COMMERCE
DEPARTMENT

July 28, 2023

Will Seuffert Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

RE: **Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. E002/CI-17-401

Dear Mr. Seuffert:

Attached are the comments of the Minnesota Department of Commerce, Division of Energy Resources (Department) in the following matter:

> Commission Investigation to Identify and Develop Performance Metrics and Potentially, Incentives for Xcel Energy's Electric Utility Operations

Northern States Power Company, d/b/a Xcel Energy (Xcel or Company) submitted Performance Based Regulation (PBR) Annual Reports on April 29, 2022, for calendar year 2021, and April 28, 2023, and Errata on July 11, 2023, for calendar year 2022. In a Notice of Comment (NOC) dated May 26, 2023, the Minnesota Public Utilities Commission (Commission) requested comments on the completeness of those two filings and identified eight additional questions.

As discussed in the attached Comments, the Department responds to the Commission questions included in the NOC and provides recommendations where appropriate. The Department also requests that Xcel provide additional information in the Company's reply comments on several metrics.

The Department is available to answer any questions that the Minnesota Public Utilities Commission may have.

Sincerely,

/s/ JOHN KUNDERT
Financial Analyst

JK/ar
Attachment

Before the Minnesota Public Utilities Commission

Comments of the Minnesota Commerce Department
Division of Energy Resources

Docket No. E002/CI-17-401

I. INTRODUCTION

The Minnesota Department of Commerce, Energy Division (Department) appreciates the opportunity to provide comments regarding Northern States Power, d/b/a Xcel Energy's (Xcel, the Company) 2021 and 2022 Performance-Based Ratemaking Annual Reports (PBR report).

A. COMMISSION NOTICE, ISSUE AND TOPICS

In its Notice of Comment in this proceeding dated May 26, 2023, the Minnesota Public Utilities Commission (Commission) identified one issue and eight topics that were open for comment.

- What action should the Commission take on performance-based ratemaking for Xcel Energy, including Xcel's 2021 and 2022 performance-based ratemaking annual report (PBR report)?
- Topics
  - Should the Commission accept Xcel's 2021 and 2022 PBR Annual Reports? Do Xcel's reports address the requirements set forth by Commission Orders in this docket, including but not limited to:
    - Future metrics?
    - Development of an online utility performance dashboard?
    - Data collection on and/or reductions in upstream methane emissions?
  - From the three years of data that have been filed for each metric, how should a single baseline value be calculated? Please explain your reasoning and provide calculations of the baseline for reach metric.
  - For which metrics, if any, should the Commission set targets and why?
  - Where applicable, by what methodology should targets be set? How often should targets be reviewed and potentially updated?
  - Where applicable, what are the appropriate targets for the metrics?
  - What action should the Commission take on reporting the Company's Workforce Transition Plan in docket no. E002/M-22-265 rather than the instant docket?
  - How should the Commission evaluate the metrics that do not yet have three years of baseline data?
  - Are there other issues or concerns related to this matter?

B. RESPONSES TO COMMISSION QUESTIONS

1. *Should the Commission accept Xcel's 2021 and 2022 PBR Annual Reports? Do Xcel's reports address the requirements set forth by Commission Orders in this docket, including but not limited to:*
   a. *Future metrics?*
   b. *Development of an online utility performance dashboard?*
   c. *Data collection on and/or reductions in upstream methane emissions?*

The Department recommends the Commission accept the Company's 2021 and 2022 PBR Annual Reports. Xcel identified two future metrics in its 2022 PBR Report – Momentary Average Interruption Frequency Index (MAIFI) and Power Quality. The Company explains the reporting of these two performance metrics will be delayed due to the installation of its Advanced Meter Infrastructure (AMI). The Company estimates this installation will be completed in 2025, begin tracking in 2026, and reporting in 2027. The Department has not identified any future metrics it believes should be added to Xcel's existing list of 33 metrics.

Regarding the development of an online utility dashboard, Xcel noted in its 2021 PBR Report that it organized two stakeholder meetings on this topic in March 2021 and February 2022 consistent with the Commission's direction. The Company included a proposed scorecard in its 2020 PBR Report which identified five performance metrics and provided five years of historical data.[1] The stakeholder group recommended waiting until the Xcel had reported three years of information for the different performance metrics before deciding which of those performance metrics should be included in the online utility performance dashboard. The stakeholder group also referenced the need to determine the costs associated with the online dashboard and that a stationary image updated annually and hosted on Xcel Energy's website was recommended.

After reviewing the information included in the Company's 2021 and 2022 PBR Reports, the Department now supports the Commission proceeding with the development of an online dashboard with a stationary image updated annually. The Department also recommends the Commission adopt four of the five performance metrics Xcel identified in its 2021 PBR Report. The metric the Department recommends be removed is customer complaints. While this metric is an important indicator of service quality, the Department doesn't believe the historical comparison to Xcel-only information is as useful to an Xcel ratepayer as the annual comparative customer satisfaction information included in the J.D Power benchmarked filed under the Existing Multi-Sector metric under the Customer Service category.[2]

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[1] The five-performance metrics were: a) Average Monthly Bill for Residential Customers; b) System Average Interruption Duration Index (SAIDI); c) Number of Customer Complaints; d) Total carbon emissions by (1) utility-owned facilities and PPAs and (2) all sources and e) Demand response, including (1) capacity available (MW & MWh).
[2] The Department prefers Residential Customer Satisfaction for the title of this metric and will use that designation in these comments.

The third requirement the Commission identified – data collection on and/or reduction in upstream methane emissions is a complex topic. Xcel did a reasonable job of explaining the Company's efforts to meet the Commission's various directives on this issue. For example, Xcel mentioned in its 2022 PBR Report it had begun to provide Northern States Power – Minnesota (NSPM) specific methane emissions in that report in lieu of using an Xcel company-wide average. Additionally, the Company is required to report the annual methane emissions from its distribution system to the United States Environmental Protection Agency (EPA).

Regarding the Commission requirement that Xcel propose a methodology for reporting methane emission, the Company supports reporting a quantitative metric only for methane emissions from Xcel's distribution system. In support of its proposal, the Company noted providing additional information on methane emissions from upstream and midstream operations is outside of the Company's direct control and inconsistent with the Commission's design principles identified in this docket.

The Department has not reviewed the metric design principles the Company referenced for some time. The Commission's ORDER ESTABLISHING PERFORMANCE-INCENTIVE MECHANISM PROCESS, dated January 8, 2019, includes this information. Specifically, Order Point 2-C listed seven metric design principles:

- Tied to a policy goal. A metric should clearly reflect whether the underlying policy goal is being met. That is, it should seek and evaluate data that is specifically tied to the policy goal underlying the metric.
- Clearly defined. The method of calculating the metric should be precise and unambiguous to enable meaningful comparisons and to reduce potential disputes.
- Able to be quantified using reasonably available data. Using already reported data or data that is readily available will reduce administrative burden and the costs associated with implementing the metric.
- Sufficiently objective and free from external influences. Metrics should seek to measure behaviors that are within a utility's control and free from exogenous influences, such as weather or market forces.
- Easily interpreted. Metrics should exclude the effects of factors outside a utility's control so they provide a better understanding of utility performance and should use measurement units that facilitate comparisons across time and utilities (i.e. "per kWh" or "per customer").
- Easily verified. Straight-forward data collection and analysis techniques should be used, and independent third-party evaluators can further ensure accurate verification with respect to performance metrics.
- Should complement and inform evaluation of utility performance. Performance metric systems should be designed to complement – not replace – other parts of a utility's regulatory system such as multi-year rate plans and cost trackers.

The Department assumes Xcel was referring to the fourth bullet point in that determining the amount of upstream methane emissions associated with the natural gas it consumes or sells to its customers is outside the utility's control. Xcel's reference as support for its decision to report only methane emissions from its natural gas distribution network or enterprise-wide suggests this criterion might be the basis for the Company's position. The Department asks the Company to identify the design principles supporting its proposal to use only methane emission from its natural gas distribution network or enterprise-wide in its methodology for calculating methane emissions in its reply comments.

The Commission also identified two additional methane emissions related metrics which involve the reporting of upstream methane emissions. The Commission tasked the Company with these new requirements in its ORDER ACCEPTING REPORT AND SETTING ADDITIONAL REQUIREMENTS issued February 9, 2022, at Order Points 6 and 7.

> Xcel must include in its PBR annual reports information on: availability of data specific to its gas suppliers on upstream methane emissions; regulation of methane emissions upstream of the Company's distribution system, and the Company's position on such regulations; participation in voluntary initiatives to quantify and reduce methane from gas suppliers; any certified gas purchases; pilots with gas marketers to track and source gas with lower associated methane emissions; and any other actions the Company has taken to secure data on and/or reduce upstream methane emissions. No later than 2024, the Company will re-evaluate data available on upstream methane to consider feasibility of reporting methane emissions attributable to total natural gas purchases across the full fuel cycle (from drilling to the end-use).
>
> Xcel must include in its report, once the Commission has determined adequate data on upstream methane is available to support utility-specific reporting of such emissions, methane emissions across the full fuel cycle in its calculation of greenhouse gas emissions avoided by electrification of buildings, agriculture, and other sectors.

Xcel did provide a detailed discussion of the topics included in Order Point 6 in its 2022 PBR Report on pages 18 to 21. Regarding the requirements included in Order Point 7, the Company concluded: "adequate data on upstream methane is not available to support utility-specific reporting".[3]

The Department, after reviewing the information the Company provided, concluded it had made a reasonable effort to comply with the requirements in Order Pt. 6. We also concluded Xcel's statement regarding the availability of adequate data on upstream methane is also reasonable.

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[3] 2022 PBR Report at p. 21-22.

As a result, the Department did calculate a baseline for the first methane metric using the Company's proposed local distribution company only approach. The Department did not calculate or identify a target for that metric due to the lack of similar information from other natural gas local distribution companies. If such information was available on a nationwide scale, an annual target for this metric could be developed. The Department requests the Company discuss the availability of data from other gas LDCs in its reply comments. Regarding the upstream and full fuel cycle methane metrics, the Department didn't calculate either baselines or targets due to a lack of data.

The Department does have a concern regarding the Company 2024 requirement to re-evaluate data available on upstream emissions and the feasibility of reporting those emissions across the entire fuel cycle. The "Inflation Reduction Act of 2022" (IRA) imposes a direct "charge" on methane emissions from natural gas wells gathering facilities and pipelines. This emissions charge begins at $900 per metric ton in 2024 and increases to $1,500 per metric ton in 2026.[4]

This development appears to complicate the calculation of utility-specific upstream methane emissions in that it is the equivalent of a carbon tax, imposed on methane emissions from a subset of oil and natural gas producers. While the Department is agnostic regarding the imposition of a methane emissions' fee or carbon tax from a public policy perspective, the potential imposition of the fee invalidates one of the basic assumptions regarding the development of the social cost of methane which is then used to determine the cost of upstream methane emissions throughout the full fuel cycle. That assumption is the emission of an incremental metric ton of methane by a well operator or processing facility or pipeline is a cost caused by a producer that is not financially incurred by that same producer. If a processing facility is paying $900 per metric ton for each ton of methane the EPA estimates that it emits as is required by the IRA, then that processing facility is incurring a cost associated with the production of methane and it will likely be included the cost of the methane or natural gas that same processing facility sells to upstream transporters and consumers. This outcome would violate the assumption that producers or transporters are not incurring the costs associated with the incremental methane emissions and by extension, would invalidate the concept of methane imposing environmental costs on society.

Fortunately, this is an issue that will only affect upstream natural gas providers. Thus, the Department requests Xcel incorporate a discussion of how the proposed methane emission fee can be reconciled with the calculation of upstream emissions of methane on a utility-specific basis in the Company's 2024 reporting requirement re-evaluating the data available on upstream emissions and the feasibility of reporting those emissions across the entire fuel cycle.

[4] Attachment I contains an article authorized by the Congressional Research Service dated August 29, 2022.

2. *From the three years of data that have been filed for each metric, how should a single baseline value be calculated? Please explain your reasoning and provide calculations of the baseline for each metric.*

The Department decided to use a conservative approach to developing the baselines for metrics which had pre-existing baselines or targets, rather than calculating a baseline that simply relied on three-years of data. The first step in the process involved determining whether the metric had more than three years of historical data. The Department identified nine metrics that met that criterion. Attachment A lists those metrics.

Three of those metrics had historical data, but the Commission had adopted an approach which used annual benchmarking information from the Institute of Electric and Electronic Engineers (IEEE) as the baselines for the past three years.[5] The Department included that information as baselines in its comments.

In addition, the Department reviewed the Company's Quality Service Plan (QSP) tariff. The QSP included targets for eight (8) metrics, including targets for two of the three metrics covered by the IEEE Benchmarking approach. The QSP tariff also contains disincentives for not meeting the targets identified. Thus, the QSP represents a pre-existing attempt at a performance improvement program. As such, the Department believes the QSP tariff should be modified or terminated to ensure that metrics included in this proceeding and the QSP do not have more than one baseline or target.[6]

The ninth (9) and final metric the Department identified being pre-existing and have historical information was the demand response metric, which includes capacity available, and amount called, on a MW and MWh basis. Xcel has been reporting this metric for around twenty (20) years. The Department concluded that the Commission had set a target for that metric in the Company's 2015 Integrated Resource Planning (IRP) proceeding and calculated a baseline associated with that metric. Attachment A also lists the baselines or relevant historical information regarding targets associated with those nine metrics.

In the subsequent step, the Department identified thirteen (13) metrics that had three or more years of historical data but did not have existing baselines or targets. Attachment B lists those thirteen metrics.

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[5] System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI) and Customer Average Interruption Duration Index (CAIDI).
[6] SAIDI, SAIFI and CAIDI currently have two annual targets, one from the SRSQ and one included in the QSP.

The Department used a three-year average approach to calculate baselines for seven of those metrics, several of which included multiple sub-metrics.[7] We used the three-year average approach given past discussion in this proceeding. The Department also calculated baselines for two metrics which had more than three years of data - total disconnections for nonpayment by residential customers and total arrearages by nonpayment for residential customers. The Department used a five-year average for these two metrics. Our proposed benchmark calculation excluded 2020 and 2021 because COVID-19 related policies significantly affected those two metrics.

The determination of baselines for the four (4) remaining metrics did not lend themselves to the use of a three-year average baseline due to the metrics different characteristics. Defining a baseline for the Average System Availability Index (ASAI) was perhaps the simplest of exercise of the four. The calculation for ASAI is based on SAIDI information.[8] Hence, the Department did not calculate a baseline for ASAI, rather we recommend the Commission request Xcel to convert IEEE SAIDI information to determine the baseline for ASAI and then adopt the same target as it currently has for SAIDI.

The residential customer satisfaction metric, also referred to as the existing multi-sector metrics, includes information from two organizations, the American Customer Satisfaction Index (ACSI) and J.D. Power. The publicly available ACSI information is very limited. Historically the Company hasn't subscribed to this service. Xcel would incur an incremental cost were it to subscribe to that service. Aside from that requirement, the Department notes the customer experience benchmarks listed on ACSI's website don't appear to be as understandable as the categories of information J.D Power provides.[9] The Department recommends the Commission drop the ACSI information from this metric. The J.D. Power information is presented in a manner somewhat analogous to the IEEE Benchmarking data. Information from multiple similarly situated electric utilities is pooled annually and then a percentile ranking is developed. Xcel's individual annual scores by sector and in total are ranked on a percentile basis for the year. The Department recommends that the fiftieth (50%) percentile be identified as the baseline for this metric. This is metric that can significantly vary year to year, so the Department believes the 50th percentile is a reasonable baseline. Given Xcel's history of above average service reliability and service quality over the past few years, setting a baseline for this metric of being in the top half of the utilities participating appears to be an adequate initial baseline.

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[7] Total carbon emissions by utility-owned and all sources, Carbon intensity by utility owned and all sources, Total criteria pollutants, Criteria pollutant emissions intensity, CO2 emissions avoided – transportation, Discussion of methane emissions – methodology for reporting, and Amount of demand response that SHEDS load.

[8] ASAI = 1 – (SAIDI/8760).

[9] ASCI's benchmarks include: 1) Ability to provide electric service; 2) Quality of mobile app; 3) Reliability of mobile app; 4) Ability to restore electric service after an outage; 5) Website satisfaction; 6) Ease of understanding your bill; 7) Courtesy and helpfulness of staff or representatives; 8) Information provided on energy-saving-ideas; 9) Efforts to support local community; 10) Efforts to support green programs that impact the environment; and 11) Satisfaction. J.D. Power lists: 1) Overall satisfaction; 2) Power quality and reliability; 3) Price; 4) Billing and payment; 4) Corporate citizenship, 5) Communications and 6) Customer care.

The remaining two metrics in this category are related to affordability: a) Rates per KWh on total revenue, reported: (1) by customer class and (2) with all classes aggregated, and b) Average monthly bill for residential customers. Both these metrics would both benefit from a metric that provides an annual comparison with a comparable group of similarly situated electric utilities. The Department's limited review of existing sources for the rates information only identified the United States Department of Energy, Energy Information Agency (EIA) as a source for this information. The EIA does provide information at the national, regional, and state-wide levels. Thus, the Department recommends the Commission use the comparison of annual EIA date at a national level as the baseline for this metric. The Department also notes the EIA information will need to be modified to be comparable to the rate information described in the metric. The Department asks the Company to discuss the potential for this adjustment in its reply comments. Regarding the average monthly residential bill metric, the Department proposes to set annual benchmark for that metric as being the product of the EIA national residential rate multiplied by the average number of kilowatt hours an Xcel residential ratepayer in Minnesota consumes. This approach will remove any variation in the bill due to differences in quantity.

In total the Department identified or calculated baselines for the twenty-two metrics listed in Attachments A and B. In Attachment E, the Department also provides a summary of the baselines/benchmarks for the thirty-three metrics the Commission identified in its Notice.

3. *For which metrics, if any, should the Commission set targets and why?*

The Department recommends the Commission adopt targets for the metrics that have pre-existing targets or a target that relies on information used for pre-existing targets. These include: 1) the current targets for SAIFI, SAIDI and CAIDI discussed that require second quartile performance by work-center and the QSP targets for SAIFI and SAIDI. 2) the existing targets for CELID and CEMI in the QSP; 3) a target for the Average System Availability Index (ASAI) metric that is consistent with the pre-existing SAIDI target; and 3) the non-reliability-related electric-related metrics with targets included in the Company QSP tariff: a) call center response time; b) billing invoice accuracy; and c) number of customer complaints.

The Department also recommends the Commission set initial targets for four of the seven emissions-related metrics for which it calculated baselines.[10] The targets for those four metrics should be the annual value for the metric taken from the Company's most recent Integrated Resource Plan (IRP) for the concurrent year. To the Department's knowledge, this comparison would be consistent and informative.

[10] Total carbon emissions by utility-owned and all sources, Carbon intensity by utility owned and all sources, Total criteria pollutants, and Criteria pollutant emissions intensity.

In addition, the Department suggests the Commission set the targets for the Rates per KWh and Average monthly residential bill at five percent below the baseline amounts for those two metrics. The Department references Minn. Stat. 216C.05, Subd 2 (4) as basis for the selection of this target. The statute states: "It is the energy policy of the state of Minnesota that retail electricity rates for each customer class be at least five percent below the national average." While the Department recognizes this reference is to an energy policy goal, we still consider it a reasonable target for these metrics.

The Department recognizes that its interpretation of the Commission's determining a 2023 target for the Company's demand response metric may not be consistent with the Commission's intent as envisioned in the Commission's Order in Xcel's 2015 IRP. A similar rationale could be applied to the targets identified for the rates per KWh by classes and the Average monthly residential bill targets. Thus, the Department will not recommend the Commission adopt those three targets, but rather suggest the Commission adopt them.

Procedurally, it would be preferable to clarify the status of the metrics and targets included in the QSP rather than simply calculating new baselines and/or targets. It would also likely improve the administrative efficiency of the reporting process for these metrics. Attachment A lists the seven metrics included in this category.[11]

4. *Where applicable, by what methodology should targets be set? How often should targets be reviewed and potentially updated?*

The Department didn't identify a consistent methodology for setting initial targets for metrics not having existing targets or targets for which existing information was readily available. If another party participating in this proceeding does identify a consistent methodology, the Department will review it and provide a response in our reply comments.

As to the question of how often targets should be reviewed and potentially updated, the Department suggests the Commission delay this discussion until the discussion related to possible incentives or disincentives occurs. The timing of that review process will likely be correlated with the existence and level of any incentives or disincentives associated with the PBR.

5. *Where applicable, what are the appropriate targets for the metrics?*

The Department identified or discussed targets for seventeen (17) metrics. Attachment F contains the list of metrics, the proposed targets, and the basis for those targets. The Department considers the targets (and disincentives) included in the QSP tariff to be appropriate until such time the Commission determines how it would like to proceed procedurally with that tariff. The Department notes the Commission may want to ask Xcel to provide a proposal for the future of the QSP tariff and how the Commission might incorporate the targets for the metrics identified in that tariff in its 2024 Annual PBR filing.

