Washington Utilities and Transportation Commission Docket U-210590

Phase I – Virtual Workshop: Performance Metrics

November 7, 2022 | 9:30 am to 4:30 pm PT

***Summary and meeting notes ***

Contents

Meeting Summary

On November 7, 2022, the Washington Utilities and Transportation Commission (UTC or the Commission) convened a third workshop with interested persons in UTC Docket U-210590, a proceeding to address alternatives to traditional cost of service rate making, including performance measures or goals, targets, performance incentives, and penalty mechanisms for the state's investor-owned electric and natural gas utilities. **This document summarizes key discussion points from the workshop and anonymized meeting notes**.[1]

The workshop was held virtually from 9:30 am to 4:00 pm PT. There were approximately 50 individuals who attended. The meeting was noticed in Docket U-210590 and all interested persons were welcome to attend.

This workshop series is being convened by the UTC, with technical support from the Regulatory Assistance Project (RAP), and facilitation support from the Great Plains Institute (GPI).

BACKGROUND

Across the United States, many utility regulatory commissions are considering performance-based regulation (PBR)—a catch-all term for a variety of regulatory tools—as a way to align utility performance with the public interest. This is happening against a backdrop of transformation in the energy sector from both a technology and a policy perspective. Energy systems that were built to deliver the one-way flow of electricity from large, continuous generation power plants to end users are being challenged to incorporate both intermittent and distributed energy resources. Meanwhile, the definition of what constitutes the public interest is evolving from the traditional concepts of safe, reliable, and affordable to include new concepts such as reducing greenhouse gas emissions, fostering customer choice, and ensuring equitable impacts and outcomes.

In Washington, Section 1 of Engrossed Substitute Senate Bill 5295 (SB 5295), approved in May 2021 and now codified as RCW 80.28.425, directed the UTC to "conduct a proceeding to develop a policy statement addressing alternatives to traditional cost of service rate making, including performance measures or goals, targets, performance incentives, and penalty mechanisms."[2]

The Washington Legislature directed the UTC to, as part of its proceeding, allow for participation and consultation with regulated utilities, the attorney general's office, and other interested participants including, but not limited to, residential, industrial, commercial, and low-income customers and organizations, as well as environmental or community organizations and other persons. The UTC has provided several comment period(s) and workshop(s) that were specifically designed to seek consultation and provide meaningful opportunities for participation.

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[1] The notes have been anonymized to facilitate a learning environment and to allow meeting participants to speak freely during meetings without concern of their comments being formally attributed to them in Docket U-210590.

[2] See RCW 80.28.425 (2021 c 188 Sec. 1).

The November 7, 2022, workshop is the last of three proposed workshops in Phase 1 of Docket U-210590.

The UTC is currently working on developing a work plan for Phase 2, which will also include several comment period(s) and workshop(s) that are specifically designed to seek consultation and provide meaningful opportunities for participation. The UTC anticipates providing a draft Phase 2 work plan before the completion of Phase 1. Below is an updated Phase 1 work plan.

Table 1. Phase 1 Work Plan

Event	Dates
Notice for Written Comment: Draft Work Plan	October 11, 2021
Written comments due	November 29, 2021
UTC report to the Legislature – Work plan and progress to-date	December 31, 2021
Regulatory Assistance Project report on Performance-based regulation (PBR) – literature review and best practices	March 2, 2022
Workshop: Proceeding Scope and Expectations; Preliminary Discussion of Phase 1 Topics and Expectations for Participant Input	April 19, 2022
Notice for Written Comment – Articulation of Regulatory Goals and Desired Outcomes; Principles for Metric Design	May 2, 2022
Written comments due	June 13, 2022
Workshop: Articulation of Regulatory Goals and Desired Outcomes; Principles for Metric Design; Discussion of Written Participant Comments	July 25, 2022
Notice for Written Comment – (Tentative Topics) Identifying Performance Metrics (consistent with Articulated Goals, Desired Outcomes, and Metric Design Principles)	August 5, 2022
Written comments due: Provide Proposed Metrics Respond to Proposed Metrics	September 6, 2022 September 26, 2022
Workshop: (Tentative Topics) Identifying Performance Metrics: Discussion of Written Comments	November 7, 2022
Notice for Written Comment – (Tentative Topics) Selected Performance Metrics Inclusive of November 7 Workshop Feedback	November 30, 2022
Written comments due	December 30, 2022
Policy statement (Phase I) – Anticipated Issue Date	April 28, 2023

THIS PROCEEDING

The UTC opened Docket U-210590 in response to RCW 80.28.425 (SB 5295) and subsequently issued a notice for comment on a proposed work plan for the proceeding on October 11, 2021, followed by issuance of an updated work plan in response to comments on January 27, 2022. The work plan is broken into 5 phases, shown in Table 1 below, that are expected to take place from 2022 through 2025, with continuous review and improvement thereafter. The January 27, 2022, work plan contains "anticipated" timelines and is subject to change. Changes can depend on the need to seek additional comments, hold additional workshops, developments during legislative sessions, and other general workload concerns at the UTC. This is an iterative process and therefore flexibility is key.

The first phase of the work plan seeks to establish regulatory goals, desired outcomes, metric design principles, and identify utility performance metrics or measures that are in alignment with the goals, outcomes, and principles. Importantly, consideration of incentives or penalties that may be attached to metrics will not be considered until Phase 3 of the process.

Table 2. Work Plan Phases

PHASE AND SCOPE	ANTICIPATED DATE
Phase 1 – Performance Metrics A. Identify regulatory goals, desired outcomes, and principles for metric design B. Identify performance metrics	October 2021–April 2023
Phase 2A – Reporting and Review A. Establish utility-specific performance metrics B. Establish reporting and review process	April 2023–December 2023
Phase 2B – Multiyear Rate Plan (MYRP) Revenue Adjustment Mechanisms A. Identify approaches to utility cost containment B. Identify principles for designing revenue adjustments within multiyear rate plans C. Reexamine existing mechanisms (*e.g.*, decoupling mechanisms, power cost adjustments, cost recovery mechanisms, etc.)	December 2023–December 2024
Phase 3 – Performance Incentive Mechanisms (PIM) A. Identify PIM design principles B. Identify performance baselines, performance targets C. Identify guidelines for PIM development D. Establish incentive/penalty mechanisms E. Examine interplay between existing mechanisms, MYRPs, performance metrics, and PIMs	January 2024–December 2024 (Subject to Change)

Phase 4 – Alternatives to Traditional Cost-of-Service A. Educational/level-setting webinar alternatives to traditional cost-of-service regulation B. Identify alternatives to traditional cost-of-service regulation C. Consider the merits and prospects for alternative forms of regulation for regulated utilities in Washington state	January 2025–December 2025 (Subject to Change)
Phase 5 – Continuous Policy Process A. Establish a continuous process for re-evaluating/improving Commission policy on performance-based ratemaking and other alternative forms of regulation B. Continuously reevaluate regulatory objectives C. Continuously reevaluate metrics, targets, and incentive mechanisms	January 2025–ongoing (Subject to Change)

MEETING OBJECTIVES

The first phase in this proceeding is to establish a draft set of regulatory goals, desired outcomes, and metric design principles that can collectively inform the development of performance metrics or measures. Accordingly, the first workshop, held on April 19, 2022, focused on building a shared understanding of the overall proceeding as well as basic concepts of performance-based regulation. Furthermore, the workshop also solicited initial comments from participants on the current regulatory framework, incentives and measures utility performance and any input and ideas on regulatory goals, desired outcomes, and metric design principles.

A second workshop was convened to discuss the Commission's draft guidance related to regulatory goals, desired outcomes, and performance metric design principles. The Commission defines these terms as follows:

- Regulatory Goals: Aligns utility behaviors with commission, societal, or legislative goals or mandates.
- Desired Outcomes: With a focus on outputs (rather than inputs), aligns regulatory goals with desired results and impact on ratepayers and society.
- Performance Metric: Measurable and quantifiable data used to track specific actions, outcomes, or results. It is often expressed in terms of standard power system measures or consumer impact measures.

