id=165777211](https://app.insightengine.org/dockets/ny-20-00652-20-g-0131/filings/16815248?version=beta&filing_search_id=1615753&document_id=165777211)



### Case Study: National Fuel Gas Distribution Corporation (NFG) LTP

National Fuel Gas Company was the first utility to submit a long-term plan in accordance with the NY gas planning process in December 2022. NFG operates in western New York and Pennsylvania and supplies gas to approximately 540,000 customers in New York.<sup>47</sup> NFG submitted an LTP that included three scenarios: a reference case, a “supply-constrained economy” (SCE) scenario, and an “aggressive” scenario. Over the 20-year planning horizon, the SCE scenario results in only modest emissions reductions, largely driven by the blending of green hydrogen and renewable natural gas. In addition to similar alternative fuel assumptions, the aggressive scenario assumes electrification plays a substantial role in decarbonization, though also includes similar alternative fuel assumptions to the SCE scenario.<sup>48</sup> As a result, the aggressive scenario results in double the emissions reductions relative to the SCE scenario, as illustrated in Figure 8 below.<sup>49</sup>

While NFG found the aggressive scenario to more greatly reduce emissions, it also determined that, across the planning period, customer bills would increase by 121% in the aggressive scenario and only 33% in the SCE scenario.<sup>50</sup> The Company assessed that the net present cost of decarbonization in the aggressive scenario was over three times greater due to the higher costs of all-electric assets, such as heat pumps.<sup>51</sup>

NFG did not propose to adopt one scenario over the other; instead, it provided a set of actions that will guide its long-term planning. These included weatherization investments, implementing hybrid heat pumps with gas backups, and the adoption of RNG and hydrogen.<sup>52</sup> Overall, the proposed long-term plan most closely resembled the SCE scenario.

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<sup>47</sup> New York Public Service Commission. Docket No. 22-G-0610. *National Fuel Gas Distribution Corporation Initial Long-Term Plan*, page 5. December 22, 2022. Available at: [https://app.insightengine.org/dockets/ny-22-02158-22-g-0610/filings/17545827?version=beta&filing\\_search\\_id=1615836&document\\_id=168444886](https://app.insightengine.org/dockets/ny-22-02158-22-g-0610/filings/17545827?version=beta&filing_search_id=1615836&document_id=168444886)

<sup>48</sup> *Id.* at 47

<sup>49</sup> *Id.* at 45

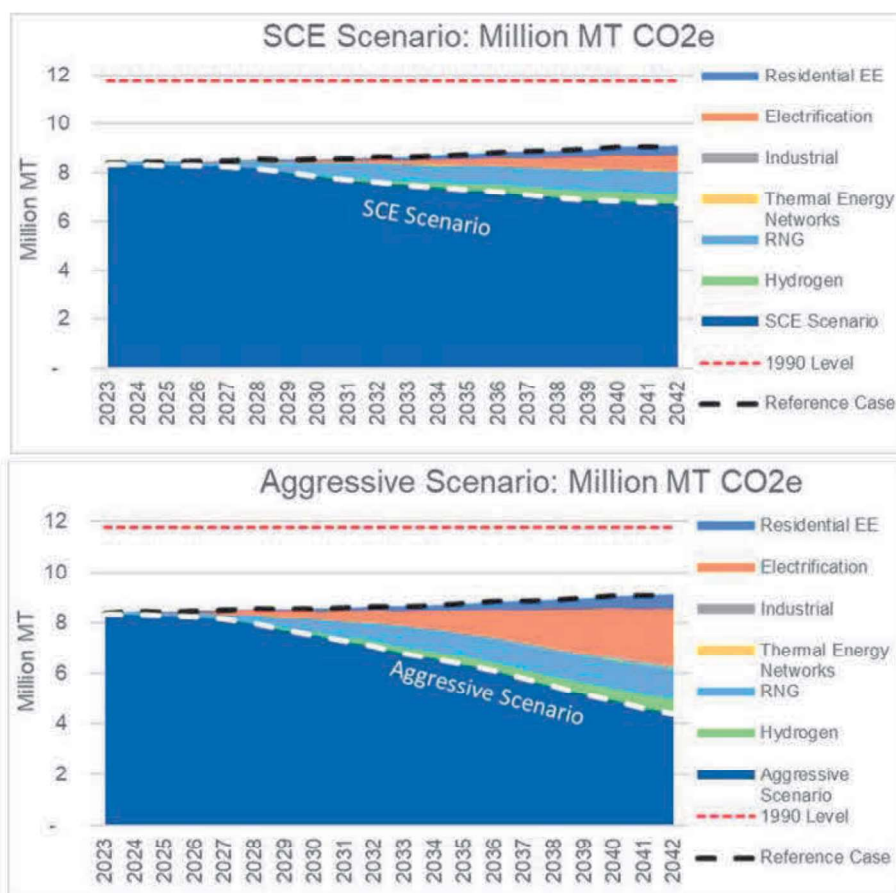
<sup>50</sup> *Id.* at 45

<sup>51</sup> *Id.* at 46

<sup>52</sup> *Id.* at 50-51



Figure 8 – Comparison of NFG LTP Scenarios<sup>53</sup>



### CASE STUDY FINDINGS

Stakeholders provided comments on several topics including cost assumptions, electrification adoption rates, compliance with state emissions policies, and NPAs. Stakeholder comments were consistent and highlighted the utility’s misvaluation of non-infrastructure solutions, such as electrification and NPAs. In response, NFG made minor revisions to its LTP, but still intends to pursue a strategy similar to the SCE scenario. As of the time of writing, the NY PSC has yet to rule on NFG’s long-term plan. Nevertheless, the NFG’s first LTP illustrates the challenges facing the gas sector, especially gas-only utilities that do not stand to benefit from electrification. Stakeholders opposed critical elements of NFG’s LTP, urging greater efforts to decarbonize and electrify, and also disagreed with numerous NFG assumptions. Although the utility and the stakeholders were unable to reach a consensus, the gas planning process has already produced several benefits:

<sup>53</sup> *Id.* at 47



1. NFG analyzed multiple scenarios, quantifying costs, bill impacts, and emission reductions. Although NFG included little assessment of risk, the LTP measured the impact of electrification and alternative fuels on gas rates and emission reductions.
2. The public process allowed for stakeholders and an independent third-party consultant to influence the LTP. While NFG's revisions did not address the majority of the recommendations of other parties, NFG did modify some assumptions. The data NFG provided in its report and appendices also allowed stakeholders to understand the core assumptions that shaped the utility's planning. This transparency allowed stakeholders to more fully critique NFG's electrification and RNG availability assumptions.
3. The LTP provided estimates of emission reductions through 2042, which allowed stakeholders to identify and present concerns related to compliance with New York's climate law.

On the other hand, the New York LTP is not a perfect model for gas planning. NFG's LTP did not model the electric sector load increases and associated costs in the SCE or aggressive scenarios. The impacts of electrification should be quantified to better understand the impacts across the energy system and to begin moving utilities towards greater collaboration between utility gas and electric divisions and with overlapping electric utilities. Furthermore, NFG provided only two alternatives to the reference scenario and did not conduct sensitivity analyses. Additional scenarios and sensitivities could have provided stakeholders with a greater understanding of the impact of specific measures on bills and emissions reductions. For example, modeling changes to policy, such as a gas moratorium, or greater competition for alternative fuels would have provided a more nuanced understanding of scenario risks. Finally, the lack of a short-term action plan limits the impact of any NY PSC decision in the near term. NFG did not provide a specific set of short-term investments related to its preferred long-term plan. For example, instead of specifying potential RNG projects along with associated forecasted cost and emissions impact, NFG's initial RNG action plan is to "promote regional anaerobic digestion projects." As a result, the NY PSC cannot evaluate specific projects, weakening the link between gas planning and rate cases.

### **Pacific Northwest Integrated Resource Plans (IRPs)**

Both Oregon and Washington State require gas utilities to file integrated resource plans. Although some terminology differs (e.g., Washington regulations require the "lowest-reasonable cost" portfolio to be adopted; Oregon regulations require the "least-cost, least risk" portfolio), the requirements are very similar. Both states require the evaluation of all demand- and supply-side resources, alternative scenarios, analysis of various load scenarios,



assessments of scenarios by cost and risk, and a sensitivity analysis.<sup>54</sup> Utilities must also detail a short-term action plan that addresses investments in the two years following the acknowledgment of IRP.<sup>55</sup> Additionally, both states stress the importance of stakeholder participation: The Oregon PUC specifies, “[t]he public, which includes other utilities, should be allowed significant involvement in the preparation of the IRP.”<sup>56</sup> Oregon rules stipulate that IRP forecasts should extend at least twenty years while Washington requires a minimum of ten years, though Washington utilities have typically exceeded the minimum requirements to also use 20-year planning periods.<sup>57</sup>

Utilities in both states must also model compliance with recently enacted state climate laws; the Climate Protection Program (CPP) in Oregon, and the Climate Commitment Act (CCA) in Washington. The CPP is a cap-and-trade program that mandates a 50% greenhouse gas reduction by 2035 and a 90% reduction by 2050. The CPP covers all natural gas utilities in the state under a declining cap. Washington’s CCA caps greenhouse gas emissions and requires the state to reduce emissions levels by 95% by 2050.<sup>58</sup> The CCA provides natural gas utilities with “free” allowances and holds auctions for the trading of allowances, with both free and tradeable allowance totals declining annually.<sup>59</sup>

The enactment of climate laws in the Pacific Northwest has dramatically altered natural gas planning in the region; within a couple of years, gas utilities in Washington and Oregon have shifted from largely business-as-usual planning to IRPs that model significant emission reductions. The following case study explores the first utility to model compliance with the CPP and CCA.

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<sup>54</sup> Oregon Public Utility Commission Docket. No. UM 1056. Order 07-002; Oregon Administrative Rule 860-027-0400, available at <https://secure.sos.state.or.us/oard/viewSingleRule.action?ruleVrsnRsn=302069>; Washington Administrative Code 480-90-238, available at <https://apps.leg.wa.gov/wac/default.aspx?cite=480-90-238>

<sup>55</sup> *Id.*

<sup>56</sup> Oregon Public Utility Commission. Docket UM 1056, *Order No. 07-002*, page 2. January 2007. Available at: <https://apps.puc.state.or.us/orders/2007ords/07-002.pdf>

<sup>57</sup> Oregon Public Utility Commission. Docket UM 1056, *Order No. 07-002*, page 2. January 2007. Available at: <https://apps.puc.state.or.us/orders/2007ords/07-002.pdf>; Washington Utilities and Transportation Commission. Docket No. UG-030312. *Adoption Hearing For Proposed Rules In Chapter Wac 480-90-238, Relating To Least Cost Plan*. March 2003. Available at: [https://app.insightengine.org/dockets/wa-ug-030312?version=beta&docket\\_search\\_id=1615874](https://app.insightengine.org/dockets/wa-ug-030312?version=beta&docket_search_id=1615874)

<sup>58</sup> Revised Code of Washington 70A.45.020. Available at: <https://apps.leg.wa.gov/rcw/default.aspx?cite=70A.45.020>

<sup>59</sup> Kasia Patora. Washington State Department of Ecology. *Final Regulatory Analyses for Chapter 173-446 WAC, Climate Commitment Act Program*. September 2022. Available at: <https://apps.ecology.wa.gov/publications/documents/2202047.pdf>

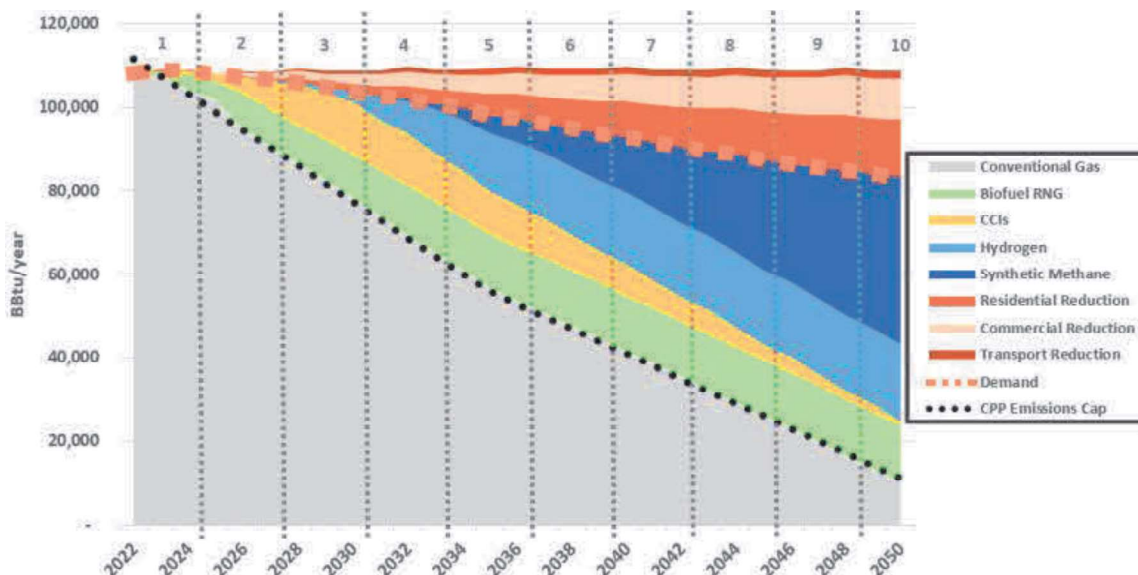


## Case Study: Northwest Natural 2022 Gas IRP

Spanning across both Oregon and Washington, NWN’s IRP addresses the requirements of both the CPP and the CCA. NWN modeled nine distinct scenarios that leveraged varying amounts of alternative fuels and electrification as well as scenarios that modeled potential policies, including a new gas customer moratorium and federal policy support for alternative fuels.<sup>60</sup> NWN provided a comprehensive analysis of resource cost, resource acquisitions (both demand and supply), and customer demand for each scenario. NWN identified a compliance portfolio, which relies heavily on the acquisition of alternative fuels for compliance in both states.

The accompanying short-term action plan identifies goals for RNG acquisition, energy efficiency, compliance investments in Oregon, and emissions offsets and allowances in Washington. NWN’s short-term action plan complements its long-term vision for the future of its gas system and compliance with climate laws. The utility’s analysis included cost optimization modeling, including a Monte Carlo simulation (a mathematical technique used to evaluate possible outcomes from uncertain events). Notably, the preferred portfolio (Figure 9) was not one of the nine scenarios presented, and the Oregon PUC decided not to acknowledge several sections of the filing.

Figure 9 – NWN Preferred Portfolio in Oregon<sup>61</sup>



<sup>60</sup> Oregon Public Utility Commission. Docket No. LC 79. *NW Natural’s 2022 Integrated Resource Plan, Chapter 7*. September 2022. Available at: [https://app.insightengine.org/dockets/or-lc-79?version=beta&docket\\_search\\_id=1615879](https://app.insightengine.org/dockets/or-lc-79?version=beta&docket_search_id=1615879)

<sup>61</sup> Oregon Public Utility Commission. Docket No. LC 79. *NW Natural’s 2022 Integrated Resource Plan*, p. 26. September 2022. Available at: [https://app.insightengine.org/dockets/or-lc-79?version=beta&docket\\_search\\_id=1615879](https://app.insightengine.org/dockets/or-lc-79?version=beta&docket_search_id=1615879)



## CASE STUDY FINDINGS

Stakeholders identified several limitations with the utility's IRP, including NWN's insufficient consideration of risk and lack of detailed analysis in its preferred portfolio.<sup>62</sup> In its reply comments, NWN supported its initial positions and did not waiver from its action plan or long-term preferred compliance scenario.<sup>63</sup>

The Oregon PUC's decision only to acknowledge the IRP in part highlights the benefits of gas planning. The non-acknowledgment of elements in the short-term and long-term plan provides a clear indication that the utility's rationale and assumptions for its investment decisions were inadequate. Despite NWN's significant quantitative work, the PUC deemed that the utility did not meet the state's regulatory standard. To pursue the long-term investments identified in its IRP, NWN will need to provide a more robust risk assessment to demonstrate that its preferred portfolio is the least-cost, least-risk pathway to meeting climate targets – a demand first made by stakeholders and later echoed by the PUC. Regardless of the result of the subsequent analysis, the additional information in an IRP update will provide better insight as to the decarbonization approach that produces the most ratepayer benefits.

In the absence of an IRP, the utility would still have internally assessed compliance approaches but could have relied on unvetted assumptions or failed to adequately assess risk. Via stakeholder and PUC involvement, the IRP process identified these issues in advance of the investment decision, potentially forestalling investments that may not be in the public interest. The IRP process thus reduced the informational asymmetry inherent to utility regulation, whereby the utility holds most information related to its decision-making, by ensuring stakeholders and the PUC had enough information to make informed evaluations of the utility's plan. This is especially important considering the complexity and uncertainty related to meeting climate goals.

While the Oregon regulations have established a high bar for gas planning, the applicable statute does not require gas utilities to quantify electric system costs or benefits, which creates significant gaps in the public's understanding of the societal impacts of modeled scenarios. Even within its electrification scenario, NWN did not quantify any electricity system impacts related to fuel switching, such as, incremental electric transmission, distribution, and generation costs, or efficiencies from increasing electric load at off-peak times. Instead, the electrification scenario only quantifies a reduction in gas system fuel costs. As a result of the

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<sup>62</sup> Oregon Public Utilities Commission. Docket No. LC 79. *Climate Advocates Opening Comments*. December 30, 2022. Available at: [https://app.insightengine.org/dockets/or-lc-79/filings/17562241?version=beta&filing\\_search\\_id=1615994&document\\_id=168501265](https://app.insightengine.org/dockets/or-lc-79/filings/17562241?version=beta&filing_search_id=1615994&document_id=168501265)

<sup>63</sup> Oregon Public Utilities Commission. Docket No. LC 79. *NW Natural Reply Comments*. February 3, 2023. Available at: [https://app.insightengine.org/dockets/or-lc-79/filings/17670786?version=beta&filing\\_search\\_id=1615994&document\\_id=168867825](https://app.insightengine.org/dockets/or-lc-79/filings/17670786?version=beta&filing_search_id=1615994&document_id=168867825)



omission of incremental electric system costs and benefits, the electrification scenario does not provide an accurate picture to inform PUC decision-making.

Stakeholders were also concerned that NWN's IRP did not allow demand-side management resources, such as energy efficiency, electrification, and demand response, to compete against supply-side resources to meet future customer demand. NWN only modeled demand-side management resources as a reduction to customer load, but once that load forecast was determined, NWN restricted the model from selecting additional demand-side resources to meet future demand. In its comments to the commissioners, OPUC Staff stated that "This likely obscures some of the best pathways for customers as these resources are not compared on an even basis."<sup>64</sup>

Finally, while the scenario analysis provided comprehensive resource cost modeling, the lack of gas capital investment forecasts undermined the planning exercise. Without detailed information, stakeholders have no understanding of how much NWN is investing in its system. Furthermore, the utility assumed that distribution capital investments were the same in each scenario despite the very different customer counts and system needs in the electrification scenarios.<sup>65</sup> The amount of necessary asset replacements, asset upgrades, and new pipelines will vary significantly depending on whether the utility pursues a decarbonization approach based on electrification or alternative fuels, and investments should align with the approved approach. This case study underscores the importance of including capital investment forecasts within regulatory requirements for gas plans.

### **Michigan's Consumers Energy Natural Gas Delivery Plan**

Since 2020, Consumers Energy Company in Michigan (Consumers) has been providing an annual "Natural Gas Delivery Plan" (Delivery Plan). Unlike LTPs or IRPs, there is no legislative requirement for Consumers to publish public gas planning documents. Instead, Consumers developed the plan in response to requirements created by the 2019 Michigan Public Service Commission's Statewide Energy Assessment. The Delivery Plan details a ten-year forecast of Consumers' system investments, forecasts for gas prices, and decarbonization initiatives.<sup>66</sup> The Delivery Plan provides valuable data and insights into the utility's strategic planning. Consumers breaks down capital investments by function (transmission, distribution, storage, compression, digital) for each year of their plan. The capital forecast provides elaborate

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<sup>64</sup> Oregon Public Utilities Commission. Docket No. LC 79. *Staff Opening Comments*, p. 6. December 30, 2022. Available at: [https://app.insightengine.org/dockets/or-lc-79/filings/17562239?version=beta&filing\\_search\\_id=1616002&document\\_id=168501263](https://app.insightengine.org/dockets/or-lc-79/filings/17562239?version=beta&filing_search_id=1616002&document_id=168501263)

<sup>65</sup> *Id.* at 6

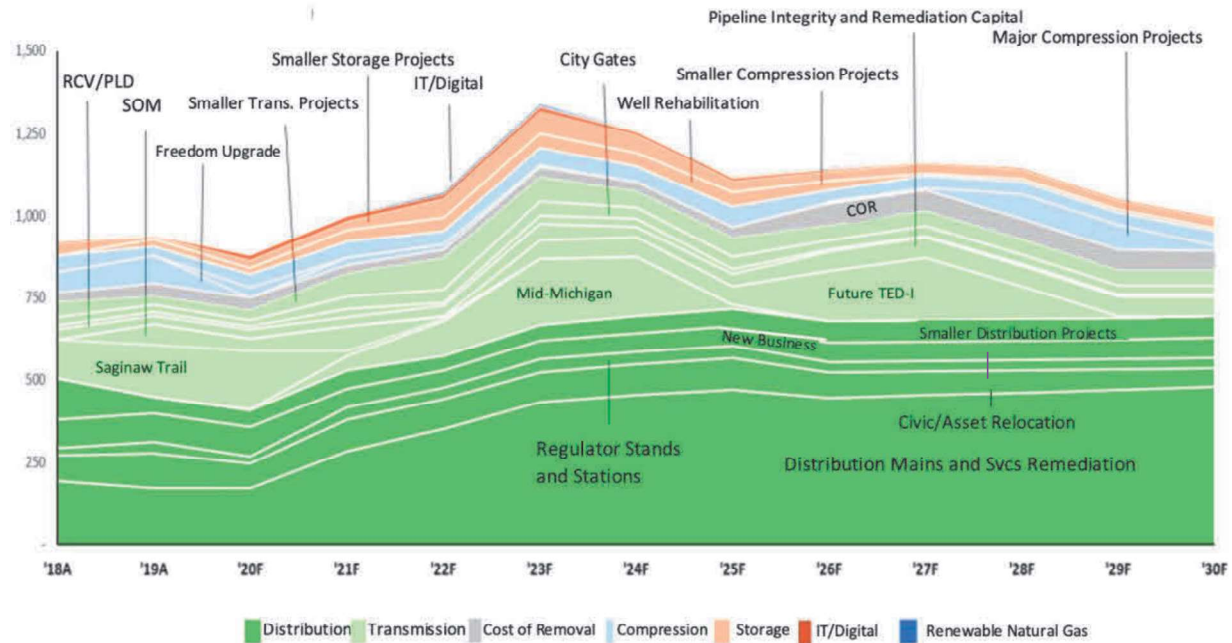
<sup>66</sup> Consumers Energy. *Natural Gas Delivery Plan*. December 11, 2020



descriptions of asset age, utilization, and system reliability needs, such that stakeholders can better understand the utility’s investment rationale.

Figure 10 – Consumers Energy Michigan Capital Plan Annual Gas Delivery

Loaded Capital Spend<sup>67</sup>



There is no commonly accepted format for a “capital plan,” though Consumers’ Delivery Plans share many common elements with LTPs and IRPs. However, the Delivery Plan is classified as a capital plan because of its focus and detail on its capital investments, wherein Consumers has provided greater depth in their spending estimates and rationale than other utilities do in LTPs and IRPs. Figure 10 offers an illustration of this detail.