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[11] SAIDI, SAIFI, CELID, CEMI, Call center response time, Billing invoice accuracy, and Number of customer complaints

6. *What action should the Commission take on reporting the Company's Workforce Transition Plan in docket no. E002/M-22-265 rather than the instant docket?*

The Department recommends the Commission transfer the Workforce Transition Plan metric to a separate docket (Docket No. E002/M-22-265). While this is an important topic, it doesn't affect most of Xcel's customers and may not appropriate for inclusion in the PBR.

7. *How should the Commission evaluate the metrics that do not yet have three years of baseline data?*

A response to this question would not provide a complete reconciliation of the 33 metrics the Commission identified in the Notice. For clarity, the Department prefers to provide a response which will summarize the 15 metrics that remain to be discussed after subtracting the 17 metrics that have proposed baselines and targets, and the Workforce Transition Metric which we support moving to a separate docket.

- Total disconnections by nonpayment by residential customers and total arrearages by nonpayment for residential customers are two metrics which were significantly affected by policies enacted during the COVID-19 pandemic. The Department proposed a calculation that attempted to adjust the annual baselines to account for those effects. The Department defers to the Commission regarding whether the Company should initiate actions to bring those metrics back into line with historical amounts and the timeline related to that decision. This action could potentially set targets for these two metrics.

- MAIFI and Power Quality are two reliability-related metrics for which the collection of system-wide data will not be possible until Xcel completes the installation of its AMI system.

- Transportation – carbon dioxide avoided emissions is a metric that contains seven sub-metrics. The Department did calculate baselines for those seven sub-metrics using 2 or 3 years of data. Given the uncertainty regarding the applicability of federal tax credits for the purchase of electric vehicles and Xcel's recent changes to its EV charging program, the Department did not attempt to develop targets for the seven sub-metrics.

- Buildings, agriculture and other – avoided carbon dioxide emissions is a second CO2-related metric which lacks a methodology as well as data. Hence, the Department did not calculate a baseline or a target for this metric.

- Methane emissions - there are three metrics related to this topic: 1) Discussion of methodology for reporting; 2) Status and Company actions on reporting upstream methane emissions and 3) Information on methane emissions from across the full fuel cycle. The Department did calculate a baseline for the first metric listed using Xcel-specific information and the three-year average approach. We did not calculate a target for this metric due to a lack of data. Relative to the second and third methane-related metrics, the interaction of the methane emissions fee which will be assessed and collected by the EPA on large producers, gathering facilities operators and transporters with the calculation of the social cost of methane is a concern for the Department. Thus, we did not calculate baselines or targets for those two metrics. While the Department recognizes the Commission's desire to quantify the volumes and calculate the costs associated with those upstream emissions as quickly as possible, the Department suggests that the determination of those values may be better suited for a natural gas integrated resource planning proceeding. In support of this suggestion, the Department notes it recommended emissions targets for carbon dioxide and the criteria pollutants based on information provided in the Company's electric IRP.

- Demand response – there are four metrics related to this topic in Attachment G: 1) Amount of demand response that SHAPES load; 2) Amount of demand response that SHIFTS load; 3) Amount of demand response that SHEDS load and 4) Demand response performance incentive.[12] The Department did identify a baseline for the SHEDS metric that was identical to the pre-existing demand response metric's baseline. The Department decided not to calculate a target due to an issue related to a sub-metric that Xcel recommends the Commission re-evaluate. The SHAPES and SHIFTS metrics do not have data to date, so no calculations were performed for baselines or targets. As for the demand response performance incentive, the Department's recommendation is the Commission eliminate this metric. It is the Department's understanding Xcel submitted an incentive proposal with the Commission in Docket No. E002/M-21-101 and that the Commission did not approve the proposed incentive. It appears this concept may have been referred to Conservation Improvement Program (CIP).

- Public – this topic represents more of a deliverable and a summary of other metrics rather than a metric. The Company held stakeholder meetings as required and proposed a public dashboard. In response stakeholders decided to defer the decision as to whether to modify or proceed with Xcel's proposal. The Department now supports the Commission have Xcel initiate the development of an online dashboard with a stationary image updated annually. The Department also recommends the Commission adopt four of the five performance metrics Xcel identified in its 2020 PBR Report. The exception would be the customer complaints metric. The Department considers the J.D Power benchmarked customer satisfaction information to be more valuable to customers in that it provides an annual comparison to the Company's peers rather than an historical Xcel-specific customer complaint metric.

[12] There is also a fifth demand response related metric on the list of 33 metrics – Demand response, capacity available and amount called. The Department did identify an existing target for this metric.

- Evaluation criteria and benchmarks – This metric is more of a process-related metric and doesn't lend itself to baseline/target development. The Company requested the Commission determine an appropriate time to begin next phase of evaluation and benchmarking. The Department interpreted Commission's Notice of Comment as initiating this next phase of the process. That said, the Department doesn't disagree with Xcel's request. If the scope of this metric includes the removal of current metrics from the Commission's list of 33, the Department recommends the removing the Workforce transition plan and Demand response performance incentive.[13]

Attachment G lists the fifteen metrics discussed in this section.

8. *Are there other issues or concerns related to this matter?*

The Department's analysis identified a two-tiered methodology which identifies metrics and targets that are already in use in existing Commission proceedings that are considered sufficiently significant to be elevated to a smaller, more select set of metrics included in the PBR proceeding. The reliability metrics and targets identified in the Company's SRSQ could serve as an example of this approach. Not all the reliability metrics identified in the SRSQ need be included in the PBR, just those considered the most important. The metrics included in the QSP have already been vetted as to their importance, so the Department would be inclined to include them as well. If the Commission believes the pre-existing metrics don't cover all the topics needed, the Department's suggests the Commission base targets on readily available information from recent proceedings. The Department's proposed targets for the four emissions-related metrics referenced earlier are an example of this approach.

The Department also suggests the Commission revisit the search for electric utilities with performance-based regulation proceedings. Six years have passed since this docket was initiated. The National Association of Regulatory Utility Commissions (NARUC) publishes a document titled: "Tracking State Developments of Performance-Based Regulation" on its website. The most recent tracker lists eighteen states and the District of Columbia as having ongoing or completed proceedings on this topic.[14] Parties might benefit from reviewing information related to those efforts in other jurisdictions. The Department performed a cursory review of the NARUC document, and we were struck by the scope of some of the PBR proceedings in the different states. In some states, de-coupling and CIP incentives were included in the PBR discussion. The CIP incentive has been discussed in this proceeding, but not included. De-coupling has not been discussed at any point to the Department's recollection.

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[13] The first metric would be transferred to a separate docket for reporting purposes. The second is being addressed in CIP.
[14] Attachment H includes a copy of this document.

II. ANALYSIS

The Department's analysis is structured as follows:

1. Section A contains our review of the pre-existing metrics and their respective historical benchmarks if applicable.
2. Section B contains our review of metrics that have three or more years of reported data.
3. Section C reviews proposed of proposed metrics that do not have three years of reported data.
4. Section D delineates the Department's process for identifying baselines for pre-existing and proposed metrics.
5. Section E delineates the Department's process for identifying targets for pre-existing and proposed metrics.
6. Section F discusses metrics that don't have targets or fall into other miscellaneous categories.

A. PRE-EXISTING METRICS AND BENCHMARKS

The Department considers the following metrics to be pre-existing in the sense the Commission has historically required this information:

1. Total disconnections for nonpayment for residential customers
2. Total arrearages for residential customers
3. System Average Interruption Duration Index (SAIDI) *total minutes of interruptions, for events that are at least 5 minutes or longer/ total customers*
4. System Average Interruption Frequency Index (SAIFI) *total minutes of interruptions, for events that lasted at least 5 minutes/ total customers*
5. Customer Average Interruption Duration Index (CAIDI) *average time to restore service to customers that have been interrupted for 5 minutes or longer*
6. Customers Experiencing Long Interruption Duration (CELID) *customers experiencing interruptions of 24 hours or more / total customers*
7. Customers Experiencing Multiple Interruptions (CEMI) *customers experiencing more than 5 interruptions that last 5 minutes or more/total customers*
8. Call center response time
9. Billing invoice accuracy
10. Number of customer complaints
11. Demand response, including (1) capacity available (MWh) and (2) amount called (MW, MWH per year)

One third of the metrics identified in this docket are included in this category. Eight of the metrics have one or more identified baselines.[15] One has a Commission approved target. The Department inferred from this target that a baseline should also exist and calculated one. Two metrics have historical data but

[15] See Attachment A to these comments.

don't have baselines or targets.[16] The Department has included those two in the subsequent section since they have three or more years of data but no explicit baselines or targets.

The Department separated the nine pre-existing performance metrics with baselines into four different sub-categories consistent with the categories the Commission has used previously.

1. Affordability
    a. Total disconnections for nonpayment for residential customers
    b. Total arrearages for residential customers

2. Reliability
    a. SAIDI
    b. SAIFI
    c. CAIDI
    d. CELID
    e. CEMI
3. Customer Service
    a. Call center response time
    b. Billing invoice accuracy
    c. Number of customer complaints
4. Alignment of Generation and Load
    a. Demand response, including (1) capacity available (MWh) and (2) amount called (MW, MWH per year)

Subsequently the Department reviewed various reliability and service quality related Minnesota Rules to see if they were applicable to any of these pre-existing performance metrics. We completed the same exercise relative to Xcel's Quality of Service Program (QSP) tariff developed in Docket No. E,G002/CI-02-2034 and then refined in Docket No. E,G002/M-12-383, as well as relevant Commission Orders. Nine metrics were included in this category.

Seven of the nine pre-existing metrics in Attachment A are included in the QSP tariff and have proposed targets and existing disincentives associated with them.[17] During the Commission's review of parties' comments regarding Xcel's Locational Reliability map and associated topics in this docket on May 11, 2023, Commissioner Tuma expressed support for the idea of phasing out the QSP tariff in favor of performance metrics and related incentives/disincentives in this proceeding. Hence, the Department incorporated this perspective in our discussion of these pre-existing performance metrics.

The Department then calculated a baseline for the demand response metric given a Commission ordered 2023 target of 400 MW of additional demand response.

[16] Total disconnections by nonpayment for residential customers and Total residential arrearages are the two metrics identified are the affordability-related metrics.
[17] These include: 1) SAIDI; 2) SAIFI; 3) CAIDI, 4) CELID; 5) CEMI; 6) Call center response time; 7) Billing invoice accuracy; and 8) Number of customer complaints.

B. PERFORMANCE METRICS IDENTIFIED IN THIS PROCEEDING WITH THREE YEARS 0R MORE YEARS OF DATA

The Department identified the following thirteen performance metrics as meeting the criterion of having three or more years of data or of reporting.

1. Affordability
    a. Rates per KWh on total revenue, reported: (1) by customer class and (2) with all classes aggregated
    b. Average monthly bills for residential customers
    c. Total disconnections by nonpayment for residential customers
    d. Total arrearages for residential customers
2. Reliability
    a. ASAI
3. Customer Service Quality
    a. Residential customer satisfaction
4. Environmental Performance
    a. Total carbon emissions by: (1) utility-owned facilities and PPAs and (2) all sources
    b. Carbon intensity (emissions per MWh) by (1) utility-owned facilities and PPAs and (2) all sources
    c. Total criteria pollutant emissions
    d. Criteria pollutant emissions intensity (criteria pollutant emissions per MWh)
    e. Carbon dioxide emissions avoided by electrification of transportation – Alternative & Original approach
        i. Percent of electric vehicles in Xcel Energy's Minnesota service territory participating in managed charging programs or on whole house rates
        ii. Percent of managed charging customers residential electric vehicle charging load occurring during off-peak hours
        iii. Carbon dioxide avoidance calculated from electric vehicle charging.
    f. Discussion of methane emissions, including proposed methodology for reporting
5. Cost Effective Alignment of Generation and Load
    a. Amount of demand response that SHEDS loads that can be curtailed to provide peak capacity and supports the system in contingency events:
        i. For available load
        ii. For actual load reduction
        iii. Metrics that measure the effectiveness and success of (a&b) individually and in aggregate

Attachment B includes this list as well as the methodology for calculating a baseline, a baseline and where available, the Department's recommended or suggested targets.

C. PROPOSED PERFORMANCE METRICS IDENTIFIED IN THIS PROCEEDING WITH LESS THAN THREE YEARS OF DATA

The Department identified eleven (11) metrics as meeting the criterion of having three years of data or of reporting.

1. Reliability
    a. Momentary Average Interruption Frequency Index (MAIFI)
    b. Power quality
2. Environmental Performance
    a. Carbon dioxide emissions avoided – buildings, agriculture, and other sectors.
    b. Availability of data specific to is gas suppliers on upstream methane emissions; regulation of methane emissions upstream of the Company's distribution system, and the Company's position on such regulations; participation in voluntary initiatives to quantify and reduce methane from gas suppliers; any certified gas purchases; pilots with gas marketers to track and source gas with lower associated methane emissions; and any other actions the Company has taken to secure data on and/or reduce upstream methane emissions. No later than 2024, the Company will re-evaluate data available on upstream methane to consider feasibility of reporting of methane emissions attributable to total natural gas purchases across the full fuel cycle (from drilling and extraction to the end-use).
    c. Methane emissions across the full fuel cycle in its calculation of greenhouse gas emissions avoided by electrification of buildings, agriculture, and other sectors.
3. Cost Effective Alignment of Generation and Load
    a. Amount of demand response that SHAPES customer load profiles through price response, time varying rates, or behavior campaigns
    b. Amount of demand response that SHIFTS energy consumption from times of high demand to times where there is a surplus of renewable generation
4. Workforce and Community Development
    a. Workforce Transition Plan
5. Other Stakeholder Discussions
    a. Public Dashboard
    b. Demand Response Performance Incentive
    c. Evaluation Criteria and Benchmarks

Attachment C provides summary information regarding historical information and additional notes on these metrics.

D. DEVELOPING BENCHMARKS FOR EXISTING, PROPOSED METRICS

1. Proposed Benchmarks

The Department parsed the thirty-three metrics identified in Xcel filing into three classifications: 1) pre-existing metrics; 2) metrics with three-years of data; and 3) future metrics or metrics that have less than three-years of data. If one of the pre-existing metrics already has a baseline or benchmark that is included in Minnesota Rule, Xcel's electric tariff or an existing Commission order, then the Department recommends the Commission simply transfer this pre-existing benchmark to this proceeding.[18]

a. *Pre-Existing Metrics*

The Department included nine (9) metrics in the classification contained in Attachment A. Of those pre-existing metrics, the Department identified eight (8) metrics that have what the Department would consider a pre-existing a baseline and one metric that has a pre-existing target which the Department believes infers the existence of a baseline as noted previously. Table 1 summarizes that information.

Table 1 – Pre-existing Metrics with Baselines – All Metrics Evaluated on an Annual Basis (yr.)[19]

Line No.	Description	Baseline Source	Baseline Value	Baseline Calculation
1.	System Average Interruption Duration Index (SAIDI)	Minn. R. 7826.05 Commission Order and Quality of Service Tariff	Institute of Electrical and Electronic Engineers (IEEE) Annual Benchmark data	Calculated by IEEE using data collected from multiple electric utilities
2.	System Average Interruption Frequency Index (SAIFI)	Minn. R. 7826.05 Commission Order and Quality of Service Tariff	IEEE Annual Benchmark data	Calculated by IEEE using data collected from multiple electric utilities
3.	Customer Average Interruption Duration Index (CAIDI)	Minn. R. 7826.05 Commission Order and Quality of Service Tariff	IEEE Annual Benchmark data	Calculated by IEEE using data collected from multiple electric utilities
4.	Customers Experiencing Long Interruption Duration (CELID)	Commission Orders	CELID 4, 5 and 6	Calculations provided in Xcel's annual Service Quality and Service Reliability (SQSR) Report and Quality of Service (QSP) compliance filing
5.	Customers Experiencing Multiple Interruptions (CEMI)	Commission Orders	CEMI 4, 5 and 6	Calculations provided in Xcel's annual SQSR Report and QSP compliance filing
6.	Call Center Response Time	Minnesota Rules 7826.1200, subp. 2 and 7826.1700	Greater than 80% of calls answered within 20 seconds	Calculation provided in Xcel's annual Service Quality and Service Reliability Report
7.	Billing Invoice Accuracy	Commission Order	Greater than 99.3% accurate	Calculation provided in Xcel's QSP tariff compliance filing
8.	Number of Complaints	Minnesota Rules 7826.2000 and QSP tariff	Number of customer complaints less than 0.2059 complaints per 1,000 customers	Calculation provided in Xcel's QSP tariff compliance filing
9.	Demand response, capacity available and amount called	Docket Nos. E002/M-01-1024, E002/M-02-421 and E002/RP-15-21	Capacity Available – 764 MW, Amount Callable – 156,189 MWh, Amount Called – 557 MWh	2022 reported program information

[18] Attachment A summarizes this performance metrics included in this classification.
[19] Table 1 equates baseline values for QSP metrics with target values.

The Department suggests this approach of adopting existing or implied baselines for these nine metrics due to its administrative efficiency.

Regarding the two (2) pre-existing metrics that do not include benchmarks the Department notes:

i. <u>Total disconnections for nonpayment for residential customers</u> – This information is required by Minn. R. 7820.1500 to be filed in the Company's annual SQSR report. Hence, there is a lengthy historical record for this metric. In the Department's comments in Xcel's 2023 SQSR report we noted that this metric had been significantly affected by COVID-19 policies that suspended disconnections for a lengthy period. Given this external shock to this metric, the Department recommends using a 5-year average as the baseline for this metric. The five years included would be 2016 through 2019 and 2022. The 2016 through 2019 time represents Xcel's normal business pre-pandemic. The inclusion of 2022 recognizes this was the first full year after the pandemic during which Xcel was allowed to disconnection residential customers for the entire calendar year. The calculation of this baseline value is included in Attachment D.

ii. <u>Total arrearages for residential customers</u> – This information is included in Cold Weather Rule (CWR) compliance reports filed with the Commission. Like residential disconnections, there is a lengthy historical record for this metric. Like the residential disconnection metric, the Department assumes the annual results for this metric for 2020 and 2021 were affected by the policies associated with the COVID-19 pandemic and that the baseline for this metric should be calculated using the same approach as the one used for residential disconnections. The calculation of this baseline value is included in Attachment D.

b. *New Metrics with 3 Years or More of Data*

The Department identified thirteen (13) metrics which have three or more years of data. The two metrics discussed in the previous section – Total disconnections for non-payment for residential customers and Total arrearages for residential customers are included in this list as well. Six of the remaining eleven concern environmental metrics. Table 2 summarizes those 6 metrics and potential baselines.

Table 2 – Environmental Metrics with Three Years or More of Baseline Data

Line No.	Description	Baseline Calculation Methodology	Baselines	Notes
1.	Total carbon emissions by utility-owned and all sources	Three-year average	13,017,670 and 13,083,564	See Attachment D for calculation
2.	Carbon intensity by utility owned and all sources	Three-year average	636 and 638	See Attachment D for calculation
3.	Total criteria pollutants	Three-year average	NOx – 6,723, SO2 – 3,532, PM – 502, Mercury – 0.0396, Lead – 0.0577	See Attachment D for calculation
4.	Criteria pollutant emissions intensity	Three-year average	NOx – 0.44, SO2 – 0.23, PM – 0.033, Mercury – 0.000003, Lead – 0.000004	See Attachment D for calculation
5.	CO2 emissions avoided – transportation	Two or three-year average	Seven sub-metrics with lengthy descriptions – see Attachment D	See Attachment D for calculation
6.	Discussion of methane emissions – methodology for reporting	Local distribution company only	Gas distribution system – 0.116%, Enterprise wide – 0.151%	See Attachment D for calculation

The Department elected to use available data and the simplest calculation available for the determining proposed baselines for these six metrics. The first four of these metrics are straight-forward environmental performance measures. We don't see a need to complicate the development of those baselines. However, if another intervenor has developed a different methodology which the Department determines preferable, the Department will support that approach in reply comments.

The metric related to avoided carbon dioxide emissions require more complicated calculations and a significant number of assumptions. Given this complexity, the Department prefers to keep the baseline calculation as simple as possible so as not to introduce further complications or confusion.

The methane emissions methodology metric can either be a straightforward calculation, assuming one restricts the scope of the calculation to the local distribution company, or it can become a very complicated, if the scope is expanded to the entire fuel cycle. Given the concerns the Department discussion relative to the proposed methane emissions fee that is scheduled to be implemented by the EPA in 2024, the Department recommends the Commission limit the scope of this metric to the methane emissions Xcel can directly control, those being the emissions associated with the local distribution company.