The regulatory goals, desired outcomes, and performance metric design principles were included on the Commission's July 18, 2022, Notice of Virtual Workshop. The second workshop sought to solicit input on whether these goals, outcomes, and metric design principles should be kept as-is, modified, or discarded, and whether new goals, outcomes, and metric design principles should be included. The resulting goals, outcomes, and metric design principles established helped to inform the next step of this proceeding: selection of utility performance metrics.

The third workshop in Phase 1 provided participants with the opportunity to voice their feedback and input on a selection of 32 metrics, consolidated from approximately 200 plus metrics

submitted through written comment. Accordingly, this workshop focused on the following objective:

- To seek feedback on the 32 selected metrics for the established goals and outcomes.
- To achieve consensus, if possible, on draft metrics. Consensus is not necessary, but it would be useful to identify where consensus exists.
- To gain clarity on the specifics related to the selected metrics as well as terms used (*i.e.*, define benefits).
- To evaluate metrics in concept and assess based on fit with the goals, outcomes, and design principles. Some metrics may be ready to implement today, and some may require additional development and data needs.

AGENDA SUMMARY

PART 1: Getting Started

9:30 a.m. Welcome, introductions, agenda review

9:45 a.m. Goals and Ground Rules

PART 2: Review and Discuss Metrics by Outcome and Goal Area[3]

9:50 a.m. Resilient, reliable, and customer-focused distribution grid

10:50 a.m. BREAK

11:00 a.m. Customer affordability

12:00 p.m. LUNCH

1:00 p.m. Advancing Equity in utility operations

2:00 p.m. Environmental improvements

3:00 p.m. BREAK

PART 3: Additional Discussion as Needed

3:15 p.m. Revisit metrics or topics needing further discussion

4:30 p.m. ADJOURN

[3] Times below represent the maximum initial time allotted for each goal area, with the option to move faster or to revisit outcomes needing more discussion later in the agenda. Participating organizations with multiple employees in attendance are asked to consider limiting their participation to a single representative of the organization during each goal area.

Meeting Notes

NOTE: Meeting notes are organized in an alphanumeric format for organizational and reference purposes only; the format does not indicate any ranking or prioritization of items unless otherwise noted.

Getting Started: Introductory Comments

1. No questions about the Workshop Notice (issued November 2, 2022) or overall process.
2. Commissioners' opening statements:
    a. Chair Danner
        i. This workshop pertains to the identified performance metrics that the Commissioners have developed in collaboration with the performance-based regulation team.
        ii. None of the performance metrics currently proposed are concrete.
        iii. Important to look at alternatives to the traditional cost-of-service regulation model moving forward.
    b. Commissioner Rendahl
        i. Developing the proposed performance metrics was a significant collaborative effort from the Commission, Great Plains Institute (GPI), the Regulatory Assistance Project (RAP), and proposing parties.
        ii. UTC wants to hear feedback moving forward.
        iii. The Commissioners selected what they think are the best metrics to carry to the next steps in the process but want to hear opinions and suggestions so that UTC can move forward to developing the Policy Statement.
    c. Commissioner Doumit
        i. Echoes Chair Danner, looking forward to the discussion.
3. Ground rules:
    a. GPI facilitating the discussion and providing UTC with support throughout the process.
    b. Seeking feedback on draft proposed performance metrics.
    c. Workshop goal: collectively evaluate the metrics in concept based on how well they fit with the Goals, Outcomes, and Metric Design Principles
        i. Identify the best metrics.
        ii. Specific definitions and calculations (as well as some metrics as a whole) may need further consideration/modification.
        iii. Today, UTC is aiming to solidify key concepts for the performance metrics, not the specific calculations.
        iv. Specific details pertaining to each selected performance metric will be determined at a later phase in the process.
4. Key workshop questions:

a. Whether they have clarifying questions about the proposed metrics (*i.e.*, questions seeking to better understand what is being proposed or how the metric works).
b. Whether any of the selected metrics should be modified (and if so, how) or removed to better align the metrics with the goals, outcomes, and design principles.
c. Whether additional metrics should be added to better align the metrics with the goals, outcomes, and design principles.

5. UTC: The 32 metrics discussed today reflect a combination of metrics proposed by proceeding participants and were not developed by the UTC, RAP, or GPI.
6. Process Questions:
    a. The notice containing the draft proposed performance metrics was posted less than a week ago. Many of the metrics are challenging, the issues are diverse and wide in breadth, and the metrics require extensive review by subject matter experts to fully understand potential ramifications. What opportunities will parties have beyond this workshop to further analyze and provide feedback on the proposed performance metrics?
        i. At the end of the workshop, UTC will discuss the next steps. The Commission received responses containing proposed performance metrics in September, narrowed the list of >200 proposed performance metrics by consolidating duplications, refining metrics to what best fit within UTC's regulatory goals, desired outcomes, design principles, etc.
        ii. Final performance metrics will be established for specific investor-owned utilities (IOUs) in Phase 2A.
        iii. Today is the primary opportunity to discuss the proposed performance metrics, but UTC will pursue further discussions after this workshop if needed.
        iv. UTC is currently considering the proposed performance metrics and their calculations in concept—final calculations will not be determined today.
    b. Initial comments and proposed performance metrics were very high-level. Still concerned with not having sufficient opportunity to fully vet the (now more specific) performance metrics.
        i. Everyone has had access to all submitted comments and proposed performance metrics since September 6th. If one participant is having these concerns, others may have them, too. UTC will check in on this at the end of today's workshop.
    c. Will today's workshop be structured such that we spend approximately 1 hour on each goal?
        i. Yes, we will spend approximately one hour for each goal, and we will go outcome-by-outcome within each goal (and metric-by-metric within each outcome).
        ii. Individual participant comments regarding the metrics as a whole—of the 32 proposed performance metrics, they support half of them as-written,

and either support-with-modification or have further questions about the other half.

(1) Generally, agrees with the proposed performance metrics, but it is difficult to separate the calculation discussion with the broader conceptual discussion.

(2) There are 140 individual calculations associated with just these 32 metrics—not as concise as it seems.

Goal 1: Resilient, reliable, and customer-focused distribution grid

OUTCOME 1: ENSURE UTILITY RESPONSIVENESS TO CUSTOMER OUTAGES AND RESTORATION TIMES.

Metric 1: Equity in Reliability (SAIDI) for Named Communities and Non-named Communities.

Metric 1 calculation: Sum all customer interruption minutes for interruptions greater than 5 minutes for one year and divide it by the average annual customer count. Provide this calculation for the service territory as a whole and separately for Named Communities.

