White Paper: Performance-based Compensation Framework

Introduction

To modernize the traditional utility business model in light of industry changes and Minnesota's public policy goals, e21 set forth in its first phase two big goals:

- *Shift away from a business model that provides customers few options (everyone gets the same grid electricity produced largely with coal, natural gas, or nuclear power at large central stations) toward one that offers customers more options in how and where their energy is produced and how and when they use it, while maintaining fair and competitive pricing, reliability, and minimal environmental impacts*

- *Shift away from a regulatory system that rewards the sale of electricity and building large, capital-intensive power plants and other facilities toward one that reasonably compensates utilities for achieving an agreed-upon set of performance outcomes that the public and customers want*

This shift is meant to encourage a least-cost, best-value[4] approach to achieving agreed-upon performance outcomes that includes consideration of both central station and distributed energy resources in meeting electric system needs.

Utility regulation is based upon a regulatory compact,[5] having two facets. First, utilities accept an obligation to serve all customers requesting service in return for a monopoly franchise in a given area. Second, utilities are allowed an opportunity to recover, and earn a reasonable rate of return on, the prudent capital investments that are reasonable and necessary to serve its captive customers. When a utility believes its sales revenues are no longer sufficient to recover these costs, the utility can petition to increase rates with the agency having jurisdiction over its operations. In the case of Minnesota, that agency is the Minnesota Public Utilities Commission (PUC). Other Minnesota government agencies that also participate in this process include the Minnesota Department of Commerce and the Minnesota Office of the Attorney General. In general terms, a utility rate case has two sets of issues: (1) the revenue requirement—how much rates should increase according to an analysis of the utility's filed cost of service, and (2) the revenue allocation—who pays for the rate increase ultimately resolved under (1).[6]

Although there are exceptions and policy considerations, the general rule under Minnesota state law is that rates set by the Minnesota PUC must be just and reasonable. This has historically meant that rates are based on cost of service balanced against other non-cost factors. In other words, rates are intended to reflect the cost of the fuel needed to produce electricity and the cost of building, operating, and maintaining the system of power plants, wires, poles, and equipment to generate and deliver electricity. Under this current cost-of-service model, it is largely the utilities' investment of capital that drives utility earnings and shareholder value.

[4] "Least cost, best value" includes the analysis of desired outcomes and then the search for methods that will achieve those outcomes at the lowest cost for customers.
[5] Charles F. Phillips, Jr., *The Regulation of Public Utilities* (Arlington, Va.: Public Utilities Reports, Inc. 1993).
[6] *Id.*

Because utilities rely, in part, on financial markets to fund capital improvements, investors are an important part of the utility's business. Generally speaking, financially strong companies are able to borrow money at lower interest rates; therefore, assuming a utility is recovering its prudent investments with a reasonable rate of return, the utility should remain financially strong. All else being equal, a financially healthy utility is able to provide service at a lower rate than a less financially healthy utility.

Cognizant of the interplay between financial health of the utility, cost-of-service regulation, and utility rates, e21 proposed in its phase I that Minnesota evolve this model toward a performance-based approach to utility compensation—an approach that would tie a portion of a utility's earnings to their achieving an agreed-upon set of performance metrics. Such a compensation system will enable utilities, regulators, and stakeholders to work together proactively to define the outcomes they want utilities to deliver—such as greater energy efficiency and customer access to more utility and third party products and services—and then compensate utilities appropriately while maintaining rates that are competitive and affordable. In short, a performance-based approach provides utilities a clear financial incentive to produce the outcomes valued by customers, policymakers, and regulators.