The Department does support the concept of expanding the scope of the determination of methane emissions to the full fuel cycle at some point in the future. That approach would be consistent with the Commission's current approach for estimating the environmental costs associated with other emissions-related pollutants if those upstream methane emissions are not subject to the equivalent of a carbon tax.

Regarding the five (5) additional metrics with three or more years of data the Department notes:

i. Rates per KWh on total revenue by class and in aggregate – Minn. Stat. 216C.05, Subd 2 (4) states: "It is the energy policy of the state of Minnesota that retail electricity rates for each customer class be at least five percent below the national average." While the Department recognizes this reference is to an energy policy goal, we still consider it a reasonable target for this metric. This same language identifies a baseline - the national average retail electricity rate by class. The Department's limited review of existing sources for the rates information only identified the United States Department of Energy, Energy Information Agency (EIA) as a source for this information. The EIA does provide information at the national level. Thus, the Department recommends the Commission use the comparison of the annual EIA rates by class at a national level as the baseline for this metric. The Department did not review the EIA's protocol for calculating these figures and recognizes it is likely the EIA information will need to be adjusted to develop a baseline that is consistent with the Commission-approved approach for calculating the baseline rate per kilowatt hour in this proceeding.[20] In addition, the EIA information is not provided promptly. The most current information is from 2021. Attachment D includes an example calculation that compares Xcel and EIA National rates using the 2021 information. The Department requests that Xcel provide its feedback regarding this proposed baseline in its reply comments.

ii. Average monthly bill for residential customers - The Department supports a similar approach to that proposed for the rates per KWh metric for calculating a baseline for this metric. Specifically, the Department proposes to set annual the baseline for that metric as being the product of the EIA national residential rate multiplied by the average number of kilowatt hours an Xcel residential ratepayer in Minnesota

[20] One noticeable difference is EIA calculates a rate for the transportation class. Xcel doesn't.

consumes.[21] Attachment D includes an example of this calculation. The Department requests that Xcel provide its feedback regarding this proposed baseline in its reply comments.

iii. Average Service Availability Index (ASAI) –As the Commission noted in its ORDER ESTABLISHING PERFORMANCE METRICS issued on September 18, 2019, at page 5 in footnote 15, this reliability metric was not reported prior this proceeding, but the calculation is derived from SAIDI which has been reported by the Company for several years. Given this potential lengthy historical record, the Department recommends the Commission order Xcel to calculate this reliability metric annually using the IEEE SAIDI benchmark to derive the annual baseline in future years.

iv. Residential customer satisfaction – This is a metric which the Company has been tracking via an agreement with J.D. Power even before the Commission initiated this proceeding. Xcel has been reporting this information for both the residential and small commercial classes in its annual SRSQ Report since at least 2016. The Department views the information provided by J.D. Power as equivalent to a benchmarking exercise in which Xcel compares itself to similarly situated electric utilities like that performed by the IEEE Distribution Working Resource Group for reliability metrics. Thus, the Department is inclined to accept the J.D Power information as adequate for an input for providing a baseline for this metric. The Department has identified the 50th percentile as an appropriate baseline for this metric as a starting point and recommends the Commission adopt this approach.

v. Amount of demand response that sheds load – This is another proposed metric that contains multiple sub-metrics. The results for the first two sub-metrics appear to be consistent with the information provided in response to the long-standing Demand response metric. The development of a baseline for those sub-metrics would likely be like the one developed for the Demand response metric. The calculation of the third sub-metric, "Load factor for load net of variable renewable generation" is the calculation the Commission accepted in its September 18, 2019, Order. The annual results for this metric have been declining since 2019 going from 52.05% in 2019 to 40.50% in 2022. Those results suggest Xcel's performance relative to this metric is declining. According to the Company, the reason for this decline is: "the rapid adoption of

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[21] This approach will remove any variation in the bill due to differences in quantity.

variable renewable generation. This adoption has greatly reduced the amount of energy in the load net of variable renewable generation. To produce a reduction in load factor, this requires a dramatic reduction in peak load that may be beyond the potential of demand response."[22] The Company also suggests in the filing that the Commission may want to re-evaluate this metric given the changes in Xcel's system since 2019. The Department agrees with Xcel that a re-evaluation of this metric is a warranted and will not develop or recommend a baseline for this metric at this time.

c. New Metrics with Less Than Three Years of Historical Data

The Department identified eleven metrics which have less than three years of data. Attachment C lists those metrics, and the data that has been collected to date (if any) and the Department's notes on the different metrics.

A summary of Attachment C suggests the process of development of data for those metrics is not complete or may not be applicable. Thus, the Department has not calculated proposed baselines or targets for any of those eleven metrics.

Attachment E summarizes the different benchmarks or other reporting requirements or administrative changes the Department recommends regarding the thirty-three metrics identified.

E. *DEVELOPING TARGETS FOR EXISTING OR PROPOSED METRICS*

1. Targets for Existing Metrics

The Department's approach was to identify metrics which we classify as having existing targets. We identified nine metrics in this category. The Department's rationale for not proposing new targets for these existing metrics was administrative efficiency. The Commission approved the targets for those metrics in three different proceedings, each with its own set of facts. The Department's goal for this stage of the process was simply to define a reasonable population of metrics and targets for those metrics.

[22] Filing at page 11.

Table 4-a – Existing and Proposed Targets for Commission-Approved Metrics

Line No.	Metric	Existing Target(s)	Proposed Target(s)	Notes
1.	SAIDI	IEEE Second quartile performance for large utilities for Statewide, East and West Metro work centers, second quartile performance for medium utilities for Northwest and Southeast work centers and less than 133.23 minutes with disincentive of $1.0 million annually for exceeding target	Same as existing targets	Targets originated in Annual Service Quality Report and QSP tariff
2.	SAIFI	IEEE target is identical to #1 and less than or equal to 1.21 outage events with disincentive of $1.0 million annually for exceeding target	Same as existing targets	Same as #1
3.	CAIDI	IEEE target is identical to #1. No QSP target.	Same as existing target	Targets originated in Annual Service Quality Report
4.	CELID	For each interruption lasting more than 24 hours, customer receives $50 credit,*	Same as existing target	QSP tariff - $1.0 million total credits available for CELID and CEMI
5.	CEMI	If customer experiences:* • six or more interruptions per year, customer receives $50 credit; • five or more interruptions in consecutive years customer receives $75 credit; • four or more interruptions in third consecutive year customer receives $100 credit • four or more interruptions for four or more consecutive years, customer receives $125 credit	Same as existing targets	Same as #4
6.	Call Center Response Time	Eighty (80) percent of calls answered within 20 seconds with $1.0 million disincentive for failing to meet target	Same as existing target	QSP tariff
7.	Billing Accuracy	Ninety-nine-point 3 (99.3) percent correctly billed invoices with $1.0 million disincentive for failing to meet target	Same	QSP tariff
8.	Number of Customer Complaints	Number of complaints submitted to CAO exceeds 0.2059 complaints per 1,000 customers $1.0 million disincentive for failing to meet target	Same as existing target	QSP tariff
9.	Demand Response, Capacity Available and Amount Called	Additional 400 MW of Demand response by 2023	Same as existing target	Commission Order in Docket No. E002/RP-15-21**

*Also includes credits for municipal pumping customers which Department did not include for brevity.
** See Commission ORDER APPROVING PLAN WITH MODIFICATIONS AND ESTABLISHING REQUIREMENTS FOR FUTURE RESOURCE PLAN FILINGS, Order Point 10.

2. Targets for Proposed Metrics with Three or More Years of Data

For metrics with three or more years of data, the Department identified seven proposed targets. We also included the Residential customer satisfaction metric on this list because the Department believes it provides considerable value to customers even without a target. Table 4.b summarizes those metrics and the proposed targets.

The targets for the rate and bill-related metrics were discussed in detail in a previous section. The ASAI target is merely an extension of the SAIFI target discussed previously. The targets for the four environmental metrics are based on emissions information included in the Company's most recent approved IRP. The forecasted annual values calculated in that proceeding appear to be the best estimate available for the amounts and intensity of Xcel's annual emissions.

The Department didn't calculate proposed targets for four (4) of the twelve (12) metrics.[23] Our review and experience in this proceeding suggests some of those metrics may be better reflected or understood within the context of other proceedings. The Department discusses this issue in its response to the last Commission question.

Table 4.b – Proposed Metrics with Calculated Baselines and Proposed Targets

Line No.	Description	Baseline Calculation	Baseline	Target
1.	Rates per KWh on total revenue, reported: (1) by customer class and (2) with all classes aggregated	EIA National rates by customer class for most recent available year - will need to be adjusted to be consistent with Commission's metric	\$0.13660 – res, \$0.11220 – comm \$0.07180 – ind, \$0.10200 – trans \$0.11100 - total	Five percent below these national average rates by class
2.	Average monthly bills for residential customers (\$/month)	EIA National rates by customer class for most recent available year multiplied by the average monthly residential usage for an Xcel residential customer.	\$89.02	Five percent below the baseline amount or \$84.57 for this example
3.	ASAI	Calculate using IEEE SAIFI benchmark data	Equivalent to existing SAIFI baseline	Same target approved for SAIFI in Annual Service Quality Report
4.	Residential Customer Satisfaction	J.D. Power calculates on Xcel's position on a percentile basis	50th percentile	Does not lend itself to a target-based approach
5.	Total carbon emissions by utility-owned and all sources (tons/year)	Three-year average	13,017,670 and 13,083,564	Annual emissions calculated as part of

[23] Those four metrics include: 1) Total disconnections by non-payment by residential customers; 2) Total arrearages by non-payment; 3) CO2 emissions avoided – transportation; and 4) Discussion of methane emissions – methodology for reporting.

				most recently approved IRP
6.	Carbon intensity by utility owned and all sources (lbs./MWh)	Three-year average	636 and 638	Annual emissions calculated as part of most recently approved IRP
7.	Total criteria pollutants (tons/year)	Three-year average	NOx – 6,723, SO2 – 3,532, PM – 502, Mercury – 0.0396, Lead – 0.0577	Annual emissions calculated as part of most recently approved IRP
8.	Criteria pollutant emissions intensity (lbs./MWh)	Three-year average	NOx – 0.44, SO2 – 0.23, PM – 0.033, Mercury – 0.000003, Lead – 0.000004	Annual emissions calculated as part of most recently approved IRP

Attachment F lists the seventeen (17) metrics for which the Department identified existing targets or for which the Department proposes initial targets or aren't necessarily suited for a target due to metric specific issues.

F. EXISTING OR PROPOSED METRICS WITHOUT TARGETS AND OTHER MISCELLANEOUS CATEGORIES

As noted previously, this section discusses metrics that: 1) may or may not have baselines; 2) don't have targets; 3) may no longer be relevant due to legislative or administrative changes in the regulatory environment; or 4) are more procedural in nature.

Attachment G includes fifteen (15) metrics. It assumes the Workforce Transition Plan metric will be moved to a separate docket. The reasons as to why these metrics don't have targets, or in many instances no baselines or even data to calculate baselines or targets vary:

- Total disconnections by nonpayment by residential customers and total arrearages by nonpayment for residential customers are two metrics which were significantly affected by policies enacted during the COVID-19 pandemic. The Department proposed a calculation that attempted to adjust the annual baselines to account for those effects. The Department defers to the Commission regarding whether the Company should initiate actions to bring those metrics back into line with historical amounts and the timeline related to that decision.
- MAIFI and Power Quality are two reliability-related metrics for which the collection of system-wide data will not be possible until Xcel completes the installation of its AMI system.
- Transportation – carbon dioxide avoided emissions is a metric that contains seven sub-metrics. The Department did calculate baselines for those seven sub-metrics using 2 or 3 years of data. Given the uncertainty regarding the applicability of federal tax credits for the purchase of electric vehicles and Xcel's recent changes to its EV charging program, the Department did not attempt to develop targets for the seven sub-metrics.

- Buildings, agriculture and other – avoided carbon dioxide emissions is a second CO2-related metric which lacks a methodology as well as data. Hence, the Department did not calculate a baseline or a target for this metric.
- Methane emissions-there are three metrics related to this topic: 1) Discussion of methodology for reporting; 2) Status and Company actions on reporting upstream methane emissions and 3) Information on methane emissions from across the full fuel cycle. The Department did calculate a baseline for the first metric listed using Xcel-specific information and the three-year average approach. The interaction of the methane emissions fee which will be assessed and collected by the EPA on large producers, gathering facilities operators and transporters with the calculation of the social cost of methane is a concern for the Department. Thus, we did not calculate a target for the methodology metric, or baselines or targets for the remaining two metrics. While the Department recognizes the Commission's desire to quantify the volumes and calculate the costs associated with those upstream emissions as quickly as possible, the Department suggests that the determination of those values may be better suited for a natural gas integrated resource planning proceeding. In support of this suggestion, the Department notes it recommended emissions targets for carbon dioxide and the criteria pollutants based on information provided in the Company's electric IRP.
- Demand response – there are four metrics related to this topic in Attachment G: 1) Amount of demand response that SHAPES load; 2) Amount of demand response that SHIFTS load; 3) Amount of demand response that SHEDS load and 4) Demand response performance incentive.[24] The Department did identify a baseline for the SHEDS metric that was identical to the pre-existing demand response metric's baseline. The SHAPES and SHIFTS metrics do not have data to date, so no calculations were performed for baselines or targets. As for the demand response performance incentive, the Department's recommendation is the Commission eliminate this metric. It is the Department's understanding Xcel submitted an incentive proposal with the Commission in Docket No. E002/M-21-101 and that the Commission did not approve the proposed incentive. It appears this concept may have been referred to Conservation Improvement Program (CIP).
- Public dashboard – this topic represents more of a deliverable and a summary of other metrics rather than a metric. The Company held stakeholder meetings as required and proposed a public dashboard. In response stakeholders decided to defer the decision as to whether to modify or proceed with Xcel's proposal. The Department now supports the Commission have Xcel initiate the development of an online dashboard with a stationary image updated annually. The Department also recommends the Commission adopt four of the five performance metrics Xcel identified in its 2020 PBR Report. The exception would be the customer complaints metric. The Department considers the J.D Power benchmarked customer satisfaction information Xcel to be more valuable to customers in that it provides an annual

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[24] There is also a fifth demand response related metric on the list of 33 metrics – Demand response, capacity available and amount called. The Department did identify an existing target for this metric.

comparison to the Company's peers rather than an historical Xcel-specific customer complaint metric.

- Evaluation criteria and benchmarks – This metric is more of a process-related metric and doesn't lend itself to baseline/target development. The Company requested the Commission determine an appropriate time to begin next phase of evaluation and benchmarking. The Department interpreted Commission's Notice of Comment as initiating this next phase of the process. That said, the Department doesn't disagree with Xcel's request. If the scope of this metric includes the removal of current metrics from the Commission's list of 33, the Department recommends the removing the following metrics, Workforce transition plan and Demand response performance incentive.

III. CONCLUSIONS AND RECOMMENDATIONS

Due to the number of recommendations included in these comments, the Department elected to separate those recommendations into two categories – policy and procedural.

A. POLICY

The Department reviewed information included in Xcel's Annual Service Reliability and Service Quality Reports, its annual QSP tariff filing and certain Commission Orders. Combining that information with data provided in by the Company in its 2021 and 2022 PBR Annual Reports, the Department identified or calculated baselines and targets for 17 of the metrics the Commission listed including: 1) SAIDI; 2) SAIFI; 3) CAIDI; 4) CELID; 5) CELID; 6) Call Center Response Time; 7) Billing Accuracy; 8) Number of Customer Complaints; 9) Demand Response, Capacity Available and Amount Called; 10) Rates per KWh on Total Revenue Reported: (i) by Customer Class and (ii) With All Classes Aggregated; 11) Average Monthly Bills for Residential Customers; 12) ASAI; 13) Total Carbon Emissions by Utility-Owned and All Sources; 14) Carbon Intensity by Utility-Owned and All Sources; 15) Total Criteria Pollutants; 16) Criteria Pollutant Emissions Intensity and 17) Residential Customer Satisfaction.[25] Attachment F includes more information on these seventeen metrics.

The Department recommends the Commission adopt baselines and targets for fourteen of the seventeen metrics. Specific recommendations concerning those metrics include the Commission:

- Adopt the pre-existing baselines and targets for the following eight (8) metrics: 1) SAIDI; 2) SAIFI; 3) CAIDI; 4) CELID; 5) CEMI; 6) Call center response time; 7) Billing invoice accuracy; 8) Number of customer complaints.
- Approve the use of converted IEEE SAIDI information to determine the baseline for ASAI and then adopt the same target as it currently has for SAIDI.

[25] The Residential customer satisfaction metric consists of the J.D. Power information currently via subscription. It was previously named the Existing multi-sector metric.

- Rename the metric currently titled Existing multi-sector metric to Residential customer satisfaction.
- Discontinue the requirement that Xcel provide information from the American Consumer Satisfaction Index for the Residential customer satisfaction metric.
- Adopt the fiftieth (50^{th}) percentile of the J.D. Power annual residential customer survey as the baseline for the Residential customer satisfaction metric.
- Not identify a target for the Residential customer satisfaction metric currently but include it in this category;
- Adopt annual baselines using historical three-year averages and targets from the appropriate analyses included the Company's most recently approved IRP for the four following emissions metrics: 1) Total carbon emissions by utility-owned and all sources; 2) Carbon intensity by utility owned and all sources; 3)Total criteria pollutants, and 4) Criteria pollutant emissions intensity.
- Direct Xcel to work with interested parties to re-evaluate the calculation of the "Load factor for load net of variable renewable generation" sub-metric included in the Amount of demand response that sheds load metric.

The Department considers the rationale that supports the baselines and targets associated with three of those seventeen metrics to be a bit more speculative due to its interpretation of Commission intent or data which is not yet comparable to the information required by the metric. Thus, the Department only suggests the Commission adopt these three metrics and their respective targets.

- Demand response, capacity available and amount called.
- Rates per KWh on total revenue, reported: (1) by customer class and (2) with all classes aggregated.
- Average monthly bills for residential customers ($/month).

The Department did not develop targets for the remaining 16 metrics. Attachment G includes this list of metrics and the Department's rationale for not setting targets for those metrics.

B. PROCEDURAL

The Department recommends the Commission:

- Accept the Company's 2021 and 2022 PBR Annual Reports.
- Approve the development of an online dashboard with a stationary image updated annually public dashboard with the following five performance metrics: a) Average Monthly Bill for Residential Customers; b) System Average Interruption Duration Index (SAIDI); c) Residential Customer Service; d) Total carbon emissions by (1) utility-owned facilities and PPAs and (2) all sources and e) Demand response, including (1) capacity available (MW & MWh).
- Approve the Company's request to move the Workforce Transition Plan metric to a separate proceeding.

- Remove the Demand response performance incentive metric from its list as this metric/incentive appears to have been moved to the Conservation Improvement Plan.
- Direct Xcel to provide a proposal for the future of the QSP tariff and how the Commission might incorporate the targets for the metrics identified in that tariff in its 2024 Annual PBR filing.

The Department also requests additional information on the following metrics from Xcel in its reply comments:

- Discussion of methane emissions, methodology for reporting – Xcel referenced design the Commission's design principles as the basis for this approach. The Department asks the Company: 1) to identify the design principles supporting its proposal to use only methane emission from its natural gas distribution network or enterprise-wide in its methodology for calculating methane emissions and 2) to discuss the availability of data on annual methane emissions from other gas LDCs.
- Methane emissions, status and Company actions and Information on methane emissions across the full fuel cycle – The Department requests Xcel incorporate a discussion of how the proposed methane emission fee can be reconciled with the calculation of upstream emissions of methane on a utility-specific basis in the Company's 2024 reporting requirement re-evaluating the data available on upstream emissions and the feasibility of reporting those emissions across the entire fuel cycle.
- Rates per KWh on total revenue, reported: 1) by customer class and (2) with all classes aggregated - The Department notes the EIA information it recommends as being used for this baseline will need to be modified to be comparable to the information described in the metric. The Department asks the Company to discuss the potential for this adjustment.
- Average monthly residential bill – The Department recommends a baseline for this metric where the calculation is the EIA National average residential rate multiplied by the monthly average usage for a residential customer. The Department asks the Company to discuss the potential for this adjustment.

The Department also suggests the Commission ask interested parties to review the NARUC publication titled: "Tracking State Developments of Performance-Based Regulation" and to provide feedback on the information included in that document. It lists eighteen states and the District of Columbia as having ongoing or completed proceedings on this topic. Parties in this proceeding might benefit from reviewing information related to those efforts in other jurisdictions, particularly regarding the appropriate scope of a PBR proceeding.