<sup>67</sup> Text enhanced for readability



## Case Study: Consumers Energy's 2021-2031 and 2023-2033 Delivery Plans

### 2021-2031 Delivery Plan

The first revision of the Delivery Plan, published in 2020, includes a projection of residential bill impacts and gas commodity costs. Consumers forecasted a 4-5% annual growth rate in residential gas bills through 2025 and a 5-6% growth in bills from 2026 to 2030.<sup>68</sup>

Consumers' natural gas spot price base scenario assumed gas prices would hover around \$3/MMBtu through 2040.<sup>69</sup> The utility's narrative provided additional insight into the logic for its capital investment forecast; "now is the time to invest as gas is forecasted to be fairly flat over the next 10 years."<sup>70</sup>

This data provides critical transparency for the PUC and stakeholders. Not long after Consumers published its capital plan, gas prices soared to three times their projections.<sup>71</sup> Considering that Consumers projected roughly a 5% annual increase in residential bills over the next decade during a forecasted period of low gas prices, it is evident that the surge in commodity prices will significantly burden ratepayers in those periods of volatility. Insights gained from the capital forecast allowed the PUC and stakeholders to further assess and question infrastructure investments in light of changing economic conditions.

The Delivery Plan also details the utility's efforts to meet climate goals. Consumers' emissions reduction investments focus on the reduction of methane leaks; the utility is aiming for an 80% reduction in methane emissions by 2030.<sup>72</sup> However, the plan forecasted few investments made towards reducing end-use emissions from gas in buildings. Consumers Energy also had no plans to incorporate alternative fuels over the ten years of the plan and did not believe that electrification was "economical from an emissions or cost perspective."<sup>73</sup> Shortly before the release of the Delivery Plan, Michigan Executive Directive 2020-10 established a plan for the state to reach carbon neutrality by 2050.<sup>74</sup> Because Consumers' did not have adequate time to revise its Delivery Plan to meet Michigan's decarbonization goals, the 2021-2031 Delivery Plan data indicated that the utility was planning a business-as-usual investment strategy.

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<sup>68</sup> Consumers Energy. *Natural Gas Delivery Plan*, p. 23. December 11, 2020. Available at:

<sup>69</sup> *Id.* at 30

<sup>70</sup> *Id.*

<sup>71</sup> Data sourced from S&P Capital IQ Consumers Energy CityGate prices.

<sup>72</sup> Consumers Energy. *Natural Gas Delivery Plan*, p. 113. December 11, 2020

<sup>73</sup> *Id.* at 116.

<sup>74</sup> Michigan Department of Environment, Great Lakes, and Energy. *MI Healthy Climate Plan*. April 2022. Available at: <https://www.michigan.gov/egle/about/organization/climate-and-energy/mi-healthy-climate-plan>



## 2023-2033 Delivery Plan

The Delivery Plan released in December 2022 is notably different than the previously issued plans as it is the first plan for Michigan's Executive Directive 2020-10. The 2023-2033 Delivery Plan evaluated six decarbonization scenarios including business-as-usual, decommissioning of the gas system, electrification, alternative fuels with fossil gas, alternative fuels without fossil gas, and carbon sequestration mixed with some electrification (called the "balanced" scenario).<sup>75</sup> Consumers' analysis of these scenarios included impacts on both the gas and electric side,<sup>76</sup> and an assessment of the utility's need for fuels for each scenario (Figure 11). The utility concluded that the electrification scenario could result in 50 GW of electrical system demand, double that of the business-as-usual scenario, and increase winter electricity system peaks to 40% greater than summer peaks.<sup>77</sup>

Consumers then analyzed each scenario to determine a resource mix and the associated net present cost of implementation. Consumers selected the "balanced scenario," which relies on cost-effective electrification and natural gas offset by carbon sequestration, as the least-cost scenario through 2050.

This most recent Delivery Plan also included the other gas planning features present in the 2021-2031 Delivery Plan. Gas price forecasts reflected a more current understanding of commodity price trends, the forecast of annual capital investments reflected the utility's decarbonization approach, and the bill impact analysis was updated to reflect the increases in gas costs and capital spending. The forecasts in the Delivery Plan were significantly different than the first iteration released in 2020, as it accounted for changes in economic conditions.

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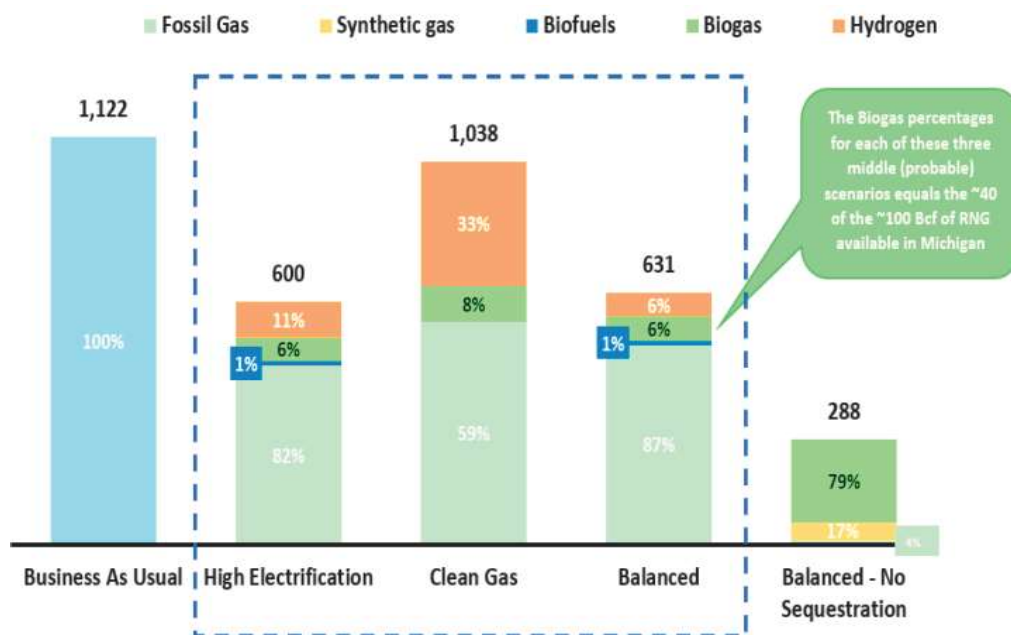
<sup>75</sup> Consumers Energy. *Natural Gas Delivery Plan*, p. 116. December 1, 2022. Available at: <https://www.consumersenergy.com/-/media/CE/Documents/company/What%20We%20Do/consumers-energy-natural-gas-delivery-plan.ashx>

<sup>76</sup> Consumers Energy. *Natural Gas Delivery Plan*, p. 120. December 1, 2022. Available at: <https://www.consumersenergy.com/-/media/CE/Documents/company/What%20We%20Do/consumers-energy-natural-gas-delivery-plan.ashx>

<sup>77</sup> Consumers Energy. *Natural Gas Delivery Plan*, p. 117. December 1, 2022. Available at: <https://www.consumersenergy.com/-/media/CE/Documents/company/What%20We%20Do/consumers-energy-natural-gas-delivery-plan.ashx>



Figure 11 – Consumers Energy Forecasted Fuels by Scenario in 2050<sup>78</sup>



### CASE STUDY FINDINGS

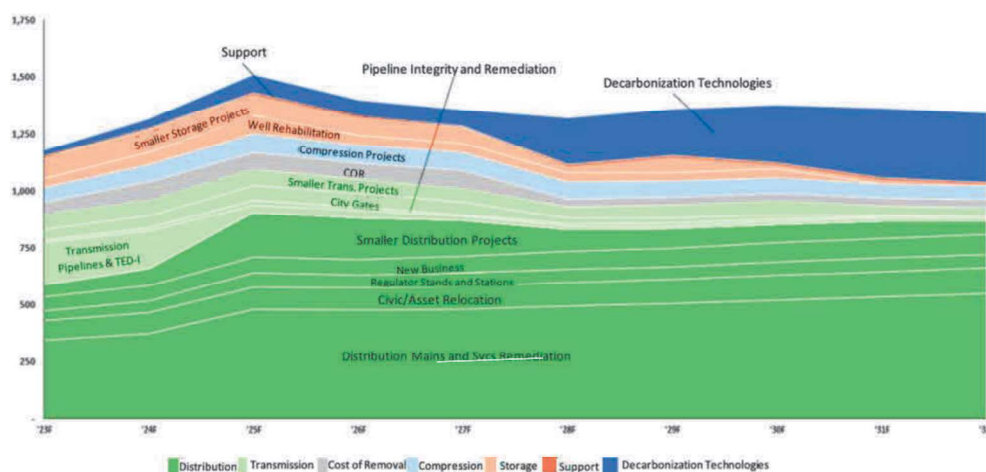
Consumers’ Delivery Plans provide an excellent example of how policy can influence system investments. The utility’s evolution in just two years demonstrates that it was operating business-as-usual until Governor Whitmer’s Executive Directive on carbon neutrality. In 2022, the utility dramatically increased its proposed capital spending approach, with decarbonization investments becoming a driver of new capital spending by 2028, as depicted in Figure 12.

While the data in the Delivery Plan is insightful, it also reveals the importance of a formal gas planning proceeding. Because there is no regulatory gas planning requirement in Michigan, Consumers does not provide stakeholders with the opportunity to assess, or the Michigan Commission to approve its Delivery Plan. Yet, Consumers’ capital plan poses significant areas of concern for ratepayers. Consumer’s bill impact analysis forecasts residential rates to nearly double in a decade, from roughly \$65/month in 2021 to just under \$115/month in 2030. And given the risk of voluntary customer electrification and efficiency reducing system throughput and that the forecasted pace of investments continues to be quite high, residential rates over the next decade will likely continue to rise beyond the planning horizon.

<sup>78</sup> Consumers Energy. *Natural Gas Delivery Plan*, p. 119. December 1, 2022. Available at: <https://www.consumersenergy.com/-/media/CE/Documents/company/What%20We%20Do/consumers-energy-natural-gas-delivery-plan.ashx>



Figure 12 – 2023-2033 Consumers Capital Forecast Annual  
 Gas Delivery Loaded Capital Spend (\$M) <sup>79,80</sup>



Specifically, Consumers’ new business forecast accentuates rate impact concerns; the utility continues to forecast an annual increase in customers despite significant historical reductions in service connections.<sup>81</sup> Considering the growing cost-competitiveness of electric appliance alternatives, the sudden projected increase in service connections is concerning. If the utility adds fewer customers than forecasted – or loses customers to electrification – fixed system costs will be spread across fewer customers, further raising rates.

These concerns are highly salient for Michigan gas customers, but stakeholders have no opportunity to formally voice their perspectives. Moreover, the Michigan Public Service Commission has no authority to acknowledge or not to acknowledge Consumers’ Delivery Plan, preventing the Commission from influencing the utility’s decision-making. The Michigan example demonstrates clearly how gas planning does not produce the same benefits to ratepayers when there is no stakeholder and PUC involvement.

### Colorado Gas Infrastructure and Clean Heat Plans

In 2021, the Colorado legislature passed several bills related to the clean energy transition, including Senate Bill 21-264. The bill requires gas utilities to file a Clean Heat Plan in which the utilities put forth a portfolio of resources they intend to source to meet a 4% reduction in 2015 GHG emissions by 2025 and a 22% reduction in 2015 GHG emissions by 2030.<sup>82</sup> The utilities

<sup>79</sup> *Natural Gas Delivery Plan*, Consumers Energy, December 1, 2022. Page 128. <https://www.consumersenergy.com/-/media/CE/Documents/company/What%20We%20Do/consumers-energy-natural-gas-delivery-plan.ashx>

<sup>80</sup> Text enhanced for readability

<sup>81</sup> *Natural Gas Delivery Plan*, Consumers Energy, December 1, 2022. Page 87. <https://www.consumersenergy.com/-/media/CE/Documents/company/What%20We%20Do/consumers-energy-natural-gas-delivery-plan.ashx>

<sup>82</sup> Colorado Senate Bill 264 (2021)



must file Clean Heat Plans at least every four years and cover a period of five years.<sup>83</sup> The plans must demonstrate emissions reductions at the “lowest reasonable cost.”<sup>84</sup>

In addition to Clean Heat Plans, the Colorado Public Utilities Commission (COPUC) also developed regulations for gas utilities to file Gas Infrastructure Plans (GIPs). GIPs must be filed every two years and detail planned capital spending by project type (capacity expansion, system safety and integrity, new business, and mandatory relation).<sup>85</sup> GIP regulations also require utilities to evaluate non-pipeline alternatives, evaluate reference, low, and high demand and resource forecasts, and provide system maps.<sup>86</sup> Together, the GIP and Clean Heat Plan create Colorado’s gas planning framework.

### Case Study: Xcel Energy’s GIP and Clean Heat Plan

In May 2023, Xcel released its first GIP detailing its forecasts, planned investments from 2023 to 2029 (Figure 13), and a non-pipeline alternative methodology.<sup>87</sup> Xcel provided a spending forecast, including a sensitivity analysis of project spending under the low, reference, and high design day forecasts.<sup>88</sup> Additionally, Xcel provided NPA analyses for five capacity expansion projects and chose to advance two.<sup>89</sup>

In its first Clean Heat Plan, Xcel developed and analyzed four scenarios and selected a preferred portfolio.<sup>90</sup> The Company identified forecasted costs and emissions reduction for each scenario. The majority of the data Xcel presented focused on the five-year plan period, although Xcel extended some modeling to 2030 to determine compliance with state laws. Additionally, Xcel provided a bill impact analysis for each of its portfolios (Figure 14).

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<sup>83</sup> Colorado Senate Bill 264 (2021)

<sup>84</sup> Colorado Senate Bill 264 (2021)

<sup>85</sup> Section 4 Code of Colorado Regulations (CCR) 723-4-4552 and Section 4 CCR 723-4-4553

<sup>86</sup> Section 4 CCR 723-4-4553

<sup>87</sup> Public Service Company of Colorado, Docket No. 23M-0234G. *Initial 2023-2028 Gas Infrastructure Plan*. May 18, 2023.

Available at: [https://app.insightengine.org/dockets/co-23m-0234g/filings/18120210?document\\_id=170250685&filing\\_search\\_id=1616056](https://app.insightengine.org/dockets/co-23m-0234g/filings/18120210?document_id=170250685&filing_search_id=1616056)

<sup>88</sup> *Id.* at 38

<sup>89</sup> *Id.* at 73

<sup>90</sup> Public Service Company of Colorado. Docket No. 23A-0392EG. *Direct Testimony and Attachments of Jack W. Ihle*. August 1,

2023. Available at: [https://app.insightengine.org/dockets/co-23a-0392eg/filings/18299162?document\\_id=171493905&filing\\_search\\_id=1616060](https://app.insightengine.org/dockets/co-23a-0392eg/filings/18299162?document_id=171493905&filing_search_id=1616060)



Figure 13 – Xcel 2023-2028 GIP Planning Investments

Planned Project Category	Number of Projects	Action Period			Informational Period			2029	Estimated Total GIP Expenditures	Estimated Total Project Expenditures*
		2023	2024	2025	2026	2027	2028			
System Safety & Integrity	6	\$22.8	\$3.1	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$25.9	\$26.2
Capacity Expansion <sup>21</sup>	8	\$5.4	\$10.0	\$6.4	\$2.9	\$2.7	\$11.8	\$19.0	\$39.2	\$58.3
Mandatory Relocation	1	\$4.1	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$4.1	\$4.2
New Business	0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
<b>Planned Projects Total:</b>	<b>15</b>	<b>\$32.3</b>	<b>\$13.1</b>	<b>\$6.4</b>	<b>\$2.9</b>	<b>\$2.7</b>	<b>\$11.8</b>	<b>\$19.0</b>	<b>\$69.2</b>	<b>\$88.7</b>

\* Includes capital expenditures for included planned projects before and after the GIP total period. Differences in sums due to rounding.

### CASE STUDY FINDINGS

Even in its first iteration, Colorado’s new gas planning process appears to produce significant benefits for customers. The GIP and Clean Heat Plan together created a direct link between utility investments and gas system emissions reduction goals. The GIP process also resulted in the implementation of two NPAs that relied primarily on electrification measures.

Figure 14 – Example of a Bill Impact Analysis from Xcel's Clean Heat Plan Preferred Portfolio<sup>91</sup>

	2024	2025	2026	2027	2028
<b>CHSEA Annual Costs (\$millions)</b>					
Beneficial Electrification - Amortized Costs	\$1,270,100	\$4,732,958	\$10,489,180	\$19,168,422	\$30,644,615
Total CHSGA Costs	\$1,270,100	\$4,732,958	\$10,489,180	\$19,168,422	\$30,644,615
<b>Sales Volumes Adjusted for Decreases Associated with DSM &amp; Electrification</b>	29,385,815,257 kWh	29,893,285,261 kWh	30,452,694,053 kWh	30,988,281,473 kWh	31,711,125,576 kWh
<b>Forecasted CHSEA Rate</b>	\$0.00004/kWh	\$0.00016/kWh	\$0.00034/kWh	\$0.00062/kWh	\$0.00097/kWh
<b>Baseline Average Rate Forecast</b>	\$0.12415/kWh	\$0.12403/kWh	\$0.12766/kWh	\$0.12835/kWh	\$0.13178/kWh
<b>Average Rate With CHSEA</b>	\$0.12419/kWh	\$0.12419/kWh	\$0.12800/kWh	\$0.12897/kWh	\$0.13275/kWh
<b>CHSEA Rate Impact</b>	+ 0.0%	+ 0.1%	+ 0.3%	+ 0.5%	+ 0.7%
<b>Average Monthly Residential Usage</b>	606 kWh	606 kWh	606 kWh	606 kWh	606 kWh
<b>Impact To Average Monthly Residential Bill</b>	\$0.03	\$0.10	\$0.21	\$0.37	\$0.59

However, the initial GIP also illuminated challenges with the current regulations. Because the GIP requirements stipulate that only projects (or sets of related projects) above \$3 million must be included, Xcel reported a small percentage of its total forecasted investments. In three of the GIP years, Xcel provided data on \$32.3 million in investments, \$13.1 million, and \$6.4 million (see Figure 13). For comparison, in Rate Case 20AL-0049G, Xcel proposed \$830.2

<sup>91</sup> Id. at 129



million in capital additions from January 2017 to September 2020.<sup>92</sup> This threshold, forecasting methodologies, and benefit-cost methodologies have been some of the main points of contention between stakeholders and the utility.

While the adjudication of the first Clean Heat Plan is ongoing at the time of this paper's release, stakeholders in that proceeding<sup>93</sup> have taken issue with the inclusion of Certified Natural Gas and carbon offsets as a clean heat resource and cost assumptions around electrification. In direct response to stakeholder pressure, Xcel re-filed the plan without counting Certified Natural Gas and offsets towards its emissions reduction targets.<sup>94</sup>

Colorado's Clean Heat Plan and GIP, considered together, resemble the NY utilities' long-term plans. Xcel filings included demand forecasts, multiple scenarios with the selection of a preferred portfolio, a bill impact analysis, non-pipeline alternatives, and a limited capital investment forecast. The most significant difference between the Colorado legislation and the NY LTPs is Colorado's shorter, five-year planning horizon for the clean heat plan. This is especially critical when considering long-term emissions reduction goals, such as carbon neutrality. Xcel's preferred clean heat portfolio is based only on modeling through 2030. However, resources that are cost-effective and help meet the 2030 emission target may not be viable, long-term solutions. For example, there are significant concerns related to whether RNG and hydrogen can fully decarbonize the gas system. Xcel's analyses determined that a portfolio that leverages RNG and hydrogen resources was the most cost-effective through 2030, but neither fuel is likely to enable the full decarbonization of the gas system due to availability and safety concerns, respectively. The Department of Energy's Clean Hydrogen Strategy and Roadmap identifies hard-to-decarbonize sectors, such as industry and heavy-duty transportation, as the highest-value applications for hydrogen, and recommends building regional networks (Hubs) to site hydrogen production close to high-priority hydrogen users.<sup>95</sup> A five-year planning horizon may be too short-sighted given the longer-term issues associated with the energy transition.

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<sup>92</sup> Public Service Company of Colorado. Docket No. 20AL-0049G. *Direct Testimony of Luke A. Litteken*, page 20 February 5, 2020. Available at: [https://app.insightengine.org/dockets/co-20al-0049g/filings/21692257?version=beta&filing\\_search\\_id=1616063&document\\_id=178440484](https://app.insightengine.org/dockets/co-20al-0049g/filings/21692257?version=beta&filing_search_id=1616063&document_id=178440484)

<sup>93</sup> Colorado Public Utilities Commission. Docket No. 23A-0392EG. *Public Service Company – Clean Heat Plan*. August, 2023. Available at: [https://app.insightengine.org/dockets/co-23a-0392eg?version=beta&docket\\_search\\_id=1616066](https://app.insightengine.org/dockets/co-23a-0392eg?version=beta&docket_search_id=1616066)

<sup>94</sup> Tom DiChristopher, S&P Global Market Intelligence. *Xcel drops certified gas, carbon offsets from Colo. clean heat plan*. November 2023. Available at: <https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/xcel-drops-certified-gas-carbon-offsets-from-colo-clean-heat-plan-78391280>

<sup>95</sup> U.S. Department of Energy, *U.S. National Clean Hydrogen Strategy and Roadmap*, p. 2. June 2023. Available at: <https://www.hydrogen.energy.gov/library/roadmaps-vision/clean-hydrogen-strategy-roadmap>



## Illinois Long-Term Gas Infrastructure Plan

On November 16<sup>th</sup>, 2023, the Illinois Commerce Commission (ICC) ruled on three gas utility rate cases: Ameren, Nicor, and People’s Gas. In the Peoples Gas Order, the ICC acknowledged that the absence of a publicly-filed gas system plan create an information asymmetry that made it difficult for the ICC, customers, and stakeholders to determine whether the utilities’ investments were just, reasonable, and prudent. In addition to disallowing recovery of hundreds of millions of dollars related to pipeline replacement programs, the Order created a new “Long-Term Gas Infrastructure Plan” (LTGIP) “[t]o remedy the difficulty of obtaining information in this case and to aid in the Commission’s informed review of the Companies’ future rate increase requests.”<sup>96</sup>

By order, gas utility LTGIPs are required to: 1) detail a 5-year action plan of investments within a longer-term planning horizon, 2) estimate the total cost and annual incremental revenue requirement of the action plan, 3) explain each project or program and justify why it cannot be deferred to future years; 4) provide comparative evaluations of resource procurements and major capital investments; 5) map the distribution system, identifying areas of constraints and risk, locations of planned projects, pressure districts served by each project, and locations of environmental justice communities; 6) describe the lowest societal cost of investments necessary to meet customer demand and comply with state public policy objectives; 7) demonstrate that programs or projects will minimize rate impacts on customers, particularly low-income and equity investment eligible communities; 8) use scenarios and sensitivities to test the robustness of the utility’s portfolio; 9) publicly file workpapers documenting all inputs and assumptions with limited use of confidentiality; and 10) summarize stakeholder participation, and how stakeholder input was incorporated into the filing. At least a year before the filing of the plan, utilities must outline contents of their upcoming LTGIP and the timing and extent of their planned public participation. The ICC expects its first plans by July 1, 2025, and every two years thereafter.

As the ICC Orders are recent and the utilities have not yet filed a workplan, it is impossible to say what the final product will look like. Based on a review of the requirements, the LTGIP looks most similar to New York’s Long-Term Plan. The primary difference between the LTGIP requirements and the NY LTP is that ICC’s primary focus is on customer rate protection rather than emission reductions. While the NY CAC played a significant role in the establishment of the LTP, the ICC’s ruling appears largely borne out of a concern that customers may experience rate increases from unreasonable utility investments. Most notably, the ICC’s requirements will enable stakeholders to understand the potential impacts of capital

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<sup>96</sup> Illinois Commerce Commission. Docket No. 23-0069. *Final Order*, p. 119. November 16, 2023. Available at: [https://app.insightengine.org/dockets/il-23-0069/filings/21929960?version=beta&filing\\_search\\_id=1616070&document\\_id=179007711](https://app.insightengine.org/dockets/il-23-0069/filings/21929960?version=beta&filing_search_id=1616070&document_id=179007711)



investments on customer bills through scenario modeling. At this time, we are also unable to evaluate the extent of public engagement in the development of the LTGIPs.