To implement this performance-based approach, e21 proposed in its first phase that Minnesota provide an option for utilities that opt in to work collaboratively with stakeholders and regulators to develop a performance-based multi-year rate plan that integrates a range of planning, policy, and rate issues and results in a cohesive package that will support the achievement of the selected performance outcomes and policy goals. A multi-year rate plan fits very well with a more performance-oriented regulatory framework, since it may take a utility a few years to set in motion new business activities that result in the desired performance outcomes, some of which may be measured for the first time. Benefits of this approach include that

a. utilities are incentivized to achieve outcomes aligned with customer needs and expectations
b. multi-year rate plans give utilities sufficient time to achieve the public outcomes they commit to in the plan
c. utilities are encouraged to choose the least-cost, best-value option for achieving any particular outcome—regardless of whether or not doing so requires capital, third-party, or operational expenditures
d. multi-year rate plans could provide more predictable rates for customers
e. multi-year rate plans could reduce the frequency and cost of rate cases, which are a challenge for utilities and intervenors under the current regulatory approach

In phase I, e21 participants recommended an option for utilities to file a business plan, covering a period of up to five years. The plan would describe the utility's proposed investments and anticipated decisions over that time frame and, where applicable, how it would achieve the desired performance outcomes. The plan would include the five-year action plan that is currently produced as part of the 15-year integrated resource plan, but is now proposed to be developed as part of the collaborative business plan process instead, though still informed by the integrated resource plan.[7] Additional required components of the business plan would include, at a minimum:

[7] Shifting the development of the five-year action plan may require statutory change.

a. rationale and evidence for the requested revenue requirement
b. a process for adjusting rates during the plan period[8]
c. the rate designs that will collect the approved revenue

The business plan may include other features as well, including incentives and processes for cost control, cost review and reconciliation, and for accurate financial forecasting.

New Statutory Language on Multi-Year Rate Plans

In 2015, the Minnesota legislature modified the existing multi-year rate plan statute (Minnesota statute § 216B.16, subd. 19) to allow for the extension of rate plans from up to three years to up to five years and to provide greater flexibility and further guidance regarding the permissible features of a multi-year rate plan. Some of the key amendments to the statute include:

a. A utility proposing a multi-year rate plan must provide a general description of the utility's major planned investments over the plan period.

b. The Minnesota PUC may require the utility to provide a set of reasonable performance measures and incentives that are quantifiable, verifiable, and consistent with state energy policies.

c. The PUC may allow the utility to adjust recovery of its cost of capital or other costs in a reasonable manner within the plan period.

d. Recovery of the utility's forecasted rate base may be based on a formula, a budget forecast, or a fixed escalation rate, individually or in combination.

e. Recovery of operations and maintenance expenses may be based on an electricity-related price index or other formula.

f. The plan can include tariffs that expand the products and services available to customers, including, but not limited to, an affordability rate for low-income residential customers.

g. A plan can also provide for adjustments to the rates approved under the multi-year rate plan for rate changes that the PUC determines to be just and reasonable, including, but not limited to, changes in the utility's cost of operating its nuclear facilities, or other significant investments not addressed in the plan.

One focus of this white paper is the second bullet in bold above—identifying reasonable performance measures that can be implemented as part of this statutory framework.

[8] With the current volatile landscape in the electricity sector, there must be flexibility and a means to consider significant policy changes that come about in the middle of a period.

Charge to the Performance-based Compensation Subgroup

This paper is an initial attempt to scope potential outcomes and metrics for a performance-based compensation framework for utilities. The identified metrics are intended to be illustrative and are not exhaustive. e21's goal was to provide some early thinking to help guide future conversations. Similarly, we acknowledge that many implementation questions associated with a shift to a more performance-based model remain to be answered. The main body of the paper is organized in sections as follows:

I. Overarching Objectives of a Shift to Performance-based Compensation
II. Different Models or Stages of Reform
III. Role of Performance Mechanisms
IV. Principles for Selection of Performance Outcomes and Metrics
V. Potential Performance Outcomes and Associated Metrics

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Section I: Overarching Objectives of a Shift to Performance-based Compensation

With the new statutory framework in mind, this white paper offers the following objectives that e21 believes address, at a high level, what a performance-based regulatory model should achieve over the long term.

a. The central objective of a performance-based regulatory framework is to shift away from a regulatory system that primarily rewards increasing the sale of electricity and building capital-intensive facilities and infrastructure, and toward a system that rewards utilities for delivering public policy outcomes and meeting customers' service expectations.

b. This shift is also intended to achieve the following core objectives:

    i. Utilities become indifferent to how a particular system need is met (e.g., large central generation or distributed generation) and by whom (utility or non-utility). Utilities would evaluate all options and pursue non-utility solutions when they are more cost-effective.

    ii. Real costs for electricity decline over the long term as utilities and customers are incentivized to make choices that optimize the alignment between generation and load to better utilize the existing system.

    iii. Financial incentives (positive or negative) drive utility performance. High-performing utilities may earn more than their costs would indicate, and utilities that do not meet performance outcomes may earn less.

    iv. A more customer-centric framework that meets growing expectations of customers regarding service, product, and technology options, including providing affordable services to low-income customers.