Attachment A – Pre-Existing Metrics, Benchmarks and Targets

Line No.	Description	Source of Reporting Requirement	Historical Information?	Existing Benchmark	Existing Target	Proposed Benchmark	Proposed Target	Existing Incentive/ Disincentive?
1.	SAIDI	Minnesota Rules 7826.05, subp. 1 and Quality of Service (QSP) tariff	Yes, but no longer used.	Institute of Electrical and Electronic Engineers (IEEE) Annual Benchmark data	IEEE Second quartile performance and less than 133.23 minutes	Pre-existing information	Pre-existing information	Disincentive of $1.0 million annually
2.	SAIFI	Minnesota Rules 7826.05, subp. 1 and QSP tariff	Yes, but no longer used.	IEEE Annual Benchmark data	IEEE Second quartile performance, less than 1.21 outage events	Pre-existing information	Pre-existing information	Disincentive of $1.0 million annually
3.	CAIDI	Minnesota Rules 7826.05, subp. 1 and QSP tariff	Yes, but no longer used.	IEEE Annual Benchmark data	Second quartile performance	Pre-existing information	Pre-existing information	No
4.	CELID	QSP Tariff	Yes	Commission Order	Outages lasting 24 hours or longer	Pre-existing information	Pre-existing information	Disincentive of $50 per customer, total in 2022 was $21,750*
5.	CEMI	QSP Tariff	Yes	Commission Order	Six or more outages/year	Pre-existing information	Pre-existing information	Disincentive of $50 per customer, total in 2022 was $263,050*

6.	Call center response time	Minnesota Rules 7826.1200, subp. 2 and 7826.1700	Yes, but affected by pandemic policies	Codified in Minn. Rules	Greater than 80% of calls answered within 20 seconds	Pre-existing information	Pre-existing information	Disincentive of $1.0 million annually
7.	Billing invoice accuracy	QSP tariff	Yes	Commission Order	Greater than 99.3%	Pre-existing information	Pre-existing information	Disincentive of $1.0 million annually
8.	Number of customer complaints	Minnesota Rules 7826.2000 and QSP tariff	Yes, but affected by pandemic policies	Commission Order	Number of customer complaints less than 0.2059 complaints per 1,000 customers	Pre-existing information	Pre-existing information	Disincentive of $1.0 million annually
9.	Demand response, capacity available and amount called	Docket Nos. E002/M-01-1024 and E002/M-20-421	Yes	Department interpreted Commission Order calling for an additional 400 MW of demand response as creating an implicit baseline.	400 MW of additional demand response	Capacity Available – 764 MW Amount Callable – 156,189 MWh, Amount Called – 557 MWh	Capacity Available – 1164 MW Amount Callable and Amount Called – no targets specified	No

*Disincentive increases if customer experiences consecutive years of outages.

Attachment B – Performance Metrics with Three or More Years of Historical Data, Potential Benchmarks and Targets

Line No.	Description	Baseline Calculation Methodology	Baseline	Target
1.	Rates per KWh on total revenue, reported: (1) by customer class and (2) with all classes aggregated	Annual National EIA rates by customer class adjusted for the Commission metrics requirements. U.S Total Rates by Class for 2021 (last year reported)	$0.13660 – res $0.11220 – comm $0.07180 – ind $0.10200 – trans $0.11100 - total (Example only – calculation needs to be adjusted)	Five percent below national average rate
2.	Average monthly bills for residential customers ($/month)	U.S Total Rates by Class for 2021 (last year reported) multiplied by Xcel's average monthly residential usage	$89.02 - (Example only – calculation needs to be adjusted)	Five percent below national average residential bill or $84.57 for this example
3.	Total disconnections for nonpayment by residential customers (number of customers/year)	Five-year average combining 2016 – 2019 and 2022	15,790 per year	No target identified
4.	Total arrearages by nonpayment for residential customers ($/year)	Five-year average combining 2016 – 2019 and 2022	$52,827,772	No target identified
5.	ASAI	Calculate using IEEE SAIDI benchmark data	Equivalent to existing SAIDI baseline	Same target approved for SAIDI in Annual Service Quality Report
6.	Residential Customer Satisfaction	Proprietary	Fiftieth (50%) percentile results	No target identified - recommend

			using J.D. Power information.	including Company-specific information but not setting target
7.	Total carbon emissions by utility-owned and all sources (tons/year)	Three-year average	13,017,670 and 13,083,564	Annual value calculated as part of most recently approved IRP
8.	Carbon intensity by utility owned and all sources (lbs/MWh)	Three-year average	636 and 638	Annual value calculated as part of most recently approved IRP
9.	Total criteria pollutants (tons/year)	Three-year average	NOx – 6,723, SO2 – 3,532, PM – 502, Mercury – 0.0396, Lead – 0.0577	Annual value calculated as part of most recently approved IRP
10.	Criteria pollutant emissions intensity (lbs/MWh)	Three-year average	NOx – 0.44, SO2 – 0.23, PM – 0.033, Mercury – 0.000003, Lead – 0.000004	Annual value calculated as part of most recently approved IRP
11.	CO2 emissions avoided – transportation – three sub-metrics	Two or three-year average	Seven sub-metrics with lengthy descriptions – see Attachment D	No target identified
12.	Discussion of methane emissions – methodology for reporting	Three-year average	Gas distribution system – 0.116%, Enterprise wide – 0.151%	No target identified

13.	Amount of demand response that SHEDS load	Three-year average when data was available, otherwise available data	Capacity available – 764 MW, Amount callable – 156,189 MWh, Amount called 1671 MWh	No baselines or targets identified – Xcel suggests one of the sub-metrics be re-evaluated. Department agrees.

Attachment C – Performance Metrics with Less than Three Years of Historical Data, Proposed Benchmarks and Notes

Line No.	Description	Source of Reporting Requirement	Historical Information?	Proposed Benchmark	Notes
1.	Momentary Average Interruption Frequency Index (MAIFI)	Commission Order	Limited	Not calculated – inadequate data	Need to complete AMI rollout before data includes entire system
2.	Power Quality	Commission Order	Limited	Not calculated – inadequate data	Need to complete AMI rollout before data includes entire system
3.	C02 Emissions Avoided – Buildings, Agriculture and Other	Commission Order	No	Not calculated – no data and concerns about IRA methane emission fee	
4.	Methane emissions – status and Company actions	Commission Order	Limited	Not calculated – inadequate data and concerns about IRA methane emission fee	Specific data for upstream methane emissions by gas supplier is not available. Xcel will provide information on the feasibility of reporting methane emissions across the full fuel cycle in 2024 annual filing. May be an issue that would be better to address in the Natural Gas Integrated Resource Plan proceeding – G008, G002, G011/CI-23-117
5.	Information on methane emissions across the full fuel cycle	Commission Order	Limited	Same as #3	Same as #3
6.	Amount of demand response that SHAPES customer load profiles	Commission Order	Limited	Not calculated – inadequate data	Company did identify an approved methodology but did not provide data. Department requests Company provide a

	through price response, time varying rates, or behavior campaigns				timeline for providing data in reply comments.
7.	Amount of demand response that SHIFTS energy consumption from times of high demand to times when there is a surplus of renewable generation.	Commission Order	Limited	Not calculated – inadequate data	Company did identify an approved methodology but did not provide data. Department requests Company provide a timeline for providing data in reply comments.
8.	Workforce Transition Plan	Commission Order	Extensive	Not calculated - Xcel requested to move reporting into a new separate docket.	Department supports Xcel's proposal to move this reporting requirement into a separate docket for administrative purposes.
9.	Public Dashboard	Commission Order	Company held stakeholder meetings, proposed a public dashboard, stakeholders wanted to defer decision	Not applicable – related more to the presentation of metrics results.	Department supports Xcel's proposed dashboard with modifications. See response to Commission question a.ii above.
10.	Demand Response Performance Incentive	Commission Order	Xcel submitted an incentive proposal with the Commission in Docket No.	No data available	Concept appears to have been referred to Conservation Improvement Program. Department recommends metric be removed from the list.

			E002/M-21-101. The Commission did not approve the proposed incentive.		
11.	Evaluation Criteria and Benchmarks	Commission Order	Limited – more a process question than a metric	Not calculated	Company requested Commission determine an appropriate time to begin next phase of evaluation and benchmarking. Department interpreted Commission's Notice of Comment as initiating this next phase of the process.

Attachment D - Summary and Selected Examples Calculations Supporting Proposed Baselines

Metric No. **Metric Description**

1. ***Rates per KWh based on total revenue, reported: (1) by customer class and (2) all*** **EXAMPLE CALCULATION**

	Description	Xcel ($/KWh)	National EIA ($/KWh)	Variance	Percentage Difference	Xcel ($/KWh)	Midwest Region EIA ($/KWh)	Variance	Percentage Difference
.	Residential	$0.13921	$ 0.13660	$0.00261	1.9%	$0.13921	$ 0.12190	$0.01731	14.2%
b.	Commercial	$0.11576	$ 0.11220	$0.00356	3.2%	$0.11576	$ 0.10660	$0.00916	8.6%
c.	Industrial	$0.10263	$ 0.07180	$0.03083	42.9%	$0.10263	$ 0.07350	$0.02913	39.6%
d.	Transportation	not applicable	$ 0.10200	not applicable		not applicable	$ 0.09360	not applicable	
e.	Total	$0.11689	$ 0.11100	$0.00589	5.3%	$0.11689	$ 0.09900	$0.01789	18.1%

2. ***Average Monthly Bill for Residential Customers***

	Year	Xcel ($/month)	Minnesota EIA ($/month)	Variance		Xcel ($/month)	Midwest Region EIA	Variance	
a.	2021	$90.72	$ 106.00	($15.28)	-14.4%	$90.72	$ 112.40	($21.68)	-19.3%

3. ***Total Disconnectons for Nonpayment for Residential Customers***
   a. Proposed Benchmark — 15,790 per year

4. ***Total Arrearages for Residential Customers***
   a. Proposed Benchmark — $ 52,827,772

5. ***System Average Duration Index (SAIDI)***
   a. Proposed Benchmark — Calculated by IEEE annual reliability data from multiple electric utilities

6. ***System Average Frequency Index (SAIFI)***
   a. Proposed Benchmark — Calculated by IEEE annual reliability data from multiple electric utilities

7. ***Customer Average Frequency Index (CAIDI)***
   a. Proposed Benchmark — Calculated by IEEE annual reliability data from multiple electric utilities

8. ***Customers Experiencing Long Interruption Duration (CELID)***
   a. Proposed Benchmark — Outages lasting longer than 24 hours result in a payment of $50 - from QSP tariff

9. ***Customers Experiencing Multiple Interruptions (CEMI)***
   a. Proposed Benchmark — Six or more outages per year result in a payment to customer of $50 - from QSP tariff

10. ***Average Service Availability Index***
    a. Proposed Benchmark — Calculated by Xcel using IEEE SAIDI annual benchmark from multiple electric utilities

11. ***Momentary Average Interruption Frequency Index (MAIFI)***
    a. Proposed Benchmark — Future metric - inadequate data for benchmark

12. ***Power Quality***
    a. Proposed Benchmark — Future metric - inadequate data for benchmark

13. ***Residential Customer Satisfaction***
    a. Proposed Benchmark — Calculated annually by J.D. Power

14. ***Call Center Response Time***
    a. Proposed Benchmark — Greater than 80% of calls answered within 20 seconds - disincentive of $1.0/year - from Minnesota Rules and QSP tariff

15. ***Billing Invoice Accuracy***
    a. Proposed Benchmark — Greater than 99.3% accurate - disincentive of $1.0 million/year - from QSP tariff

16. ***Number of Complaints***
    a. Proposed Benchmark — Number of customer complaints is less than 0.2059 per 1,000 customers - discinentive of $1.0 million/year - from QSP tariff

17. ***Total Carbon Emissions by Utility-Owned and All Sources***
    a. Utility-owned Proposed Benchmark (tons/year) — 13,017,670
    b. All Sources Proposed Benchmark (tons/year) — 13,083,564

18. ***Carbon Intensity by Utility-Owned and All Sources***
    a. Utility-owned Proposed Benchmark (pounds/MWh) — 636

	b.	All Sources Proposed Benchmark (pounds/MWh)	638
19.	***Total Criteria Pollutants Emitted - Utility-owned (tons/year)***		
	a.	NOx	6723.3
	b.	SO2	3532.0
	c.	PM	501.7
	d.	Mercury	0.0396
	e	Lead	0.0577
20.	***Criteria Pollutants Emissions Intensity (pounds per MWh)***		
	a.	NOx	0.44
	b.	SO2	0.23
	c.	PM	0.033
	d.	Mercury	2.33333E-06
	e.	Lead	0.000004
21.	***Carbon Dioxide Emissions Avoided - Transportation***		
	a.	Percent of Evs participating in managed charging programs on whole house rates	9%
	b.	Customers on EV-specific managed charging rates or are on whole-house TOU rates who have self-identified as EV owners	2,016
	c.	Number of Evs registered in Xcel's service territory	20,695
	d.	Percent of managed charging customers residential EV charging load occurring during off-peak hours	88%
	e.	Total annual energy consumed by EVs charging during off-peak hours at the residence of customers enrolled in Xcel's EV TOU rates or other managed charging programs	5,679
	f.	Total annual energy consumed by Evs charging at residences of customers enrolled in Xcel's EV TOU rates or other managed charging programs	6,451
	g.	Carbon dioxide avoided calculated from EV charging (tons/year)	5,807
22.	***Carbon Dioxide Emmissions Avoided by Electrification of Buildings, Agriculture, and Other Sectors***		
	a.	Proposed Benchmark	Inadequate or insufficiently well-defined data - no benchmark proposed
23.	***Discussion of Methane Emissions, Including Proposed Methodology for Reporting***		
	a.	Gas distribution system	0.116%
	b.	Enterprise wide	0.151%
24.	***Availability of data specific to is gas suppliers on upstream methane emissions; regulation of methane emissions upstream of the Company's distribution system, and the Company's position on such regulations; participation in voluntary initiatives to quantify and reduce methane from gas suppliers; any certified gas purchases; pilots with gas marketers to track and source gas with lower associated methane emissions; and any other actions the Company has taken to secure data on and/or reduce upstream methane emissions. No later than 2024, the Company will re-evaluate data available on upstream methane to consider feasibility of reporting of methane emissions attributable to total natural gas purchases across the full fuel cycle (from drilling and extraction to the end-use).***		
	a.	Proposed Benchmark	Inadequate or insufficiently well-defined data - no benchmark proposed
25.	***Methane emissions across the full fuel cycle in its calculation of greenhouse gas emissions avoided by electrification of buildings, agriculture, and other sectors.***		
	a.	Proposed Benchmark	Inadequate or insufficiently well-defined data - no benchmark proposed
26.	***Demand Response, Capacity Available and Amount Called***		
	a.	Proposed Benchmark - Capacity Available Year End 2023	968 MW with 117 MW of incremental capacity added since 2017
	b.	Proposed Benchmark - Amount Called (MWh)	1643
27.	***Amount of Demand Response that SHAPES Customer Load Profiles through Price Response, Time Varying Rates, or Behavior Campaigns***		

	a.	Proposed Benchmark	Inadequate or insufficiently well-defined data - no benchmark proposed
28.		***Amount of Demand Response that SHIFTS Energy Consumption from Times of High Demand to Times Where There is a Surplus of Renewable Generation***	
	a.	Proposed Benchmark	Inadequate or insufficiently well-defined data - no benchmark proposed
29.		***Amount of Demand Response that Sheds Load (Proposed Benchmarks)***	
	a.	Capacity Available (MW)	764
	b.	Amount Callable (MWh)	156,189
	c.	Amount Called	557
30.		***Workforce Transition Plan***	
	a.	Proposed Benchmark	Company requests reporting be moved to a separate docket - Department agrees - no benchmark proposed
31.		**Public Dashboard**	
	a.	Proposed Benchmark	Department supports the development of an online dashboard with a stationary image updated annually - Also recommends dashboard include five metrics and five years of historical data - Metrics include: a)SAIDI, b) total annual carbon emissions by (1) utility-owned facilities and (2) PPAs, c) Average monthly bills for residential customers, d) Demand response including (1) capacity available and (2) amount called
32.		**Demand Response Performance Incentive**	
	a.	Proposed Benchmark	Commission did not approve Xcel's proposed incentive - Xcel will pursue concept through its CIP efforts - no benchmark proposed
33.		***Evaluation Criteria and Benchmarks***	
	a.	Proposed Benchmark	Consistent with Commission's Notice of Comment, Department identified potential benchmarks where possible - no benchmark proposed

Table 2.10. Average Price of Electricity to Ultimate Customers by End-Use Sector, by State, 2021 and 2020 (Cents per Kilowatthour)

Census Division and State	Residential		Commercial		Industrial		Transportation		All Sectors	
	Year 2021	Year 2020	Year 2021	Year 2020	Year 2021	Year 2020	Year 2021	Year 2020	Year 2021	Year 2020
New England	21.51	21.25	16.34	15.84	12.80	12.89	8.83	8.75	18.03	17.73
Connecticut	21.91	22.71	16.46	16.58	9.63	13.07	12.50	13.34	18.32	19.13
Maine	17.02	16.81	12.90	12.56	9.55	8.86	--	--	13.96	13.54
Massachusetts	22.89	21.97	16.99	16.03	15.18	14.51	6.51	6.24	19.06	18.19
New Hampshire	19.85	19.04	16.13	15.41	13.81	13.11	--	--	17.37	16.63
Rhode Island	22.30	22.01	15.51	15.94	16.06	15.76	19.75	22.23	18.44	18.54
Vermont	19.26	19.54	16.59	16.39	11.38	11.20	--	--	16.34	16.33
Middle Atlantic	16.48	15.93	13.37	12.47	6.87	6.38	11.63	11.42	13.22	12.56
New Jersey	16.35	16.03	12.69	12.35	10.70	10.01	9.24	9.19	14.01	13.63
New York	19.48	18.36	16.07	14.56	6.34	5.54	12.67	12.14	16.11	14.87
Pennsylvania	13.76	13.58	8.91	8.50	6.54	6.16	6.84	8.58	9.97	9.70
East North Central	14.07	13.56	10.66	10.27	7.22	6.78	6.67	6.75	10.69	10.28
Illinois	13.18	13.04	9.65	9.15	7.30	6.70	6.42	6.56	10.14	9.75
Indiana	13.37	12.83	11.58	11.21	7.39	6.98	10.05	10.21	10.36	9.92
Michigan	17.54	16.26	12.31	11.71	7.69	7.24	12.30	11.39	12.93	12.21
Ohio	12.77	12.29	9.75	9.53	6.55	6.16	7.41	6.71	9.76	9.44
Wisconsin	14.52	14.32	10.95	10.75	7.63	7.29	15.12	14.64	11.01	10.82
West North Central	12.19	11.96	9.97	9.65	7.35	7.11	9.36	8.62	9.90	9.69
Iowa	12.73	12.46	10.17	9.96	6.63	6.43	--	--	9.13	8.97
Kansas	12.98	12.85	10.52	10.40	7.38	7.30	--	--	10.47	10.38
Minnesota	13.50	13.17	11.22	10.43	8.29	7.67	10.38	9.40	11.08	10.57
Missouri	11.41	11.22	9.17	8.93	7.11	6.84	8.23	7.84	9.85	9.64
Nebraska	10.75	10.80	8.81	8.89	7.26	7.38	--	--	8.84	8.97
North Dakota	10.85	10.44	9.17	9.02	7.37	7.26	--	--	8.65	8.53
South Dakota	12.22	11.75	10.15	9.65	8.02	7.79	--	--	10.43	10.06
South Atlantic	12.10	11.79	9.41	9.05	6.51	6.25	8.19	8.13	10.12	9.84
Delaware	12.52	12.56	9.48	9.18	7.60	6.70	--	--	10.50	10.24
District of Columbia	13.09	12.63	13.00	11.85	7.87	7.99	9.76	9.60	12.81	11.90
Florida	11.90	11.27	9.51	8.85	7.65	7.15	8.31	7.69	10.67	10.06
Georgia	12.51	12.02	10.61	10.08	6.49	5.77	6.61	5.39	10.43	9.93
Maryland	13.12	13.01	10.26	9.72	8.46	7.81	7.58	7.79	11.48	11.15
North Carolina	11.32	11.38	8.50	8.69	6.14	6.31	7.85	7.67	9.29	9.43
South Carolina	12.86	12.78	10.67	10.35	6.07	5.98	--	--	9.96	9.90
Virginia	11.96	12.03	7.79	7.63	6.49	6.28	8.49	8.77	9.14	9.16
West Virginia	12.15	11.80	9.50	9.40	6.07	6.09	--	--	8.87	8.75
East South Central	11.74	11.34	11.07	10.73	5.97	5.55	--	--	9.69	9.32
Alabama	12.96	12.57	11.84	11.55	6.33	5.87	--	--	10.18	9.84
Kentucky	11.50	10.87	10.75	10.34	5.95	5.31	--	--	9.12	8.58
Mississippi	11.56	11.17	10.81	10.38	5.95	5.63	--	--	9.50	9.13
Tennessee	11.07	10.76	10.87	10.56	5.51	5.33	--	--	9.78	9.52
West South Central	11.78	11.17	8.94	7.82	6.12	5.06	6.81	6.65	9.03	8.17
Arkansas	11.27	10.41	9.56	8.61	6.57	5.89	13.56	13.32	9.10	8.32
Louisiana	11.02	9.67	10.23	8.85	6.21	4.88	10.77	8.77	8.82	7.51
Oklahoma	11.00	10.12	8.70	7.82	5.50	4.61	--	--	8.52	7.63
Texas	12.11	11.71	8.72	7.60	6.12	5.07	6.59	6.52	9.14	8.36
Mountain	12.04	11.76	9.71	9.46	6.68	6.25	9.94	9.33	9.70	9.40
Arizona	12.54	12.27	10.33	10.11	6.79	6.07	9.33	9.38	10.73	10.44
Colorado	13.07	12.36	10.84	10.29	8.01	7.48	9.44	8.64	10.90	10.27
Idaho	10.16	9.95	7.89	7.75	6.39	6.23	--	--	8.17	7.99
Montana	11.22	11.24	10.54	10.51	6.24	5.18	--	--	9.50	9.13
Nevada	11.49	11.34	7.77	7.45	6.02	5.61	7.72	8.84	8.58	8.33
New Mexico	13.52	12.94	10.80	10.28	6.16	5.58	--	--	9.79	9.33
Utah	10.43	10.44	8.13	8.27	6.19	5.90	11.21	10.69	8.34	8.27
Wyoming	11.17	11.11	9.68	9.65	6.83	6.88	--	--	8.25	8.27
Pacific Contiguous	18.01	16.67	16.23	15.07	10.81	10.30	11.47	10.03	15.70	14.63
California	22.82	20.45	19.18	17.53	14.82	14.27	11.79	10.07	19.65	18.00
Oregon	11.37	11.17	9.10	9.00	5.97	5.70	9.71	9.46	8.95	8.82
Washington	10.11	9.87	9.14	8.92	5.81	5.08	9.89	9.93	8.75	8.33
Pacific Noncontiguous	28.85	27.02	25.48	24.13	24.19	22.01	--	--	26.19	24.44
Alaska	22.55	22.57	19.61	19.58	16.85	15.88	--	--	20.02	19.82
Hawaii	33.49	30.28	30.88	28.41	27.12	24.45	--	--	30.31	27.55
U.S. Total	13.66	13.15	11.22	10.59	7.18	6.67	10.20	9.90	11.10	10.59

See Technical notes for additional information on the Commercial, Industrial, and Transportation sectors.