1. Concerned about the focus on interruptions >5 mins in Metric 1 and Metric 2. IOUs often only measure longer-term outages, but this participant's area has many short-term outages, which impacts residents and small businesses. A two-second interruption can impact a business for hours.
    a. IOUs have a responsibility to manage their system to prevent surges on power lines from short-term outages, which permanently damaged his electronics.
    b. Long-term and short-term outages are both important.
    c. Recommends inclusion of a performance metrics that tracks short-term outages.
2. For both Metric 1 and Metric 2, would the System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) calculations include major event days? The Institute of Electrical and Electronics Engineers (IEEE) says unless specifically stated otherwise, SAIDI and SAIFI should exclude major event days.
    a. A major event day is based on a calculation of total customer outage minutes compared to outage minutes from the prior year. When an outage reaches a certain target (threshold updated every calendar year), it is a major event day. The distinction is based less on individual system faults than on factors that would be likely to overwhelm any system.
        i. Blue sky reliability vs. catastrophic events.
    b. To understand base reliability level, you don't include major event days. That doesn't mean that major event days are not important, but it may be better to have one calculation that excludes major event days, and one that includes major event days.
    c. A major event day should be something like a day with 60 mph winds. If an IOU experiences outages on days with <30 mph winds, it should be an indication that the utility needs to be doing more to ensure reliability.
        i. Defining a major event day as a day when many customers lose power is not a good idea.
            (1) GPI: Defining a major event day will be part of later discussions.
    d. Additional SAIDI/SAIFI calculation questions and comments:
        i. Would the comparison between Named vs. Non-named communities be in aggregate?
        ii. SAIDI/SAIFI are not customer-centric, but Outcome 1 is customer-centric; these metrics may fit better under Outcome 3. Customer Average Interruption Duration Index (CAIDI)/Customer Average Interruption Frequency Index (CAIFI) may be better customer-focused metric because

they can be calculated down to the census tract or Named Community level.

iii. Cannot bifurcate SAIDI for low-income customers, even as a minimum level of granularity, and struggles to get Washington-specific SAIDI/SAIFI data.

e. UTC: Is there a way to overcome feeder line barriers to Named Communities?
   i. It may not be possible. Feeder lines can stretch hundreds of miles. From an electric system standpoint, there will never be a 1:1 relationship between feeder lines and Named Communities and some feeder lines cross into different states. SAIDI/SAIFI are informative for system-level calculations, not community-level calculations, but other metrics may be able to better achieve community-level granularity.

f. Outlying communities are often out of power for days or weeks after major events. IOUs should report this.

g. Concerns about switching to CAIDI/CAIFI from SAIDI/SAIFI because they measure different things. Might want to consider including all four as performance metrics.
   i. Sum of all customer interruption durations / total number of customer interruptions (essentially the frequency) – increasing the frequency of customer interruptions could lower CAIDI.
   ii. CAIDI actually measures average interruption duration, as opposed to the average number of minutes that customer is without power.
   iii. Acknowledges challenges with SAIDI/SAIFI in Named vs. Non-named Communities.
      (1) Original commenter does not recommend replacing SAIDI/SAIFI metrics with CAIDI/CAIFI metrics but thinks that these metrics may fit better under Goal 1, Outcome 3.

3. Are Metric 1 and Metric 2 only relevant to electric utilities?
   a. All Goal 1 outcome metrics are electric IOU-focused.
4. Gas utilities have a large group of customers who sign up for service that is designed to be potentially interrupted.
   a. If a customer is not set up to handle an interruption it is very bad.
   b. If gas is included in this metric, UTC needs to consider load that may be shed intentionally as part of these customers' intentionally interruptible service.
      i. Metric 6 (under Goal 1, Outcome 2) may fit this better.

Metric 2: Equity in Reliability (SAIFI) for Named Communities and Non-named Communities

Metric 2 calculation: Sum the total number of all customer interruptions, for interruptions greater than 5 minutes, for one year and divide it by the average annual customer count. Provide this calculation for the service territory as a whole and separately for Named Communities.

1. Participants discussed Metric 1 and Metric 2 together. Refer to Metric 1 notes for a comprehensive discussion of participants' comments on both proposed performance metrics.

Metric 3: Equity in Reliability: length of power outages.

Metric 3 calculation: Average and median length (in minutes) of power outages per year, separately calculating Named and Non-named Communities for comparison.

1. Many of the proposed metrics are electric-only. Recommend addressing generic language or terminology.
    a. Example: Could change "length of power outages" to "length of energy outages."

Metric 4: Historically Worst Performing Circuits.

Metric 4 calculation: The 10 worst performing circuits in any given year separately by both frequency and duration. In addition, of the 10 worst performing circuits (separately by frequency and duration), the number of years over the past five years that a circuit has appeared on the list.

1. What should be used to calculate frequency and duration?
    a. There is a menu to select from for identifying the worst performing circuits.
    b. Participant notes that they are ok with the concept of the metric, but are unsure how it will be calculated, whether this calculation would be uniform across utilities, etc.
    c. All metrics under Goal 1, Outcome 1 are electric specific as defined by IEEE.

OUTCOME 2: UTILITIES ARE PREPARED FOR AND RESPOND TO OUTAGES AND OTHER IMPACTS CAUSED BY CYBERATTACKS, SIGNIFICANT EVENTS, WILDFIRES, STORMS, EXTREME WEATHER EVENTS, AND OTHER NATURAL DISASTERS.

Metric 5: Wildfire Avoidance.

Metric 5 calculation: Number of utility-caused wildfires, ignitions (that do not result in wildfires but could have), and risk events (event with probability of ignition).

1. The most common causes of fires in fault zones are gas infrastructure incidents. Are gas fires from earthquakes considered under Outcome 2?
    a. GPI: Response to gas infrastructure incidents resulting from earthquakes would certainly be included in the Metric 6, which pertains to response time.
    b. If the goal of PBR is to measure performance, metrics should track things that occur on a regular basis. Gas infrastructure incidents in fault zones would be a serious emergency, and utilities need to have safety protections in place to prevent such incidents from happening, but this might not be ideal for a regularly tracked metric (there would be a lot of "zero" entries each year).
        i. Three other participants agree with this comment.
2. Because wildfire avoidance is more of an emerging problem, input-based metrics (*e.g.*, status of wildfire mitigation plans, other data/metrics to better understand performance related to wildfire avoidance) may work better here.
    a. State of Hawaii's order for performance metrics does have a few input-related emergency metrics, including emergency response training requirements. Worth considering some specific input metrics.
3. Not sure that there are industry standard metrics that can be applied to "probability of ignition."
    a. This terminology was derived from the California handbook on wildfire mitigation. Washington does not have a standardized wildfire mitigation handbook.
    b. UTC will need some standardized definitions (here and elsewhere).

   c. This proposal was targeted towards electric IOUs.
   d. Not sure that this is the appropriate metric. Basing a performance metric on utility-caused wildfires establishes issues on liability, causation, etc.
      i. Looking at vegetation management, prevention activities in high fire consequence areas, wildfire mapping, etc. could be better.
4. Participant notes their support for Metric 5 as written.
5. Should be able to track line maintenance through a metric, rather than waiting for a town to burn down.
6. As previously stated, many of the proposed metrics are electric-only (wildfire avoidance is not a significant natural gas issue).

Metric 6: Response Time to Natural Gas System Emergencies

Metric 6 calculation: Average and median length (in minutes) from customer call to arrival of field technician in response to natural gas system emergencies.

1. Gas utilities' response time to gas infrastructure incidents resulting from earthquakes would be included under this metric.
2. Participant notes their support for Metric 6 as written.

OUTCOME 3: RESILIENT INFRASTRUCTURE AND SERVICE, INCLUDING DISTRIBUTED ENERGY RESOURCES, TO ENABLE CUSTOMERS TO MAINTAIN ESSENTIAL FUNCTIONS DURING TIMES OF POTENTIAL OUTAGES.

Metric 7: Equity in Resilience Investments.

Metric 7 calculation: Percent of proposed resilience projects in Named Communities that are completed every year, compared to a proposed projects list that is approved by the Commission.

1. Would this metric involve reporting a single percentage, or three different percentages? Worth clarifying.
2. Need to define what "resilience project" is and what "approval" means. Also, unclear what is being approved by the Commission (and where)? The Commission does not usually approve or deny resilience projects.
   a. Questions the value of Metric 7 entirely If approval means "pre-approval."
      i. The Commission would already have proof of how many projects are to be completed, and which ones would have equity goals. If approval does not necessarily mean "pre-approval," this is less of a concern.
   b. UTC: May need to rethink "approved" as "communicated with."
   c. RAP: The Commission could review proposed resilience projects to evaluate their potential community benefits.
3. It might be better to track funding or benefits, rather than projects.
   a. Another participant agrees with this comment, adding that this metric needs some more clarity and tracking the percent of spending may be more meaningful than tracking the percent of projects.
   b. RAP: Tracking how much money is being spent would be against the principles that the Commission is trying to adhere to.
   c. UTC: UTC is tracking dollars spent, but that is an input, and the intent is to track outputs. Tracking the number of projects would also be an input. Tracking both

the number of projects and dollars spent could be a better reflection of resilience investments.

   d. Commissioner Rendahl: The UTC's focus is on the IMPACT of dollars spent on resilience investments in Named Communities. What is the impact of the projects? The impact is the outcome, and that impact is related to the input. Need to identify how to best measure the impact of the dollars spent and/or the number of projects.
      i. One potential impact could be the percent or number of energy/power interruptions avoided.