This shift will be driven by more directly tying a portion of utility earnings to performance that is quantifiable, verifiable, and aligned with e21's guiding principles, as opposed to returns solely based on capital investments. The shift should be gradual and allow for the utility to maintain a viable and reasonable financial position as the framework evolves over time. As with all of the components considered under the performance-based compensation approach, the existing requirements that rates be "just and reasonable" and "free from unreasonable preference, prejudice, or discrimination" will be preserved and will continue to be subject to Commission interpretation and determination, as stated in Minnesota statute 216b.03.

Consistent with our phase I recommendations, e21 agrees there is value in moving toward a performance-based model that creates a stronger link between utility compensation and achievement of outcomes. In addition, the group agrees that this shift will occur over time, likely adding features and increasing the share of earnings tied to performance as experience is gained.

Minnesota is well positioned to enact this shift, as it has a history of using performance mechanisms to encourage utilities to take certain actions. For example, the Department of Commerce's Conservation Improvement Program incentive shares the net benefits of utility demand-side management programs between the utility and customers, such that a utility can increase its earnings by increasing the energy savings achieved through its programs. As such, this mechanism has led to a significant increase in energy savings and net benefits for customers. Additionally, the Metropolitan Emissions Reduction Program included a performance incentive that varied the return on equity on qualifying projects based on actual incurred costs, such that a utility completing work under budget resulted in a higher return on equity and vice versa.[9] Minnesota can draw on these experiences as it considers expanded changes to the regulatory framework and the use of performance mechanisms.

In addition, regardless of how this shift may change the sources of utility earnings, this transition should also ultimately incorporate and be informed by resource planning processes. Consistent with e21's phase I recommendations, utilities should evaluate how to best pair the timing of the revised integrated systems plan with the five-year business plan and multi-year rate plan filings. For example, a utility that files an integrated systems plan in 2020 would file a multi-year rate plan and five-year business plan at the same time. The five-year action plan that is currently part of the integrated resource plan would be included in the multi-year rate plan and five-year business plan and subject to full regulatory review.

This effort could also encompass what otherwise might require one or two rate cases during the same time period. The scheduling and consideration of the order of submissions should be determined by the Minnesota PUC and stakeholders in the regulatory process. Stakeholders would address whether to require such filings every five years or some other agreed-upon schedule.

Finally, it is important to acknowledge that a shift to a more performance-based system under a multi-year rate plan may require additional statutory and/or procedural changes to allow efficient coordination among resource planning and the multi-year rate plan. In addition, this shift will likely require regulatory resources to be deployed in a new way. This may require different or broader tools and skills for regulatory staff to effectively evaluate utility plans, including an increased need for consideration of performance metrics and targets as part of the overall revenue requirement. Similarly, additional regulatory staff may be needed to process the multi-year rate plan and associated reporting.

Section II:
Different Models or Stages of Reform

Table 1 represents three points along a continuum of reform, with the degree of change increasing from column 1 to 3. It is intended to provide three representations of what a shift might look like at different stages or manifestations, but should not be read as prescriptive, exhaustive, or necessarily sequential. There is a diversity of views among e21 participants as to when moves would take place and how best to implement change.

[9] See settlement agreement filed December 11, 2003, in Minnesota Public Utilities Commission Docket No. E002/M-02-633.