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Notes: - See Glossary for definitions. - Values are final.

See Technical Notes for a discussion of the sample design for the Form EIA-826.

Utilities and energy service providers may classify commercial and industrial customers based on either NAICS codes or demands or usage falling within specified limits by rate schedule.

Changes from year to year in consumer counts, sales and revenues, particularly involving the commercial and industrial consumer sectors, may result from respondent implementation of changes in the definitions of consumers, and reclassifications.

Totals may not equal sum of components because of independent rounding.

Source: U.S. Energy Information Administration, Form EIA-861, Annual Electric Power Industry Report.

Average Bill Workpaper -2021 EIA Average Bill Calculation

Line No.	Description	Minnesota	
		Annual Usage (KWh)	**Number of Customers**
1.	Residential	23,246,000,000	2,496,406
2.	Commercial	22,093,000,000	306,605
3.	Industrial	21,227,000,000	9,130
4.	Transportation	23,000,000	1
5.	Total	66,589,000,000	2,812,142
6.	Check total	66,589,000,000	2,812,142
		West North Central Region	
		Annual Usage (KWh)	**Number of Customers**
1.	Residential	107,760,000,000	9,738,760
2.	Commercial	99,433,000,000	1,502,864
3.	Industrial	98,747,000,000	128,943
4.	Transportation	43,000,000	3
5.	Total	305,983,000,000	11,370,570
6.	Check total	305,983,000,000	11,370,570

Avg. Ann. Use/Cust.	Avg. Mon. Use/Customer	Avg. Ann. Rate	Avg. Mon. Bill
9,312	776	$ 0.13660	$ 106.00
72,057	6,005	$ 0.11220	$ 673.73
2,324,973	193,748	$ 0.07180	$ 13,911.09
23,000,000	1,916,667	$ 0.10200	$ 195,500.00
23,679	1,973	$ 0.11100	$ 219.03
23,679	1,973		

Avg. Ann. Use/Cust.	Avg. Mon. Use/Customer	Avg. Ann. Rate	Avg. Mon. Bill
11,065	922.09	$ 0.12190	$ 112.40
66,162	5,513.53	$ 0.10660	$ 587.74
765,819	63,818.25	$ 0.07350	$ 4,690.64
14,333,333	1,194,444.44	$ 0.09360	$ 111,800.00
26,910	2,242.51	$ 0.09900	$ 222.01
26,910			

Residential Disconnections Workpaper

Line No.	Year	Number of Disconnections
1.	2016	20,754
2.	2017	17,777
3.	2018	16,218
4.	2019	14,939
5.	2022	9,263
6.	Total	78,951
7.	Average	15,790

Annual Residential Arrearage Workpaper

Line No.	Year	Annual Arrearages	
1.	2016	$	44,885,663
2.	2017	$	40,898,573
3.	2018	$	44,895,753
4.	2019	$	44,976,724
5.	2022	$	88,482,147
6.	Total	$	264,138,860
7.	Average	$	52,827,772

Emissions Workpaper

1. ***Emissions Metrics***

Description

a. Total Carbon Emissions - Utility-Owned (tons/year)
b. Total Carbon Emissions - All Sources (tons/year)
c. Carbon Intensity - Utility-Owned (pounds per MWh)
d. Carbon Intensity - All Sources (pounds per MWh)
c. **Total Criteria Pollutants Emitted (tons/year)**
d. NOx
e. SO2
f. PM
g. Mercury
h. Lead
i. **Criteria Pollutants Emissions Intensity (pounds per MWh)**
j. NOx
k. SO2
l. PM
m. Mercury
n. Lead
o. ***CO2 Emissions Avoided - Transportation***

p. Percent of Evs participating in managed charging programs on whole house rates
q. Customers on EV-specific managed charging rates or are on whole-house TOU rates who have self-identified as EV owners
r. Number of Evs registered in Xcel's service territory
s. Percent of managed charging customers residential EV charging load occurring during off-peak hours

t. Total annual energy consumed by EVs charging during off-peak hours at the residence of customers enrolled in Xcel's EV TOU rates or other managed charging programs
u. Total annual energy consumed by Evs charging at residences of customers enrolled in Xcel's EV TOU rates or other managed charging programs
v. Carbon dioxide avoided calculated from EV charging (tons/year)
w. Carbon Dioxide Emmissions Avoided by Electrification of Buildings, Agriculture, and Other Sectors

x. **Discussion of Methane Emissions, Including Proposed Methodology for Reporting**
y. Gas distribution system
z. Enterprise wide

2. ***Demand Response, Capacity Available and Amount Called***

a. Amount Called (MWh)

3. ***Amount of Demand Response that Sheds Load (Proposed Benchmarks)***

   a. Capacity Available (MW)
   b. Amount Callable (MWh)
   c. Amount Called

2020	2021	2022	Average
12,710,943	13,729,970	12,612,098	13,017,670
12,801,300	13,800,098	12,649,295	13,083,564
640	667	602	636
643	669	603	638
6,050	7,318	6,802	6,723
3,356	3,886	3,354	3,532
472	541	492	502
0.0435	0.0378	0.0376	0.0396
0.0532	0.0563	0.0635	0.0577
0.416	0.479	0.439	0.445
0.231	0.254	0.216	0.234
0.032	0.035	0.032	0.033
0.000003	0.000002	0.000002	0.000002
0.000004	0.000004	0.000004	0.000004
7%	9%	11%	9%
Not provided	1,761	2,271	2,016
Not provided	20,449	20,941	20,695
94%	90%	87%	88%
Not provided	4,847	6,510	5,679
Not provided	5,415	7,487	6,451
53,784	76,895	75,180	5,807
Not provided	Not provided	Not provided	Not applicable
2019	**2020**	**2021**	
0.00107	0.00121	0.00121	0.116%
0.00144	0.00146	0.00163	0.151%
2020	**2021**	**2022**	

1066	2192	1671	1643
755	764	772	764
155,967	147,466	165,134	156,189
-	-	1,671	557

Attachment E – Summary of Performance Metric Baselines/Benchmarks

Line No.	Outcome/ Metric Description	Baseline(s)	Baseline Calculation
	Affordability		
1.	Rates per kWh based on total revenue, reported: (1) by customer class and (2) all classes aggregated	\$0.1366 – residential \$0.1122 – commercial \$0.0718 – industrial \$0.1020 - trans \$0.1110 – total (Example – calculation will need to be adjusted)	Annual National EIA rates by customer class adjusted for the Commission metrics requirements. U.S Total Rates by Class for 2021 (last year reported)
2.	Average monthly bill for residential customers	\$89.02/month (Exampled – rate used for calculation may need to be adjusted)	U.S National residential rates for 2021 (last year reported) multiplied by Xcel's average monthly residential usage
3.	Total disconnections for nonpayment for residential customers	15,790 per year – See Attachment D.	Modified five-year average – 2016 through 2019 and 2022. Adjusted to remove effect of pandemic
4.	Total arrearages for residential customers	\$52,827,772 – See Attachment D.	Modified five-year average – 2016 through 2019 and 2022. Adjusted to remove effect of pandemic
	Reliability		
5.	System Average Interruption Duration Index (SAIDI)	Institute of Electrical and Electronic Engineers (IEEE) annual benchmark data	Calculated by IEEE using data collected from multiple electric utilities QSP disincentive
6.	System Average Interruption Frequency Index	IEEE annual benchmark data	Calculated by IEEE using data collected from multiple electric utilities QSP disincentive
7.	Customer Average Interruption Duration Index (CAIDI)	IEEE annual benchmark data	Calculated by IEEE using data collected from multiple electric utilities
8.	Customers Experiencing Long Interruption Duration (CELID)	CELID 4, 5 and 6	Calculations provided in Xcel's annual Service Quality and Service Reliability (SQSR) Report and Quality of Service (QSP) compliance filing

9.	Customers Experiencing Multiple Interruptions (CEMI)	CEMI 4, 5 and 6	Calculations provided in Xcel's annual SQSR Report and QSP compliance filing
10.	Average Service Availability Index	Modified IEEE SAIDI annual benchmark data	Equal to one minus SAIDI divided by 8760 hours.
11.	MAIFI	Not calculated – insufficient data	Report with and without Major Event Days – Equal to Sum of Total Momentary Customer Interruptions divided by Total Number of Customers Served
12.	Power Quality	Not calculated – insufficient data	Specific capabilities under discussion and will be determined in the coming years
	Customer Service Quality		
13.	Residential customer satisfaction	50^{th} percentile for J.D. Power benchmark data	Calculated by J.D. Power
14.	Call Center Response Time	Greater than 80% of calls answered within 20 seconds	Calculation provided in Xcel's annual Service Quality and Service Reliability Report
15.	Billing Invoice Accuracy	Greater than 99.3% accurate	Calculation provided in Xcel's QSP tariff compliance filing
16.	Number of Complaints	Number of customer complaints less than 0.2059 complaints per 1,000 customers	Calculation provided in Xcel's QSP tariff compliance filing
	Environmental Performance		
17.a	Total carbon emissions by utility-owned sources	13,017,670 tons/year – See Attachment D.	Three-year average
17.b	Total carbon emissions by all sources	13,083,564 tons/year – See Attachment D.	Three-year average
18.a	Carbon intensity by utility owned sources	636 lbs/MWh – See Attachment D.	Three-year average
18.b	Carbon intensity by all sources	638 lbs/MWh – See Attachment D.	Same
19.	Total criteria pollutants by utility owned sources	See Attachment D.	Three-year average
19.a	Nitrogen Oxide	6,723 ton/year	Same
19.b	Sulfur Dioxide	3,532 tons/year	Same
19.c	Particulate Matter	501 tons/year	Same

19.d	Mercury	0.0396 tons/year	Same
19.e	Lead	0.0577 tons/year	Same
20.	Criteria pollutant emissions intensity	See Attachment D.	Three-year average
20.a	Nitrogen Oxide	0.44 lb/Mwh	Same
20.b	Sulfur Dioxide	0.23 lb/MWh	Same
20.c	Particulate Matter	0.033 lb/MWh	Same
20.d	Mercury	0.000002 lb/MWh	Same
20.e	Lead	0.000004 lb/MWh	Same
21.	CO2 emissions avoided – transportation – three sub-metrics	See Attachment D.	Three-year average
21.a	Percent of EVs participating in managed charging programs on whole house rates	9%	Same
21.b	Customers on EV-specific managed charging rates or are on whole-house TOU rates who have self-identified as EV owners	2,016 customers	Two-year average
21.c	Number of EVs registered in Xcel's service territory	20,695 vehicles	Two-year average
21.d	Percent of managed charging customers residential EV charging load occurring during off-peak hours	88%	Three-year average
21.e	Total annual energy consumed by EVs charging during off-peak hours at the residence of customers enrolled in Xcel's EV TOU rates or other managed charging programs	5,679 MWh	Two-year average
21.f	Total annual energy consumed by EVs charging at residences of customers enrolled in Xcel's EV TOU rates or other managed charging programs	6,451 MWh	Two-year average
21.g	Carbon dioxide avoided calculated from EV charging (tons/year)	5,807 tons	Three-year average
22.	CO2 emissions avoided – buildings, agriculture, and other sectors -	Not calculated – no data	

23.	Discussion of methane proposals, including proposed methodology for reporting	Calculated for Xcel Minnesota only due to lack of adequate upstream methane emissions data	Three-year average – 2019 through 2021 due to reporting lag
23.a	Gas distribution system	0.116%	Same
23.b	Enterprise wide	0.151%	Same
24.	Availability of data specific to is gas suppliers on upstream methane emissions; regulation of methane emissions upstream of the Company's distribution system, and the Company's position on such regulations; participation in voluntary initiatives to quantify and reduce methane from gas suppliers; any certified gas purchases; pilots with gas marketers to track and source gas with lower associated methane emissions; and any other actions the Company has taken to secure data on and/or reduce upstream methane emissions. No later than 2024, the Company will re-evaluate data available on upstream methane to consider feasibility of reporting of methane emissions attributable to total natural gas purchases across the full fuel cycle (from drilling and extraction to the end-use).	No baseline calculated - Adequate data for upstream methane emissions by gas supplier is not available.	Xcel will provide information on the feasibility of reporting methane emissions across the full fuel cycle in 2024 annual filing. May be an issue that would be better to address in the Natural Gas Integrated Resource Plan proceeding – G008, G002, G011/CI-23-117
25.	Methane emissions across the full fuel cycle in its calculation of greenhouse gas emissions avoided by electrification of buildings, agriculture, and other sectors.	No baseline calculated -Adequate data for upstream methane emissions by gas supplier is not available.	Xcel will provide information on the feasibility of reporting methane emissions across the full fuel cycle in 2024 annual filing
	Cost Effective Alignment of Generation and Load		
26.	Demand response, capacity available and amount called	968 MW and 117 MW of incremental controllable load	2023 target governed by Commission Order – using 2022 Xcel actuals as baseline

27.	Amount of demand response that SHAPES customer load profiles through price response, time varying rates, or behavior campaigns	No baseline calculated - Company did not provide data	Xcel has identified methodology, Department requests Xcel provide a timeline for this metric in its reply comments
28.	Amount of demand response that SHIFTS energy consumption from times of high demand to times where there is a surplus of renewable generation	No baseline calculated - Company did not provide data	Xcel has identified methodology, Department requests Xcel provide a timeline for this metric in its reply comments
29.	Amount of demand response that SHEDS load that can be curtailed to provide peak capacity and supports the system in contingency events: a) for available load; b) for actual load reduction and c) metrics that measure the effectiveness of (a) and (b) in aggregate.	Capacity available – 764 MW, Amount callable – 156,189 MWh, Amount called 1671 MWh - Company noted its performance relative to this metric is declining and suggests Commission may want to re-evaluate this metric. Department decided not to calculate a baseline given results and Xcel's request.	Xcel has identified a methodology. Department supports Xcel's request the Commission re-evaluate the sub-metric.
	Workforce and Community Development		
30.	Workforce Transition Plan	No baseline calculated - Xcel requested to move reporting into a new separate docket. Did provide data.	Department decided not to calculate a baseline given Xcel's request given its review of the relevant information.
	Other Stakeholder Discussions		
31.	Public Dashboard	No baseline calculated - Company fulfilled Commission requirements. Department now supports the Commission proceeding with the development of an online dashboard with a stationary image updated annually.	The Department also recommends the Commission adopt four of the five performance metrics Xcel identified in its 2020 PBR Report except for customer complaints. The Department supports including the J.D Power customer satisfaction information rather than Xcel customer complaint metric.
32.	Demand Response Performance Incentive	No baseline calculated - Xcel fulfilled Commission requirement. Commission did not approve the proposed incentive.	Proposal appears to have been referred to Conservation Improvement Program. Metric/topic may no longer be relevant to this proceeding

33.	Evaluation Criteria and Benchmarks	No baseline calculated for this metric - Xcel provided data on certain metrics but did not delineate evaluation criteria or benchmarks.	Department interpreted Commission's Notice of Comment topic and question as initiating this next phase of the process. Attempted to provide evaluation criteria or baselines for all metrics.

Attachment F – Performance Metrics with Targets

Line No.	Metric	Proposed Target(s)	Notes
1.	SAIDI	IEEE Second quartile performance for large utilities for Statewide, East and West Metro work centers, second quartile performance for medium utilities for Northwest and Southeast work centers and less than 133.23 minutes with disincentive of $1.0 million annually for exceeding target	Targets originated in Annual Service Quality Report and QSP tariff
2.	SAIFI	IEEE target is identical to #1 and less than or equal to 1.21 outage events with disincentive of $1.0 million annually for exceeding target	Same as #1
3.	CAIDI	IEEE target is identical to #1. No QSP target.	Targets originated in Annual Service Quality Report
4.	CELID	For each interruption lasting more than 24 hours, customer receives $50 credit,*	QSP tariff - $1.0 million total credits available for CELID and CEMI
5.	CEMI	If customer experiences:* • six or more interruptions per year, customer receives $50 credit; • five or more interruptions in consecutive years customer receives $75 credit; • four or more interruptions in third consecutive year customer receives $100 credit • four or more interruptions for four or more consecutive years, customer receives $125 credit	Same as #4
6.	Call Center Response Time	Eighty (80) percent of calls answered within 20 seconds with $1.0 million disincentive for failing to meet target	QSP tariff

7.	Billing Accuracy	Ninety-nine point 3 (99.3) percent correctly billed invoices with $1.0 million disincentive for failing to meet target	QSP tariff
8.	Number of Customer Complaints	Number of complaints submitted to CAO exceeds 0.2059 complaints per 1,000 customers $1.0 million disincentive for failing to meet target	QSP tariff
9.	Demand Response, Capacity Available and Amount Called	Additional 400 MW of Demand response by 2023	Commission Order in Docket No. E002/RP-15-21**
10.	Rates per KWh on total revenue, reported: (1) by customer class and (2) with all classes aggregated	Five percent below national average rate by class	Minnesota Stat. 216C.05, subd 2 (4)
11.	Average monthly bills for residential customers ($/month)	Five percent below national average monthly residential bill assuming same level of usage as Xcel	Minnesota Stat. 216C.05, subd 2 (4)
12.	ASAI	Same target as SAIFI in Annual Service Quality Report adjusted for this calculation	Department proposed
13.	Total carbon emissions by utility-owned and all sources (tons/year)	Annual carbon emissions calculated as part of most recently approved IRP	IRP information
14.	Carbon intensity by utility owned	Annual emissions carbon intensity calculated as part of most recently approved IRP	IRP information

	and all sources (lbs/MWh)		
15.	Total criteria pollutants (tons/year)	Annual criteria pollutant emissions calculated as part of most recently approved IRP	IRP information
16.	Criteria pollutant emissions intensity (lbs/MWh)	Annual criteria pollutant emissions calculated as part of most recently approved IRP	IRP information
17.	Residential Customer Satisfaction	No target methodology identified	No target calculated

Attachment G – Performance Metrics With or Without Baselines and Without Targets Except for Workforce Transition

Line No.	Description	Baseline	Target	Notes
1.	Total disconnections by nonpayment by residential customers (number of customers/year)	15,790 per year	No target identified	Metric has more than 3 years of historical data.
2.	Total arrearages by nonpayment for residential customers ($/year)	$52,827,772	No target identified	Metric has more than 3 years of historical data.
3.	CO2 emissions avoided – transportation – three sub-metrics	Seven sub-metrics with lengthy descriptions – see Attachment D	No targets identified	
4.	Discussion of methane emissions – methodology for reporting	Gas distribution system – 0.116%, Enterprise wide – 0.151%	No target identified	
5.	Amount of demand response that Sheds load	Capacity available – 764 MW, Amount callable – 156,189 MWh, Amount called 557 MWh	No target identified – Xcel suggests the metric be re-evaluated.	Identical baseline to Demand response metric Department identified as having the 400MW target – This metric or one of its sub-metrics appears to require re-evaluation according to Xcel. Department agrees with Xcel's suggestion.
6.	Momentary Average Interruption Frequency Index (MAIFI)	Not calculated – inadequate data	No target identified	Need to complete AMI rollout before data includes entire system
7.	Power Quality	Not calculated – inadequate data	No target identified	Need to complete AMI rollout before data includes entire system
8.	C02 Emissions Avoided – Buildings, Agriculture and Other	Not calculated – no data and concerns	No target identified	

		about IRA methane emission fee		
9.	Methane emissions – status and Company actions	Not calculated – inadequate data and concerns about IRA methane emission fee	No target identified	Specific data for upstream methane emissions by gas supplier is not available. Xcel will provide information on the feasibility of reporting methane emissions across the full fuel cycle in 2024 annual filing. May be an issue that would be better to address in the Natural Gas Integrated Resource Plan proceeding – G008, G002, G011/CI-23-117
10.	Information on methane emissions across the full fuel cycle	Not calculated – inadequate data and concerns about IRA methane emission fee	No target identified	See Notes for #9 above.
11.	Amount of demand response that SHAPES customer load profiles through price response, time varying rates, or behavior campaigns	Not calculated – inadequate data	No target identified	Company did identify an approved methodology but did not provide data. Department requests Company provide a timeline for providing data in reply comments.
12.	Amount of demand response that SHIFTS energy consumption from times of high demand to times when there is a surplus of renewable generation.	Not calculated – inadequate data	No target identified	Company did identify an approved methodology but did not provide data. Department requests Company provide a timeline for providing data in reply comments.