4. Rather than tracking how much money an IOU spends, the Commission should track the reduction in hours of outages per dollar spent in Named Communities (*i.e.*, how well a utility spends their money).
5. Does ease of permitting and lifting barriers for solar, storage, V2I, etc. for customers fit into this metric? If we don't have a resilience "result" metric (like we do for energy efficiency and savings), then we might need to focus more on inputs.
   a. GPI: In response to the first question, might be better suited for Goal 4, but open to other thoughts.

Metric 8: Customers Experiencing Multiple Interruptions (CEMI) for Named and Non-named Communities

Metric 8 calculation: Average number of outages for customers experiencing multiple interruptions. Total number of customers that experience more than three sustained interruptions divided by the total number of customers served. Provide this calculation for the service territory as a whole and separately for Named Communities.

1. Recommends tracking CEMI on a 0-8 level.
2. One participant notes that in their CEIP, they agreed to track the number of outages for customers (tracked separately for Named Communities), using CEMI with a value of 0.
   a. Intention was to understand any differences in outages experienced. This participant's entity does not report CEMI for other values at this time, but CEMI=3 is a common metric.

Metric 9: Customers Experiencing Long Duration Outages (CELID) for Named and Non-named Communities.

Metric 9 calculation: Number of customers experiencing more than X hours of interruptions per year/total number of customers served, providing separate calculations for X = 0 through X = 8. Provide this calculation for the service territory as a whole and separately for Named Communities.

1. What is the purpose of requiring the CELID calculation for all values 0 to 8?
   a. Duration of outages becomes more difficult to handle the longer it goes on. If UTC chooses a snapshot (*i.e.*, x=3), it knows that some customers experience longer outages, but how much longer? Need to understand the # of customers experiencing very long duration outages.
   b. X=0 would be perfect service (no interruptions). This calculation will not indicate how long an outage was but will indicate the number of customers experiencing outages 6 hours or longer, 7 hours or longer, 8 hours or longer.

   i. Commissioner Rendahl: How to set X will need to be considered when finalizing the calculation. If X=0 indicates perfect service, is it really the best measure?
   ii. UTC may find that hardly anyone experiences 8-hour-duration outages, and maybe X=3 to 6 would be better. UTC will need more than one value for this calculation because each value is a snapshot. This metric is also useful for comparing across communities because it offers more insight into the nature of outages in a community.
- c. One participant notes that as written, Metric 9 contains 18 different calculations, which may not be necessary.

2. There are communities that experience outages on the scale of days, not hours. Would like to see a way for utilities to address these problems.

Goal 2: Customer Affordability

OUTCOME 1: REDUCE ENERGY BURDEN FOR CUSTOMERS EXPERIENCING HIGH ENERGY BURDEN, ESPECIALLY THOSE IN HIGHLY IMPACTED COMMUNITIES, VULNERABLE POPULATIONS, AND LOW-INCOME CUSTOMERS.

1. One participant notes that the entity they represent does not view cost drivers as key. Rather, they view the impacts (O&M, tariff riders, etc.) as key. These are discussed in rate cases, but affordability should be tied back to customer impact, which is the customer's average annual bill.
    a. Interested in an additional metric related to average bill.
2. Another participant notes that much of this is out of their entity's control due to the economy itself. An economic downturn may drive arrearages, energy burden, etc. In those conditions, their entity works hard to keep prices down through programs, but arrearages still go up.
    a. Interested in an additional metric about the utility's price (price that customers pay per kilowatt-hour).
3. UTC staff are having conversations about whether and when it might be appropriate for Named Community data tracking to fall within CEIP.
    a. Is there data regarding Named Communities for gas utilities, or is this only for electric utilities?
    b. "Named Communities" is defined in statute for utilities that are required to comply with CETA, which does not apply to gas companies.[4]
    c. Vulnerable Communities are only defined for electric utilities, but gas utilities do look to public health maps.

Metric 10: Arrearages by Month (reported quarterly).

Metric 10 calculation: Arrearages by month, by class, measured by zip code – to include 30+, 60+, and 90+ days arrears for total company, and electric and natural gas stated separately for dual fuel utilities.

1. One participant notes that they, overall, support cost metrics, but is generally concerned about lack of affordability metrics as a whole. A couple participants put forth many metrics that would help UTC better understand what is driving system costs. If the Commission locks in revenue growth for a MYRP for a certain period of time, IOUs could put forth riders in-between MYRPs. Wants the Commission to reconsider this metric.
    a. GPI: Can the Commission already track this without PBR?
        i. Affordability is one of the Commission's primary concerns. The Commission could track this, but this participant is trying to articulate what is most important for the Commission to measure.
    b. UTC: The only way to incite behavior is to make it comparable. Is there a way to express these concepts in a way that is comparable over time and across IOUs? The Commission will have metrics for general rate cases because it is a

[4] RCW 70A.02.020, https://app.leg.wa.gov/RCW/default.aspx?cite=70A.02.010

requirement under the MYRP statute. Here, the UTC is trying to find a way to track other behaviors that are important to groups in Washington.
    i. Two key comparability aspects—Comparability within the utility itself, and comparability across utilities.
    ii. A raw number or value per customer may differ between utilities, but the UTC can still compare percentage change to identify what is driving utility costs to better understand what is going on.
2. Recommends providing information by Named Communities (which is by census tract) rather than zip code (both in Metric 10 and globally) – two other participants note their agreement.
3. Arrearages are currently reported to customers in aggregate (gas and electric). This commenter would prefer to continue providing customers with this aggregated data.

Metric 11: Percent of Customers in Arrears with Arrearage Management Plans

Metric 11 calculation: Number of residential customers, by zip code, in arrears with arrearage management plans (AMPs)/Total customers in arrears 60+ days.

1. One participant recommends that UTC consider using 30+ days for Metric 11.
2. Should customers being in Arrearage Management Plans be a goal? Ideally customers would not need to get on arrearage management plans, and instead would be enrolled in programs to prevent that need.
3. Another participant notes that they would support the inclusion of additional metrics in this area, not just Arrearage Management Plans.

Metric 12: Customer Disconnections and Reconnections

Metric 12 calculation: Number and percentage of (1) disconnect notices, (2) residential disconnections for nonpayment, and (3) reconnection, each broken out by month and zip code, for known low-income households, Highly Impacted Communities, and Vulnerable Populations, for total company, and for electric and natural gas service stated separately for dual fuel utilities.

1. Reporting both a raw number and a percentage here may not be necessary.
    a. Not necessarily appropriate to separate out electric and natural gas IOUs for Metric 12.
    b. One participant notes that the entity they represent first disconnects electric service, then gas service, but customers generally view this as one disconnection.

Metric 13: Average Energy Burden

Metric 13 calculation: Annual residential bill/average area median income by zip code for all customers, comparing outcomes in Non-named Communities with Named Communities, with electric and natural gas service stated separately for dual fuel utilities.