Table 1: Potential Continuum of Reform

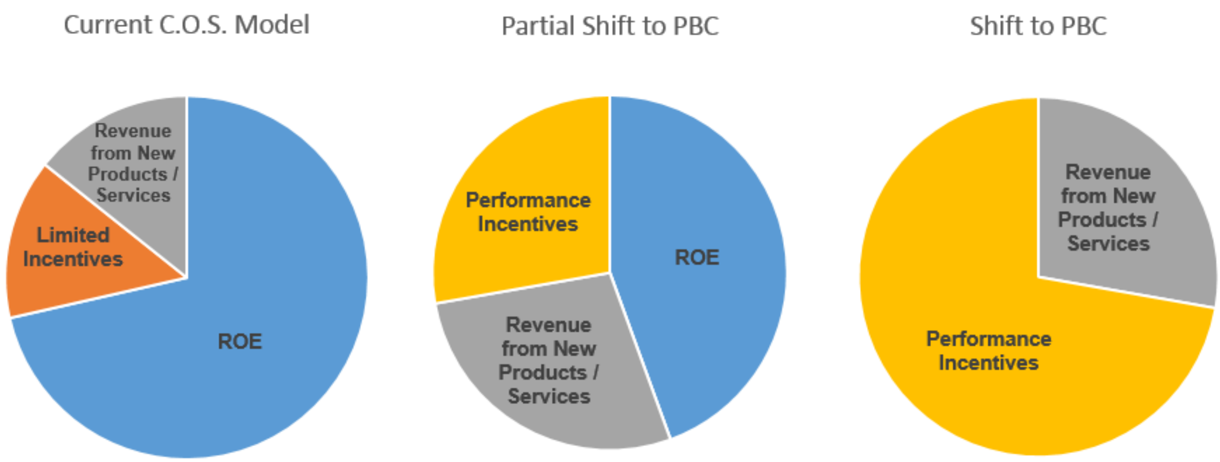
	(1) Current Cost-of-Service Model + Limited Incentives	(2) Partial Shift to Performance-based Compensation	(3) Shift to Performance-based Compensation
General Description	This alternative would maintain Minnesota's current cost-of-service regulatory framework, but add limited performance incentives for particular policy outcomes that are not incentivized by the current system. The Conservation Improvement Program incentive is an example of an existing performance incentive. Similar tools could be used to target other outcomes. For example, increased adoption of distributed energy resources was identified by e21 as another potential targeted area for performance incentives. Another example could be a return on equity band on specific types of investments, similar to the Metropolitan Emissions Reduction Project. In this alternative, utility earnings from performance are incremental to returns set in a rate case.	This alternative would be a hybrid approach of the current cost-of-service model and a performance-based framework. It would allow utility earnings to be derived from a combination of returns on capital investments and from performance outcomes. The net effect encourages utilities to achieve performance goals, but maintains a return on capital expenditures. In this alternative, the potential for performance incentives and/or penalties is addressed in a rate case.	This alternative would be a change from the current cost-of-service model to a model where utility shareholder value is based on utility performance. This framework seeks to reduce or eliminate incentive for capital expenditure as the driver of shareholder value, and instead incentivizes utilities to achieve agreed-upon outcomes using whatever means best achieves them. However, it does not seek to *disincentivize* utility capital investment, as utilities would still be allowed cost recovery for reasonable capital investments. However, to be clear, utility capital investments would not earn shareholder returns, but would recover the cost of financing. Shareholder returns would instead be earned through a combination of utilities' achieving performance goals and possible new product and service revenue opportunities. In this alternative, the potential for performance incentives and/or penalties is addressed in a rate case as part of a comprehensive package.

Summary of Earnings Drivers	Earnings from capital investment remain the primary driver for utility shareholder value. Performance incentives are additional.	Earnings are driven by a combination of performance outcomes and capital investments. The relative share of earnings coming from each would be determined over time.	Shareholder value is driven entirely by utility performance. Under this approach, one option is to link recovery of all equity-related costs to performance. Another option is to determine a cost of equity and allow that to be recovered as a financing cost through rates.[10] This alternative would also enable the utility to establish new revenues from new products and services. Net income from these new products and services could be an additional source of earnings.

[10] There is disagreement among e21 participants as to whether the PUC-approved return on equity is greater than the utility's cost of equity.