## Coordinated Gas and Electric System Planning

Coordinated gas and electric system planning is an emerging area of planning, so there is little historical precedent upon which to draw. The energy transition, spurred in part by cost-effective building electrification and decarbonization solutions, will accelerate gas-to-electric fuel switching. As will be explained, this shift in energy use – combined with the impacts of transportation electrification – can either yield significant benefits or burden ratepayers and the electric grid, depending on whether the transition is proactively managed.

Electrification of space and water heating will have varying effects, both positive and negative, on electricity generation, transmission, and distribution, and needs to be factored into both gas and electric utility load forecasting. A summer peaking electric utility may not incur marginal capacity costs to accommodate additional space heating load. In this case, the additional space heating load could cause downward pressure on electricity rates, all else constant, by spreading fixed costs over more units of sale – analogous to the benefits electric vehicle charging provides.

In some regions, significant space heating electrification could alter an electric utility's load profile enough to turn the utility into a dual- or winter-peaking utility. In these cases, heating electrification may trigger additional electrical infrastructure needs.

A higher degree of coordination between gas and electric planning, whether across divisions within the same utility or across utilities, can provide a more comprehensive view of the needs and costs of both systems. Ultimately, states may need to move towards formal integrated energy system planning, but as described below, there are several important steps that states can take today to avoid making risky investments with ratepayer dollars while developing the tools, processes, and frameworks for more fundamental changes. These steps, from most incremental to most significant, are illustrated in Figure 15.



Figure 15 – Range of Coordination Options From Least to Most



\* Assumptions can be synced around: **RNG** (economic and technical potential, specific offtakers), **hydrogen** (where it will be produced, where will it be used, cost), and **electrification** (costs, technological capabilities, impacts to the electric grid, temperature at which the heat pump is inefficient, economic crossover temperature)

### Coordinated Planning in Practice in British Columbia

The most advanced example of coordinated gas and electric planning to date is in British Columbia, Canada. In December 2021, the British Columbia Utilities Commission (BCUC) opened a process to identify pathways for achieving the province’s greenhouse gas emissions reduction targets, given that the electric utility, BC Hydro, and the gas utility, FortisBC Energy Inc. (FEI), have a “significant and correlated role” in achieving emissions reductions.<sup>97</sup> The BCUC also identified that the electricity and gas systems had numerous interdependencies including within the emerging areas of hydrogen, synthetic gas production, and carbon capture and storage (CCS). The BCUC identified six different energy scenarios: 1) Diversified energy; 2) Diversified energy with less renewable natural gas by 2040; 3) Diversified energy with more carbon capture and storage by 2040; 4) Diversified energy achieving BC’s sectoral GHG emissions targets by 2030; 5) Electrification; and 6) Deeper Electrification.<sup>98</sup> The Commission then invited the two utilities to comment on the scenarios.

In response, BC Hydro proposed that “the load scenarios in BC Hydro and FEI’s respective integrated resource plans should be the basis for developing a view of the province’s evolving needs for electricity and gas resources.”<sup>99</sup> The BCUC agreed with BC Hydro’s alternative approach and ordered the two utilities to share the data required for each to file the load forecast results based on the other utility’s scenarios, with supporting commentary regarding the supply resource impacts, rate impacts, and emissions impacts.<sup>100</sup> The BCUC ordered

<sup>97</sup> British Columbia Utilities Commission. *British Columbia Hydro and Power Authority and FortisBC Energy Inc. - Energy Scenarios*. December 3, 2021. Available at: [https://docs.bcuc.com/documents/proceedings/2021/doc\\_65110\\_2021-12-03-bcuc-request-information-on-fei-bch-energy-scenarios.pdf](https://docs.bcuc.com/documents/proceedings/2021/doc_65110_2021-12-03-bcuc-request-information-on-fei-bch-energy-scenarios.pdf)

<sup>98</sup> *Id.* at 2

<sup>99</sup> British Columbia Utilities Commission. *British Columbia Hydro and Power Authority and FortisBC Energy Inc. - Energy Scenarios*. January 21, 2021. Available at: [https://docs.bcuc.com/documents/arguments/2022/doc\\_65400\\_2022-01-21-fei-bch-energy-scenarios-request.pdf](https://docs.bcuc.com/documents/arguments/2022/doc_65400_2022-01-21-fei-bch-energy-scenarios-request.pdf)

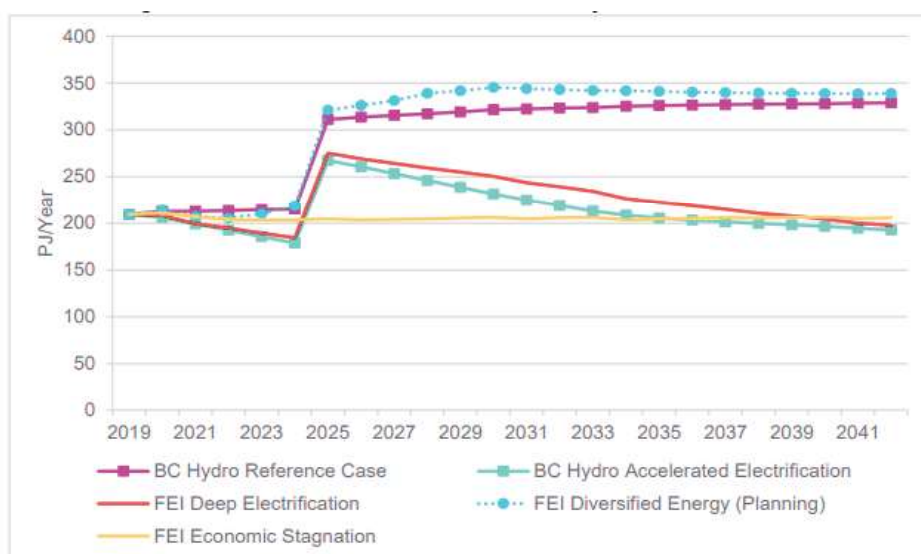
<sup>100</sup> *Id.*



responsive filings in six months and requested monthly updates from the two utilities. The two utilities reported their findings to the BCUC on August 12, 2022,<sup>101</sup> and the results of the modeling exercise can be seen in Figure 16.

As of Fall 2023, no final determination had been made in either of the separate FEI or BC Hydro planning proceedings. And though the process of using competing load forecasts may be found to be imperfect, especially in its first iteration, the attempt to sync planning inputs across two separate utilities is a meaningful first step. This case study also demonstrates that through PUC oversight, separate gas and electric utilities can work together, share data and inputs, and inform the PUC and public about the potential impacts to demand from various future conditions.

Figure 16 – FortisBC's Forecasted Annual Gas Demand by Scenario<sup>102</sup>



### Coordinated Planning Challenges

There are several challenges to coordinated gas and electric planning that PUCs need to consider and/or address. They include:

- What jurisdiction or legal authority do PUCs have to encourage or require joint planning?

<sup>101</sup> British Columbia Utilities Commission. *BC Utilities Commission Energy Scenarios for BC Hydro and FEI*. Available at: <https://www.bcuc.com/OurWork/ViewProceeding?applicationid=959>

<sup>102</sup> British Columbia Utilities Commission. *British Columbia Hydro and Power Authority and FortisBC Energy Inc. Energy Services, Energy Scenarios – Stage Two*. August 12, 2022. Available at: [https://docs.bcuc.com/documents/proceedings/2022/doc\\_67461\\_2022-08-12-fei-stage2-submission.pdf.page.4](https://docs.bcuc.com/documents/proceedings/2022/doc_67461_2022-08-12-fei-stage2-submission.pdf.page.4).



- Who develops building electrification values, costs, and benefits assumptions?
- What scenario and sensitivity analyses should the utilities model?
- What information and data do the utilities need to share and how?
- What are the implications for stakeholder participation as two distinct processes begin to align or merge?
- Is it appropriate for gas utilities to develop electrification assumptions and model them as part of their planning process?
- How do gas utilities coordinate with publicly owned utilities that are not regulated by the PUC?

Each state will have to answer these questions for itself, though it is unavoidable that gas and electric utilities will need to share data and inputs such as resource cost assumptions, granular load profiles, and localized and general electrification impacts to better understand the energy transition.

Importantly, gas utilities must have electrification assumptions to use in their planning. There are numerous electric appliances on the market including air-source and ground-source heat pumps, heat pump water heaters, and induction stoves, that are competing with their gas counterparts. A utility must make assumptions about the costs of appliances (as well as ancillary costs including wiring and electrical panel upgrades), whether the electric distribution grid can support the additional load, the efficacy of the appliances under various temperatures, electricity prices, and natural gas prices. Some of these assumptions are outside the internal expertise of the gas utility, or would beget results contrary to the gas utility's financial incentives. Therefore, PUCs will need to decide who develops those assumptions.

In Oregon, the PUC Staff engaged a third-party consultant to develop proxy electrification assumptions for use in gas utility IRPs. In another similar example, the Northwest Power and Conservation Council develops long-term regional demand forecasts for the Bonneville Power Administration (BPA) to include in BPA's planning. Alternatively, if the electric utility has reasonable estimates and forecasts, and those assumptions can be vetted through a stakeholder process, the PUC may be able to require the gas utility to incorporate those assumptions into its own modeling.

### **Getting Started with Coordinated Gas Planning**

Coordinated electricity and gas planning adds complexity but also offers significant benefits. The obstacles for dual-fuel (combined) utilities are less daunting than for coordination



between separate gas and electric utilities. There is commercially available cost-optimization modeling software (for example, Plexos) that can model both the gas and electricity systems. Dual-fuel utilities can develop a plan that holistically assesses both systems, recognizes load shifts from fuel switching, and optimizes both electricity and gas capital investments and resource supply to develop a least-cost, least-risk plan for customers.

Coordinating across separate gas and electric utilities is a more significant challenge and PUCs may need to take a more incremental approach. As the British Columbia example showed, for gas-only utilities, there are several options for beginning to tackle coordinated planning:

1. PUC-determined planning scenarios and sensitivities,
2. Gas and electric utilities model the other utility's scenarios and report findings,
3. A third party provides inputs and assumptions to both utilities (after appropriate vetting with stakeholders), or
4. A combination of 1 – 3.

The best approach will depend on the specifics of the state. If the electric and gas utilities already have robust planning processes and established stakeholder engagement, then it may be reasonable to defer to the utilities to model each other's scenarios. On the other hand, if there is not a robust stakeholder engagement process that provides input to scenario development, or one of the utilities does not have a well-developed planning process, then it may be more appropriate for the PUC to determine which scenarios the two utilities should model, and/or which inputs and assumptions utilities must include.

The next step, after coordinated planning, would be a whole-system modeling approach where cost is optimized based on energy demand, inclusive of the electric and gas systems. Such a centralized approach, as far as is known, has only been examined in academic settings.<sup>103</sup> Regardless of approach, PUCs should begin to consider how to capture the interactive effects between the electricity and gas systems. This is true even in states without decarbonization targets, as market-driven gas-to-electric fuel switching could still have a significant impact on both electric and gas customers. Understanding the potential impacts to customers through modeling will help PUCs manage the risk that utility capital investment plans are not aligning with customer demand.

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<sup>103</sup> Marko Aunedi, et al. Renewable and Sustainable Energy Reviews, Volume 187, 2023. *System-driven design and integration of low-carbon domestic heating technologies*. November 2023. <https://doi.org/10.1016/j.rser.2023.113695>



## Comparison of Gas Plan Types

With the framework developed in Part I of this paper, we can assess the existing gas planning frameworks referenced in Part II for their comprehensiveness. From there, we may draw some conclusions about minimum best practices and areas that may need further development or refinement across the states. The recommended criteria presented in Table 3 below provide a comprehensive gas planning procedural template that, if followed, should help reduce costs and risk for ratepayers as a result of the energy transition.

None of the case studies presented in this report contain all of the recommended elements of a robust and effective gas plan, though overall, New York’s long-term planning framework and the Pacific Northwest’s Integrated Resource Plans are the most comprehensive. Still, both approaches would benefit from a greater emphasis on a review of the utility’s capital investment plans.

**Table 3 – Comparison of Gas Plans**<sup>104</sup>

	<b>New York’s Long-Term Plan</b>	<b>Pacific Northwest’s IRP</b>	<b>Michigan Natural Gas Delivery Plan</b>	<b>Colorado GIP and Clean Heat Plan</b>	<b>BC’s Coordinated Gas and Electric Planning</b>
<b>Process Features</b>					
<b>Filing Cadence</b>	Every 3 years	Every 2 years	Annual	GIP: Every 2 years Clean Heat Plan: Every 4 years	Every 2 – 5 years
<b>Planning Horizon</b>	20 years	10+ years (WA) <sup>105</sup> 20+ years (OR)	10 years	GIP: 6 years Clean Heat Plan: 5 years	20 years

<sup>104</sup> As addressed earlier in this paper, the Illinois Commerce Commission ordered three gas utilities to develop and file gas infrastructure plans shortly before publication. Illinois’ gas planning requirements include several of the analytical and process requirements identified here. However, because of the recency of the requirements and the relative lack of detail with respect to implementation, we did not include Illinois in this evaluative table.

<sup>105</sup> In practice, Washington gas utilities plan across a 20-year horizon.



<b>Stakeholder Comments</b>	✓	✓		✓	✓
<b>Technical Working Group</b>		✓			✓
<b>Third-Party Evaluation</b>	✓				
<b>Draft and final plan</b>	✓	✓		✓	✓
<b>PUC Review</b>	✓	✓		✓	✓

	<b>New York's Long-Term Plan</b>	<b>Pacific Northwest's IRP</b>	<b>Michigan Natural Gas Delivery Plan</b>	<b>Colorado GIP and Clean Heat Plan</b>	<b>BC's Coordinated Gas and Electric Planning</b>
<b>Analytical Features</b>					
<b>Short-term action plan</b>		2-4 years	Specific investments detailed	GIP: 3 years	4 years
<b>Load Forecasting</b>	✓	✓	✓	✓	✓
<b>Scenario and Sensitivity Analysis</b>	✓	✓	✓	✓	✓
<b>Identification of Preferred Portfolio</b>	✓	✓	✓	✓	✓
<b>Equity Analysis</b>	✓				
<b>Bill Impact Analysis</b>	✓		✓	✓	✓



<b>Capital Investment Forecast</b>	√ *		√	√	
<b>Coordination with Electric Sector</b>					√
<b>NPA Assessment</b>	√	Recently required by Oregon PUC		√	
<b>System Mapping</b>		Sometimes included but not required		√	

\*A capital investment forecast is not explicitly required in the NY PSC’s gas planning order. However, a capital investment forecast is necessary for a reasonable bill impact analysis and, at the time this report was published, each of the New York gas utilities have included capital forecasts in their initial filings.

### Process Requirements

Both New York’s LTP and the Pacific Northwest IRPs provide stakeholders with a strong understanding of utility investments and long-term direction. The LTP excels in its inclusion of independent third-party analysis of gas plans, while the IRPs involve stakeholders in technical working groups throughout the entirety of the process. As of the time of writing, utilities in Colorado have not yet completed the full GIP and Clean Heat Plan cycle; however, public involvement appears to be restricted due to confidential workpapers, limited technical sessions, and short turnaround times. Consumers Energy’s Natural Gas Delivery plan stands out for a different reason: Though the natural gas delivery plan provides extensive analytical features, public stakeholders are not involved in the planning process at all, which significantly undermines the benefits of the exercise. All five examples are compared in Figure 17.



Figure 17 – Assessment of Gas Plan Process Requirements<sup>106</sup>

	New York's Long-Term Plan	Pacific Northwest IRPs	Michigan Natural Gas Delivery Plan	Colorado's GIP and Clean Heat Plan	BC's Coordinated Gas and Electric Planning
Process Requirements					

### Analytical Features

Via their scenario analysis, detailed capital investment forecasts, and bill impact analysis, Consumers' Natural Gas Delivery Plan provides the most comprehensive analytical features among the various types of gas plans reviewed here (illustrated in Figure 18). The only analytical elements lacking from the Michigan Natural Gas Delivery Plans are 1) an equity analysis and 2) coordination with the electric.<sup>107</sup> The New York LTPs include nearly all of the same features as Consumers' Natural Gas Delivery Plans except a short-term action plan detailing specific investments that align with a long-term planning approach. The IRPs provide the best scenario analysis but do not include any forecasts of capital infrastructure investment or bill impacts. Too often, resource portfolios overshadow the impact of capacity investments and other system upgrades, even though infrastructure costs are important factors that drive customer rate increases and must be well understood. Therefore, it is more challenging for Pacific Northwest IRP stakeholders to determine if distribution system investments align with the preferred portfolio than it is for the NY LTP or Michigan Natural Gas Delivery Plan. The combined Colorado GIP and Clean Heat Plan are limited by the 5-year planning period of the Clean Heat Plan, which is too short to effectively evaluate the long-term potential of decarbonization strategies.

While some of the gas regulations governing these various planning processes required bill impact analysis, none of the existing gas plans had a comprehensive equity evaluation. Bill impacts that only reflect averages across a population and can hide inequities. Regulations must do more to ensure that disadvantaged populations not only are not harmed by changes in the gas system but also earn benefits from utility investments and are included in the development of the plan.






<sup>106</sup> The purple fill signifies the gas plan's robustness; the more purple fill, the more robust.

<sup>107</sup> Both plans include some detail on the impacts to the electric grid, but the analysis lacks robustness.



The Colorado GIP is the only gas plan that integrates non-pipeline alternatives substantively. While the New York LTPs require the evaluation of NPAs for leak-prone pipe replacement and there is a history of NPA implementations in the state, utilities in New York have not proposed NPA projects within their gas plans.

Figure 18 – Assessment of Gas Plan Analytical Features

	New York's Long-Term Plan	Pacific Northwest IRPs	Michigan Natural Gas Delivery Plan	Colorado's GIP and Clean Heat Plan	BC's Coordinated Gas and Electric Planning
Analytical Features					



## Conclusion and Recommendations

The energy transition is increasing gas customer risks due to competition from high-efficiency building electrification, decarbonization policies, and gas price volatility. Comprehensive gas planning regulations can address each of these risks and ultimately help reduce customer costs. Gas planning generates such benefits through the mitigation of resource acquisition risks, an increase in transparency, compliance with state policies, and greater utility coordination. Ultimately, a balance in cost and risk is critical in ensuring that ratepayers are not unduly harmed by bill increases, and an amalgamation of information allows for the utility, public stakeholders, and the PUC to move together toward an outcome that maximizes societal benefits.

### Recommendations

The below list offers a compilation, by topic, of the recommendations, best practices, and suggestions to avoid pitfalls experienced by existing gas plans and/or electric planning processes that have been embedded throughout this report.

#### Overarching Recommendations:

- In states without an existing gas planning framework, regulators should take proactive steps to set up a modern gas planning framework. In states with existing gas plans, PUCs should consider iterating on their own frameworks to improve outcomes in light of new market conditions, and as appropriate, new state policy goals.
- PUCs should err on the side of more required information, including planned gas infrastructure projects, inputs, and assumptions, when drafting requirements for a new gas plan. It is widely acknowledged that there is an inherent informational asymmetry in utility regulation, as utilities have more information than any other party about their own systems. The more a utility provides, the better stakeholders can assess the impacts and potential benefits of utility investments.

#### Recommendations for Process Requirements:

- **PLANNING HORIZON:**
  - While a 20-year planning horizon helps identify long-term decarbonization strategies, it is challenging to confidently model resource and capital costs over such a period. There is less uncertainty in a long-term planning period of 10 years



and short-term utility investments can clearly and directly contribute to 10-year targets. Utilities should nonetheless still describe a strategic direction for 20 years but impacts over the next 10 years should be given greater consideration.

- **FILING CADENCE:**

- Due to the rapid evolution of the energy sector, filings should occur within two years of a PUC decision on a previous gas plan. A shorter cadence is especially critical if the PUC does not acknowledge or approve parts of a gas plan. Following a non-acknowledgment or non-approval, a utility should demonstrate a change in direction that aligns with PUC recommendations through an updated filing. A longer cadence increases the risk that ratepayers will be burdened with unnecessary or unwise investments.

- **STAKEHOLDER INVOLVEMENT:**

- Stakeholders must be an integral part of the gas planning process. At a minimum, they must be provided the opportunity to comment on utility gas plans, though formalizing public involvement and reducing barriers to information access throughout the entire planning process allows for a more rigorous analysis of utility investment strategies.
- In the early stages of the planning process, a technical group should be formed to represent the voices of stakeholders.
- In the leadup to stakeholder comments, the utility must provide non-confidential information whenever possible, as confidential material can reduce transparency and undermine the public process.
- Stakeholders should be invited to submit comments that detail any recommended revisions to the draft plan. The utility should evaluate stakeholder recommendations and make revisions to its gas plan, as needed, ahead of its final filing.
- If the utility does not incorporate a piece of stakeholder feedback in its final plan, it should document the reasons in writing. Stakeholders should then be allowed at least one additional opportunity to address any concerns with the utility's plan. The PUC should consider all stakeholder concerns and rebuttals in its evaluation of the utility's final gas plan.



- **EVALUATING GAS PLANS:**

- PUCs should provide utilities with clear rulings and, in the case of a non-acknowledgment or non-approval, specify the steps the utility should take.
- PUCs should retain the authority to request additional scenarios, sensitivities, and revised forecasts in response to their own concerns or those of stakeholders.
- PUCs should consider alternative fuel proposals carefully, and ensure that they have sufficient answers to the questions posed in Part I.C, Evaluating RNG and Hydrogen in Modern Gas Plans.

### Recommendations for Analytical Features:

- **FORECASTS:**

- Given that a thorough gas planning process relies on significant analysis of load forecasts, resource portfolios, supply forecasts, capital forecasts, and bill impacts, establishing a set of regulations governing the forecasting and analysis of data is a key step to establishing a successful gas planning process.
- Load forecasting must be conducted both on the system-wide scale and down to varying climate zones and localities/neighborhoods that might be experiencing different trends in gas use.

- **SHORT-TERM ACTION PLAN:**

- The gas planning process should yield a five-year action plan that is congruent with a long-term strategy. To be acknowledged or approved by the PUC, a utility gas plan should identify a least-cost, least-risk portfolio of resources, which details anticipated near-term investments that align with market trends and meet state climate goals, if applicable.

- **INCORPORATING EQUITY:**

- In designing stakeholder and public engagement around modern gas plans, PUCs and utilities should ensure that communities have an opportunity to meaningfully participate.
- PUCs should consider adopting the Department of Energy's Distributional Energy Analysis Metric Framework for review of DER-related projects within a gas plan.



- Gas plans should consider equity via a distributional analysis of impacts and define a minimum percentage of clean energy investment or benefits that must be implemented for or accrue to disadvantaged populations, if possible, within state law.
- PUCs should leverage national and state work to define and map disadvantaged communities for use in the gas plans, and consider requiring gas utilities to overlay a map of proposed capital projects and resource acquisitions in the short-term action plan with a map of all disadvantaged populations in the utility's service area.
- **NON-PIPELINE ALTERNATIVES:**
  - PUCs should develop NPA frameworks to embed within their gas planning processes.
  - An NPA framework should include three phases: preliminary screening, portfolio development, and portfolio evaluations. The preliminary screening process should filter projects based on safety as well as cost and time thresholds.
  - Ultimately, *portfolios* (not individual projects) should be judged by their ability to address the system need and their cost, benefit, and risk compared with the traditional infrastructure solution.
  - Regulations may consider indicating a preference for demand-side solutions since such resources typically provide more customer benefits and lead to greater emissions reductions than supply-side resources.
  - Competitive solicitations should be leveraged where possible to ensure that the market has the ability to put forth innovative and cost-competitive solution options.
  - The portfolio evaluation step should include a BCA, a quantitative assessment of vendors, and an equity analysis.
  - PUC should consider complementary policy changes to support NPA projects, such as a shared-savings mechanism.
- **SYSTEM MAPPING:**
  - System mapping should be used to inform stakeholders of capacity plans and to support equity analysis.