1. Participants strongly supports measuring energy burden. Specifically, they want to know the number or percent of burdened customers, but Metric 13 does not provide that information as proposed.
    a. Average energy burden is helpful information, but excess energy burden is what IOUs are able to act on – Two other participants share this opinion.
        i. Energy burden should not be calculated separately for electric and gas utilities because energy burden is a combination of those two services

(and that burden should not exceed 6%). The Commission will need to determine how to address gas-only customers (New Jersey uses 3% for gas-only customers, another group uses 2.3%).

ii. 6% is not always the best energy burden threshold. Customers having different heating fuels (propane, wood, etc.) and different areas within IOUs' service territories can significantly impact this, and these factors are not captured here. UTC will need to separate out dual-fuel and non-dual-fuel utilities to allow for comparison.

OUTCOME 2: MAXIMIZE UTILIZATION OF COST-EFFECTIVE DISTRIBUTED ENERGY RESOURCES AND GRID-ENHANCING TECHNOLOGIES.

1. The metrics included under Goal 2, Outcome 2, do not track cost-effectiveness. Recommends that UTC include metrics like "Amount of MWh per year, per dollars invested" to better track this.
    a. GPI: Metric 14 has a cost-benefit analysis requirement. Does that address your concern?
        i. It is possible to have a large net benefit that isn't cost-effective.
        ii. GPI: Some commenters also suggested that you could have a very cost-effective investment with little net benefit.
        iii. Should not assume that just because the UTC approved something, it's cost-effective. UTC should not approve non-cost-effective DER investments that the utility could have invested in a more cost-effective way.
2. What is the time frame to determine cost-effectiveness and external costs such as health, climate change?
    a. GPI: This will be defined in another proceeding, UE-210804.
3. DR that is enrolled is useful regardless of whether it's called, as it allows the utility to avoid other more costly capacity alternatives, which benefits everyone.
    a. Good point that DR that is enrolled but not called may also be useful. But there may also need to be a performance metric to (1) ensure that the DR is actually called when needed, and (2) ensure that the DR shows up when it's called.

Metric 14: Net Benefits of DERs and GETs

Metric 14 calculation: Net benefits of distributed energy resources and grid-enhancing technologies, as measured through a Commission approved cost-benefit analysis (*e.g.*, docket 210804).

1. Customers might not necessarily understand that these net benefits are without additional context, or maybe another complementary metric.
2. 14 need more clear definitions of terms, but this commenter is generally okay with metric in concept.
    a. UTC is open to hearing how utilities define these terms.
    b. One participant recommends using existing definitions when they are available.
3. Metric 14 could alternatively use the term "net present value of benefits," and/or include a benefit-cost ratio to better reflect the total magnitude of net benefits.
4. It seems implied that this metric intends to track the net benefits of installed DERs, GETs.

5. DERs that are enrolled but not called upon can also be useful, but those may be better tracked under a different metric.

Metric 15: DER Utilization

Metric 15 calculation: Count of MWh and MW provided by each DER programs, and Percentage of MWh and MW provided by each DER program as a total of MW demand.

1. Considering cost-effectiveness is important, but UTC should not predispose that DER will inevitably be the lowest cost solution. If DERs provide affordability to customers, they should be pursued, but they might not always be the best way to do so.
    a. This may be a good reason to have metrics that are different from PIMs. There may be low-income programs that are not cost-effective but are in the public interest.
2. Is reporting by both MWh and MW actually useful, or just possible? UTC should measure actual benefits rather than just capacity. May also be helpful to better define "provided."
3. There can be well-reasoned DER investments that may not be cost-effective (may be part of a rate case, community solar, etc.).
4. It would be helpful to have a column indicating whether these metrics are either electric-only or both industries (electric and natural gas). Is metric 15 supposed to be electric-only? If not, this metric needs clarity and not use "MW" since this is an electric measurement.
    a. Two other participants echo these sentiments.

OUTCOME 3: MAXIMIZE THE BENEFIT AND EFFICIENCY OF THE ENERGY ASSISTANCE PROCESS SO THAT SUPPORT CAN BE PROVIDED TO CUSTOMERS BASED ON THE PROGRAM RESOURCES AVAILABLE.

Metric 16: Percent of Utility Assistance Funds Dispersed

Metric 16 calculation: Utility rate-based assistance funds spent/Annual budget for utility rate-based assistance.

1. Participant notes that they support this metric, but funding will likely increase every year up to a cap, while percentage dispersed may go down (sometimes for good reasons). Metric 16 may need to be presented with additional context to account for the fact that there could be good reasons for assistance funds to decrease year-over-year.
2. The term "rate-based" is unclear and should perhaps be changed to "customer-funded."

OUTCOME 4: LOWEST REASONABLE COST COMPLIANCE WITH PUBLIC POLICY GOALS AND ENVIRONMENTAL REQUIREMENTS.

Metric 17: Incremental Cost

Metric 17 calculation: For electric, as calculated and reported in utility filed CEIP. For natural gas, lowest reasonable cost of compliance with CCA.

1. The UTC should understand the distribution of costs of projects. Some projects may be very cost-effective, while others may not be. Would like to see a metric that captures both extremes.
2. Focusing on CETA and CCA in this outcome. The equity dimensions included in these metrics go beyond those established CETA/CCA—not sure how this could be done. UTC may want to consider a metric that focuses on geographic distribution of costs (which may or may not be insubstantial).

OUTCOME 5: INCREASE AWARENESS OF AND EQUITABLE ACCESS TO UTILITY SERVICES, ASSISTANCE, EDUCATION, AND BENEFITS FOR ALL CUSTOMERS, WITH A FOCUS ON HIGHLY IMPACTED COMMUNITIES, VULNERABLE POPULATIONS, AND LOW-INCOME CUSTOMERS.

1. The metrics under Goal 2, Outcome 5, would measure performance related to participation (language availability, increasing awareness of utility services, etc.), but the outcome itself is most important. UTC needs creative ways to report metrics.
    a. UTC should consider tracking participation in other programs/services (this is proposed under other metrics) as a result of awareness and access. UTC could have a website where users can connect outcomes together.

Metric 18: Availability of Materials in Multiple Languages

Metric 18 calculation: Percentage of utility engagements — including workshops, mailers, and community meetings — offered in multiple languages or with translation services.

1. The term "utility engagements" needs clarification here.
    a. One participant notes that their entity tracks a similar (but more focused) metric in its CEIP.
    b. Some materials would be easy/straightforward to translate, while other materials may not be. Could Metric 18 be narrowed to the area's most impactful to customers?
        i. It would be valuable to identify what types of engagement materials make the most sense to have available in many languages.
        ii. Another participant echoed their concern about the breath of this metric.

Metric 19: Customer Awareness of Services/Assistance

Metric 19 calculation: Percent of customers in Named Communities stating that they are "somewhat aware of" or "very aware of" specific utility services and assistance programs.

1. Metric 19 identifies the need for a new survey or tool to ask this question. A new requirement like this does come at a cost, and utilities would need to recover those costs.
2. One participant is concerned about the breath of this metric—would the survey be broad enough to effectively capture non-English speakers?
3. Perhaps change to customer-funded energy assistance programs.

Metric 20: Customers Who Participate in One or More Bill Assistance Programs

Metric 20 calculation: Unique number of low-income customers who participate in at least one bill assistance program/vetted estimate of total number of low-income customers that qualify for bill assistance.

1. One participant generally supports Metric 20, but the term "vetted" needs to be defined/clarified.
    a. Utilities would need to agree on a process with an outreach group to establish estimation procedures.
    b. Some utilities have self-verified income. Customers can say whether they're low-income.

Goal 3: Advancing Equity in Utility Operations

OUTCOME 1: EQUITABLE AND DIVERSITY-FOCUSED UTILITY HIRING, PROMOTION, AND VENDOR SELECTION PRACTICES.

Metric 21: Workplace Diversity

Metric 21 calculation: Percentage of employees and senior management separately identifying: (a) C-suite employees and (b) directors and employees more senior than directors who identify as: (i) a person of color and/or (ii) a woman or non-binary.