The pie charts in Figure 1 provide illustrations of the differences between the three points along the continuum of reform. In the chart for the current cost-of-service model, incentives are in addition to the allowed return on equity. In the second, some earnings come from the return on equity and the balance comes from performance. In the third, earnings are based entirely on performance.

Figure 1. Sources of Utility Earnings under Three Scenarios



Note: In all of these scenarios, it is assumed that utilities would recover their prudently incurred costs, including stranded costs as determined by the PUC. These pie charts are only meant to illustrate conceptually where utility earnings would come from under each of the three scenarios, and do not attempt to indicate the precise size of each source.

Formula for Utility Earnings. In interpreting the differences between the models represented above, it is useful to reference the formula for utility earnings under cost-of-service regulation and then illustrate how the formula may change under the other two models. As noted above, these descriptions are illustrative and are not intended to preclude other strategies or mechanisms. The same is true for the formulas below.

RR = Revenue requirement

Weighting considerations

W_d = weighted percentage of debt based on utility's capital structure

W_e = weighted percentage of equity based on utility's capital structure

W_p = weighted performance toward goals (unless performance is simply binary)

Cost considerations

C_d = cost of debt

C_e = cost of equity

C_{roe} = return on equity over and above cost of equity, if any

Operating expenses (OE) = annualized expenses allowed by the Minnesota PUC for a given test year

Rate base = original cost of the utility's plant used and useful in providing service less accumulated depreciation

Performance considerations*

P_p = the percentage attached to a particular metric, which may get larger with a greater shift toward performance-based compensation

$Pn = \pm (W_p)(P_p)$

$P_r = \sum_{P1}^{Px}$

X = the number of applicable performance metrics

*This is only an example of how performance might be calculated for illustration purposes; there are likely other ways to calculate and account for performance-related utility earnings.

1: Current cost-of-service model. Any additional performance incentives are considered outside the rate case and do not affect the revenue requirement. (They would be over and above the revenue requirement.)

$RR_1 = OE + [\text{rate base} \times (W_d \times C_d + W_e \times (C_e + C_{roe}))]$

- Shareholder earnings come from a regulator-authorized return on equity plus limited incentives on top of that.

2: Partial shift to performance-based compensation framework

$RR_2 = OE + [\text{rate base} \times (W_d \times C_d + W_e \times (C_e + C_{roe}))] \pm (P_r \times RR_1)$

- Shareholder earnings come from utility performance, a reduced return on equity, and potential new revenue streams from providing new services.

3: **Shift to performance-based compensation framework**

$RR_2 = OE + [\text{rate base} \times (W_d \times C_d + W_e \times C_e)] \pm (P_r \times RR_1)$

- Shareholder earnings come from utility performance and potential new revenue streams from providing new services.

In scenarios 2 and 3, the performance earnings are determined by calculating an aggregate performance rate (P_r) based on whether the utility met certain performance goals. That rate is then multiplied by the traditional revenue requirement as would be calculated in scenario 1. Particularly as we shift from the traditional framework to a performance framework, this will help keep the performance component within a reasonable band of the revenue requirement (i.e., if the old RR was $100,000,000, the performance calculation could be set such that it would not exceed plus or minus $10,000,000, or some other discrete range relative to the RR).

Another scenario that the e21 group discussed was one in which utility earnings are, like in scenario 3, based entirely on utility performance, but utilities would recover all or part of their cost of equity via performance incentives. This means that authorized recovery of the cost of equity could range from 0 to 100%. The closer to 0% that it gets, the more the equity-related costs would be recovered via a utility's performance. Several e21 participants expressed concerns that such a scenario may be seen by investors as overly risky and have the unintended consequence of unacceptably raising the cost of capital. The impact of any shift toward a performance-based compensation framework will hinge on the size of the earnings opportunities available.