13.	Public Dashboard	Not applicable – related more to the presentation of metrics results.	Individual metric targets will be included for some metrics.	Company held stakeholder meetings, proposed a public dashboard, stakeholders wanted to defer decision. Department supports Xcel's proposed dashboard with modifications.
14.	Demand Response Performance Incentive	Not calculated – inadequate data	No target identified	Xcel submitted an incentive proposal with the Commission in Docket No. E002/M-21-101. The Commission did not approve the proposed incentive. Concept appears to have been referred to Conservation Improvement Program. Department recommends metric be removed from the list.
15.	Evaluation Criteria and Benchmarks	More of a process-related metric, doesn't lend itself to benchmark/target approach	No target identified	Company requested Commission determine an appropriate time to begin next phase of evaluation and benchmarking. Department interpreted Commission's Notice of Comment as initiating this next phase of the process.

PBR State Working Group

Tracking State Developments of Performance-Based Regulation

Updated April 25, 2023

The PBR State Tracker is maintained by NARUC staff as a tool to present information summarizing developments for states currently implementing a performance-based regulatory framework. This tracker is updated on a quarterly basis with input and review by members of the PBR State Working Group. Please contact NARUC staff with any questions, feedback, or additions.

The tracker includes the following categories:

- Overview/Background: History and general description of the performance-based regulatory developments by commission, including references to notable legislation, dockets, cases, etc.
- Status/Recent Developments: This column provides information on the latest developments, including proceedings, announcements, legislation, utility progress, etc.
- Topics/PIMs: This column includes topics that are currently (or under consideration for) being addressed with performance-based regulatory approaches. This includes information related to performance incentive mechanisms (PIMs) that may be tied to targets and associated financial incentives or penalties.
- Additional Resources: Includes relevant links for users to access more detailed information related to the state's PBR efforts.

State	Overview / Background	Status / Recent Developments	Topics Addressed / PIMs	Additional Resources
AZ	• Per customer revenue decoupling • Southwest Gas Corporation is the only utility with full revenue decoupling. • Lost Fixed Cost Recovery Mechanism, Performance Incentives			
CO	• The Governor signed SB19-236 into law May 30, 2019. Decision No. R20-0052-I by Hearing Commissioner John Gavan in Proceeding 19M-0661EG sets the first public stakeholder for Feb. 2020. • Study (2020: Investigation into PBR in Colorado (§ 40-3-117, C.R.S.) was completed Nov. 2020 determining the commission would not move forward with a PBR case at that time • The mechanism is based on the total revenue method with a 3% per year revenue adjustment cap. • Performance incentives; Acknowledgement of lost revenues (ALR) • Investor-owned utility Xcel Energy is implementing a revenue decoupling adjustment pilot program that will conclude in 2023	Exploration; some metrics established for utilities, outside of the ratemaking process (e.g., Xcel has performance metrics with financial incentives outside of their rate case)	Energy Efficiency; Demand Response	
CT	• Revenue decoupling enacted 2013 for IOUs. • On May 26, 2021, PURA initiated Docket No. 21-05-15 to investigate, develop, and adopt a framework for implementing PBR for Eversource and United Illuminating Company. • The findings were released in October 2022 • Workshops will continue to explore this	Status: Phase 1: goals and topics identified On March 17, 2023, the Connecticut Public Utilities Regulatory Authority issued a proposed decision on the development and adoption of a performance based regulation (PBR) framework pursuant to Section 1 of Public Act 20-5 (“Take Back Our Grid Act”) and developed through an iterative stakeholder process. In its proposed decision, the Authority established four regulatory goals for PBR: 1. excellent operational performance, 2) public policy achievement, 3) customer empowerment and satisfaction, and 4) reasonable, equitable, and affordable rates. The Phase 2 Investigation will explore: ➢ Revenue adjustment mechanisms ➢ Performance mechanisms ➢ Other regulatory mechanisms The proposed final order outlines how the Authority anticipates that each priority outcome will be served by PBR regulatory mechanisms, Equitable Modern Grid (EMG) dockets, and other mechanisms.	PURA established the following priority outcomes through its stakeholder process to support the four identified goals: For goal 1: a) efficient business operations, b) comprehensive and transparent system planning, c) distribution system utilization, and d) reliable and resilient electric service; for goal 2: e) social equity, f) greenhouse gas reduction; for goal 3: g) customer empowerment, h) quality customer service; and for goal 4: i) affordable service. The Phase 2 Investigation will explore performance mechanisms and other regulatory mechanisms	

State	Overview / Background	Status / Recent Developments	Topics Addressed / PIMs	Additional Resources
		.		
DC	• Per-customer revenue decoupling implemented in 2009, including Performance Incentive mechanisms. • On December 20, 2019, the commission approved a Pepco proposed framework to review and consider utility requests for alternative forms of regulation (Formal Case No. 1156), which includes a performance-based aspect to rate-setting where certain performance goals or increased efficiencies must be met.			
GA	• Georgia has had a Multi-Year Rate Plan for several years. • The Commission approved a 2020-2022 plan. • The Commission also looks at incentive structures for Renewable Energy and Energy Efficiency every three years during the IRP process. • The incentives are based on the utility receiving a percentage of the net savings or projected savings that the customer will receive.			
HI	• Investigated PBR (Docket No. 2018-0088); Affected utilities include the Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited. • Completed deliberate and thorough review and discussion of PBR concepts and proposed mechanisms in Phase 1 of Docket No. 2018-0088, using combination of facilitated workshops and staff reports. • Conceptual Framework Approached on May 23, 2019 (Order No. 36326) • Currently engaged in collaborative process with stakeholders using combination of facilitated working groups and workshops to discuss, vet, and refine individual stakeholder proposals for PBR framework. Working group process will continue through May 2020, with stakeholders' official proposals submitted in June 2020. Phase 1 Decision and Order • Phase 2 proposal under discussion. Decision anticipated December 2020. Final proposals will be subject to discovery, briefing, and possibly an evidentiary hearing during the latter half of 2020. Phase 2 Convening Order	Implementation; data collection, metric evaluation and benchmarking have been completed; targets have been established. Commission is now tracking utility progress (tied to PIMs). The PUC most recently adopted a new series of PIMs on June 17, 2022 (Hawaii Public Utilities Commission, Decision and Order No. 38429; Public Utilities Commission; Docket No. 2018-0088. Decision and Order No. 38429.	Affordability; Capital Formation; Cost Control; Customer Engagement; Customer Equity; DER Asset Effectiveness; Electrification of Transportation; GHG Reduction; Grid Investment; Efficiency; Interconnection Experience; Resilience	• PBR SWG Expert Webinar on PIMS – HI • Hawaiian Electric Performance Scorecard and Metrics
ID	• The state's first fixed-cost adjustment mechanism was adopted in 2007 for Idaho Power. Avista Utilities FCA introduced a fix-cost adjustment mechanism in 2013. • Per customer revenue decoupling enacted in 2013; a Fixed Cost Adjustment (FCA) is calculated based on the total number of consumers, fixed cost per consumer, and weather-normalized sales. This applies for Idaho Power Co and Avista.			
IL	• Illinois history of PBR: Public Act 97-0616, enacted in 2011, requires a PBR mechanisms; commission uses a formula ratemaking approach for electric utilities with more than 500k customers (220 ILCS 5/16-108.5 (f) to (f-5)). • Commission has conducted formula rate cases for ComEd and Ameren every year since the inception of the law.	Implementation; performance-based formula rates underway for Ameren and ComEd	Advanced Metering Infrastructure ("AMI"); EIMA; Reliability; Credit and Collections	• Ameren Performance Metrics • Commonwealth Edison Performance Metrics

State	Overview / Background	Status / Recent Developments	Topics Addressed / PIMs	Additional Resources
	• Senate Bill 2408v (The Energy Transition Act) in 2021 directed the commission to pursue significant utility business model reforms through a "comprehensive performance-based regulation framework." • Public Act 102-0662 was enacted by the General Assembly with an effective date of September 15, 2021. The Act requires the Commission to conduct a series of workshops with the purpose of facilitating the development of performance • and tracking metrics for Ameren and ComEd. • Pursuant to the Energy Infrastructure Modernization Act (Illinois Public Act 97-616, or "EIMA") and other initiatives, Ameren and ComEd currently submit detailed data regarding Advanced Metering Infrastructure ("AMI"), EIMA Performance Metrics ("PM"), Reliability, Credit and Collections, and other areas. Such data is available at various locations on the ICC website.			
MA	• D.T.E. 94-158 - Strongly encouraged all gas & electric utilities to devise and propose incentive plan. Further, the Department directed… any utility that does not file an incentive plan will be required to demonstrate with full specificity in its next base rate case how it is seeking to achieve more efficient operations... • Restructuring Act of 1997 authorized performance-based rates for each Distribution, Transmission, and Gas Company doing business in the Commonwealth. G.L. c. 164, § 1E(a). • Several recent rate cases have approved PBR plans for gas and electric companies (NSTAR Electric, D.P.U. 17-05; National Grid (Mass Electric), D.P.U. 18-150; NSTAR Gas, D.P.U. 19-120; National Grid (Boston Gas), D.P.U. 20-120; NSTAR Electric, D.P.U. 22-22).	2022 NSTAR Electric PBR includes a K-Bar Adjustment, calculated on the basis of a five-year rolling average of actual capital costs and intended to provide predictable and adequate funding for capital investments. PIMs under consideration in Grid Modernization (D.P.U. 21-80; D.P.U. 21-81; D.P.U. 21-82) and EV Programs (D.P.U. 21-90; D.P.U. 21-91; D.P.U. 21-92).		
MD	• Initiated concept of PBR when multi-year rate plans were introduced; established working group on PBR/PIMs • The commission has conducted several rate cases since 2019, but has not accepted any PIMs proposals to date. • In 2023, Baltimore Gas & Electric will be coming requesting a rate case that will propose a set of PIMs. • Outside of rate cases, exploring the use of PBR/PIMs for EE programs (6th cycle in 2024) as a compensation mechanism.			
ME	• Annual revenue reconciliation - a 2% cap is placed on decoupling-related rate increases, but there is no cap on decoupling-related rate decreases. • Energy efficiency budgets, programs, and incentives are administered by Efficiency Maine with oversight from the MPUC			
MI	• Per customer revenue decoupling enacted in 2016 • Decoupling only applies to natural gas utilities and electric utilities serving less than 200,000 customers. • PA 295 of 2008 established an energy efficiency resources standard (EERs) and financial incentive mechanism (FIM) for utility EWR measures. Legislation increased savings targets annually until 2021 when the target caps at 1%. To encourage deployment of EWR above	Commission guidance in DTE Electric's most recent rate case order in November 2022 in Case No. U-20836 provided the Commission would provide further guidance on	Distribution, Grid Modernization, Reliability, Energy Efficiency/Energy Waste Reduction, Demand Response, Performance Incentive Mechanism (PIM), Financial Incentive Mechanism	MI Power Grid Incentives/Disincentives Workgroup REPORT ON THE STUDY OF PERFORMANCE-

State	Overview / Background	Status / Recent Developments	Topics Addressed / PIMs	Additional Resources
	the 1% target, MI adopted an incentive mechanism (IM) that allows an electricity provider to receive a financial award for exceeding the EWR standard. • PA 341 & 342 of 2016 amended the 2008 legislation to update the financial incentive (FI). PA 342 established tiers for utilities when they achieved 1.25% and 1.5% annual savings from 2017-2021. The legislation also increased the maximum incentives utilities could receive if annual savings exceed 1.5%. The incentive received by the electricity provider is calculated using the lesser of the following amounts: 1) a percentage of the NPV of life-cycle cost reductions experienced by the customers in that year as a result of EWR implementation, or 2) a percentage of the provider's actual waste reduction expenditures for the year. • Pursuant to PA 341 Section 6t(15), the Commission shall consider and may authorize a financial incentive that does not exceed the utility's weighted average cost of capital for purchase power agreements (with non-affiliates). • 2016 PA 341 Sec 6u, MCL 460.6u MI Legislature required the MPSC to study PBR, report listed in resources column. • Financial Incentive Mechanisms (FIMs) have been approved in Demand Response (DR) reconciliation cases. Design of DR incentives is left to the discretion of the Commission.	performance-based regulation by the end of the year or soon thereafter. The MPSC has granted financial compensation mechanisms (FCM) for several utilities in their Integrated Resource Planning (IRP) cases related to PPAs The Commission's MI Power Grid initiative Phase III, Incentives/Disincentive will explore PBR. In rate case orders, the Commission directed its two largest utilities to include PBR proposals in subsequent 5-year distribution plans (U-20561 DTE Electric & U-20697 for Consumers Energy)	(FCM), Infrastructure Recovery Mechanism (IRM)	BASED REGULATION APPENDICES
MN	• In 2007, the Next Generation Energy Act required utilities to incorporate shared-savings mechanisms for energy efficiency and established decoupling and a minimum spending percentage on energy efficiency, demand-side management, and renewable energy. • Subsequent legislation directed the commission to perform a Utility Rates Study (PDF) in 2009 and authorized MRPs in 2011. • Minnesota Statute 216B.19 subd 19 (a and h) authorizes the Commission to initiate a proceeding to determine a set of performance measures that can be used to assess a utility under a Multi Year Rate Plan (MYRP). • The Minnesota Attorney General's office recommended a regulatory proceeding on PBR; the commission conducted an exploratory study. • Xcel Energy Minnesota included a set of PIMs in its 2015 filing that, resulted in the commission opening a separate proceeding to "evaluate Xcel's proposed metrics, craft additional metrics, and consider whether to tie any financial penalties or incentives" to the utility's performance. In 2017, the MN Commissioned opened a PBR-focused docket, initiated by the Commission's order resolving Xcel Energy's 2017 rate case (Findings of Fact, Conclusions, and Order. Docket E-002/GR-15-826, June 12, 2017). Xcel proposed an initial set of metrics that stakeholders were tasked with reviewing. The Commission's January 8, 2019 Order established the Performance Incentives Mechanism (PIM) process to guide stakeholders through the development of performance metrics and potentially incentives (ORDER ESTABLISHING PERFORMANCE-	Implementation; development of metrics Commission has been working on a mapping component to display a subset of 2-3 metrics; open comment period right now to get feedback. Focus is on Locational reliability, equity-reliability, and equity in customer service. Commission is currently collecting 3 years of baseline data for the PBR – then will determine if performance targets are needed and if PIMs are needed. Third year of baseline data will be filed in docket no. 17-401 in April 2023.		

State	Overview / Background	Status / Recent Developments	Topics Addressed / PIMs	Additional Resources
	INCENTIVE MECHANISM PROCESS issued January 8, 2019, DOCKET NO. E-002/CI-17-401) • 5 defined outcomes: affordability, reliability, customer service quality, environment, alignment of generation & load (many of these include metrics that utilities were already reporting); using time-tested metrics; other outcomes did require coordination with stakeholders.			
NV	• PBR related efforts have been underway since legislation was enacted in 2019 (SB300). • Initial efforts involved education, workshops, and stakeholder engagement. • 2022 was the first year of policy implementation. • Regulation drafted throughout 2022 – legislative counsel sent it back and iterated; have had adoption hearings - ready for it to be released. • Alternative ratemaking is optional in the state (3yr general rate case cycle, 1-yr fuel purchase adder. • Commission is encouraging utilities to explore benefits of PBR, including more flexibility. • Currently, PBR is under legislative review.			
NC	• NC House Bill 951 authorizes filing and approval of PBRs that include decoupling, PIMs, and an MRP framework; commission will consider whether PBRs encourage DERs, beneficial electrification, and equity • PBR-related legislation was approved in 2022 to establish multi-year rate plans for water utilities, and one for an electric utility. • Two large water utilities filed late in 2022 with the corresponding order expected in spring 2023. • Utility & consumer advocates have recently agreed to explore specific PBR measures with the commission. • PIMs have been used for energy efficiency for several years; recent call for a review of cost recovery mechanism. • There are currently some performance-based approaches through the efficiency riders, which were established a long time ago.	Exploration; rules under development by commission. In early-2023, HB1007 was introduced as a bill that would establish a study on performance-based ratemaking and codify how much capacity utilities should be able to fulfill through generation or purchasing electricity from other sources.		
OK	• SB 1103 would change the way utilities get regular reviews of rates charged to customers. It would also require the Corporation Commission to accept utility plans to move to performance-based rate-making. • While the commission has the authority to approve PBR cases for utilities, it has not approved previous requests by both Oklahoma Gas & Electric Co. and Public Service Co. of Oklahoma to move away from full-rate cases; PSO has an active case before the commission asking for performance-based rates. • Some natural gas utilities in the state are already regulated using performance-based rate-making plans.	Exploration		
RI	• The commission does not have a universal policy for performance incentives. • In 2018, the Rhode Island Commission rejected six PIM proposals put forward by National Grid, including those focused on the time to interconnect DERs, heating electrification, and installing energy storage,	Implementation		

State	Overview / Background	Status / Recent Developments	Topics Addressed / PIMs	Additional Resources
	stating that the commissioners were not satisfied with the data provided to prove that the incentives were net beneficial • Rhode Island has had incentives for energy efficiency since the 1990s as well as penalties for poor performance on safety and customer service. Targets and allowed incentive amounts have been increased several times since 1990 (incentive money has grown from 4.25% to 5% of spending; the threshold requirement to achieve a financial rewards has become more challenging, increasing from 45% of the targeted annual energy savings to 75%. • Apr 2019 Guidance Document Regarding Principles to Guide the Development and Review of Performance Incentive Mechanisms (Docket No. 4943) • Docket Currently On-Going; Guidance Document Regarding Principles to Guide Development and Review of Performance Incentive Mechanisms • The Commission has drafted a guidance document intended to provide direction on how the PUC will apply its general and specific authority to set rates, tariffs, tolls, and charges to proposals for performance incentives for public utilities under the PUC's jurisdiction. The draft Guidance Document addresses applicability and states principles for the review of performance incentive mechanisms. Docket No. 4943; Draft Guidance Document			
VT	• Statutory basis for performance-based regulation for efficiency – 30 V.S.A. §209(f)(2) • PBR for electric and gas is established in 30 V.S.A. §218d(a)(1) • For efficiency: a litigated process – every three years (2 three-year performance periods) called the Demand Resources Proceeding (DRP) that establishes budgets and QPIs (Quantifiable Performance Indicators) and includes consumer advocate/state energy office, electric utilities, efficiency utilities and third parties (VT PUC Case No. 19-3272-PET). • Efficiency Vermont, which is regulated as a performance-based utility, is responsible for implementing energy efficiency programs and meeting minimum performance requirements • Utilities can earn up to 2.5% of total program budget if it meets peak demand reduction target • Metrics established through a three step process, every 3-4 years (VT PUC Case No 21-3707-PET	Implementation; metrics have been established; currently benchmarking performance over (multi-year process)	Energy Efficiency; summer and winter peak demand savings; greenhouse gas reductions, administrative efficiency, capital expenses; power portfolio; DG; DERs (dynamic controls); EVs; customer service; storage deployment; low-income access Yes	• PBR SWG Expert Webinar on PIMs – VT
WA	• Some forms of PBR have been part of ratemaking for a long time, including decoupling, MYRPs, escalating factors for additional years, earnings sharing mechanisms. • In 2021, legislature passed MYRP law (ESSB 5295) now codified as RCW 80.28.425 which requires, among other things: all utilities to file MYRPs beginning in 2022; the UTC to develop metrics to assess utilities' MYRPs; the UTC to use collaboration and participation to provide clarity and certainty on PBR details; metrics/incentives/penalties may consider: lowest reasonable cost planning, affordability, increases in energy burden, cost of service, customer satisfaction and engagement, service reliability, clean energy or renewable procurement, conservation	Proceeding paused through April 2023 to accommodate legislative workload. Proceeding anticipated to restart in May 2023 – updated work plan to follow. Phase 1: Performance Metrics • Developed metric design principles. • Developed four regulatory goals, and desired outcomes for each:	Current Proposed Topics: Reliability, Equity in reliability, Wildfire avoidance, Natural gas emergency response, Equity in resilience investments, Arrearages, Disconnections, Reconnections,	RCW 80.28.425 U-210590 Proposed PBR Work Plan reported to the Legislature. PSE UE-220066/UG-220067 Final Order