- **COORDINATING WITH THE ELECTRIC SECTOR:**

- Combined utilities should begin to develop an internal team that is responsible for planning across both fuels. A PUC can assist this effort by developing a timeline of expectations. For example, the utility could start on the path toward coordinated planning by simplifying the process and filing a separate, outside-the-plan analysis that examines the impacts on both systems from a single scenario.
- Any plans, teams, or processes for coordinated planning within a combined utility should be transparent and include opportunities for stakeholder participation and input, wherever appropriate.
- PUCs overseeing separate gas and electric utilities should explore options, including developing PUC-determined planning scenarios and sensitivities, directing gas and electric utilities to model each other scenarios and report findings, or contracting with a third party to provide inputs and assumptions to both utilities (after appropriate vetting with stakeholders).
- PUCs should explore with the utilities and the stakeholder community the appropriate level of data to be shared between utilities and stakeholders. For example, electric utilities are increasingly producing hosting capacity analysis maps that inform DER developers and customers of the ability of an individual feeder to absorb additional supply or demand. This level of information may be valuable for conducting gas utility NPA analysis or identifying areas for the state, a municipality, or a utility to prioritize beneficial electrification programs.



## Appendix: State Examples of Data Access and Open Access Modeling

### Arizona

On March 2, 2022, the Arizona Corporation Commission issued an order<sup>108</sup> in a resource planning and procurement docket to require that utilities, for future Integrated Resource Plans (IRPs), negotiate access to, and cover the costs for, up to 12 Resource Planning Advisory Council members and Staff to perform their own modeling runs in the same software package as the utilities. The order also required utilities to provide all necessary data and support for those stakeholders to fully utilize the models.

### New Mexico

In late 2018, the Public Service Company of New Mexico (PNM) proposed to decommission the San Juan Generating Station. When initiating the proceeding, the Public Regulation Commission (PRC) required PNM to provide access to all computer models used to support its selection of replacement resources.<sup>109</sup> Stakeholders could either have virtual access to PNM's modeling software to run their own scenarios or request that PNM run specific scenarios on their behalf.<sup>110</sup> The PUC ultimately selected an intervenor proposal, which provided lower costs, greater resource diversity, and more community benefits than the utility proposal.<sup>111</sup> In May 2021, the PRC took a broader step towards expanding access to utility modeling by opening a docket to revise its integrated resource planning rules. Its goals were 1) to ensure that utilities prioritize resources aligned with state greenhouse gas reduction targets and grid modernization, and 2) to improve transparency for regulators, stakeholders, and the public.<sup>112</sup> On September 14, 2022, the PRC issued an order requiring utilities to provide staff and

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<sup>108</sup> Arizona Corporation Commission. Docket no. E-00000V-19-0034. *Order*. December 15 and 16, 2021. Available at: <https://docket.images.azcc.gov/0000206081.pdf?i=1663624640116>.

<sup>109</sup> New Mexico Public Regulation Commission. Docket No. 19-00018-UT. *Order Initiating Proceeding on PNM's Verified Compliance Filing Concerning Continued Use of & Abandonment of San Juan Generating Station*. January 30, 2019. Available at: [https://powersuite.aee.net/dockets/nm-19-00018-ut/filings/13489170?version=beta&filing\\_search\\_id=1258879&document\\_id=157217274](https://powersuite.aee.net/dockets/nm-19-00018-ut/filings/13489170?version=beta&filing_search_id=1258879&document_id=157217274).

<sup>110</sup> Public Service Company of New Mexico. Docket No. 19-00195-UT. *Public Service Company of New Mexico's Proposal to Provide Parties Access to Resource Planning Models and Information Regarding Requests for Proposals*. July 29, 2019. Available at: [https://powersuite.aee.net/dockets/nm-19-00195-ut/filings/13490125?version=beta&filing\\_search\\_id=1258965&document\\_id=157218322](https://powersuite.aee.net/dockets/nm-19-00195-ut/filings/13490125?version=beta&filing_search_id=1258965&document_id=157218322).

<sup>111</sup> New Mexico Public Regulation Commission. Docket No. 19-00195-UT. *Order on Recommended Decision on Replacement Resources – Part II*. 2020. July 29, 2020. Available at: [https://powersuite.aee.net/dockets/nm-19-00195-ut/filings/13763830?version=beta&filing\\_search\\_id=785299&document\\_id=157812089](https://powersuite.aee.net/dockets/nm-19-00195-ut/filings/13763830?version=beta&filing_search_id=785299&document_id=157812089).

<sup>112</sup> New Mexico Public Regulation Commission. Docket No. 21-00128-UT. *Order Opening Docket, Initiating Rulemaking and Establishing Workshop Schedule*. May 26, 2021. Available at: [https://powersuite.aee.net/dockets/nm-21-00128-ut/filings/15296428?version=beta&filing\\_search\\_id=1258851&document\\_id=161996498](https://powersuite.aee.net/dockets/nm-21-00128-ut/filings/15296428?version=beta&filing_search_id=1258851&document_id=161996498).



stakeholders with reasonable access to the same modeling software and all modeling information used by the utility.<sup>113</sup>

## Oregon

On October 30, 2020, the Oregon Public Utility Commission accepted a stipulation on one of PacifiCorp's rate adjustment mechanisms, which included measures to increase understanding of and access to the utility's new production cost model.<sup>114</sup> In this stipulation, the utility agreed to 1) host a public workshop on its new modeling, 2) provide modeling licenses for all PUC staff and intervenors, and 3) share all inputs, data, modeling settings, and constraints used by the utility in its forecasts.

## Kentucky

On November 25, 2020, the Kentucky Utilities Company (KU) and Louisville Gas and Electric Company (LG&E), together referred to as LG&E/KU, filed applications with the Kentucky Public Service Commission requesting approval for significant increases in revenue and several tariff revisions.<sup>115</sup> Upon investigation, the Commission found a notable lack of transparency in LG&E/KU's modeling, which it stated would likely become increasingly problematic as renewable energy penetration deepens. On June 30 and September 24, 2021, the Commission denied the requested increase in revenue<sup>116</sup> and the proposed tariff revisions, ordering LG&E/KU to submit a proposal detailing how they would increase their modeling transparency.<sup>117</sup> In response, LG&E/KU proposed to include more granular summaries of their inputs and outputs in future filings; run models on behalf of intervenors; support the

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<sup>113</sup> New Mexico Public Regulation Commission. Docket No. 21-00128-UT. *Final Order*. September 14, 2022. Available at: [https://powersuite.aee.net/dockets/nm-21-00128-ut/filings/17239777?version=beta&filing\\_search\\_id=1258833&document\\_id=167477708](https://powersuite.aee.net/dockets/nm-21-00128-ut/filings/17239777?version=beta&filing_search_id=1258833&document_id=167477708).

<sup>114</sup> Oregon Public Utility Commission. Docket No. UE 375. *Order No 20-392*. October 30, 2020. Available at: <https://apps.puc.state.or.us/orders/2020ords/20-392.pdf>

<sup>115</sup> Kentucky Utilities Company. Docket No. 2020-00349. *Kentucky Utilities Company's Statutory Notice, Customer Notice of Rate Adjustment, Application, Filing Requirements, Direct Testimony, and Petition for Confidential Protection for an adjustment of its Electric Rates and other requests*. November 25, 2020. Available at: [https://app.insightengine.org/dockets/ky-2020-00349?filing\\_search\\_id=1616084&version=beta&workspace=all#search-results-anchor](https://app.insightengine.org/dockets/ky-2020-00349?filing_search_id=1616084&version=beta&workspace=all#search-results-anchor); Louisville Gas and Electric Company. Docket No. 2020-00350. *Electronic Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates, A Certificate of Public Convenience and Necessity to Deploy Advanced Metering Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of a One-Year Surcredit*. 2020. Available at [https://psc.ky.gov/pscscf/2020-00350/rick.lovekamp%40lge-ku.com/11252020085918/05-LGE\\_Application\\_%282020-00350%29.pdf](https://psc.ky.gov/pscscf/2020-00350/rick.lovekamp%40lge-ku.com/11252020085918/05-LGE_Application_%282020-00350%29.pdf)

<sup>116</sup> Kentucky Public Service Commission. Docket No. 2020-00349. *Order*. 2021. Available at: [https://psc.ky.gov/pscscf/2020%20Cases/2020-00349//20210630\\_PSC\\_ORDER.pdf](https://psc.ky.gov/pscscf/2020%20Cases/2020-00349//20210630_PSC_ORDER.pdf)

<sup>117</sup> Kentucky Public Service Commission. Docket Nos. 2020-00349 and 2020-00350. *Order*. September 24, 2021. Available at: [https://psc.ky.gov/pscscf/2020%20Cases/2020-00349//20210924\\_PSC\\_ORDER.pdf](https://psc.ky.gov/pscscf/2020%20Cases/2020-00349//20210924_PSC_ORDER.pdf)



Commission seeking licenses to run the model with alternative inputs; and increase access to online data.<sup>118</sup>

## South Carolina

On December 23, 2020, the South Carolina Public Utilities Commission issued an order directing Dominion Energy South Carolina to expand its IRP modeling and transparency, including negotiating a discounted licensing agreement that would allow interested stakeholders to perform their modeling using the same software as the utility.<sup>119</sup>

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<sup>118</sup> Louisville Gas & Electric and Kentucky Utilities Company. *2020 Rate Case*. December 22, 2021. Available at: [https://psc.ky.gov/pscecf/2020-00349/rick.lovekamp@lge-ku.com/12222021084221/Closed/3-LGE\\_KU\\_Response\\_12-22-2021.pdf](https://psc.ky.gov/pscecf/2020-00349/rick.lovekamp@lge-ku.com/12222021084221/Closed/3-LGE_KU_Response_12-22-2021.pdf)

<sup>119</sup> South Carolina Public Utilities Commission. Docket No. 2019-226-E. *Order No. 2020-832, Order Rejecting Dominion's Integrated Resource Plan and Requiring Dominion to Make Modifications to Its 2020 Integrated Resource Plan, Future Updates and Future Integrated Resource Plans*. December 23, 2020. Available at: <https://dms.psc.sc.gov/attachments/order/a4b59f43-e545-43bd-9f35-a846b7602c39>





# Non-Pipeline Alternatives to Natural Gas Utility Infrastructure:

An Examination of Existing  
Regulatory Approaches

Prepared for the



**Lawrence Berkeley  
National Laboratory**



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# Introduction

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

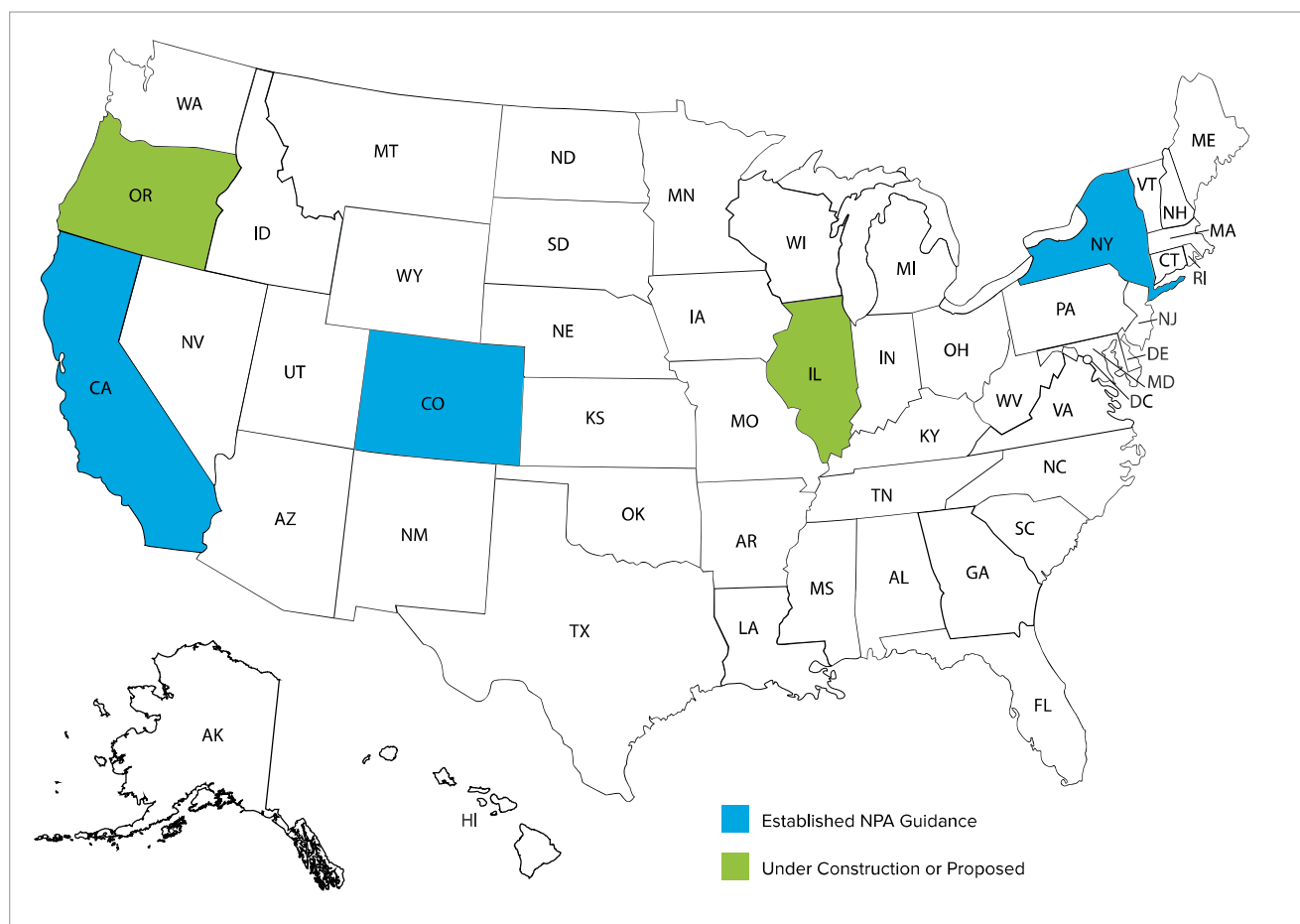


FIGURE 1: States That Have Proposed a Non-Pipeline Alternative Proceeding

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

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

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

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

## Non-Pipeline Alternatives

### NPA Definition

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

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

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

TABLE 1: Summary of NPA Definitions

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

## Colorado<sup>2</sup>

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

## New York

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

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

TABLE 2: New York Gas Utility NPA Definition<sup>7</sup>

## Rhode Island

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

## California

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

<sup>2</sup> For more information on Colorado’s Gas Infrastructure Plans and Clean Heat Plans, see *Appendix A*.

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

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

<sup>5</sup> “Non-Pipe Alternatives.” New York State Electric and Gas. [https://www.nyseg.com/documents/40132/5899449/NYSEG%2BCanandaigua%2BNPA%2BAttachment%2BA%2B-%2BDefiniti\\_07.29.22+%281%29.docx/2774522a-755a-9382-bb65-200fb18c9be3?t=1662755838606](https://www.nyseg.com/documents/40132/5899449/NYSEG%2BCanandaigua%2BNPA%2BAttachment%2BA%2B-%2BDefiniti_07.29.22+%281%29.docx/2774522a-755a-9382-bb65-200fb18c9be3?t=1662755838606).

<sup>6</sup> “What is an NPA?” National Grid. <https://www.nationalgridus.com/Business-Partners/Non-Pipeline-Alternatives/What-is-an-NPA>.

<sup>7</sup> NY PSC 20-G-0131  
 NY PSC 17-G-0606  
 NY PSC 19-G-0066  
 NY PSC 17-G-0460  
 NY PSC 17-G-0432

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

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

## Public Policy Premise and Filing Requirements for Performing an NPA Evaluation

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

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

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

### Colorado

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

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

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

<sup>10</sup> [https://www.dora.state.co.us/pls/efi/efi\\_p2\\_v2\\_demo.show\\_document?p\\_dms\\_document\\_id=955970&p\\_session\\_id=](https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=955970&p_session_id=)

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

<sup>12</sup> *Ibid.*, 27.

## New York

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

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

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

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

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

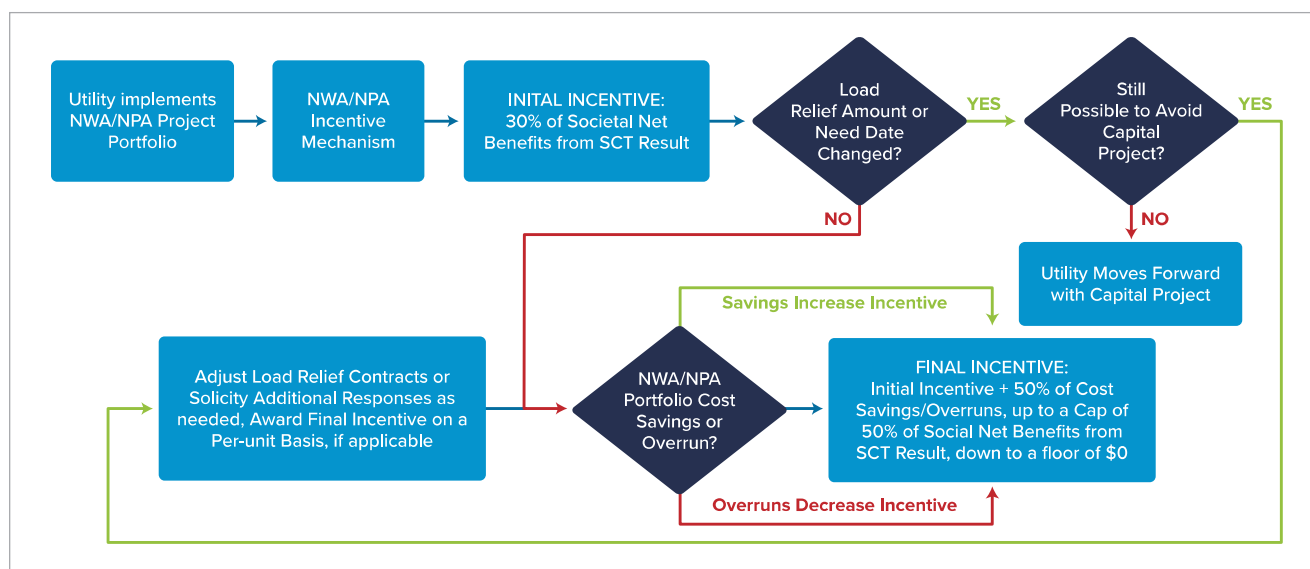


FIGURE 2: New York NPA Incentive Mechanism

<sup>13</sup> 20-G-0131 Order Adopting Gas System Planning Process, May 12, 2022, pages 2-5.

<sup>14</sup> 20-G-0131 Order Adopting Gas System Planning Process, May 12, 2022.

<sup>15</sup> 20-G-0131 Order Adopting Gas System Planning Process, May 12, 2022, Page 40.

<sup>16</sup> 19-E-0378, Order Approving Electric and Gas Rate Plans in Accord with Joint Proposal, With Modifications. p.161.

<sup>17</sup> Ibid.

<sup>18</sup> Ibid. Appendix HH.

## Rhode Island

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

## California

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

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

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

<sup>19</sup> RIPUC Docket No. 5080, 2021-2023 System Reliability Procurement Three-Year Plan. November 20, 2020. Page 8.

<sup>20</sup> Rhode Island General Law 39-1-27.7

<sup>21</sup> Docket 5015.

<sup>22</sup> Docket 5015 Order, page 18.

<sup>23</sup> RIPUC Docket No. 5080, 2022 System Reliability Procurement Plan Year-End Report, June 1, 2023. Pages 9-17.

<sup>24</sup> RIPUC Docket No. 5080, 2022 System Reliability Procurement Plan Year-End Report, June 1, 2023. Page 1-3.

<sup>25</sup> CPUC Rulemaking 20-01-007, Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Perform Long-Term Gas System Planning, p. 4-13. January 27, 2020.

<sup>26</sup> CPUC Rulemaking 20-01-007, Assigned Commissioner’s Amended Scoping Memo and Ruling, p. 5-6. January 5, 2022.

<sup>27</sup> CPUC Rulemaking 20-01-007, Staff Proposal on Gas Distribution Infrastructure Decommissioning Framework in Support of Climate Goals, p. 21-22. December 21, 2022.

<sup>28</sup> CPUC Rulemaking 20-01-007, Decision Adopting Gas Infrastructure General Order, Attachment A, p. 12-14.

<sup>29</sup> CPUC Rulemaking 20-01-007, Decision Adopting Gas Infrastructure General Order, Attachment A, p. 14.

<sup>30</sup> Pacific Gas and Electric Company 2023 General Rate Case Prepared Testimony Exhibit (PG&E-3). Pages 1-10.

## Project Eligibility Standard That Triggers NPA Analysis

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

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

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

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

### Colorado

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

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

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

**TABLE 3:** Colorado CPCN Investment Threshold

<sup>31</sup> CPUC docket number R.20-01-007.

<sup>32</sup> 4 Colo. Code Regs. § 723-4-4553(a)(III)(B).

## New York

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

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

LDC	Cost		Timeline		Size		
	Large Project	Small Project	Large Project	Small Project	Large Project	Small or Large Project (could go either way)	Small Projects
NFG	> \$2 million	< or equal to \$2 million	36-60 months	24-36 months	Covers a larger geographic area; associated with significant regulator station upgrades or larger high-pressure mains	Involves several streets or a small neighborhood	Involves a limited number of streets or only a few services
ConEd	> \$2 million	< or equal to \$2 million	36-60 months	24-36 months			
O&R	> \$2 million	< or equal to \$2 million	36-60 months	24-36 months			
Central Hudson	> \$2 million	< or equal to \$2 million	> 24 months	12-24 months			
KEDLI and NMPC*	> \$2 million	\$500k to \$2 million	> 36 months	24-36 months	Covers a larger geographic area; associated with significant regulator station upgrades or larger high-pressure mains	Involves several streets or a small neighborhood	Involves a limited number of streets or only a few services
KEDNY*	> \$3 million	\$750k - \$3 million	> 36 months	24-36 months			
Corning	Project costs equal to or greater than 2% of utility plan less than depreciation reserve and deferred income tax	Project costs less than 2% of utility plan less than depreciation reserve and deferred income tax	36-60 months	24-36 months			
SLG	> \$500k	\$100k - \$500k	36-60 months	24-36 months	No commentary provided		
NYSEG and RG&E	> \$2 million	< or equal to \$2 million	Minimum 12 months to start of construction				

\* National Grid LDCs KEDLI/NMPC and KEDNY placed explicit cost eligibility floors at \$750k and \$500k, respectively.

**TABLE 4:** Comparison of New York NPA Criteria <sup>37</sup>

<sup>33</sup> 20-G-0131 Order Adopting Gas System Planning Process, p. 21-22.

<sup>34</sup> 20-G-0131 Order Adopting Gas System Planning Process, p. 39.

<sup>35</sup> 20-G-0131 Order Adopting Gas System Planning Process, p. 37.

<sup>36</sup> 20-G-0131 Order Adopting Gas System Planning Process, p. 37.

<sup>37</sup> 20-G-0131, Comments of Environmental Defense Fund on Proposed Non-Pipes Alternative Criteria, December 19, 2022.

## Rhode Island

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

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

TABLE 5: Rhode Island Energy NPA Criteria

## California

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

<sup>38</sup> General Law 39-1-27.7.

<sup>39</sup> Rhode Island Energy is a dual-fuel utility providing both electric and gas services.

<sup>40</sup> RIPUC Docket No. 5080, 2021 Year-end report page 16.

<sup>41</sup> CPUC Rulemaking 20-01-007, Decision Adopting Gas Infrastructure General Order, Attachment A, p. 3-4.

<sup>42</sup> CPUC Rulemaking 20-01-007, Decision Adopting Gas Infrastructure General Order, Attachment A, p. 7-11.

## NPA Eligible Resources

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

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

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

### Colorado

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

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

### New York

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

<sup>43</sup> §40-1-102(1.2), C.R.S.

<sup>44</sup> Section 4 CCR 723-4-4730.

<sup>45</sup> Case 17-G-0606, Petition of Consolidate Edison Company of New York, Inc. for Approval of the Smart Solutions for Natural Gas Customers Program. Request for Proposals of Non-Pipeline Solutions to Provide Peak Period Natural Gas System Relief. December 21, 2017.