1. Participant notes their support for Metric 21 as written.

Metric 22: Supplier Diversity

Metric 22 calculation: Percentage of suppliers that are owned by people of color, women, and other marginalized groups certified with the Washington State Office of Minority and Women's Business Enterprises (OMWBE), and total dollars awarded to suppliers owned by people of color, women, and other marginalized groups certified with OMWBE.

1. One participant notes that their entity has a list of ~3500 suppliers, but it is unclear if all those suppliers have OMWBE certifications with Washington. OMWBE provides federal certification with US DOT and state certification for businesses that work with state-funded projects, local school districts, etc.; it is unclear whether these certifications are applicable to the utility space. Recommends that this metric be expanded to include businesses that self-identify as people of color-owned – or women-owned, rather than just ones associated with the designated office.
    a. Chair Danner: If a self-identifying business purports to be people of color-owned or women-owned even though they are not, there would be consequences.
2. How administratively burdensome is it to become certified with OMWBE? Many suppliers opt out of formally identifying because of the administrative or cost burden. There may also be other databases that provide this information.
    a. UTC: It does not cost money to register with the state office, and the agency does provide assistance, but this concern is recognized.
3. Do utilities prioritize veteran-owned businesses now, similar to OMWBE?
    a. Utility party responded yes; they include veteran-owned businesses in its supplier diversity goals.

OUTCOME 2: ENSURE THAT UTILITY OPERATIONAL AND INVESTMENT DECISIONS PROMOTE EQUITABLE SERVICE THAT DOES NOT UNFAIRLY HARM OR DISADVANTAGE HIGHLY IMPACTED COMMUNITIES, VULNERABLE POPULATIONS, AND LOW-INCOME CUSTOMERS.

1. Would like to see a metric in which the utility is required to provide a yes/no response to whether highly impacted customers are prohibited from participating in any programs.
    a. Utility responded that they have many services that are specific to customer types, and there are programs that are ONLY available to low-income customers, but no programs that exclude low-income customers.

Metric 23: Annual Incremental Investment Spending

Metric 23 calculation: Total amount of capital or operational expenditures that benefit Highly Impacted Communities or Vulnerable Populations in the current year/the amount of capital or operational expenditures that benefit Highly Impacted Communities or Vulnerable Populations in the previous year.

1. Annual incremental spending can be volatile (*e.g.*, whether a utility implements a large or small program in a given year, etc.) and may not provide information as meaningful as what could be obtained via a different tracking mechanism, such as dollars spent per customer.
    a. Open to alternative ways of tracking this.
    b. UTC: It would not hurt to add that dimension. Will also need to clearly define "benefit" (here and elsewhere) so all parties have a common understanding of the term.
    c. GPI: Perhaps the percent of expenditures per year would be a better metric to track than total spending amount to normalize potential budget shifts.
        i. This might not be an impactful variation; it might be better to redefine the metric on a per-customer basis.
2. Participant acknowledges understanding the intent here but note that they are spending $900 million/year on countless things, and they do not "color-code" their spending. Some parties might disagree on what is actually a benefit to a community, and "color-coding" dollars comes with a high administrative cost burden. Metric 23 requires additional clarification.
    a. Echoes participant's concerns regarding color-coding of dollars.
    b. UTC: What would the administrative burden look like?
        i. To fulfill this metric, they would need to look at every line-item expenditure under all dimensions of utility operations. This would be unwieldly and could also become a source of contention when going line-by-line in general rate cases.
        ii. Unless there's a prescriptive, well-defined set of parameters around what constitute "benefits," what costs are/are not being included, etc., this may be too challenging of a metric as written. There could be a way to obtain some of this information if this metric is significantly narrowed.

Metric 24: Percentage of Non-pipeline and Non-wires Alternative Spending

Metric 24 calculation: Total investment in non-pipeline or non-wires alternative programs targeted in Highly Impacted Communities or on Vulnerable Populations/Total investment in non-pipeline or non-wires alternative programs, separately calculated for dual fuel utilities.

1. No comments.

OUTCOME 3: EQUITABLE ACCESS TO ALL UTILITY ENERGY PROGRAMS, INCLUDING THOSE RELATED TO ENERGY EFFICIENCY, DEMAND RESPONSE, AND DISTRIBUTED ENERGY RESOURCES.

1. Would like to see a metric in which the utility is required to provide a yes/no response to whether highly impacted customers are prohibited from participating in any programs.
2. Participant notes their support for these metrics but thinks that their impact could be amplified by a program participation/enrollment metric.

   a. For the purposes of equitable access to all utility energy programs, access to major programs (energy assistance, DERs, transportation, demand response, etc.) are captured in the metrics. It may not be necessary to include a standalone program participation/enrollment metric when that is already captured in separate metrics.
      i. Considering a metric that would track the number of customers broadly participating in programs (*e.g.*, the number of low-income customers participating in energy efficiency programs vs. the total number of customers participating in that same program).
      ii. One participant notes that they capture this in other areas and proceedings, advisory group meetings, etc.
      iii. Would the metrics associated with this outcome cover all DER programs, or specific ones?
      iv. UTC: There would be a separate calculation for different types of programs. The Commissioners would like to see a higher level of granularity here, but the specific level of granularity needed is not yet established.
3. This outcome's applicability to gas utilities depends on how DERs are defined. If the DER definition includes energy efficiency, the Goal 3, Outcome 3 metrics would also apply to gas utilities.
4. Would like advice on how to track programs or investments that may be equitably funded, but that do not actually produce community benefits or do not receive significant community participation.
   a. GPI: Do Metric 24 and Metric 25 cover this?
   b. Participant will need to think about this more.

Metric 25: Equity in DER Program Enrollment

Metric 25 calculation: Number of customers in Named Communities or low-income customers enrolled in each utility distributed energy resource programs (providing a separate calculation for energy efficiency, electric vehicle, net metering, and demand response)/total customers enrolled in each program.

1. This metric intends to show how equitably a DER program serves Named communities. If there was a fairly underutilized program that proportionately served more Named Communities than a different better-utilized program, it may skew results. Both of those pieces of information would be useful.
   a. Could address this by tracking the total number of customers enrolled in a program/total eligible customers, or similar.

Metric 26: Equity in DER Program Spending

Metric 26 calculation: Separately calculated percentage of utility spending on distributed energy resources for energy efficiency, electric vehicle, net metering, demand response, and renewables that benefits Named Communities as compared to Non-named Communities.

1. No comments. Participants' perspectives on Metric 26 are largely included in the context of other Goal 3, Outcome 3 metrics.
2. Seems like metrics 25 and 26 are relevant to electric utilities, but participant is unclear on this.

OUTCOME 4: ENSURE ACTIVE AND MEANINGFUL UTILITY ENGAGEMENT WITH COMMUNITIES, INCLUDING HIGHLY IMPACTED COMMUNITIES, VULNERABLE POPULATIONS, AND LOW-INCOME CUSTOMERS SUCH THAT THEIR INPUT IS CONSIDERED IN UTILITY PLANNING PROCESSES.

No metrics selected at this time but will incorporate this outcome into Policy Statement.

1. The City of Bellevue sends out open-ended survey regarding utility service. According to those surveys, most communities were satisfied with their service, but a few were not.
2. Participant notes that they proposed a metric that would track customer engagement via a survey given to participants at the end of meetings; did not envision this being a significant effort, but rather an additional means to understand engagement.
3. UTC staff referenced the University of Michigan's Energy Equity Project report in their comments. The report contains an index with procedural justice metrics. The report provides more opportunity for conversation on what may be an appropriate metric and ways to creatively track areas that are typically challenging to track.[5]

[5] https://energyequityproject.com/wp-content/uploads/2022/08/220174_EEP_Report_8302022.pdf.