State	Overview / Background	Status / Recent Developments	Topics Addressed / PIMs	Additional Resources
	acquisition, demand side management expansion, rate stability, timely execution of competitive procurement practices, attainment of state energy and emissions reduction policies, rapid integration of renewable energy resources, and fair compensation of utility employees; and increased the public interest standard to include considerations like equity. • Phase 1: Performance Metrics • Identify regulatory goals, desired outcomes, principles for metric design, and performance metrics. • 2023: Develop a website for PBR in WA State - to include tracking and reporting metrics; workplan for Phase 2. • Phase 2 (2023/2024): Reporting, Review, MYRP Revenue Adjustment Mechanisms • UTC to collaborate on developing metric calculations (recognizing different calculations among the utilities - all gas customers are electric customers, but not vice versa); reporting by IOUs and what review process will look like among regulatory staff, intervenors, etc. • Possible rulemaking to address gaps in current rules. • Reviewing MYRPs themselves through revenue adjustments and cost containment. • Reexamine existing mechanisms (e.g., decoupling mechanisms, earning sharing, power cost adjustments, cost recovery mechanisms, etc.) • Phase 3 (2024): PIMs • Establish metric targets and baselines, building off the metrics foundation, define design principles for PIMs and how relates to ROE (topics to discuss: performance-based compensation, stick/carrot, current implied incentives). • Establish PIM mechanisms; legislation related to how earning performance is communicated.	1. Resilient, reliable, customer focused distribution system 2. Customer affordability 3. Advancing equity in utility operations 4. Environmental improvements • Approx 32 metrics being considered within that structure, in addition to 8 financial metrics being considered in the scope of general rate cases, end of proceeding will result in a policy statement to provide guidance to IOUs and participants on metrics development and selection (not necessarily calculation methodology). Note the process will be iterative and decisions are not fixed. • Working to identify “selected” metrics including those required by Order. • Recent Orders that establish MYRP assessing metrics: ➢ PSE UE-220066/UG-220067 Final Order ➢ Avista UE-220053/UG-220054 Final Order	Energy burden, DERs (for highly impacted and vulnerable customers and customers in general), Energy assistance, Incremental cost, Customer awareness of programs (including outreach in multiple languages), Utility workplace diversity, Utility supplier diversity, Expenditures in and for highly impacted communities and vulnerable populations, Participatory justice, Emissions, and Load management. PSE’s approved Settlement in PSE UE-220066/UG-220067 Final Order provides for a PIM to increase demand response.	PSE Metric Reporting Affordability Operational Efficiency Avista UE-220053/UG-220054 Final Order Avista Metric Reporting Developing UTC PBR External Website (under construction) UTC Docket Lookup
WI	• The PSCW has an investigation docket open, 5-EI-158 (Roadmap to Zero Carbon) where stakeholders commented on an interest in exploring PBR. • In January 2022, the Commission held an in-person workshop to facilitate education and dialogue on considerations and options associated with the pursuit of performance-based regulation. • In its Order of April 18, 2022, the Commission ordered Commission staff to facilitate further action to address performance-based regulation through one or more additional workshops, as well as requests for public comment and further analysis. • The Commission also expressed interest in three individual topics for further attention: customer affordability, energy efficiency, and demand response. • Four workshops were held in 2022 and stakeholders developed the following goals for continued development of PBR: Support Affordability and Reduce Energy Burden, Increase Energy Efficiency, Promote Demand Response and Grid Flexibility, Decarbonization, Promote Reliability and Resilience.	In development		Docket 5-EI-158

State	Overview / Background	Status / Recent Developments	Topics Addressed / PIMs	Additional Resources
	• Commission staff are working on a report that brings together information on the stakeholder process, identifies outcomes and potential metrics for the goals, and discusses options for continued work on developing PBR for Wisconsin			

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Inflation Reduction Act Methane Emissions Charge: In Brief

Updated August 29, 2022

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SUMMARY

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Inflation Reduction Act Methane Emissions Charge: In Brief

On August 16, 2022, President Biden signed H.R. 5376 (P.L. 117-169), a budget reconciliation measure commonly referred to as the "Inflation Reduction Act of 2022" (IRA). Among other provisions, IRA includes a charge on methane emissions that is nearly identical to the methane emissions charge in the House version of H.R. 5376, often referred to as the Build Back Better Act, which passed the House on November 19, 2021. Methane (or CH_4) is the primary component of natural gas. When extracted from geologic formations or captured by other means, it can be used as either a fuel or as a feedstock for the chemical industry.

The emissions charge applies only to methane emissions from specific types of facilities that are required to report their greenhouse gas (GHG) emissions to the Environmental Protection Agency's (EPA's) Greenhouse Gas Emissions Reporting Program (GHGRP). The charge starts at $900 per metric ton of methane, increasing to $1,500 after two years. This emissions charge is the first time the federal government has directly imposed a charge, fee, or tax on GHG emissions.

Since its inclusion in the House-passed H.R. 5376, the methane charge proposal has received considerable attention from Members and a range of stakeholders. For example, some groups have raised concerns about economic impacts resulting from the methane charge, including impacts on natural gas prices. Some policymakers are concerned about the charge in the context of EPA's proposed regulations to address methane emissions from the same categories of new and existing facilities that are subject to the methane charge.

A range of factors could play a role in determining the scope of emissions subject to the methane charge and its ultimate impacts on GHG emission levels and economic measures, such as natural gas prices. Selected factors include the following:

- **EPA Regulations of Petroleum and Natural Gas Systems.** On November 15, 2021, EPA proposed regulations to address methane emissions from the same categories of new and existing facilities that are subject to the methane charge. The degree to which the regulations will affect the methane emissions charge depends on the scope and applicability of the final regulations. In particular, IRA allows for an exemption from the emissions charge if EPA regulations addressing methane emissions (1) are in effect in all states, and (2) will "result in equivalent or greater emissions reductions as would be achieved" by the November 2021 proposed rule. IRA directs EPA to determine whether future methane regulations meet these conditions.
- **Changes to Equipment or Operations.** A charge on methane emissions from petroleum and natural gas systems provides an economic incentive for facilities to modify their equipment and operations in order to avoid paying the charge. The degree to which facilities make such changes will likely be based on site-specific economic conditions.
- **Funding for Technological Improvements.** IRA includes supplemental appropriations of $850 million to EPA to provide grants to facilities subject to the methane charge for a range of objectives, including "improving and deploying industrial equipment and processes" that reduce methane emission. The act also includes supplemental appropriations of $700 million for "marginal conventional wells" for the same purposes. These funds could lead to methane reductions at oil and natural gas facilities, thus affecting the impact of the charge.
- **Other IRA Climate and Energy Provisions.** IRA includes a range of climate and energy-related provisions that will likely affect the portfolio of fuels and sources of energy that are used in various economic sectors: electricity, transportation, and industry.

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Introduction

On August 16, 2022, President Biden signed H.R. 5376 (P.L. 117-169), a budget reconciliation measure commonly referred to as the "Inflation Reduction Act of 2022" (IRA). Among other provisions, IRA includes a charge on methane emissions from selected entities in the oil and gas industry. This emissions charge is nearly identical to the methane emissions charge[1] in the House version of H.R. 5376, often referred to as the Build Back Better Act, which passed the House on November 19, 2021.

The methane emissions charge applies only to methane emissions from specific types of facilities that are required to report their greenhouse gas (GHG) emissions to the Environmental Protection Agency's (EPA's) Greenhouse Gas Emissions Reporting Program (GHGRP). The charge starts at $900 per metric ton of methane, increasing to $1,500 after two years, which equates to $36 and $60 per metric ton of carbon dioxide equivalent, respectively. This charge is the first time the federal government has directly imposed a charge, fee, or tax on GHG emissions.[2]

Since its inclusion in the House-passed H.R. 5376, the methane charge has received considerable attention from Members and a range of stakeholders.[3] For example, some groups have raised concerns about economic impacts resulting from the methane charge, including impacts on natural gas prices.[4] Some policymakers are concerned about the charge in the context of EPA's proposed regulations to address methane emissions from the same categories of new and existing facilities that are subject to the methane charge.[5]

This report discusses the scope and applicability of the IRA methane charge. The first section of this report provides background about methane emissions in the United States. The second section discusses the scope and applicability of the methane charge and its rate structure. The last section includes selected factors that may play a role in affecting the scope of the charge and its potential impacts.

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[1] In earlier versions of the bill, this methane charge was called a methane "fee."

[2] For almost 20 years, some Members have put forth various legislative proposals that would attach a price to GHG emissions through carbon taxes, emission fees, or cap-and-trade programs. For more information, see CRS Report R45472, *Market-Based Greenhouse Gas Emission Reduction Legislation: 108th Through 117th Congresses*, by Jonathan L. Ramseur.

[3] According to some analyses, the methane charge accounts for a considerable percentage of the estimated GHG reductions that could be achieved by the Build Back Better Act. See, for example, Megan Mahajan and Robbie Orvis, *Modeling the Infrastructure Bills Using the Energy Policy Simulator*, Energy Innovation: Policy and Technology LLC, October 2021, https://energyinnovation.org/publication/modeling-the-infrastructure-bills-using-the-energy-policy-simulator/; Jeffrey Rissman, "Benefits of the Build Back Better Act's Methane Fee," Energy Innovation: Policy and Technology LLC, October 2021, https://energyinnovation.org/wp-content/uploads/2021/10/Benefits-of-the-Build-Back-Better-Act-Methane-Fee.pdf; Princeton University, Rapid Energy Policy Evaluation and Analysis Toolkit (REPEAT), "Addendum to Preliminary Report: The Climate Impact of Congressional Infrastructure and Budget Bills," November 2021, https://repeatproject.org/.

[4] See, for example, American Gas Association et al., Letter to Congressional Leaders, September 2021, https://www.aga.org/globalassets/letter-to-congress-on-methane-fees-090721_final.pdf; Eweline Czapla, "Methane Fees for Petroleum and Natural Gas Systems," American Action Forum, November 2021, https://www.americanactionforum.org/insight/methane-fees-for-petroleum-and-natural-gas-systems/; Americans for Tax Reform, "Dem Reconciliation Bill Contains $8 Billion Home Heating Tax," November 2021, https://www.atr.org/dem-reconciliation-bill-contains-8-billion-home-heating-tax.

[5] EPA, "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review," 86 *Federal Register* 63110, November 15, 2021. For more background on these issues, see CRS Report R42986, *Methane and Other Air Pollution Issues in Natural Gas Systems*, by Richard K. Lattanzio.

U.S. Methane Emissions and Sources

Methane (or CH_4) is the primary component of natural gas, which can be used as either a fuel or as a feedstock for the chemical industry.[6] Natural gas is generally produced from geologic formations in the ground through drilling and extraction activities by the oil and gas industry. As natural gas travels through the interconnected systems of exploration, production, processing, storage (sometimes), and transmission, that deliver natural gas from the wellhead to the consumer, methane emissions are released into the atmosphere in a variety of ways, including

- intentional venting from equipment (e.g., pneumatic devices);[7]
- unintentional equipment leaks, worker error, or malfunctions;
- routine maintenance of equipment; and
- flaring (burning) of excess natural gas at a petroleum production site, which can result in both uncombusted methane and carbon dioxide (CO_2) emissions.

Methane is a potent GHG. When averaged over a 100-year time period—the time period often used in annual GHG inventories—methane's global warming potential (GWP) is 25 times greater than that of an equivalent mass of CO_2.[8] Over a 20-year time period, methane's GWP is 72 times greater than that of CO_2.[9] Due to methane's shorter-term climate impacts, scientists contend that "methane mitigation [is] one of the best opportunities for reducing near term [global] warming."[10]

As illustrated in **Figure 1**, methane emissions in the United States accounted for 10% of total GHG emissions in 2019 (the most recent year of comprehensive GHG data).[11] The figure identifies the range of sources that produced these methane emissions. Methane emissions from enteric fermentation (e.g., in livestock)[12] accounted for the largest amount, followed by emissions from natural gas systems. If EPA's estimates of methane emissions from natural gas and

[6] For more information, see CRS In Focus IF10752, *Methane Emissions: A Primer*, by Richard K. Lattanzio.

[7] Methane emissions from pneumatic devices have been one of the largest sources of vented methane emissions from the industry. See EPA, *Options For Reducing Methane Emissions From Pneumatic Devices In The Natural Gas Industry*, 2006, https://www.epa.gov/sites/default/files/2016-06/documents/ll_pneumatics.pdf.

[8] Global warming potential (GWP) is an index that allows comparisons of the heat-trapping ability of different gases over a period of time, typically 100 years. Consistent with international GHG reporting protocols, EPA's most recent GHG inventory (April 2022) uses the GWP values presented in the Intergovernmental Panel on Climate Change (IPCC) 2007 *Fourth Assessment Report*. In EPA's inventories and in this report, a metric ton of methane equates to 25 metric tons of CO_2 when averaged over a 100-year time frame. The IPCC has since updated the 100-year GWP estimates, with some increasing and some decreasing. For example, the IPCC 2013 *Fifth Assessment Report* reported the 100-year GWP for methane as ranging from 28 to 36. Pursuant to the United Nations Framework Convention on Climate Change, the United States and other countries will be required to use the 2013 GWP values for GHGs beginning with their 2024 emission inventories.

[9] EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2019*, 2021, Annex 6, Table A-238, https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2019.

[10] EPA, "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review," 86 *Federal Register* 63110, November 15, 2021. To support this argument, EPA cites statements from the Intergovernmental Panel on Climate Change (IPCC), *Sixth Assessment Report,* 2021, https://www.ipcc.ch/report/ar6/wg1/#SPM.

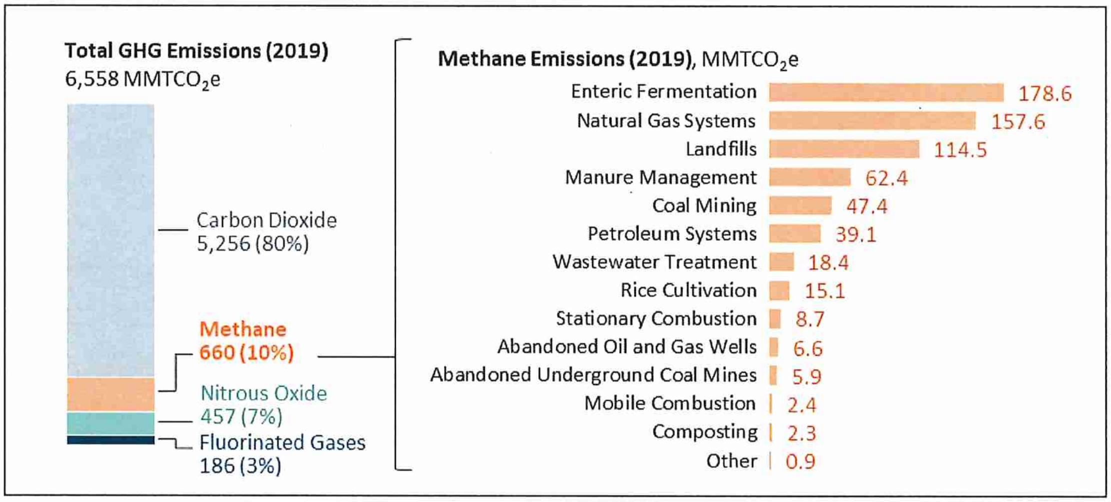
[11] EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2019*, 2021, Table ES-2, https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2019.

[12] *Enteric fermentation* refers to the normal digestive process in ruminant animals, such as cattle, during metabolism and digestion, resulting in methane emissions. For more information, see CRS In Focus IF11404, *Greenhouse Gas Emissions and Sinks in U.S. Agriculture*, by Genevieve K. Croft.

petroleum systems were grouped together, they would account for the largest source of methane emissions, approximately 3% of total U.S. GHG emissions in EPA's inventory.

Figure 1. U.S. Total GHG Emissions by Gas and Sources of Methane Emissions

2019 Emission Estimates from EPA Inventory



Source: Prepared by CRS; emissions data from EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2019*, 2021, Table ES-2, https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2019.

EPA produces the GHG emissions estimates in its annual inventories using commonly accepted emission factors and activity levels to calculate aggregate estimates for all source categories. In recent years, the emission estimates for the natural gas and petroleum system categories have received scrutiny from a range of stakeholders. Some have put forth competing—and sometimes conflicting—estimates.[13]

Inflation Reduction Act Methane Emissions Charge

Scope and Applicability

The IRA methane charge applies to methane emissions from specific types of facilities in the petroleum and natural gas industry that, under current regulations, are required to report their GHG emissions, including methane, to EPA's GHGRP. Since 2011, EPA's GHGRP has collected annual emissions data from nearly 8,000 large industrial facilities and other sources in the United States.[14] The GHGRP requirements are codified in 40 C.F.R. Part 98. Subpart W includes the detailed requirements for petroleum and natural gas facilities.

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[13] See, for example, Jeffrey S. Rutherford et al., "Closing the Methane Gap in US Oil and Natural Gas Production Emissions Inventories," *Nature Communications*, 2021; and Ramon Alvarez et al., "Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain," *Science*, June 2018. For more discussion, see CRS Report R42986, *Methane and Other Air Pollution Issues in Natural Gas Systems*, by Richard K. Lattanzio.

[14] For more information about the GHGRP, see CRS In Focus IF11754, *EPA's Greenhouse Gas Reporting Program*, by Angela C. Jones.