<sup>46</sup> New York State Climate Action Council. 2022. “New York State Climate Action Council Scoping Plan.” [climate.ny.gov/ScopingPlan](https://climate.ny.gov/ScopingPlan).

<sup>47</sup> Case 17-G-0606, Petition of Consolidate Edison Company of New York, Inc. for Approval of the Smart Solutions for Natural Gas Customers Program. Request for Proposals of Non-Pipeline Solutions to Provide Peak Period Natural Gas System Relief. December 21, 2017.

## Rhode Island

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

## California

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

# NPA Project Identification and Acquisition

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

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

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

## Colorado

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

<sup>48</sup> R.I. General Law 39-1.27.7.

<sup>49</sup> National Grid Aquidneck Island Long-Term Gas Capacity Study, p. 8.

<sup>50</sup> <https://www.portsmouthri.gov/DocumentCenter/View/4600/Portable-LNG-Vaporization-Project-Siting-Report--May-2021>

<sup>51</sup> CPUC Rulemaking 20-01-007, Decision Adopting Gas Infrastructure General Order, Attachment A, p. 8.

<sup>52</sup> Colorado Department of Regulatory Agencies Public Utilities Commission 4 Code of Colorado Regulations (CCR) 723-4 Part 4 Rules of Regulating Gas Utilities, p.37 Decision No. C23-0117.

<sup>53</sup> Colorado Department of Regulatory Agencies Public Utilities Commission 4 Code of Colorado Regulations (CCR) 723-4 Part 4 Rules of Regulating Gas Utilities, p.37 Decision No. C23-0117.

<sup>54</sup> Docket No. 23M-0234G, Public Service Company of Colorado’s Initial 2023-2028 Gas Infrastructure Plan. May 18, 2023.

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

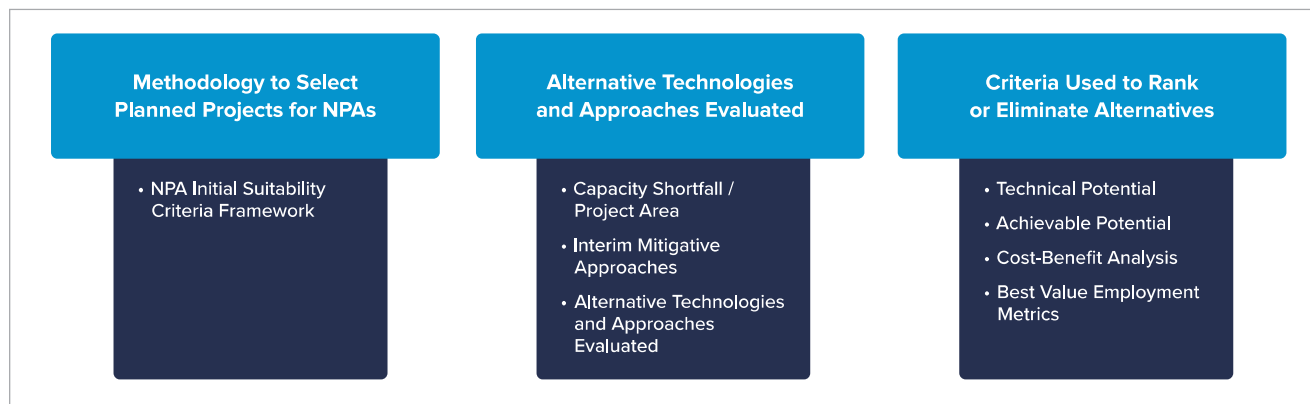


FIGURE 3: Public Service Company of Colorado NPA Methodology<sup>56</sup>

### New York

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

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

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

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

<sup>55</sup> Docket No. 23M-0234G, Public Service Company of Colorado's Initial 2023-2028 Gas Infrastructure Plan. May 18, 2023. Page 56.

<sup>56</sup> Docket No. 23M-0234G, Public Service Company of Colorado's Initial 2023-2028 Gas Infrastructure Plan. May 18, 2023. Page 56.

<sup>57</sup> Request for Proposal. December 13, 2021. <https://www.nationalgridus.com/media/pdfs/bus-partners/non-pipeline-alternatives/dny-rfp-sow-north-queens.pdf>

<sup>58</sup> NY PSC 17-G-0432. Request For Proposal. December 18, 2017. [https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=\[C74BA648-2919-4A7F-A1C9-CA57A0E58AA6\]](https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=[C74BA648-2919-4A7F-A1C9-CA57A0E58AA6])

<sup>59</sup> Consolidated Edison considers solutions that alleviate capacity or reliability constraints in the long term, i.e., 20 years, as preferable, see: Case 17-G-0606, Petition of Consolidate Edison Company of New York, Inc. for Approval of the Smart Solutions for Natural Gas Customers Program. Request for Proposals of Non-Pipeline Solutions to Provide Peak Period Natural Gas System Relief. December 21, 2017. p. 22

## Rhode Island

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

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

**TABLE 8:** Rhode Island Energy NPA Evaluation Process

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

## California

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

## Benefit-Cost Analysis<sup>63</sup>

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

<sup>60</sup> Narragansett Electric Company System Reliability Procurement 2021 Year-End Report, page 16.

<sup>61</sup> Narragansett Electric Company 2020 System Reliability Procurement Year-End Report, page 17.

<sup>62</sup> Narragansett Electric Company 2020 System Reliability Procurement Year-End Report, page 17-18.

<sup>63</sup> For more information on benefit-cost analysis, benefit-to-cost ratios and cost-effectiveness, please see: <https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/>.

<sup>64</sup> National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources. <https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/>.

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

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

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

### Colorado

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

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

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

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

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

### New York

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

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

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

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

<sup>68</sup> 14-M-0101.

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

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

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

The full list of current costs and benefits included in the framework for NPA and NWA are identified in Table 10:<sup>73</sup>

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

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

<sup>69</sup> 20-G-0131 Order Adopting Gas System Planning Process, May 12, 2022. Pages 62-63.

<sup>70</sup> The SCT captures benefits and costs that apply to society as a whole and most BCA benefits and costs are included. Measures such as lost utility revenue are not captured since the measure quantifies a transfer of wealth rather than a net impact.

<sup>71</sup> 14-M-0101: Jan 21, 2016, Order page 12.

<sup>72</sup> 14-M-0101 Order establishing BCA framework page 27.

<sup>73</sup> 14-M-0101 Order establishing BCA framework, Appendix C.

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

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

### Rhode Island

Rhode Island’s BCA framework, or the “Rhode Island Test,” applies to gas and electric utility investments and is approved for use in energy efficiency programs and NPA analysis.<sup>82</sup> The benefits identified in Table 11 were initially developed for the electric sector.

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

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

<sup>74</sup> 4-M-0101: Jan 21, 2016, Order p.33.

<sup>75</sup> NY PSC 17-G-0432, Order Approving Petition for Non-Pipeline Alternative Projects, With Modifications. June 21, 2021. p. 17.

<sup>76</sup> While the solutions adopted in the Tompkins County RFP were demand-side solutions, the utility considered several supply-side proposals. See: NY PSC 17-G-0432, Order Approving Petition for Non-Pipeline Alternative Projects, With Modifications. June 21, 2021. p. 6-9.

<sup>77</sup> NY PSC 17-G-0432, Order Approving Petition for Non-Pipeline Alternative Projects, With Modifications. June 21, 2021. p. 7.

<sup>78</sup> NY PSC 17-G-0432, Order Approving Petition for Non-Pipeline Alternative Projects, With Modifications. June 21, 2021. p. 13.

<sup>79</sup> NY PSC 17-G-0432, Order Approving Petition for Non-Pipeline Alternative Projects, With Modifications. June 21, 2021. p. 17.

<sup>80</sup> NY PSC 17-G-0432, Order Approving Petition for Non-Pipeline Alternative Projects, With Modifications. June 21, 2021. p. 17.

<sup>81</sup> 17-G-0432 Order Approving Petition for Non-Pipeline Alternative Projects, With Modifications. June 21, 2021. p. 17.

<sup>82</sup> RIPUC Docket 4600 Draft Cost Benefit Framework.

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

## California

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

- + The potential environmental impacts of NPAs, including emissions;
- + An estimate of the environmental and health impacts of the project; and
- + The direct and indirect costs of the project.<sup>84</sup>

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

## Equity

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

<sup>83</sup> National Grid Aquidneck Island Long-Term Gas Capacity Study, p. 93-94.

<sup>84</sup> CPUC Rulemaking 20-01-007, Decision Adopting Gas Infrastructure General Order, Attachment A, p. 8.

<sup>85</sup> Rhode Island does not have an equity requirement in general regulation or specifically for NPA evaluations.

<sup>86</sup> CPUC Rulemaking 20-01-007, Decision Adopting Gas Infrastructure General Order, Attachment A, p. 9.

<sup>87</sup> CPUC Rulemaking 20-01-007, Decision Adopting Gas Infrastructure General Order, Attachment A, p. 10-11.

<sup>88</sup> Colorado Public Utilities Commission (PUC) Invites the Public to Comment on Ways Its Regulation of Utilities Can be More Equitable and Address Historical Inequalities, Colorado Department of Regulatory Agencies.

Available at: <https://dora.colorado.gov/press-release/colorado-public-utilities-commission-puc-invites-the-public-to-comment-on-ways-its>

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## Distributional Equity Analysis for Energy Efficiency and Other Distributed Energy Resources<sup>89</sup>

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

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

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

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

---

## Observations and Conclusion

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

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

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

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

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

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

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

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

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

## Appendix A. Colorado Context

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

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

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

### Clean Heat Plans and Gas Infrastructure Plans

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

<sup>90</sup> Colorado House of Representatives. Concerning the Modernization of Gas Energy Efficiency Programs. House Bill 21-1238. [https://leg.colorado.gov/sites/default/files/2021a\\_1238\\_signed.pdf](https://leg.colorado.gov/sites/default/files/2021a_1238_signed.pdf).

<sup>91</sup> Colorado Senate. Concerning the Adoption of Programs by Gas Utilities to Reduce Greenhouse Gas Emissions, and, in Connection Therewith, Making an Appropriation. Senate Bill 21-264. [https://leg.colorado.gov/sites/default/files/2021a\\_264\\_signed.pdf](https://leg.colorado.gov/sites/default/files/2021a_264_signed.pdf).

<sup>92</sup> Colorado Senate. Concerning the Adoption of Programs by Gas Utilities to Reduce Greenhouse Gas Emissions, and, in Connection Therewith, Making an Appropriation. Senate Bill 21-264, Section 1(2)(b). [https://leg.colorado.gov/sites/default/files/2021a\\_264\\_signed.pdf](https://leg.colorado.gov/sites/default/files/2021a_264_signed.pdf).

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

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

<sup>95</sup> Ibid.

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

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

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

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

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

An NPA analysis must consider or include:

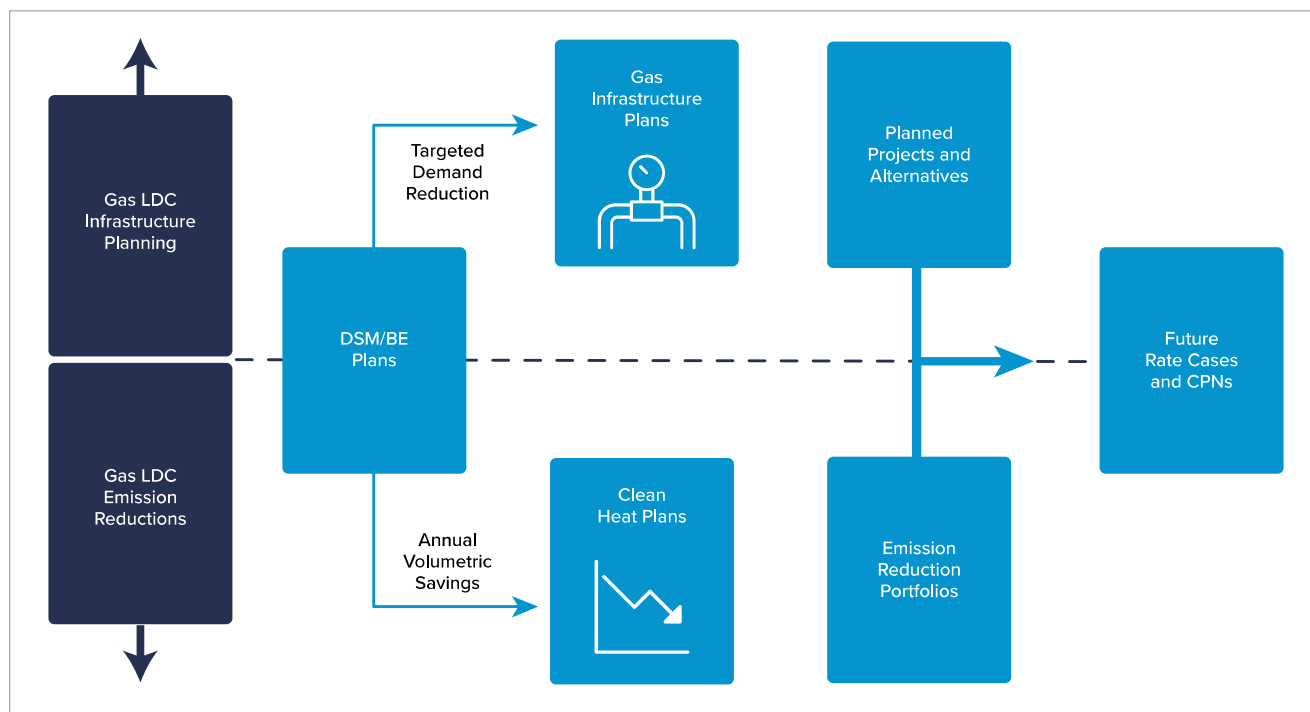
- + One or more applicable clean heat resources consistent with the utility’s CHP, DSM plan, or Beneficial Electrification Plan;
- + A BCA including the social cost of carbon and methane; and
- + Best available employment metrics associated with each alternative.

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

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

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

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



**FIGURE A-1:** Public Service Company of Colorado’s Key Gas Planning Regulatory Process<sup>98</sup>

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

## Appendix B. Benefits and Costs Summary

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



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**MPSC Case No:** U-21291

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**Requester:** CEO

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**Question No.:** CEODG-1.3a

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**Respondent:** H. J. Decker

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- Question:** 3. Please refer to HJD-80, lines 2-4, where the witness states that the Company's demand response pilot participants "received a variety of resources to motivate energy efficient behavior and peak demand savings but did not receive any monetary incentive for participating."
- a. Did the Company perform any analysis on whether offering a monetary incentive is necessary to induce customers to participate in a natural gas demand response program? Please provide all sources and documents relevant to the Company's response.

**Answer:** No, the Company did not perform any such analysis.

**Attachment:** None

**MPSC Case No:** U-21291

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**Requester:** CEO

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**Question No.:** CEODG-1.8c

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**Respondent:** H. J. Decker

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**Page:** 1 of 1

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**Question:** 8. Please refer to HJD-80, lines 11 – 15 where in a discussion about the large customer pilot, the witness testifies, “This program involved the installation of telemetry equipment at no cost to participating customers. Participants were asked to reduce load during events as well as meet with the Company to discuss the strategies they implemented during events to reduce load.”

c. Did the Company’s participating large customers have a form of backup or replacement heat?

**Answer:** No, participating customers did not have a form of backup or replacement heat.

**Attachment:** None

**MPSC Case No:** U-21291

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**Requester:** CEO

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**Question No.:** CEODG-3.7a

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**Respondent:** H. J. Decker

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**Page:** 1 of 1

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**Question:** 7. Please refer to witness Decker's testimony on the Demand Response Pilot Programs beginning at HJD-78 line 9.

- a. Did the Company develop a cost-benefit analysis for the Smart Savers pilot prior to implementing the program? If yes, please identify the cost-benefit test and provide the Company's cost-benefit analysis. Please provide all Excel spreadsheets unlocked with all formulas intact. If the Company did not develop a cost-benefit analysis, please explain why not.

**Answer:** No, the Company did not develop a cost-benefit analysis as the Commission ordered the Company to perform this pilot as part of U-20464 (Statewide Energy Assessment report). See page 8 and 9 of the Commission's February 7, 2019 order).

**Attachment:** None

**MPSC Case No:** U-21291

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**Requester:** CEO

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**Question No.:** CEODG-3.7b

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**Respondent:** H. J. Decker

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**Page:** 1 of 1

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- Question:** 7. Please refer to witness Decker's testimony on the Demand Response Pilot Programs beginning at HJD-78 line 9.
- b. Did the Company develop a cost-benefit analysis for the Energy Action Days pilot prior to implementing the program? If yes, please identify the cost-benefit test and provide the Company's cost-benefit analysis. Please provide all Excel spreadsheets unlocked with all formulas intact. If the Company did not develop a cost-benefit analysis, please explain why not.

**Answer:** No, the Company did not develop a cost-benefit analysis as the Commission ordered the Company to perform this pilot as part of U-20464 (Statewide Energy Assessment report). See page 8 and 9 of the Commission's February 7, 2019 order).

**Attachment:** None

**MPSC Case No:** U-21291

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**Requester:** CEO

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**Question No.:** CEODG-3.7c

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**Respondent:** H. J. Decker

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**Question:** 7. Please refer to witness Decker's testimony on the Demand Response Pilot Programs beginning at HJD-78 line 9.

c. Did the Company develop a cost-benefit analysis for the Commercial Program pilot prior to implementing the program? If yes, please identify the cost-benefit test and provide the Company's cost-benefit analysis. Please provide all Excel spreadsheets unlocked with all formulas intact. If the Company did not develop a cost-benefit analysis, please explain why not.

**Answer:** No, the Company did not develop a cost-benefit analysis as the Commission ordered the Company to perform this pilot as part of U-20464 (Statewide Energy Assessment report). See page 8 and 9 of the Commission's February 7, 2019 order).

**Attachment:** None

**MPSC Case No:** U-21291

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**Requester:** CEO

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**Question No.:** CEODG-3.7d

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**Respondent:** H. J. Decker

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**Page:** 1 of 1

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**Question:** 7. Please refer to witness Decker's testimony on the Demand Response Pilot Programs beginning at HJD-78 line 9.

d. Did the Company develop a cost-benefit analysis for the Smart Savers pilot after completing the pilot? If yes, please identify the cost-benefit test and provide the Company's cost-benefit analysis. Please provide all Excel spreadsheets unlocked with all formulas intact. If the Company did not develop a cost-benefit analysis, please explain why not.

**Answer:** No, the Company did not complete a cost-benefit analysis after the completing the pilot as the observed results (e.g. no benefits derived from the Pilot Program) did not support completing such an analysis.

**Attachment:** None

**MPSC Case No:** U-21291

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**Requester:** CEO

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**Question No.:** CEODG-3.7e

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**Respondent:** H. J. Decker

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**Page:** 1 of 1

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**Question:** 7. Please refer to witness Decker's testimony on the Demand Response Pilot Programs beginning at HJD-78 line 9.

e. Did the Company develop a cost-benefit analysis for the Energy Action Days pilot after completing the pilot? If yes, please identify the cost-benefit test and provide the Company's cost-benefit analysis. Please provide all Excel spreadsheets unlocked with all formulas intact. If the Company did not develop a cost-benefit analysis, please explain why not.

**Answer:** No, the Company did not complete a cost-benefit analysis after the completing the pilot as the observed results (e.g. no benefits derived from the Pilot Program) did not support completing such an analysis.

**Attachment:** None

**MPSC Case No:** U-21291

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**Requester:** CEO

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**Question No.:** CEODG-3.7f

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**Respondent:** H. J. Decker

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**Page:** 1 of 1

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- Question:** 7. Please refer to witness Decker's testimony on the Demand Response Pilot Programs beginning at HJD-78 line 9.
- f. Did the Company develop a cost-benefit analysis for the Commercial Program pilot after completing the pilot? If yes, please identify the cost-benefit test and provide the Company's cost-benefit analysis. Please provide all Excel spreadsheets unlocked with all formulas intact. If the Company did not develop a cost-benefit analysis, please explain why not.
- Answer:** No, the Company did not complete a cost-benefit analysis after the completing the pilot as the observed results (e.g. no benefits derived from the Pilot Program) did not support completing such an analysis.

**Attachment:** None

**MPSC Case No:** U-21291

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**Requester:** CEO

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**Question No.:** CEODG-3.8a

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**Respondent:** H. J. Decker

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**Page:** 1 of 1

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- Question:** 8. Please refer to witness Decker's testimony on the Demand Response Pilot Programs beginning at HJD-78 line 9.
- a. Please identify the specific quantifiable and qualitative benefits that the Company evaluated for each program. Please separately identify the benefits considered for each of the three pilots.

- Answer:** As explained to MPSC Staff and external stakeholders at the overview meeting held on October 16, 2020, the goals of the Gas DR Pilot were:
- Understand the capability of customers to reduce gas consumption following the notification of an event
  - Assess various event parameters to determine dispatch criteria to maximize customer engagement
  - Test appropriate customer incentive levels
  - Evaluate customer receptiveness to various marketing campaigns
  - Collect information on successful customer gas reduction strategies
  - Test baseline methodologies
  - Determine if a gas demand response pilot can be scaled to become a full scale program

**Attachment:** None

**MPSC Case No:** U-21291

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**Requester:** CEO

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**Question No.:** CEODG-3.8b

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**Respondent:** H. J. Decker

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**Page:** 1 of 1

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**Question:** 8. Please refer to witness Decker's testimony on the Demand Response Pilot Programs beginning at HJD-78 line 9.

b. Please identify the specific costs that Company evaluated for each program. Please separately identify the costs considered for each of the three pilots.

**Answer:** Costs by individual program are not available.

**Attachment:** None



# **Gas Demand Response Winter 2022-23 Results**

June 16, 2023

# Agenda

- Introductions
- Executive Summary
- Smart Savers Gas Overview, Results from Year 2 and Summary from Previous Events
- Energy Action Days Overview, Results from Year 2 and Summary from Previous Events
- Small and Large Commercial Customer Update
- Key Learnings and Next Steps
- Questions

# Executive Summary

- DTE conducted gas demand response pilots to determine the effectiveness of Gas DR per the Commission requirement in its order in U-20464 as part of the Statewide Energy Assessment conducted by the MPSC Staff
- Smart Savers Gas launched during the 2021-22 winter and expanded to additional customers during the 2022-23 winter season
- Energy Action Days launched later than planned last winter which limited the number of events, but more events were called this past winter
- The small and large commercial Gas DR pilot experienced some delays due to equipment lead times, but events were called last winter
- The learnings from the Gas Demand Response pilots are being used to assist in understanding the opportunity that exists within the Gas DR space and to determine future offerings

# Agenda

- Introductions
- Executive Summary
- Overview
- Smart Savers Gas Overview, Results from Year 2 and Summary from Previous Events
- Energy Action Days Overview, Results from Year 2 and Summary from Previous Events
- Small and Large Commercial Customer Update
- Key Learnings and Next Steps
- Questions

# Smart Savers Gas Program Overview

## **CURRENT PARTICIPANTS**

5,940 devices (as of 3/16/23)

## **2022-23 GOAL**

Up to 6,000 devices

## **RECRUITMENT APPROACH**

- Opt-in
- Recruiting combo and gas only customers

## **INCENTIVE**

- \$50 up-front incentive for new customers
- \$50 year-end incentive if still enrolled through March 31

## **ELIGIBILITY**

- Must have a DTE Gas account
- Qualified Wi-Fi enabled smart thermostat
- Natural gas furnace

## **EVENT PARAMETERS & METHODOLOGY**

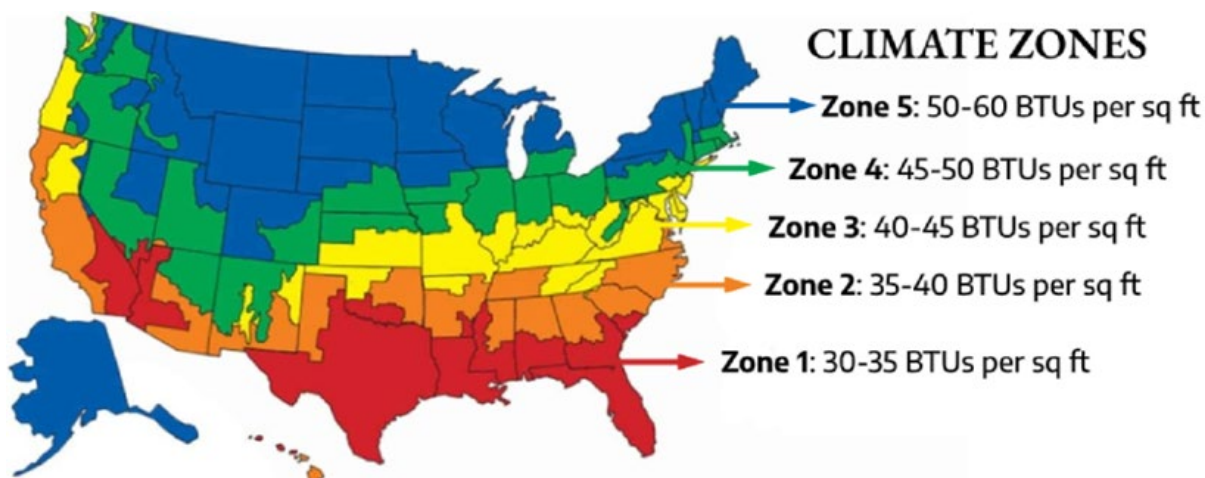
- Weekdays only, excluding holidays
- No more than 8 hours per event and will occur between \*5 a.m. – 9 a.m. and/or 5 p.m. – 9 p.m.
- Limited to no more than 14 events during the winter season

- Smart Savers Gas targets combo and gas only customers who already have a Wi-Fi enabled smart thermostat installed to reduce their gas use during periods of extremely cold temperatures
- The goal to enroll up to 6,000 devices was met and slightly exceeded on January 23, 2023, totaling 6,138 devices.
- For this pilot, we want to learn how customers respond to DR events and determine how much gas savings we can expect from this gas BYOT program.
- The 2022-23 season targeted combo and gas only customers, including Ecobee devices, which were not compatible to join the pilot during the 2021-22. Ecobee's compatibility and expanding to gas only territories helped us achieve our cap goal this season.