Goal 4: Environmental improvements

OUTCOME 1: REDUCE POLLUTION BURDEN AND POLLUTION EXPOSURE WITH A FOCUS ON COMMUNITIES WITH ELEVATED EXPOSURES TO HEALTH HAZARDS, INCLUDING HIGHLY IMPACTED COMMUNITIES, VULNERABLE POPULATIONS, AND LOW-INCOME CUSTOMERS.

Metric 27: Energy-related Air Quality Emissions.

Metric 27 calculation: Annual criteria air pollutant (CO, Pb, NOx, O3, PM10, PM2.5, and SO2) and toxic air pollutant (Hg) emissions associated with utility generation, transmission, and distribution operations (including customer direct use) for the following geographies:

- Across the utility's service territory,
- By census tract within the utility's service territory, and
- In Named vs. Non-named Communities within the utility's service territory.

1. Pb and O3 are not Criteria Air Pollutants, and Hg is not a toxic air pollutant.
    a. Data not measured by census tract at all.
    b. Not practical to install air quality monitoring devices across all the census tracts in which a utility provides service but could track some of these pollutants by service territory.
    c. Each generation plant has different air quality permits and different air quality standards.
    d. This participant recommends tabling Metric 27 and bringing environmental reporting experts to the conversation.
    e. Their CEIP has several metrics related to greenhouse gas emissions and air quality (hazardous air pollutants, number of days that exceed EPA air quality index thresholds, generation plant air emissions, greenhouse gas emissions based on what is delivered to customers, etc.). Their CEIP approach covers criteria air pollutants and how they're reported.
2. How should utilities delineate air quality emissions when they have several fossil fuel facilities within their service territory? It also might not be useful to estimate emissions from generation—need to be able to focus on what the actual air quality is, which may or may not be entirely the utility's fault.
3. This metric focuses on the utility and its customers. Confused about the "across the utility's service territory" aspect related to customer direct use.
    a. Would a generation source outside of a utility's service territory that still serves customers in Washington be counted?
    b. GPI: The way Metric 27 is currently written, no, it would not.
    c. This metric should be inclusive of utility generation as it relates to customers statewide.
4. Should also consider net pollution benefits (like those achieved through deploying electric buses).
5. Participant notes that they do not have fossil generation in their Washington service area but wants this metric to be useful. Currently it is not clear how this metric is helpful or useful to the utility.
6. Recommends adopting this metric more broadly (*i.e.*, air quality by census tract, not just the emissions that are within the utility's control).

   a. Participant notes that they think Metric 27 is reasonable as written, since it focuses on air quality emissions that would result from utility operations. It would not be fair to track general census tract-level pollution irrespective of utility operations.
   b. Another participant agrees—there could be many air pollutants in a particular area, and those pollutants may or may not be the utility's fault. A metric that tracks all pollutants in a geographic region regardless of their link to utility operations could result in pressure on the utility to do something about it, even if the actual non-utility polluter may be able to address the overall pollution burden much more cost-effectively.
7. Recommends modifying this metric to ensure that it considers generation sources located outside of utilities' Washington service territories, including emissions from facilities outside of Washington (like Metric 32 does).
   a. There are very few metrics that are without any outside influence. The Commission needs to consider this relative outside influence when they establish targets, incentives, etc.; it is ok to have relative ambiguity in some instances.
8. Why wouldn't the Commission want a utility to take existing pollution in mind when establishing a new peaker plant?
9. Are water quality issues related to utility operations considered under this metric?
   a. While there are perhaps opportunities for utilities to incentivize electrification to reduce criteria air pollutant emissions, to consider pollution from (for example) cruise ships to be within a utility's control would be unfair.
   b. What about water quality related to fracked gas?
      i. Chair Danner: There is no fracking happening in the State of Washington.
      ii. UTC: Does Washington use any gas that has been fracked in and imported from other states?

Metric 28: Utility Fleet Tailpipe Emissions Reductions

Metric 28 calculation: Utility vehicle fleet tailpipe emissions reductions by vehicle type (light-, medium-, and heavy-duty) that may operate in Named Communities, according to the utility's adoption of low- and zero-emissions vehicles, using the utility's 2022 fleet composition as baseline.

1. Participant notes their support of this metric as written.
2. Concerned about fleet location and the potential for traffic/noise implications; tailpipe emissions should not be the only consideration when it comes to utility fleets (example: significant traffic and noise associated with the UPS truck base in Redmond).
3. Is 2022 the best baseline year for utility fleets? Would a different baseline year make more sense?
   a. Commissioner Doumit: There was no real reason for selecting 2022 as the baseline year; Commissioners are open to baseline year modifications, but a baseline year is necessary.
   b. The baseline year itself matters less than establishing a baseline year from which to track miles traveled for vehicles of each type moving forward.
4. Would Metric 28 track actual emissions, or year-over-year reductions in emissions?

a. The word "may" is important because the utility's whole fleet may operate in Named Communities at some point in time during the year—utilities move resources around to address outages.
    i. Would it be helpful to use the phrase "regularly operate in Named-Communities" rather than "may operate"?
b. GPI: Wouldn't it be necessary for the utility to know their actual emissions to determine their year-by-year emissions reductions?
    i. Yes, but would like to know whether both would need to be reported.
    ii. GPI: Suspects that yes, both total tailpipe emissions and total and year-over-year tailpipe emissions reductions would need to be reported.

OUTCOME 2: COST-EFFECTIVE ALIGNMENT OF LOAD WITH CLEAN ENERGY GENERATION AND STORAGE THROUGH LOAD MANAGEMENT, ENERGY EFFICIENCY MEASURES, AND DEMAND RESPONSE.

1. This outcome indicates that cost-effectiveness will be tracked, but the metrics themselves do not seem to do so.
2. Where are the metrics for smart grids and/or coordination with residential/community-scale solar and storage to support load balancing?
    a. Those dimensions will be captured in other DER metrics.
    b. There could be a deeper discussion on the role of electric vehicles here, and the metrics included within this outcome do not have a time component.
3. Where are the metrics for smart grids and/or coordination with residential/community solar, storage captured, and load balancing?

Metric 29: Utility Electric Load Management Success

Metric 29 calculation: Energy and capacity of load reduced or shifted, and percent of load reduced or shifted, through load management activities conducted by the utility, by activity (*e.g.*, demand response versus energy efficiency).

1. Need to more clearly define what UTC is looking for in Metric 29 with respect to both gas and electric utilities.
2. Emissions intensity can be based on a unit of energy. For capacity, the emissions intensity based on emissions reductions in a given hour can be complicated, though generalizations can be made.
    a. Need to consider the baseline in the counterfactual based on what would have happened otherwise. Baselines can be technically challenging—may be difficult to adequately capture this in a sentence/metric.

Metric 30: DER GHG Reductions

Metric 30 calculation: Greenhouse gas reductions from DER programs (energy efficiency, electric vehicle, net metering, and demand response).

1. It is not clear if Metric 30 intends to track total greenhouse gas reductions from DERs in aggregate, or by program.

OUTCOME 3: ACCELERATE THE COST-EFFECTIVE ACHIEVEMENT OF COMMISSION OR STATE PUBLIC POLICY GOALS AND STATUTES, INCLUDING THE REDUCTION OF GREENHOUSE GAS EMISSIONS.

- Would like to see this measured compared to a linear glide path and would like a cost distribution study.

Metric 31: Greenhouse Gas Reductions per Dollar

Metric 31 calculation: Greenhouse gas reductions per dollar spent on programs and investments that reduce greenhouse gas emissions.

1. Would these need to be CETA-compliant programs? Need to clearly define what would constitute a qualifying program.
2. Interested in tracking this, but not sure how to attach it to a dollar amount. It will be important (and difficult) to define this approach.