Section III:
Role of Performance Mechanisms

There are several areas or situations where performance mechanisms may be beneficial to

a. motivate further action on state and federal policy goals or other PUC-approved priorities
b. promote achievement of benefits at reasonable costs and milestones associated with new projects or initiatives
c. address specific areas of underperformance
d. benchmark against other utilities in fully regulated markets
e. ensure that utilities can continue to provide reliable service and other desired outcomes under the incentive structure, taking into account dynamic circumstances
f. offset disincentives that cannot be fully addressed by more fundamental solutions

When performance mechanisms are considered for any of these purposes, the central challenges are: 1) to be specific enough, up front, about the outcomes desired to avoid disputes after the fact as to whether the performance outcomes were achieved or not; 2) to choose metrics that accurately measure progress toward the desired outcomes; and 3) establishing metrics that are measurable and verifiable by the utility and others.

Section IV: Principles for Selection of Performance Outcomes and Metrics

Here we offer basic principles to guide the selection of performance outcomes and performance metrics.

Performance outcomes should

a. tie back to accomplishing the e21 guiding principles and outcomes
b. tie back to state and federal policy goals
c. represent areas that electricity customers value and deliver benefits to all customers
d. prioritize areas of performance and metrics that are most important to regulators

Performance metrics should be

e. clearly defined and transparent
f. measurable and verifiable by any third party using available, high-quality data
g. drawn from data already reported today, if possible
h. reasonably within the utility's control
i. simple and easy to interpret and communicate
j. directly tied to the desired outcome
k. agnostic on specific means to achieve the outcome

Additional considerations could include

l. bearing in mind potential trade-offs and interactions between metrics
m. allowing sufficient time to understand whether or not metrics are effective in measuring performance, thereby avoiding frequent changes to the metrics
n. using pilot programs to encourage, and pave the way for, exemplary performance (that is, allowing utilities to use pilot programs to explore novel ways of achieving desired performance outcomes)

Section V: Potential Performance Outcomes and Associated Metrics

The following list is intended to serve as a menu of potential performance outcomes and metrics discussed by e21 participants that could be considered as part of a multi-year rate plan. The metrics offered below are not intended to eliminate other metrics from consideration, but to provide an initial screening of potential metrics to consider. e21 acknowledges that the metric examples were not fully vetted against the principles and criteria listed above and that this would be a necessary step in the implementation process. Similarly, e21 acknowledges that some of these performance outcomes are closer to being ready for near-term implementation than others. Factors that determine readiness include but are not limited to agreement on these performance outcomes, technological or other capabilities to deliver the outcomes, structural changes, and availability of data for suitable metrics. Further screening and evaluation would be necessary, noting that any and all performance outcomes and metrics would be subject to determinations of reasonableness and Commission discretion. The outcomes are numbered for ease of reference, but do not represent any ranking preferences.

Outcome 1: Distributed energy resources and grid services are fairly valued and integrated into the electric system in ways that add net benefits and minimize costs.

Explanation: Achieving this outcome means preparing the electric system to cost-effectively accommodate and integrate the adoption of distributed energy resources. Given the significant role that distributed energy resources are expected to play in Minnesota's energy future, it will be important to determine in advance how best to use them effectively as an integrated element of the electric system and compensate them appropriately so that they locate in the most beneficial places on the distribution system. The goal should be to integrate them in ways that add net benefits and minimize costs to the system as a whole. Accurate price signals can encourage distributed energy resources to locate in the best places.

Finally, achieving this outcome will require that interconnection of distributed energy resources is timely, transparent, and fair, and that it meets or exceeds statewide interconnection standards in a cost-effective manner; any necessary structural changes within the Midcontinent Independent System Operator (MISO) to value or otherwise integrate these must also occur. Utilities should take steps to reduce the costs of interconnection, including coordinating the aggregation of distributed energy resources, developing a method to share interconnection costs (e.g., group interconnection studies as is done in MISO), and proposing transparent interconnection rules with detailed study and cost information for providers of distributed energy resources to evaluate.

The metrics below reflect the goals of timely interconnection and locating distributed energy resources on the distribution grid where they provide the most value to the system. This goal does not preclude siting them in other locations, but doing so may result in lower compensation for the provider, commensurate with their value.