# Determining Gas DR Performance

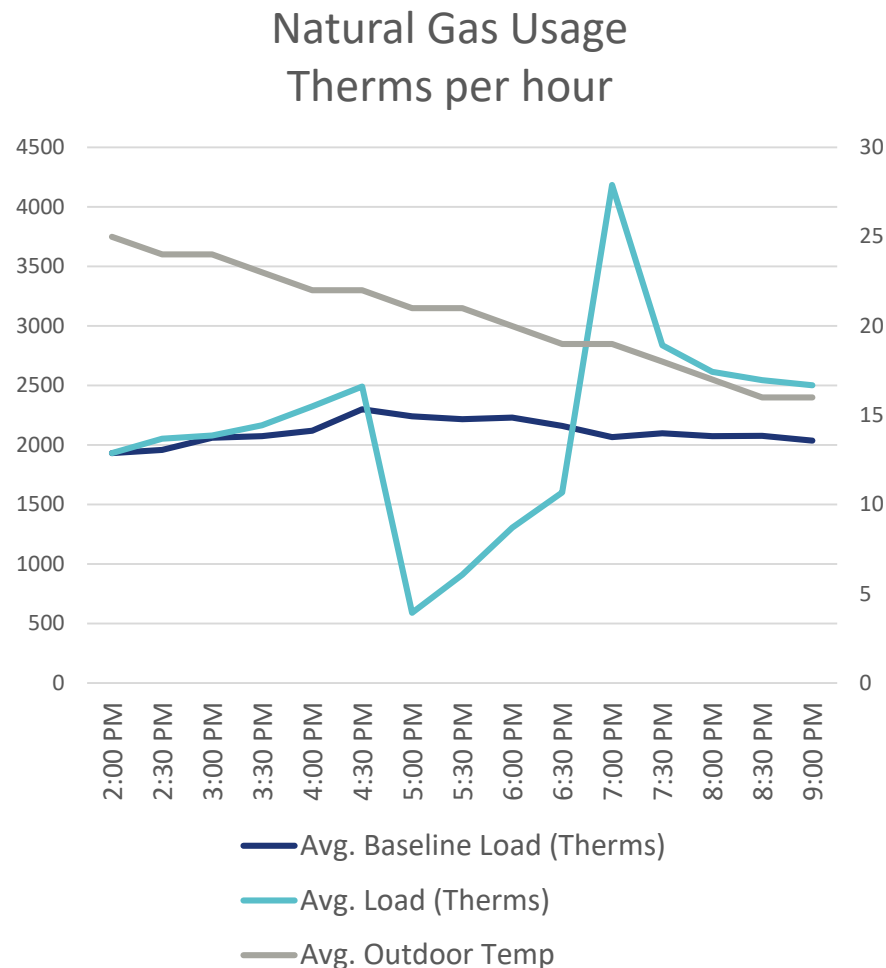
EnergyHub estimates natural gas performance using a few assumptions:

- Typical residential natural gas heating systems have a capacity of 80k to 120k BTU/hour (this is equivalent to 23-35kW); capacity assumptions vary by climate zone. A combination of zone 4 and zone 5 are used to make these assumptions (map shown below)
- Cooling devices have an average compressor size of 3.5kW
- Average home size is 2,000 sq ft (50 BTU/hour/square foot)
- Average furnace size of about 30kW (100,000 BTU/hour)
  - This is combined with thermostat runtime data to get an estimate of 15-minute intervals of gas consumption.



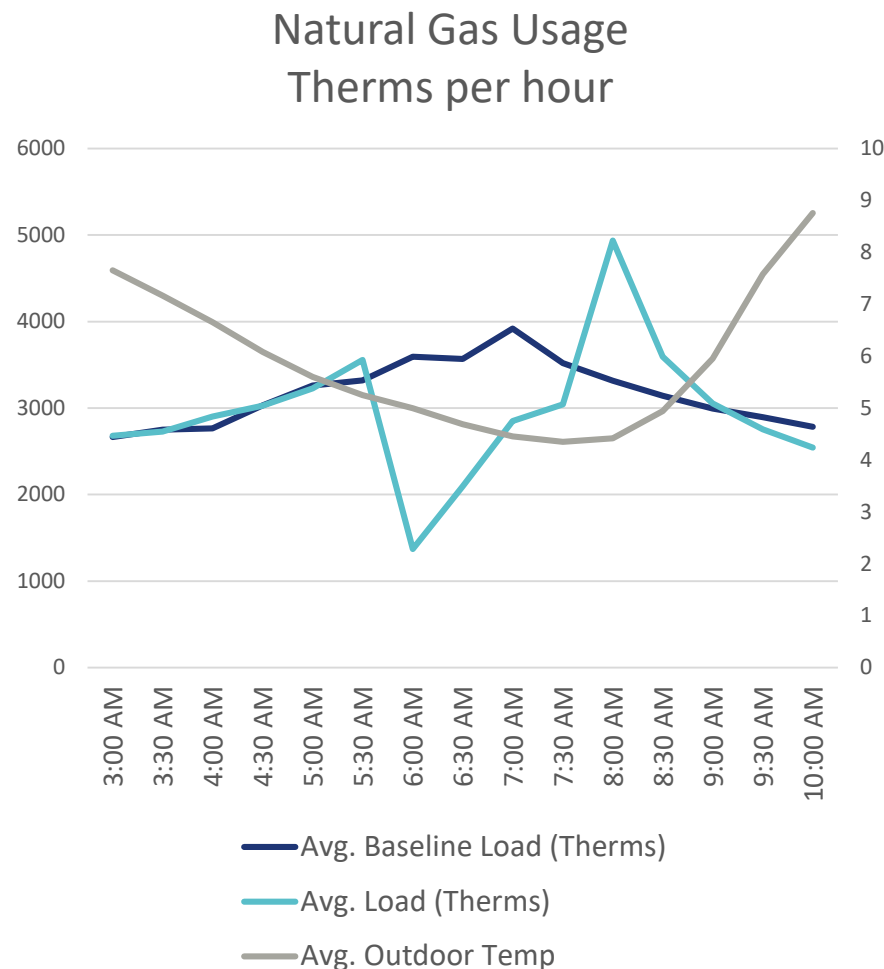
# Smart Savers Gas Event: January 30, 2023

Event Details	
Event Timing	5 p.m. – 7 p.m.
Devices Targeted	6,138
Event Avg. Temperature	21°
Total gas reduction during event	1,850.2 Therms
Total gas reduction per device	0.301 Therms
Gas reduction percentage during event	50%
Cumulative gas usage (including snapback)	<b>Decrease</b> of 241 Therms



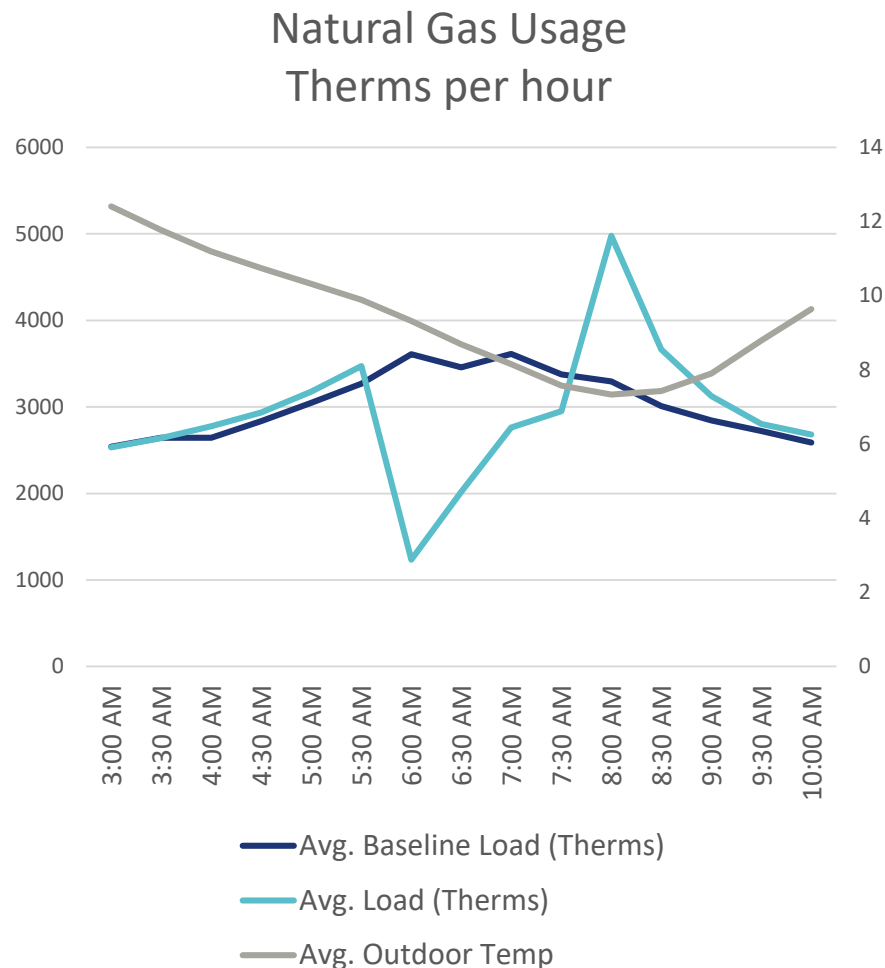
# Smart Savers Gas Event: January 31, 2023

Event Details	
Event Timing	6 a.m. – 8 a.m.
Devices Targeted	6,138
Event Avg. Temperature	5°
Total gas reduction during event	2,183.9 Therms
Total gas reduction per device	0.356 Therms
Gas reduction percentage during event	36%
Cumulative gas usage (including snapback)	<b>Decrease</b> of 1,354 Therms



# Smart Savers Gas Event: February 3, 2023

Event Details	
Event Timing	6 a.m. – 8 a.m.
Devices Targeted	6,058
Event Avg. Temperature	8°
Total gas reduction during event	2,119.6 Therms
Total gas reduction per device	0.350 Therms
Gas reduction percentage during event	36%
Cumulative gas usage (including snapback)	<b>Decrease</b> of 983 Therms



## Smart Savers Gas: All Events Summary

- Smart Savers Gas called 5 events over the 2-year pilot duration
- The pilot grew 380% year over year, from 1,278 devices enrolled in January 2022 to 6,138 devices enrolled in January 2023
- Program growth was accomplished through email marketing efforts with a broader target audience, open to gas only territories and the compatibility of ecobee devices in the 2022-23 season.

Date	Event Time	Devices targeted	Gas Reduction (therms)	Gas Reduction per Device (therms)	Cumulative Event Usage (therms)	Event Avg. Temp	Opt-Out (%)
1/20/2022	5pm-7pm	1,309	509	0.386	(349)	18°	11.2%
1/28/2022	6am-8am	1,278	387	0.295	66	13°	10.6%
1/30/2023	5pm-7pm	6,138	1,850	0.301	(241)	21°	13.0%
1/31/2023	6am-8am	6,138	2,184	0.356	(1,354)	5°	16.4%
2/3/2023	6am-8am	6,058	2,120	0.350	(1,983)	8°	15.3%

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- Introductions
- Executive Summary
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- Smart Savers Gas Overview, Results from Year 2 and Summary from Previous Events
- Energy Action Days Overview, Results from Year 2 and Summary from Previous Events
- Small and Large Commercial Customer Update
- Key Learnings and Next Steps
- Questions

# Energy Action Days Pilot Overview

## CURRENT PARTICIPANTS

- 112,434 as of June 12, 2023
- 1.5% attrition rate

## 2022-23 GOALS

90% retention of all customers that received a welcome letter in November 2022

## RECRUITMENT APPROACH

Opt-out (automatically enrolled)

## INCENTIVE

None

## ELIGIBILITY

- Pre-selected Dual-fuel or Gas-only Residential customers
- Gas-only customers include those on the Alpena, Upper Peninsula and Sault Ste. Marie/Bay Mills lines

## EVENT PARAMETERS & METHODOLOGY

- Weekdays for 24 hours, excluding holidays, during the winter months (November – March)
- Maximum of 8 events per season (increased from 5 events in prior season)
- Customers are advised to take action to reduce natural gas use

- Energy Action Days is our Gas Behavioral Demand Response pilot, which aims to use behavioral science to encourage customers to reduce their natural gas use during times of high demand
- The pilot studied customers in two DTE regions
  - Southeast Michigan: Load reduction is calculated through a randomized control trial
  - Northern Michigan: Load reduction is calculated at the system level through a baseline methodology
- Participants received a variety of resources to motivate energy efficient behavior and peak demand savings during events, including:
  - Pre-season Welcome Letter
  - Pre- and Post-Event Emails and Voice Messages
  - Post-Season Survey and/or Pilot Closing Letter
  - [Pilot webpage](#) with FAQs and tips
- Two events were called in the second winter season: January 31<sup>st</sup> and February 3<sup>rd</sup>
  - Temperature levels were the driving factor to determine dispatch
  - 2022 events: February 4<sup>th</sup> and March 3<sup>rd</sup>



# Dual-Fuel 2022-23 Event Results

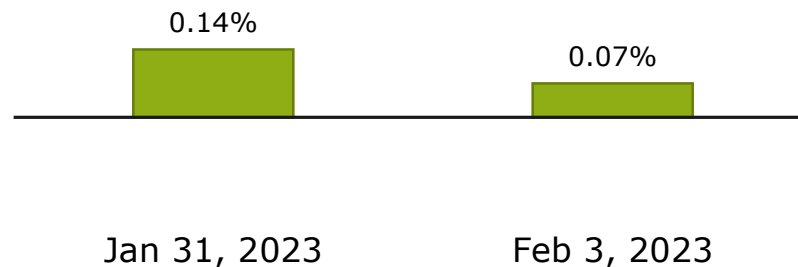
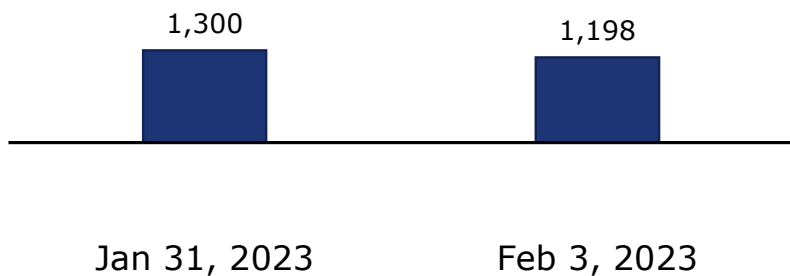
Participant event savings are determined by a comparison to the usage (daily reads) of a control group

Case No. U-21291  
Exhibit: CEO-36  
CEO Witness Cebulko  
Date: 05/07/24 Page  
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## Therm Savings

## Savings Rate

Given statistical significance, both events can be considered at "0"



Avg. Temp

13°

12°

13°

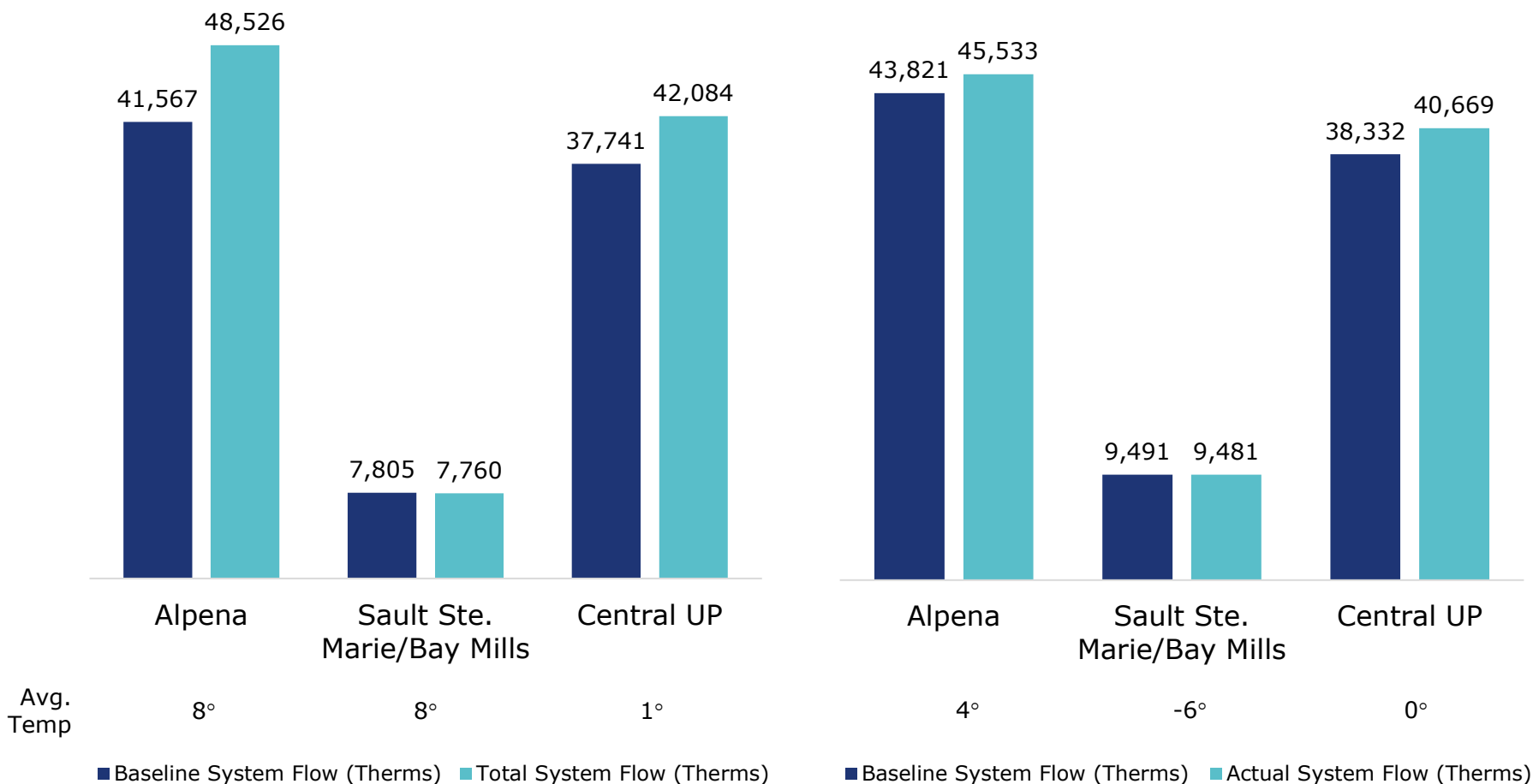
12°

# Gas-only 2022-23 Event Results

Participant event savings are determined by a comparison of actual system flow to forecasted at the system level

## January 31, 2023 Event

## February 3, 2023 Event



Baseline System Flow: Forecasts the total system load for each target region based on temperature by referencing baseload and space heat factors generated from 2 years of historical monthly usage data. Baseload factor refers to the load being used year-round, while the space heat factor is the load used for heating which is dependent on temperature

## Second Season Learnings and Next Steps

- Like the first season, the second was completed as planned but achieved low savings
  - Customer attrition remains low at 1.5%
  - Compared to the 2021-2022 season results, the savings rates improved for dual-fuel participants, but are not statistically significant
  - Event fatigue may be present as events are 24 hours long due to gas data limitations
- Pilot communications were revised based on first season learnings. Changes included:
  - Weatherization recommendations in the welcome letter
  - Actionable energy-savings tips that emphasize conserving usage for the entire duration of the event (24 hours)
- Event notification delivery and engagement metrics were normal based on vendor benchmarks
  - Email alerts experienced the highest response rate with an average open rate of 48% for pre-event notifications and 57% for post-event in the second season of the pilot
- The post-season letter was exchanged again this season for a survey, which found the Energy Action Day program had positive impact on customer satisfaction
  - 59% of participants recalled receiving Energy Action Days communications, increasing from the prior season (55%)
  - Many customers remember taking some form of Energy Action Day savings action, with two-thirds (64%) reporting an effort at usage reduction, like lowering their thermostat
- The Company is preparing a pilot wrap-up communication to participants to summarize results and notify them of pilot conclusion

# Agenda

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- **Small and Large Commercial Customer Update**
- Key Learnings and Next Steps
- Questions

# C&I Gas Pilot Overview

## 2022-23 GOALS

- Complete equipment installations on balance of enrolled customers
- Maintain engagement with enrolled customers
- Enroll large GS-2 Manufacturing Customer

## DTE'S SCOPE OF WORK

- Install required telemetry equipment at no cost
- Supply daily usage reports to customer
- Prepare customer for event, measure hourly usage post-event, and identify actions taken

## CUSTOMER EXPECTATIONS

- Participants were asked to reduce usage as much as possible during each event

## EVENT PARAMETERS

- Gas DR Season: November 1 – March 31
- Monday-Friday (non-holidays)
- Up to eight hours max per event
- Up to 20 events during the 2-season pilot

## Status Update

- Telemetry equipment was not installed on balance of enrolled accounts
  - Equipment compatibility issues
  - Limited availability of instrumentation crew
  - Long equipment lead times
  - Very limited opportunities for reductions
- Maintained engagement with enrolled customers
- Called two events
  - Jan. 31, 9:00 AM – Noon
  - Feb. 3, 2:00 PM – 6:00 PM
- Unable to persuade targeted GS-2 customer