The IRA methane charge applies only to a subset of the petroleum and natural gas system facilities that are required to report GHG emissions in Part 98, Subpart W. The facilities subject to the charge include the following industry operations:

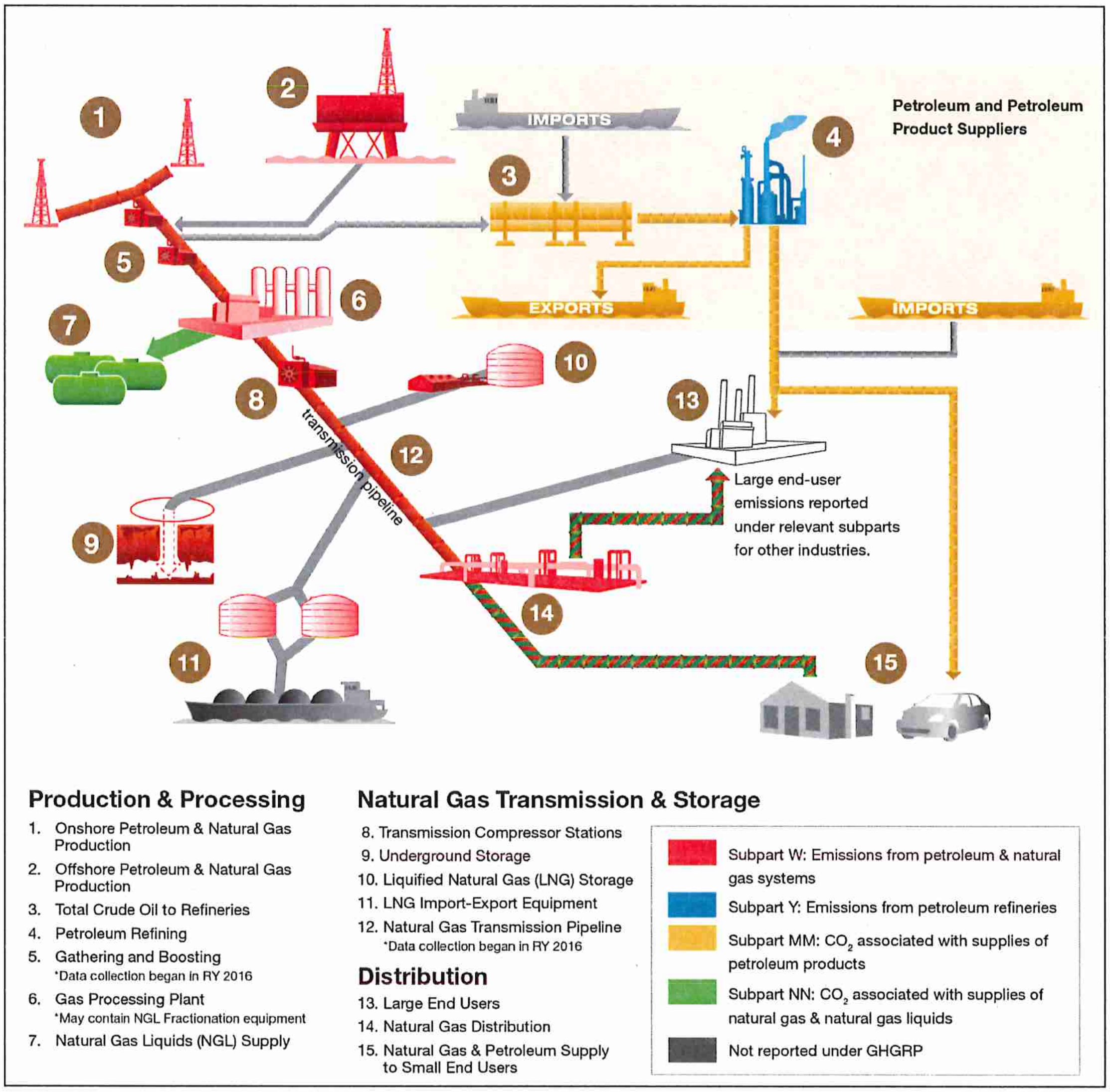
- offshore petroleum and natural gas production;
- onshore petroleum and natural gas production;
- onshore natural gas processing;
- onshore natural gas transmission compression;
- underground natural gas storage;
- liquefied natural gas storage;
- liquefied natural gas import and export equipment;
- onshore petroleum and natural gas gathering and boosting;[15] and
- onshore natural gas transmission pipelines.

Figure 2 illustrates the petroleum and natural gas system entities that are required to report their GHG emissions in EPA's GHGRP. The entities with red labels are subject to Subpart W reporting requirements. Not all of the entities that report emissions under Subpart W are subject to the methane charge. Two facility categories that report emissions under Subpart W are not subject to the methane charge: (1) natural gas distribution facilities and (2) facilities EPA describes as "other oil and gas combustion facilities."[16]

[15] According to EPA, "gathering and boosting stations receive natural gas from production sites and transfer it, via gathering pipelines, to transmission pipelines or processing facilities.... Boosting processes include compression, dehydration, and transport of gas to a processing facility or pipeline." EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2019, p. 3-90, 2021.

[16] EPA states these are "stationary fuel combustion emissions from facilities that are associated with the petroleum and natural gas industry, but that do not report process emissions from any of the above source categories." EPA, *2011-2020 Greenhouse Gas Reporting Program Sector Profile: Petroleum and Natural Gas Systems*, 2020, https://www.epa.gov/ghgreporting/ghgrp-petroleum-and-natural-gas-systems-sector-profile.

Figure 2. Petroleum and Gas Entities Subject to EPA's GHG Emission Reporting Program



Source: Reproduced from EPA, "GHGRP and the Oil and Gas Industry," https://www.epa.gov/ghgreporting/ghgrp-and-oil-and-gas-industry.

Note: RY refers to reporting year for EPA's GHGRP.

The reporting requirements in Subpart W apply to facilities that emit 25,000 metric tons of CO_2 equivalent ($mtCO_2e$) or more per year.[17] The House-passed Build Back Better Act would have directed EPA to revise that threshold (within two years) to 10,000 $mtCO_2e$. This change would have increased the number of facilities subject to EPA's reporting requirements. The methane emissions charge in IRA only applies to facilities that emit 25,000 $mtCO_2e$ or more per year, regardless of any subsequent changes to the scope of EPA's reporting requirements.

[17] Typically, GHG emissions are measured in $mtCO_2e$ because GHGs vary by global warming potential.

Table 1 identifies the number of petroleum and natural gas facilities by category that reported their GHG emissions to EPA in 2019 pursuant to the regulations in 40 C.F.R. Part 98, Subpart W.[18] The table also indicates the total methane emissions for each facility category. In 2019, reported methane emissions from facilities that are subject to the methane charge totaled 78 million mtCO_2e (MMTCO_2e). In 2019, onshore production (44.2 MMTCO_2e) and onshore gathering and boosting (21.9 MMTCO_2e) accounted for 84% of these reported emissions.

As discussed above, natural gas distribution facilities, which report emissions under Subpart W, are not subject to the charge. According to EPA reporting data, 162 natural gas distribution facilities emitted approximately 13 MMTCO_2e of methane in 2019.[19] As indicated in **Table 1**, if these facilities were subject to the charge, this group would rank third in methane emissions.[20]

Table 1. Number of Reporting Facilities and Methane Emissions from Petroleum and Natural Gas System Categories Subject to the IRA Methane Charge

Data for 2019; emissions in million metric tons of CO_2 equivalent (MMTCO_2e)

Facility Type	Number of Reporting Facilities	Reported Methane Emissions (MMTCO_2e)
Onshore petroleum and natural gas production	485	44.2
Onshore petroleum and natural gas gathering and boosting	361	21.9
Onshore natural gas transmission compression	624	4.2
Onshore natural gas transmission pipeline	39	2.9
Natural gas processing	457	2.9
Offshore petroleum and natural gas production	141	1.5
Underground natural gas storage	50	0.6
Liquefied natural gas import and export equipment	10	0.1
Liquefied natural gas storage	5	0.001
Total	**2,172**	**78.3**

Source: Prepared by CRS; data from EPA Greenhouse Gas Reporting Program, Facility Level Information on Greenhouse Gases Tool (FLIGHT), https://ghgdata.epa.gov.

Notes: The methane charge applies to facilities required to report under 40 C.F.R. Part 98, Subpart W. The reporting requirements apply to facilities that emit 25,000 metric tons of CO_2 equivalent (mtCO_2e) or more per year. Typically, GHG emissions are measured in mtCO_2e because GHGs vary by global warming potential (GWP). GWP is an index that allows comparisons of the heat-trapping ability of different gases over a period of time, typically 100 years. A number of other facilities reported methane emissions (and other GHG emissions) under Subpart W during these years, but these facilities are not subject to the methane charge. These include 162 natural gas distribution facilities, which reported 13 MMTCO_2e of methane in 2019.

[18] Although reported emissions are available for 2020, the 2019 emissions data arguably provide a more useful indication of the magnitude of emissions than 2020 data due to impacts associated with the Coronavirus Disease 2019 (COVID-19) pandemic. In 2020, the reported emissions comparable to those in **Table 1** were 69.4 MMTCO_2e, 11% lower than those in 2019.

[19] EPA Greenhouse Gas Reporting Program, Facility Level Information on Greenhouse Gases Tool (FLIGHT), https://ghgdata.epa.gov.

[20] In addition, the methane fee does not apply to emissions from facilities EPA describes as "other oil and gas combustion facilities." In 2019, 55 such facilities reported approximately 5,000 mtCO_2e of methane.

EPA's GHGRP covers a subset of U.S. methane emissions from petroleum and natural gas systems. It is uncertain what percentage of total emissions from this sector the reporting program covers. When EPA issued its final rule promulgating the Subpart W reporting regulations in 2010,[21] the agency estimated that the 25,000 $mtCO_2e$ reporting threshold would cover 85% of the methane emissions from the reporting categories. In the 2010 rule, EPA also estimated that decreasing the reporting threshold to 10,000 $mtCO_2e$ would increase the emissions coverage to 91%.[22] These estimates appear to be out of date. EPA stated in 2019 that the agency "does not have an exact estimate of what percent of U.S. emissions are covered under petroleum and natural gas systems at this time.... EPA will continue to analyze the emissions from reports as well as linking the information to the US GHG Inventory to identify what fraction of emissions from petroleum and natural gas systems are covered by the GHGRP."[23]

As a point of reference, **Table 2** lists the methane emission estimates from EPA's emission inventory for the petroleum and natural gas system activities that match the applicability of the IRA methane charge.[24] As the inventory estimates are intended to capture all of the methane emission in petroleum and natural gas systems, the inventory estimates are higher. As mentioned above, some have argued that EPA's inventory estimates of methane emissions from these systems have underestimated the magnitude of emissions. For example, a 2018 study estimated that methane emissions in these sectors are 60% higher than the estimates in EPA's inventory.[25]

Table 2. EPA GHG Emission Inventory Estimates of Methane Emissions from Petroleum and Natural Gas and Systems (2019)

Million Metric Tons CO_2e

Activity	Methane Emissions
Total onshore petroleum and natural gas production	84.7
Onshore natural gas production	*52.0*
Onshore petroleum production	*32.7*
Total offshore petroleum and natural gas production	5.8
Offshore natural gas production	*0.8*
Offshore petroleum production	*5.0*
Natural gas gathering and boosting	40.9
Natural gas processing	12.4
Natural gas transmission and storage	37.0
Total of above activities	**180.8**

[21] EPA, "Mandatory Reporting of Greenhouse Gases: Petroleum and Natural Gas Systems," Final Rule, 75 *Federal Register* 74458, November 30, 2010 (hereinafter, 2010 Final Rule).

[22] See Table 7B in 2010 Final Rule.

[23] EPA, Frequently Asked Questions, GHGRP, Subpart W, "What percentage of emissions from petroleum and natural gas systems are reported under the GHGRP?" September 25, 2019, https://ccdsupport.com/confluence/pages/viewpage.action?pageId=189038686.

[24] For example, methane emissions from natural gas distribution are not included in the table, as they are not subject to the fee.

[25] Ramon Alvarez et al., "Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain," *Science*, June 2018.

Source: Prepared by CRS; data from EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2019*, 2021, Table 3-38 and Table 3-63, https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2019.

In IRA, the scope of emissions subject to the charge is based on (1) the facility's reported emissions under EPA's GHGRP, as described above, and (2) an emissions threshold that varies by facility type.

- For petroleum and natural gas production facilities, the charge applies only to the number of reported tons of methane that exceed 0.2% of the natural gas sent to sale from such a facility.
- For nonproduction facilities, such as gathering and boosting facilities, the charge applies to methane emissions that exceed 0.05% of the natural gas sent for sale from the facility.
- For natural gas transmission facilities, the charge applies to methane emissions that exceed 0.11% of the natural gas sent for sale from the facility.

These thresholds effectively allow for some amount of methane to be released from these facilities without being subject to the charge, thus decreasing the amount of emissions reported under the GHGRP that are subject to the charge. **Table 3** compares the actual reported emissions (in 2019) for onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities (the two facility types that account for most of the methane emissions) with the emissions that are subject to the methane charge at these facilities. As the table indicates, when the thresholds are applied, the methane emissions subject to the charge decrease by about 35%.

Table 3. Estimate of Methane Emissions Subject to Charge After Applying Emissions Thresholds (Based on 2019 Data)

Million Metric Tons CO_2e

Facility Type	Reported Methane Emissions	Reported Methane Emissions Subject to Charge After Applying Emissions Threshold
Onshore petroleum and natural gas production	44.2	27.2
Onshore petroleum and natural gas gathering and boosting	21.9	15.6
Total	**66.1**	**42.8**

Source: Prepared by CRS; emissions data from EPA Greenhouse Gas Reporting Program Facility Level Information on Greenhouse Gases Tool (FLIGHT), https://ghgdata.epa.gov; facility data (sales of natural gas and barrels of oil) from EPA Envirofacts database, customized search of petroleum and natural gas systems, using "facility overview" dataset.

Notes: To estimate the methane emissions potentially subject to the charge, CRS applied the relevant emissions threshold (e.g., 0.2% for production facilities) to the natural gas or petroleum sales at each facility. This value was then subtracted from the reported methane emissions. The remaining emissions are subject to the charge. For some facilities, the threshold application resulted in these facilities not having any methane emissions subject to the charge.

In its August 3, 2022, cost estimate ("score") of the Inflation Reduction Act, the Congressional Budget Office (CBO) provided another resource that may be informative. CBO estimated the revenue that the methane charge will generate over time. CBO's estimated revenue by fiscal year is provided in the first row of **Table 4**. CBO's analysis does not provide an estimate of methane emissions subject to the charge, but **Table 4** provides these estimates by applying CBO's revenue estimate and the rate of the charge in the act. As CBO's revenue estimates are *net* revenue estimates, the second row includes an estimate of *gross* revenue from the methane charge.[26] The annual gross revenue is divided by the rate of the methane charge (ranging from $900 to $1,500) to produce annual estimates of methane emissions (in metric tons of methane). The last row converts metric tons of methane into metric tons of CO_2e for comparison purposes.

Table 4. Estimate of Methane Emissions Subject to the Charge Based on CBO's August 2022 Cost Estimate Analysis of the Inflation Reduction Act

	FY2026	FY2027	FY2028	FY2029	FY2030	FY2031
CBO Revenue Estimate (Net)	$850 million	$1,350 million	$1,400 million	$1,200 million	$1,050 million	$500 million
Estimate of Gross Revenue from Methane Charge	$1,133 million	$1,800 million	$1,867 million	$1,600 million	$1,400 million	$667 million
Methane Charge (dollars per metric ton of methane)	$900	$1,200	$1,500	$1,500	$1,500	$1,500
Estimated Methane Emissions Subject to the Charge (million metric tons methane)	1.3	1.5	1.2	1.1	0.9	0.4
Estimated Methane Emissions Subject to the Charge (million metric tons CO_2e)	31	38	31	27	23	11

Source: Prepared by CRS; the data in the first row, "CBO Revenue Estimate (Net)," are from CBO, *Estimated Budgetary Effects of H.R. 5376, the Inflation Reduction Act of 2022,* August 3, 2022, https://www.cbo.gov/publication/58366. Gross revenues are net revenues multiplied by 1.25. In the above estimates, the revenue collected in FY2026 accounts for methane emissions in calendar year 2024, during which the methane charge is $900 per metric ton of methane; the revenue collected in FY2027 accounts for methane emissions in calendar year 2025, during which the methane charge is $1,200 per metric ton of methane. Subsequent fiscal year collections involve a methane charge of $1,500 per metric ton of methane.

Rate of Charge

The methane emissions charge in IRA starts in calendar year 2024 at $900 per metric ton of methane, increases to $1,200 in 2025, and increases to $1,500 in 2026. The charge remains at $1,500 in subsequent years. **Table 5** indicates the value of the methane charge rates in $mtCO_2e$, the measure commonly used in carbon tax and emission charge proposals. The methane charge

[26] CBO explains, "When excise taxes, customs duties, and other types of 'indirect' taxes are imposed on goods and services, they tend to reduce income for workers or business owners in the taxed industry and for others throughout the economy. Consequently, revenue derived from existing 'direct' tax sources—such as individual and corporate income taxes and payroll taxes—will also be reduced. To approximate that effect, the Congressional Budget Office (CBO), the Joint Committee on Taxation (JCT), and the Treasury Department's Office of Tax Analysis (OTA) apply a 25 percent offset when estimating the net revenue that legislation imposing some form of indirect tax is expected to generate." CBO, *The Role of the 25 Percent Revenue Offset in Estimating the Budgetary Effects of Legislation*, 2009, https://www.cbo.gov/publication/20110.

rates below are comparable to the carbon tax and emission charge rates in recent legislative proposals.[27]

Table 5. Methane Charge Rates

Methane Charge Measure	2024	2025	2026	After 2026
Dollars per metric ton of CH_4 emissions	$900	$1200	$1500	$1500
Dollars per metric ton of CO_2 equivalent	$36	$48	$60	$60

Source: Prepared by CRS; dollars per metric ton of CO_2 equivalent calculated using a global warming potential (GWP) of 25. GWP is an index that allows comparisons of the heat-trapping ability of different gases over a period of time, typically 100 years. Consistent with international GHG reporting protocols, EPA's most recent GHG inventory (April 2022) uses the GWP values presented in the Intergovernmental Panel on Climate Change (IPCC) 2007 *Fourth Assessment Report*. In EPA's inventories and in this report, a metric ton of methane equates to 25 metric tons of CO_2 when averaged over a 100-year time frame. The IPCC has since updated the 100-year GWP estimates, with some increasing and some decreasing. For example, the IPCC 2013 *Fifth Assessment Report* reported the 100-year GWP for methane as ranging from 28 to 36. Pursuant to the United Nations Framework Convention on Climate Change, the United States and other countries will be required to use the 2013 GWP values for GHGs beginning with their 2024 emission inventories. A GWP for methane of 28 would lower the dollars per metric ton of CO_2 equivalent from $36 to $32.

Potential Exemption from Charge

IRA provides for a conditional exemption from the methane emissions charge if facilities are subject to and in compliance with subsequent Clean Air Act methane regulations. To date, such regulations have not been finalized. On November 15, 2021, EPA proposed regulations to address methane emissions from the same categories of new and existing facilities that are subject to the IRA methane charge.[28] IRA allows for an exemption from the emissions charge if future, final EPA regulations addressing methane emissions (1) are in effect in all states, and (2) will "result in equivalent or greater emissions reductions as would be achieved" by the November 2021 proposed rule. IRA directs EPA to determine whether future methane regulations will meet these conditions.

Selected Factors Affecting the Scope and Impact of the Methane Charge

A range of factors could play a role in determining the scope of emissions subject to the IRA methane charge and its ultimate impacts on GHG emission levels and economic measures, such as natural gas prices. A comprehensive analysis of these factors is beyond the scope of this report. Selected factors include the following:

[27] For more information, see CRS Report R45472, *Market-Based Greenhouse Gas Emission Reduction Legislation: 108th Through 117th Congresses*, by Jonathan L. Ramseur.

[28] EPA, "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review," 86 *Federal Register* 63110, November 15, 2021. For more background on these issues, see CRS Report R42986, *Methane and Other Air Pollution Issues in Natural Gas Systems*, by Richard K. Lattanzio.

- **EPA Regulation of Petroleum and Natural Gas Systems.** On November 15, 2021, EPA proposed regulations to address methane emissions from the same categories of new and existing facilities that are subject to the methane charge.[29] As discussed above, if EPA finalizes these requirements, they may provide for an exemption from the methane emissions charge. The degree to which the regulations will affect the methane emissions charge depends on the scope and applicability of the final regulations.
- **Changes to Equipment or Operations.** A charge on methane emissions from petroleum and natural gas systems provides an economic incentive for facilities to modify their equipment and operations in order to avoid paying the charge. Economic theory suggests facilities will likely find ways to reduce onsite methane emissions until the costs associated with these changes reach the level of the charge. At that point, facilities will pay the charge for the remaining emissions. The degree to which facilities make such changes will likely be based on site-specific economic conditions.
- **Funding for Technological Improvements.** The Inflation Reduction Act includes supplemental appropriations of $850 million to EPA to provide grants to facilities subject to the methane charge for a range of objectives, including "improving and deploying industrial equipment and processes" that reduce methane emission. The act also includes supplemental appropriations of $700 million for "marginal conventional wells" for the same purposes. These funds may lead to methane reductions at oil and natural gas facilities, thus affecting the impact of the charge.
- **Other IRA Climate and Energy Provisions.** IRA includes a range of climate and energy-related provisions that will likely affect the portfolio of fuels and sources of energy that are used in various economic sectors: electricity, transportation, and industry.[30]

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[29] EPA, "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review," 86 *Federal Register* 63110, November 15, 2021. For more background on these issues, see CRS Report R42986, *Methane and Other Air Pollution Issues in Natural Gas Systems*, by Richard K. Lattanzio.

[30] For example, see Rhodium Group, "A Congressional Climate Breakthrough," July 28, 2022, https://rhg.com/research/inflation-reduction-act/; and Princeton University Rapid Energy Policy Evaluation and Analysis Toolkit ("REPEAT Project"), *Preliminary Report: The Climate and Energy Impacts of the Inflation Reduction Act of 2022*, accessed August 4, 2022, https://repeatproject.org/.

Disclaimer

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I, Sharon Ferguson, hereby certify that I have this day, served copies of the following document on the attached list of persons by electronic filing, certified mail, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

Minnesota Department of Commerce
Comments

Docket No. E002/CI-17-401

Dated this **28th** day of **July 2023**

/s/Sharon Ferguson

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