Metric 32: Total Greenhouse Gas Emissions

Metric 32 calculation: Carbon intensity by CO2e (metric tons of CO2 and CO2-equivalent emissions) and CO2e/customer associated with utility generation, transmission, and distribution operations (including customer direct use), and CO2e/therm for gas utilities and in CO2e/MWh and CO2e/MW for electric utilities (dual-fuel utilities must report both separately).

1. Does this include purchased power?
    a. It is also unclear why this calculation does not cover market purchases, PPAs, etc.
2. Would this be reported separately from electric, etc.?
3. Wants to ensure that this includes methane leaks for gas utilities.

Revisit metrics or topics needing further discussion

1. Is the intent that each metric would be reported by each utility via a general proceeding, a rate case, through some other means, etc.? Understanding is that the metrics be refined into utility-specific metrics as needed, but the metrics will generally be similar. Will utilities report their metrics as part of their multi-year rate plan, or through some other means?
    a. UTC: This would be in addition to the requirements established under RCW for multi-year rate plans. The law also requires that UTC develop a policy statement to provide guidance to utilities and participating parties/interveners.
2. One participant proposed several natural gas leak/safety metrics under Goal 4, Outcome 1. Was there a reason why those metrics were omitted from consideration? Would natural gas leak/safety be captured in other metrics?
    a. One participant raised concerns about trying to add too much to some of these metrics (Metric 27 and Metric 32 would be stretched beyond their intent if they also included consideration for natural gas leaks).
    b. Consideration for CAIDI (under Goal 1, Outcomes 1 and 2) G1O1 and 2 (CAIDI) and natural gas emergency response time (Metric 6)—would these include duration of outages in emergencies for both gas and electric utilities?
        i. Defining “major event day” would clarify CAIDI concerns.
        ii. Metric 6 only covers the utility’s response time to an emergency, not the outage duration. May want to add consideration for outage duration.
        iii. It does not feel appropriate to compare outages and emergency response times.
3. Related to Goal 1, it may be helpful to change the term “grid,” which is typically used to talk about the electric industry, to “network” or “system” so it is more industry neutral.
4. Would appreciate an opportunity to provide written comment on these metrics, with more time for thoughtful review by subject matter experts.
5. Non-wired alternatives (Metric 24) are a helpful tool, but is total investment the right way to track their success? Total investment might not reflect successful planning of a non-wired alternative project.
    a. Recommends instead tracking total projects implemented/evaluated, total value of wired solutions deferred, etc.
        i. Concerned about the Commission adopting something related to number of projects evaluated or invested but intrigued by the concept of total value of wired solutions deferred to measure success. Still don’t want to lose locational value.
    b. Non-wired alternatives have their own risks that can lead to more or less successful outcomes.
6. GPI: A potential alternative calculation for Metric 15 could track the energy and capacity of all applicable DERs and percentage of that energy and capacity utilized annually.
    a. Utilization = customers actually responding (compared to those that are enrolled)

    b. DR is considered a resource in utility planning. Utilization relates less to how many customers respond and more how many times a utility calls upon DR as a resource to respond to peak load.
7. How is the customer support for vehicle-to-grid technologies/programs being captured in these metrics? Will there be fees involved with participating or getting solar, rewards for people who participate and feed stored energy back to the grid, etc.?
    a. UTC: This is called net metering. Net metering is covered under the RCW, but not specifically under UTC's PBR proceeding.
    b. How will coordination between residents, businesses and utilities be incentivized towards reaching goals?
        i. Commissioner Rendahl: Recommends that DEK reach out to her individual utility. Each utility has their own transportation electrification plans.
    c. GPI: This does also somewhat relate to the load alignment considerations under Goal 4, Outcome 2.
        i. Participant recommends including a reference to DERs and vehicle-to-grid technologies under Goal 4, Outcome 2.
8. GPI: Metric 29 could be updated to specify *fossil* load being reduced or shifted. Concerned about this modification because load management has traditionally focused on reducing cost; shifting this emphasis to emissions reduction could be a misalignment of priorities. This metric should focus on the value proposition of load management. Focusing on emissions adds noise to the metric.
    a. The addition of "fossil" implies that there is not value in reducing load even if the generation is clean and creates some measurement challenges.
    b. Agreement amongst three participants—introducing the term "fossil" makes this metric unnecessarily complex.
    c. Fossil fuel resources are necessary when trying to meet peak demand; Metric 29 priority should be peak load reduction.
        i. If the Commission wants to link peak load reduction to fossil fuel reductions, it might require another metric that tries to measure shifting load to alignment with renewable energy production.
9. Chair Danner: Conversation today centered around four fundamental questions.
    a. Is the metric within the company's control?
    b. Are there other effective ways of achieving something (such that metrics aren't even necessary for that area)?
    c. Is the information necessary, accurate, or available?
    d. How many metrics is enough, and how many is too many?
10. UTC: Thanks everyone for submissions that guided the list of proposed metrics discussed today. If any participants did not see something on the list that they think is important, please contact Melissa Cheesman at melissa.cheesman@utc.wa.gov.
11. Should include Benzene (indoor air pollutant from gas use) in Metric 27.
12. If Metric 5 would track utility-cased wildfires, are natural gas emergencies being tracked (*e.g.*, the total number of natural gas emergencies that occurred in a year)?
    a. All emergencies—pipeline incidents, incidents in the home, gas leaks, etc.

    b. UTC already tracks all incidents on the utility's side of the meter but cannot track things that are outside of the utility's control.
    c. All pipeline incidents are reported to UTC's pipeline team.
    d. GPI: This could be an area of further discussion under Goal 1, Outcome 2.
13. With respect to the cost considerations included under Goal 2, what happens if a utility invests in something that is found to not be a viable solution based on CETA, Climate Commitments Act, etc.
    a. Commissioner Rendahl: This situation would likely be addressed in individual rate cases, not metrics, though aspects of some of those issues are captured in the cost effectiveness metrics.
14. "Named Communities" covers a large, non-homogenous group of people, and distributional equity as defined under CETA is very place specific. UTC likely wants certain kinds of investments in certain places, but not every Named Community will want a particular investment. UTC needs to carefully think about when it makes sense to track metrics according to Named Community status, census tract, zip code, whole customer base, etc.
15. Utilities and UTC both often claim that an action is prudent, but it does not always look that way to customers. Metrics would provide a way to talk about some of those issues.
16. The UTC should not limit itself to a specific number of metrics and should consider creative ways to display and represent metric data.
17. Going back to Goal 1, Outcome 2, participant would like to see a metric of harmful events (fires, pollution emissions, health, etc.) related to gas removal, distribution, storage, and use.
18. What is the frequency of these metrics (*i.e.*, quarterly, semi-annual, annually?) Most of these seem to be annual or possibly quarterly.
19. Going back to Goal 2, participant would like to see more utility dollar incentives and support for residential solar, charging, and V2I. Also, public-facing incentives for electrification.
20. Are there also spheres of regulatory authority/expertise to consider, depending on how deep we want to go into environmental issues? While the UTC can/should certainly consider environmental factors within the context of the public interest, it feels like we might be creeping close to areas better addressed by other regulatory agencies.

Next steps

1. PBR proceeding workplan:
    a. Identify regulatory goals, desired outcomes, and principles for metric design.
    b. Identify performance metrics.
    c. Phase 2A (April 2023-December 2023).
2. This is the last scheduled workshop for Phase 1.
    a. UTC, RAP, and GPI will review the feedback from today's workshop and refine metrics as needed. If significant refinements are necessary, UTC is open to posting those refined metrics for further comment.
    b. Policy Statement (Phase 1) anticipated March 2023 but subject to change.

3. If there are changes to this work plan, UTC will notify participants, seek additional comments, etc.
    a. UTC will post metrics as revised on-screen today for further comment. Today's revisions do not reflect final metric decisions or language.
4. Next phase is Phase 2A: Reporting and Review.
    a. Will establish utility-specific performance metrics, establish reporting and review process throughout this phase (anticipated April 2023-December 2023).