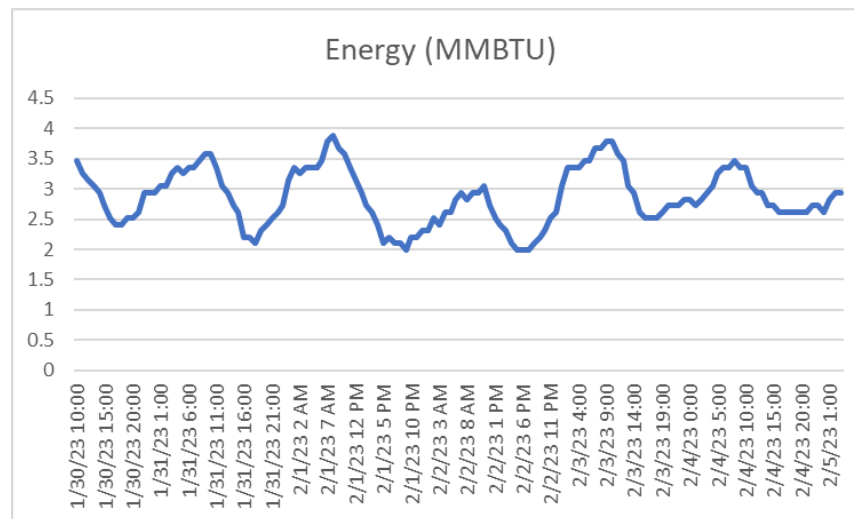
# C&I DR Event – Action and Results

## Reduction Efforts:

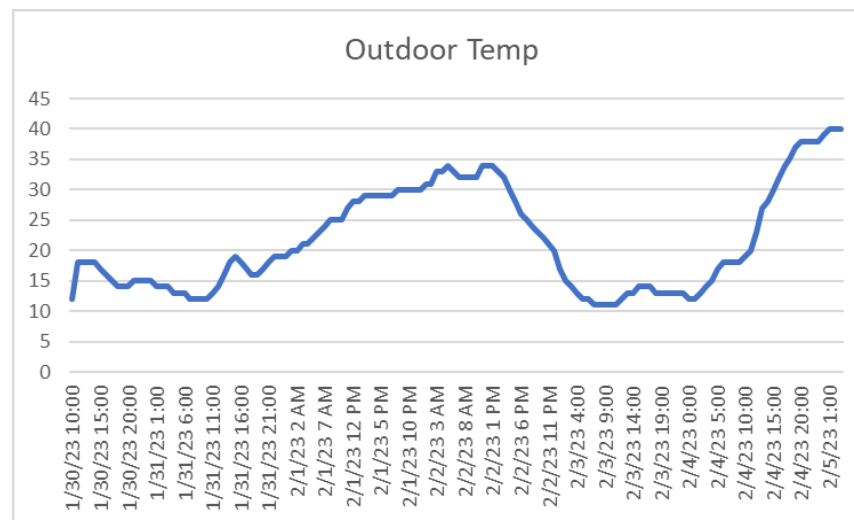
- Both sites attempted to pre-heat the spaces prior to event window
- Air Handlers were placed in "unoccupied" mode during first half of events
- "Not sure what else I can do, short of shutting them down. Then the screaming will begin." - Quote from customer

## Results

- Based on our findings, we do not believe these events resulted in energy reductions

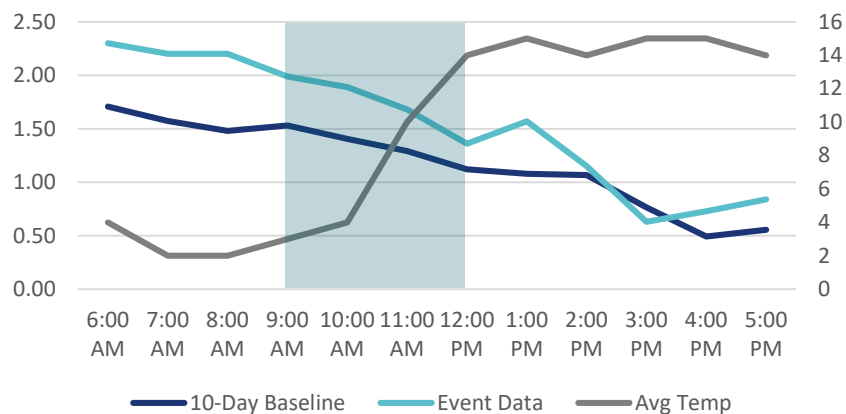


	1/30/2023	1/31/2023	2/1/2023	2/2/2023	2/3/2023	2/4/2023
9:00 AM		3.57	3.67	2.94	3.78	3.36
10:00 AM	3.46	3.57	3.57	2.94	3.78	3.36
11:00 AM	3.25	3.36	3.36	3.04	3.57	3.04
12:00 PM	3.15	3.04	3.15	2.73	3.46	2.94
2:00 PM	2.94	2.73	2.73	2.41	2.94	2.73
3:00 PM	2.73	2.62	2.62	2.31	2.62	2.73
4:00 PM	2.52	2.2	2.41	2.10	2.52	2.62
5:00 PM	2.41	2.2	2.10	1.99	2.52	2.62
6:00 PM	2.41	2.1	2.20	1.99	2.52	2.62

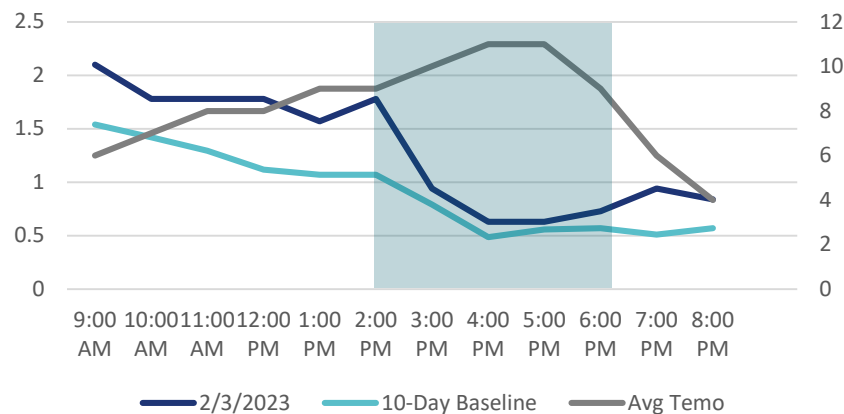


# C&I DR Event Results

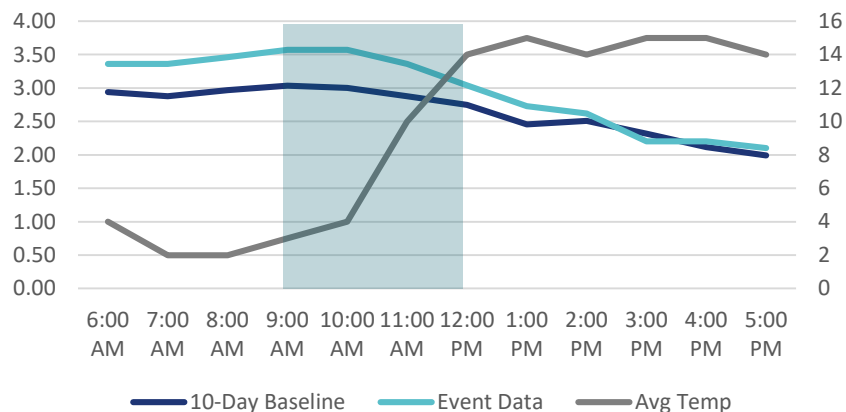
**Location 1: 1/31/23 - 9am-12pm**



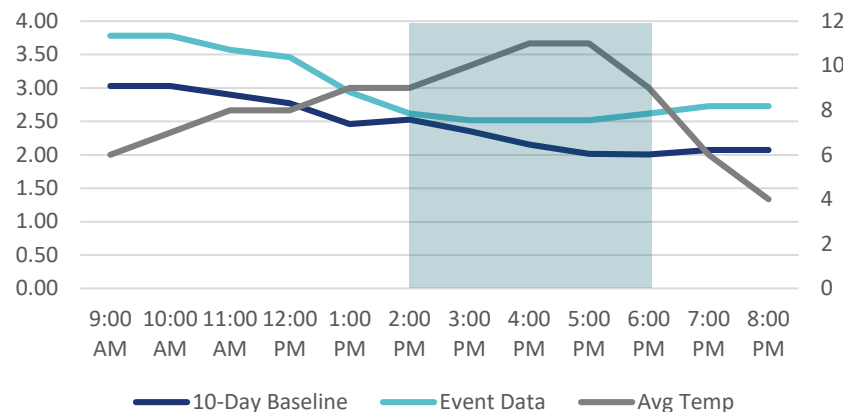
**Location 1: 2/3/23 - 2pm-6pm**



**Location 2: 1/31/23 - 9am-12pm**



**Location 2: 2/3/23 - 2pm-6pm**



# C&I Pilot Challenges, Findings, and Feedback

## Challenges

- Installation of instrument drives and compatibility of telemetry equipment
- Availability of Instrumentation Technicians
- Lack of incentive for customer
- Fear of forced reductions (manufacturing) and respective impact to operations/profitability
- Concerned about complaints
  - Employees, Customers, Students, etc.

## Findings

- Labor intensive process for each installation
  - Installation, system configurations, interface with billing, etc.
- Creation of Billing Issues
  - Physical meter reading vs. telemetry data
  - Both meters were being estimated for several months during implementation
- Reliability of equipment
- VCI stopped communicating on 3/10
  - Noticed on 3/16, resulting in billing adjustment

## Customer Feedback

- "This cost me more energy"
- "I don't even look at those reports"
- Customer requested both meters be returned to "normal"

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- Questions

# Key Learnings and Next Steps

- Key Learnings:
  - Gas only customers with Ecobee thermostats can only be enrolled in one utility program
  - Data analysis is difficult due to the availability and granularity of data
  - Smart Savers gas had the best result but still experienced a large snap-back
  - Energy Action Days did not produce significant gas reduction
  - Recruitment and installation of large customers is difficult
  - Large customers see minimal value in telemetry gas data
  - There is only so much large customers are willing to do to reduce gas consumption due to the comfort of customers and employees and the sensitivity around equipment and process specifications
- Based on learnings and cost from these pilots, the Company does not intend to request Commission approval to seek a full-scale program
- The Commission approved spend up to \$4 million to analyze gas demand response in the Company's service territory
- The Company will seek recovery of the actual spend in the next gas rate case to be filed in November of 2023

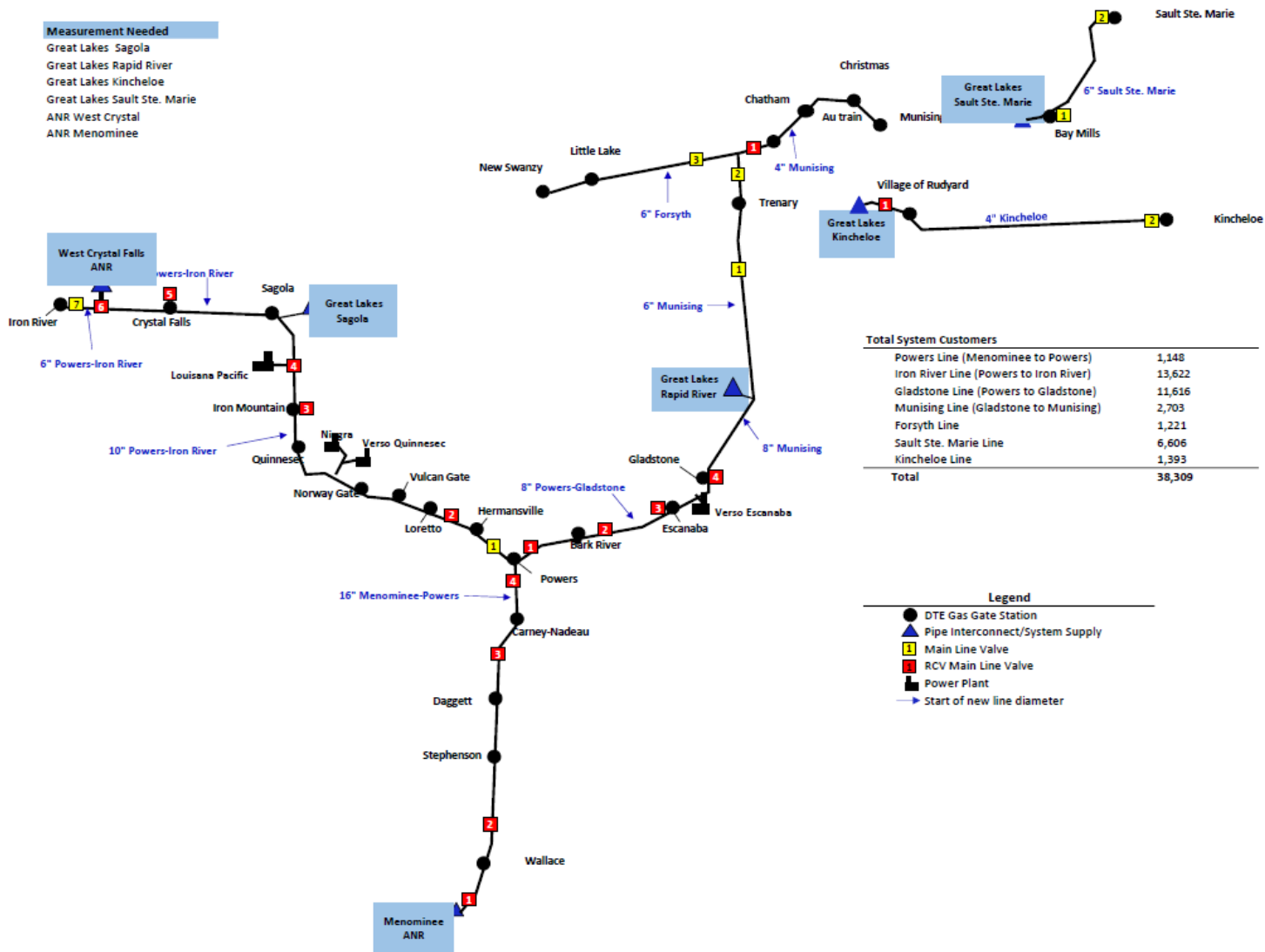
# Questions

# Appendix

# Alpena System



# UP and Sault Ste Marie System





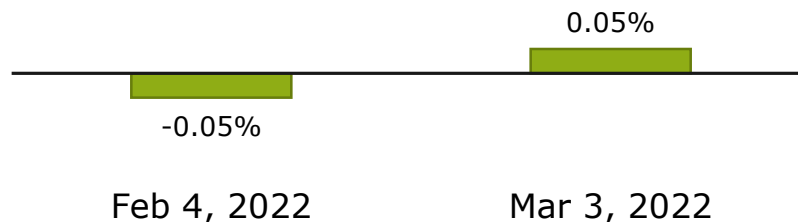
# Dual-Fuel 2021-22 Event Results

Participant event savings are determined by a comparison to the usage of a control group

## Therm Savings

## Savings Rate

Given statistical significance, all events can be considered at "0"



Avg. Temp

13°

21°

13°

21°

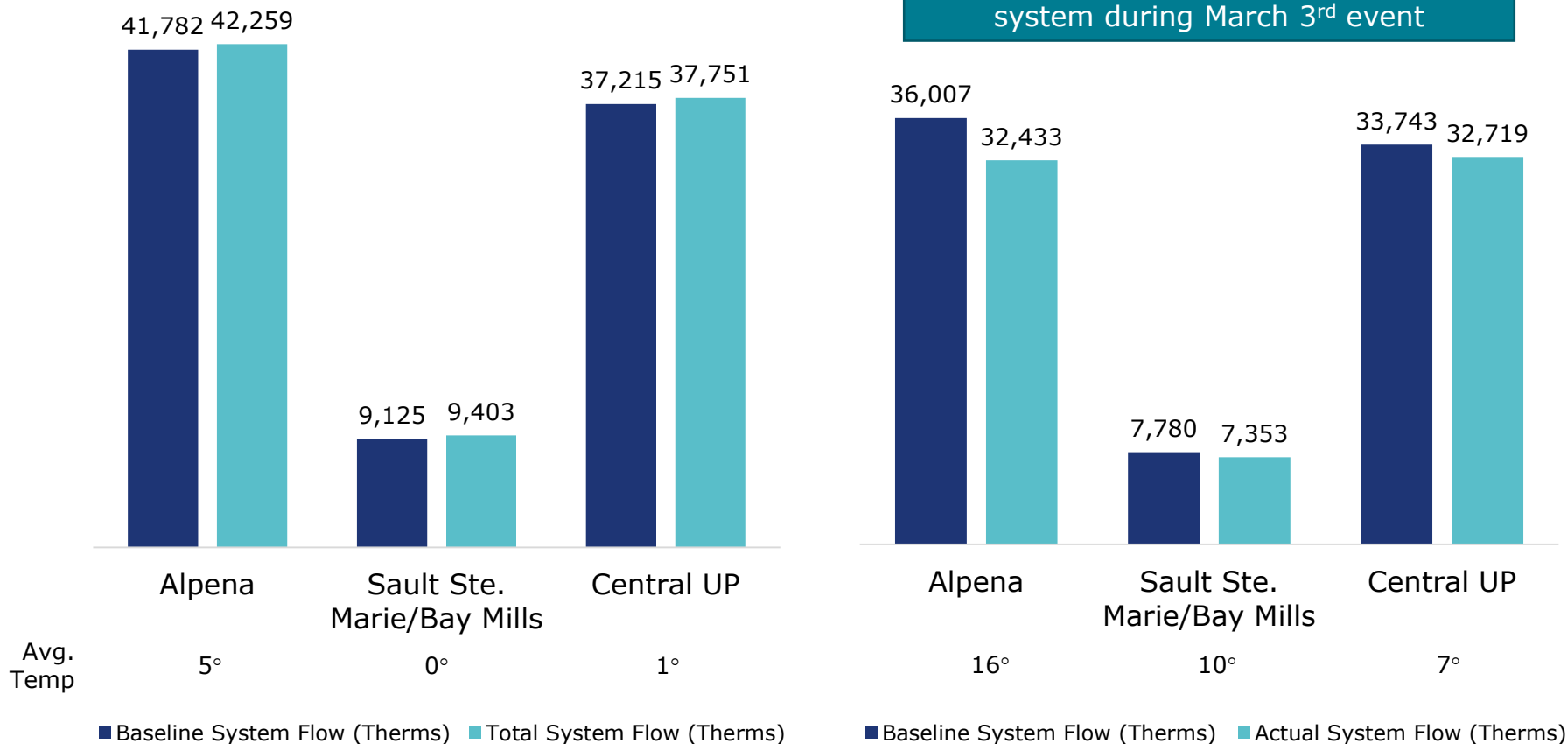
# Gas-only 2021-22 Event Results

Participant event savings are determined by a comparison of actual system flow to forecasted at the system level

## February 4, 2022 Event

## March 3, 2022 Event

Only savings observed on the Alpena system during March 3<sup>rd</sup> event



Baseline System Flow: Uses a Residential Load Calculator to provide a forecasted total system load for each target region based on temperature. The calculator references baseload and space heat factors that were generated from 2 years of historical monthly usage data. Baseload factor refers to the load being used year-round, while the space heat factor is the load used for heating which is dependent on temperature.

**MPSC Case No:** U-21291

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**Requester:** CEO

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**Question No.:** CEODG-3.12

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**Respondent:** H. J. Decker

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**Question:** 12. Please identify and explain the delays for procuring and installing the telemetry equipment.

**Answer:** The three meters that were never installed were the smallest meters among those initially enrolled. Telemetry on these meters is not something DTE utilizes today and the instrument group responsible to research and design a solution had competing priorities maintaining existing operational needs.

**Attachment:** None

**MPSC Case No:** U-21291

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**Requester:** CEO

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**Question No.:** CEODG-1.4a

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**Respondent:** H. J. Decker

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**Page:** 1 of 1

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**Question:** 4. Please refer to HJD-80, lines 2-4, where the witness states that the Company's demand response pilot participants "received a variety of resources to motivate energy efficient behavior and peak demand savings but did not receive any monetary incentive for participating."

a. Please describe in detail the Company basis for determining that customers would participate in the demand response pilot without a financial incentive.

**Answer:** Behavioral demand response programs do not include a financial incentive.

**Attachment:** None

**MPSC Case No:** U-21291

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**Requester:** CEO

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**Question No.:** CEODG-1.5a

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**Respondent:** H. J. Decker

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**Page:** 1 of 1

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**Question:** 5. Please refer to HJD-80, lines 2-4, where the witness states that the Company's demand response pilot participants "received a variety of resources to motivate energy efficient behavior and peak demand savings but did not receive any monetary incentive for participating."

a. Please list all successful demand response programs the Company is aware of that do not offer customers a financial incentive to participate.

**Answer:** All of the behavioral demand response programs run by the program implementer do not include a financial incentive to participate.

**Attachment:** None

**MPSC Case No:** U-21291

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**Requester:** CEO

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**Question No.:** CEODG-1.3c

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**Respondent:** H. J. Decker

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**Question:** 3. Please refer to HJD-80, lines 2-4, where the witness states that the Company's demand response pilot participants "received a variety of resources to motivate energy efficient behavior and peak demand savings but did not receive any monetary incentive for participating."

c. If the answer to 3a. is no, why not?

**Answer:** Behavioral demand response programs do not include a financial incentive.

**Attachment:** None

**MPSC Case No:** U-21291

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**Requester:** MNSC

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**Question No.:** MNSCDG-2.6d

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**Respondent:** H. J. Decker

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**Page:** 1 of 1

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- Question:** 6. Please refer to the following statement regarding DTE Gas's demand response pilot on page 28 of Direct Testimony of Telang, line 20-23: "At the conclusion of the second year of the demand response pilot, DTE Gas reviewed the results and determined the Demand Response program was not effective and determined not to request to extend the pilot or make the program permanent."
- d. Has DTE Gas conducted a study to assess the effectiveness of the demand response pilot? If so, please provide the study. If not, explain why not.

**Answer:** Yes. The Company conducted a two-year gas DR pilot to determine the effectiveness of Gas DR as a result of the settlement in case U-20642. Attached are the two season ending presentations presented to MPSC Staff.

**Attachment:** U-21291 MNSCDG-2.6d Gas DR Pilot Results Season 1  
U-21291 MNSCDG-2.6d Gas DR Pilot Results Season 2



# **Gas Demand Response Results – Year 1**

May 11, 2022

# Agenda

- Introductions
- Executive Summary
- Overview
- Smart Savers Gas Overview, Results and Learnings
- Energy Action Days Overview, Results and Learnings
- Small and Large Commercial Customer Update
- Questions

## Executive Summary

- DTE is conducting gas demand response pilots to determine the effectiveness of Gas DR as a result of the settlement in case U-20642
- The learnings from the Gas Demand Response pilots are being conducted to assist in understanding the opportunity that exists within the Gas DR space and to determine future offerings
- DTE ran two residential pilots successfully in year one and was able to gather valuable information for the continuation of these pilots
- The small and large commercial Gas DR pilot has experienced some delays but plans to launch later this year

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- Introductions
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# DTE is pursuing gas demand response pilots as directed by the Michigan Statewide Energy Assessment and settlement in Gas Rate Case U-20642

- “The Commission recommends convening a utility and stakeholder workgroup to review the potential for natural gas DR programs and develop recommendations to encourage the development or expansion of natural gas DR programs<sup>1</sup>.”
- “The Parties agree that DTE Gas will launch a Demand Response Pilot in the winter of 2021. In connection with this Pilot, DTE Gas will hold a conference with interested parties to share existing proposals, discuss refinement of the proposals, and agree on a process to effectuate the DR Pilot.<sup>2</sup>”
- Pilots seek to identify how our unique customer base will react to specific marketing efforts, program design features and other characteristics that are dependent on DTE’s unique combination of systems, equipment, tariffs, programs and processes

## DTE's Pilot Goals and Objectives

- Understand the capability of customers to reduce gas consumption following the notification of an event
- Assess various event parameters to determine dispatch criteria to maximize customer engagement
- Test appropriate customer incentive levels
- Evaluate customer receptiveness to various marketing campaigns
- Collect information on successful customer gas reduction strategies
- Test baseline methodologies
- Determine if a gas demand response pilot can be scaled to become a full-scale program

*Pilots seek to identify how our unique customer base will react to specific marketing efforts, program design features and other characteristics that are dependent on DTE's unique combination of systems, equipment, tariffs, programs and processes.*

# Agenda

- Introductions
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# Smart Savers Gas Program Overview

## **CURRENT PARTICIPANTS**

1,518 devices as of May 9, 2022

## **2022 GOAL**

6,000 devices enrolled

## **RECRUITMENT APPROACH**

- Opt-in
- 2021-22: Targeting combo customers already enrolled in the Smart Savers electric program
- 2022-23: Including gas only customers

## **INCENTIVE**

- \$50 up front incentive
- \$50 year end incentive if still enrolled

## **ELIGIBILITY**

- Must have a DTE Gas account
- Qualified wi-fi enabled smart thermostat
- Natural gas controlling their furnace

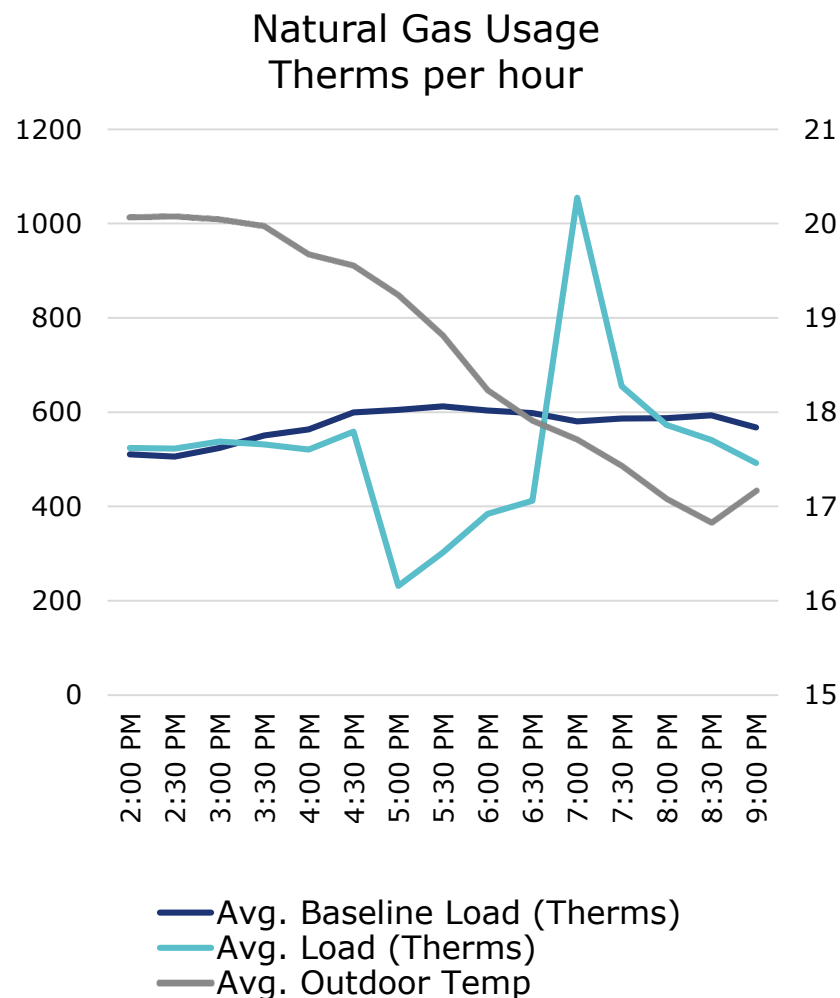
## **EVENT PARAMETERS & METHODOLOGY**

- Weekdays only, excluding holidays
- No more than 8 hours per event and will occur between 5 a.m. – 9 a.m. and/or 5 p.m. – 9 p.m.

- Smart Savers Gas targets combo and gas only customers who already have a Wi-Fi enabled smart thermostat installed to reduce their gas use during periods of extremely cold temperatures
- The goal is to enroll up to 6,000 combo and gas only customers in 2021-23, during DR Gas season, to learn how customers respond to this type of program and determine how much gas savings we can expect to achieve
- Marketing
  - 2021-22 season was targeted to combo customers already enrolled in the Smart Savers Electric program, which was around 5k at the time of recruitment
  - 2022-23 season will also target gas only customers in NW Michigan

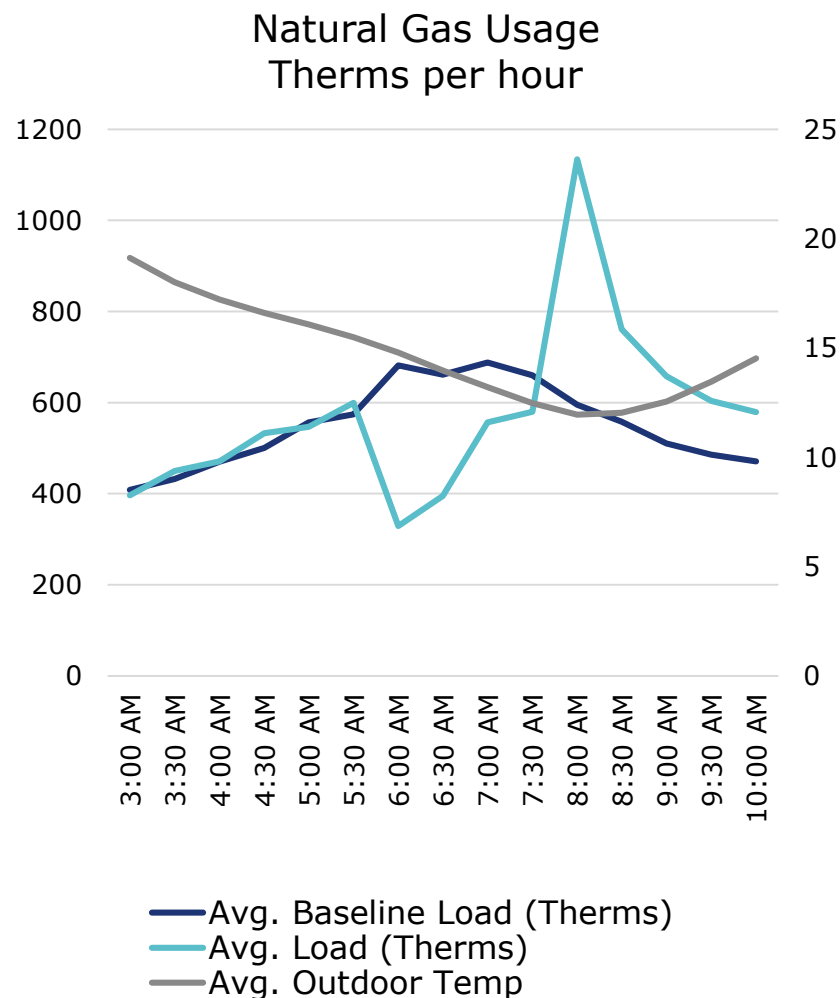
# Smart Savers Gas Event: January 20, 2022

Event Details	
Event Timing	5 p.m. – 7 p.m., no-pre-heating
Devices Targeted	1,309
Average Temperature	18 degrees
Total gas reduction during event	509.4 Therms
Total gas reduction per device	0.386 Therms
Gas reduction percentage during event	42%
Cumulative gas usage (including snapback)	<b>decrease</b> of 343 Therms



# Smart Savers Gas Event: January 28, 2022

Event Details	
Event Timing	6 a.m. – 8 a.m., no-pre-heating
Devices Targeted	1,278
Average Temperature	13 degrees
Total gas reduction during event	386.8 Therms
Total gas reduction per device	0.295 Therms
Gas reduction percentage during event	29%
Cumulative gas usage (including snapback)	<b>Increase</b> of 66 Therms



# Smart Savers Gas Learnings

- The Smart Savers Gas pilot successfully launched and dispatched two events in its first program year
- Calling an event early in the day may have had a sustained impact on gas usage for the second event on January 28
  - Lower temperatures could have also been the culprit of the large snapback once the second event ended, causing the cumulative increase of gas usage
- During the recruitment and enrollment period in 2021, ecobee devices were not eligible to participate in Gas DR due to incompatibility, which made up about half of our target population
  - Devices eligible to join the Smart Savers Gas pilot in 2022 include; ecobee, Honeywell, Nest and Sensi

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- Small and Large Commercial Customer Update
- Questions

# Energy Action Days Pilot Overview

## CURRENT PARTICIPANTS

- 89,648 as of May 9, 2022
- 1.1% attrition rate

## 2022 GOALS

90% retention of 90,625 customers that received a welcome letter

## RECRUITMENT APPROACH

Opt-out (automatically enrolled)

## INCENTIVE

None

## ELIGIBILITY

- Pre-selected Combo or Gas-only Residential customers
- Gas-only customers include those on the Alpena, Upper Peninsula and Sault Ste. Marie/Bay Mills lines

## EVENT PARAMETERS & METHODOLOGY

- Weekdays for 24 hours, excluding holidays, during the winter months
- Maximum of 5 events per season
- Customers are advised to take action to reduce natural gas use

## TIMELINE

December 2021 – March 2023

- Energy Action Days is our Gas Behavioral Demand Response pilot, which aims to use behavioral science to encourage customers to reduce their natural gas use during times of high demand
- The pilot is studying customers in two DTE regions
  - Southeast Michigan: Load reduction is calculated through a randomized control trial
  - Northern Michigan: Load reduction is calculated at the system level through a baseline methodology
- Pilot customers received a variety of resources to motivate energy efficient behavior and peak demand savings, including:
  - Pre-season Welcome Letter, which was received by customers mid-December 2021
  - Pre- and Post-Event Emails and Voice Messages
  - Post-Season/Pilot Closing Letter
- A [pilot webpage](#) is linked throughout customer communications to provide a thorough pilot overview and answer frequently asked questions
  - This page, as well as customer service resources, were refined following the MPSC complaint received in December 2021
- Two events were called in the first winter season:
  - February 4<sup>th</sup>
  - March 3<sup>rd</sup>



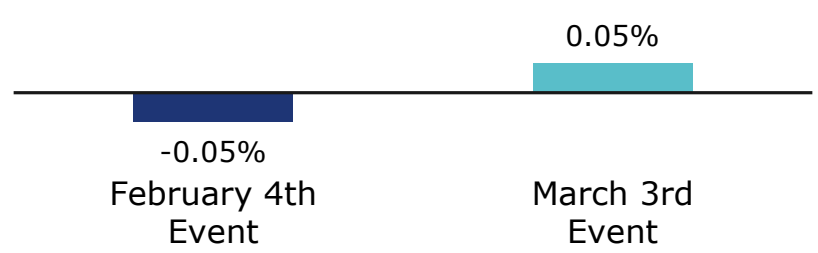
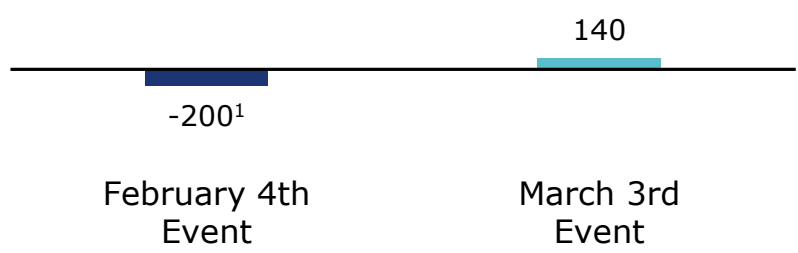
# Dual-Fuel Event Results

Participant event savings are determined by a comparison to the usage of a control group

## Therm Savings

## Savings Rate

Given statistical significance, both events can be considered at "0"



<sup>1</sup>Negative values indicate there was increased load rather than a reduction or savings during the event

# Gas-only Baseline Methodologies

DTE explored using 4 different baseline methodologies to calculate Gas-only event savings:

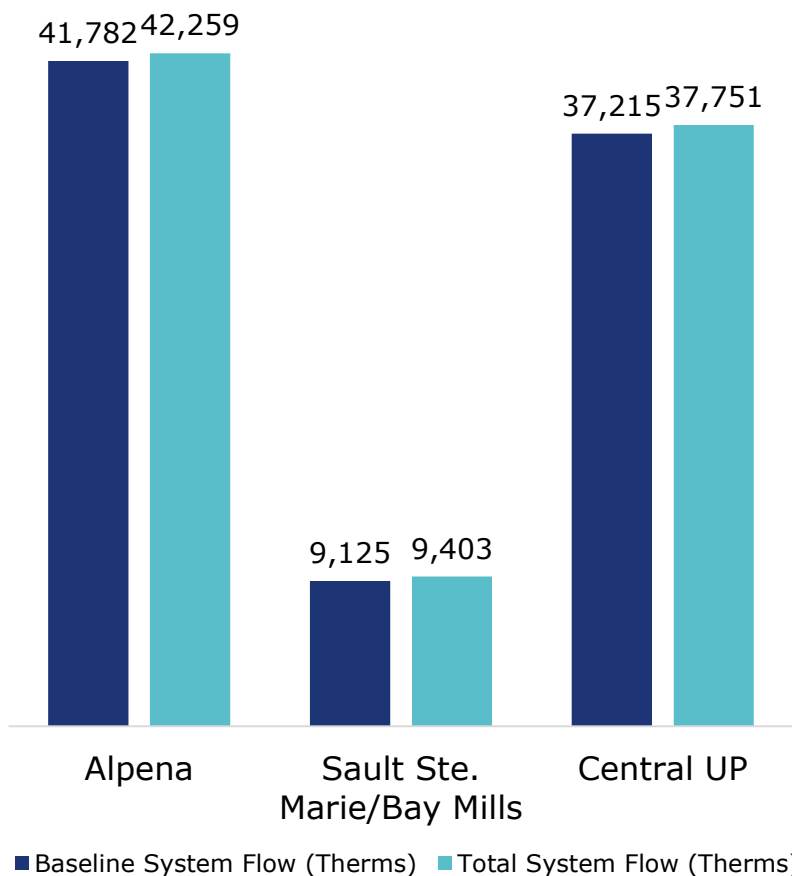
1. 1-day Baseline: Selected 1 day from the prior 5 weekdays with the most similar all-day temperature to the event day
2. 3-day Baseline: Average of the 3 highest load days of the prior 5 weekdays
3. 5-day Baseline: Average of the prior 5 weekdays
4. Forecasted Load: Internal calculator determines the forecasted system load based on average temperature, referencing baseload and space heat factors generated from 2 years of historical monthly usage data

None of the above baseline methodologies are weather normalized, except for the Forecasted Load, which is why it was selected as the preferred baseline methodology for the first winter season

# Gas-only Event Results

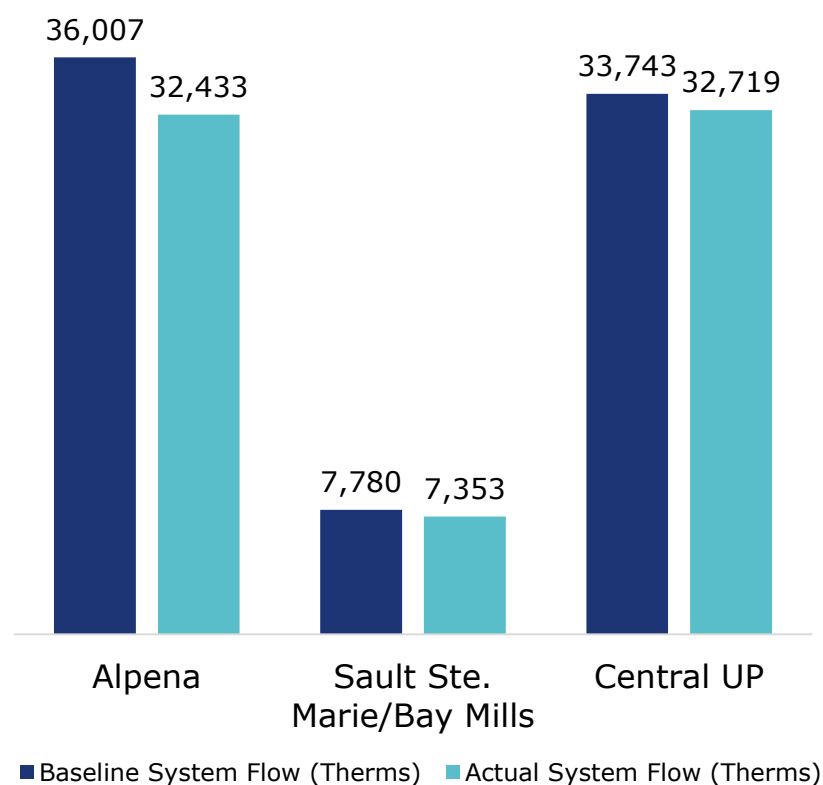
Participant event savings are determined by a comparison of actual system flow to forecasted at the system level

## February 4<sup>th</sup> Event



## March 3<sup>rd</sup> Event

Only significant savings observed on the Alpena system during March 3<sup>rd</sup> event



Baseline System Flow: The Residential Load Calculator can provide a forecasted total system load for each target region based on temperature in that region. The calculator references baseload and space heat factors that were generated from 2 years of historical monthly usage data (4/1/201 to 3/31/2021). Baseload factor refers to the load being used year-round, while the space heat factor is the load used for heating which is dependent on temperature.

# First Season Learnings

- The first season was successfully run despite low savings
  - Event notification delivery and engagement metrics were normal based on vendor benchmarks
  - Event fatigue may be present since events are 24 hours long due to gas data limitations
- The post-season letter will be exchanged for a survey to gauge customer satisfaction and experience, and to understand what actions, if any, customers took during Energy Action Days
- Pilot communications will be revised based on survey results, as well as season learnings. Initial changes include:
  - Provide energy-savings tips that emphasize conserving usage for the duration of the entire event (24 hours)
  - Include weatherization recommendations in the welcome letter

# Agenda

- Introductions
- Executive Summary
- Overview
- Smart Savers Gas Overview, Results and Learnings
- Energy Action Days Overview, Results and Learnings
- **Small and Large Commercial Customer Update**
- Questions

# Small and Large Commercial Pilot Overview

## **CURRENT PARTICIPANTS**

5 customers

## **2022 GOAL**

Targeting 10 customers

## **RECRUITMENT APPROACH**

- Work with Gas Account Managers to recruit customers

## **INCENTIVE**

- Telemetry Meter (new cellular meter) which allows the customers to manage their usage data by the hour (\$4,700 value)

## **ELIGIBILITY**

- GS1, GS2 or S Rate Gas customers

## **EVENT PARAMETERS & METHODOLOGY**

- DTE to measure the customer's usage and learn what they did during the events we call. i.e., thermostat reduction, pre-heat prior to events, etc.
- Customers will be required to participate and curtail as much as possible on event days

## **PILOT STATUS**

- Current back order on telemetry metering

- The small and large commercial Gas pilot aims to target 10 (up to 20) customers for a 2-year pilot to join this behavioral demand response initiative
- Gas DR Season: November 1 – March 31
- We will recruit customers that are on GS1, GS2 or S rate to reduce load during called DR Gas events
- DTE to measure the customer's usage and learn what they did during the events we call. (i.e., thermostat reduction, pre-heat prior to events, etc.)
  - Customers will be required to participate and curtail as much as possible on event days.
- Program availability
  - Monday-Friday (non-holidays)
  - Up to eight hours max DR window per day (i.e., 8 hours in PM, or 4 hours in AM and 4 hours in PM)
  - Up to 10 event days per season (subject to change in Year 2)

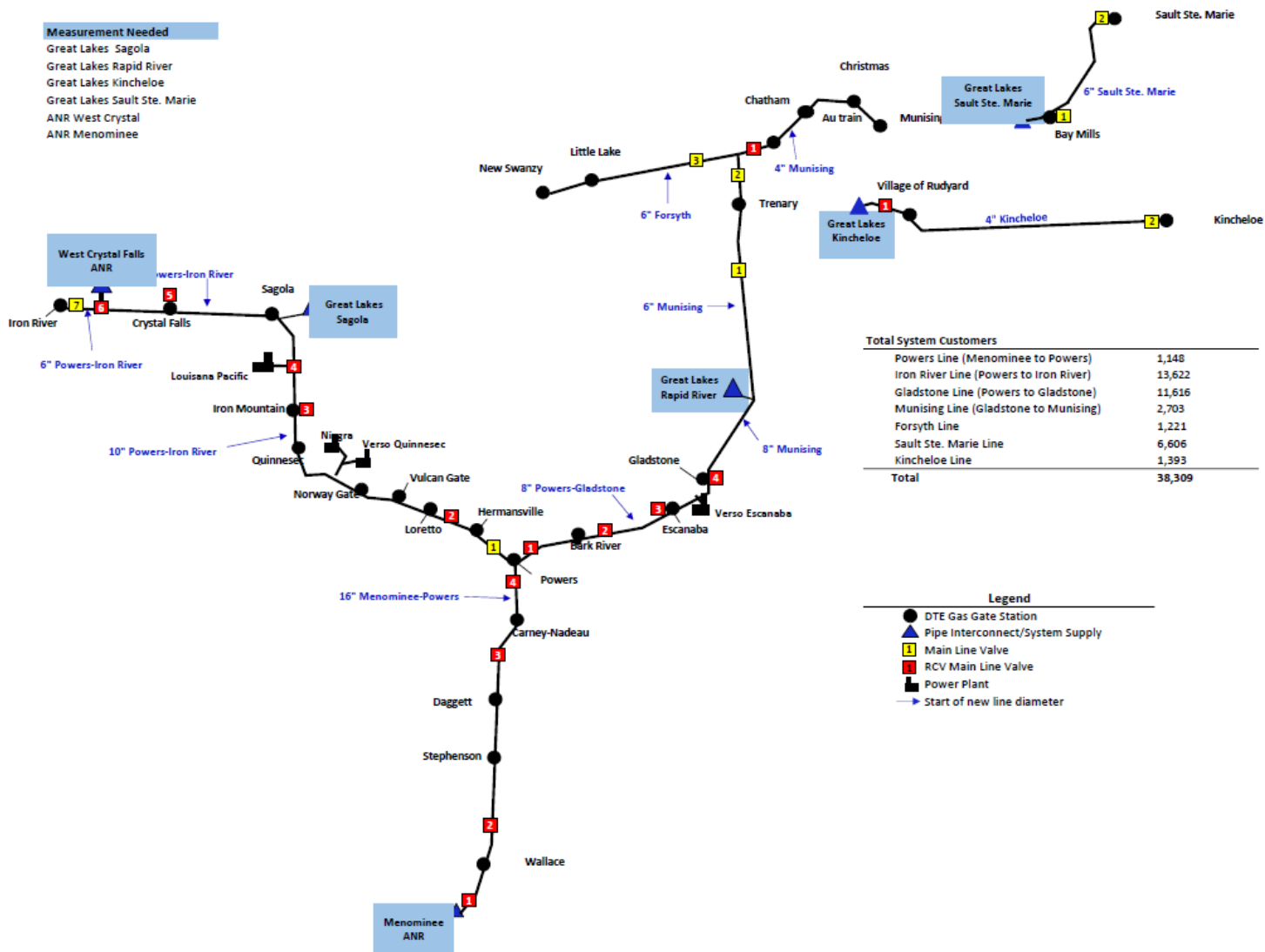
# Questions

# Appendix

# Alpena System



# UP and Sault Ste Marie System



**MPSC Case No:** U-21291

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**Requester:** CEO

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**Question No.:** CEODG-4.1bi

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**Respondent:** H. J. Decker

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**Page:** 1 of 1

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- Question:** 1. The Michigan Department of Environment, Great Lakes, and Energy has developed a draft interactive screening tool that identifies Michigan communities that may be disproportionately impacted by environmental hazards. The tool is called MiEJScreen: Environmental Justice Screening Tool. It is available at: <https://www.michigan.gov/egle/maps-data/miejscreen>
- b. Does DTE Gas use MiEJScreen to inform decisions about capital project locations?
- i. If yes, how?

**Answer:** No.

**Attachment:** None

**MPSC Case No:** U-21291

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**Requester:** CEO

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**Question No.:** CEODG-4.1di

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**Respondent:** H. J. Decker

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**Page:** 1 of 1

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- Question:** 1. The Michigan Department of Environment, Great Lakes, and Energy has developed a draft interactive screening tool that identifies Michigan communities that may be disproportionately impacted by environmental hazards. The tool is called MiEJScreen: Environmental Justice Screening Tool. It is available at: <https://www.michigan.gov/egle/maps-data/miejscreen>
- d. Does DTE Gas use MiEJScreen to inform decisions about any other Company program design or implementation?
- i. If yes, how?

**Answer:** No.

**Attachment:** None