- **Examples of Metrics:**
  a. Interconnection
     i. Percentage of applications meeting standards defined and established by the Minnesota PUC
     ii. Median time to connect distributed energy resources (by category)
  b. Number or percentage of high value installations (e.g., elements of value might include locational, temporal, and ancillary service value)
  c. Timely and effective provision of locational value information to customers regarding distributed energy resources
  d. Percentage of customers participating in distributed energy resource programs (e.g., electric vehicles, solar, storage, and demand response)
  e. Percentage of system needs met by distributed energy resources

- **Notes:** Minnesota statute 216B.1611 authorizes the PUC to develop financial incentives based on a public utility's performance in encouraging residential and small commercial customers to participate in on-site generation. There may be areas of the distribution grid that are more constrained and would benefit from distributed energy resources, but this locational information needs more development as part of utility distribution planning. Once this information is available, resources that can relieve these constraints should be compensated accordingly.

Outcome 2: Utilities have sufficient incentive to manage controllable costs, particularly operations and maintenance.

- **Explanation:** At a high level, this outcome should be achieved through the overall design of a performance-based multi-year rate plan, such as through a stay-out provision (an agreement to "stay out" of the rate revision process for a given length of time), and tying operating and maintenance increases to an inflation index. More specifically, one area of focus under this goal is to minimize the cost of fuel and purchased energy.
- **Example of Metrics:** Number and duration of unplanned generation outages, which cause the utility to procure replacement energy or capacity.
- **Notes:** The pending AAA docket (AA-12-757) is exploring potential fuel clause cost management.

Outcome 3: The system is made more efficient.

- **Explanation:** This goal seeks to optimize the alignment between generation and load to better utilize the existing system in a cost-effective manner, thus improving resource utilization and potentially avoiding new capital investment that may not be necessary for the long term. This goal also seeks additional efficiencies to be gained at the generation, transmission, and customer levels. e21 participants acknowledge that there are multiple approaches to achieving this goal, including leveraging the existing Conservation Improvement Program and encouraging greater adoption of time-of-use rate options that send more accurate price signals. Metrics could address the high-level goal of optimizing the alignment between generation and load to better utilize the existing system, or address more specific means to achieving the goal. Both types of metrics are listed below.
- **Examples of Metrics:**
    a. Costs incurred to reduce system peak (dollars per annual (or seasonal) peak reduction (kilowatts))
    b. Number of kilowatts shifted to off peak
    c. Percentage of load shifted to off peak
    d. Number of customers participating in demand response programs
    e. System load-factor (average / peak)
    f. Conservation Improvement Program—annual electricity savings (kilowatt hours)
    g. Conservation Improvement Program—cost per unit of electricity saved
    h. Conservation Improvement Program—net benefits achieved
    i. Least amount of BTU (British thermal units) value wasted
    j. Reduction in line losses
    k. Percentage of customers participating in time-of-use programs
    l. Percentage of customers participating in a price signal program, such as Dakota Electric's Stoplight program
    m. The addition of new time-based rate options

n. Increased penetration of advanced metering infrastructure or other enabling technologies
o. Combined heat and power capacity

- **Notes:** One method to achieving this goal would be increased use of demand response, via a utility-issued request for proposals.

Outcome 4: Reductions are achieved in the pollution and carbon emissions in any part of the energy economy in a cost-effective manner beyond what is required in law.

- **Explanation:** The desired outcome of this goal is a faster reduction in emissions at a larger scale than what would be achieved under state or federal requirements. The intent is not to reward utilities for achieving compliance obligations. As with all of the proposed performance outcomes, the benefits of achieving this will be balanced against cost considerations.

- **Examples of Metrics:**
    a. Reduction in tons CO_2 and other pollutants
    b. Reduction in tons CO_2 per megawatt hour
    c. Progress toward meeting goals for reducing greenhouse gas emissions
    d. Costs per additional unit of reduction beyond existing requirements

- **Notes:** Some e21 participants believe this goal is already addressed in the integrated resource planning process. The group also recognized that the Clean Power Plan, if it is implemented, may result in metrics or other mechanisms to address this goal. The impact on electric bills of emissions reduction was raised as an important consideration.

Outcome 5: Electricity customers, including low-income customers, have increased access to a wider range of utility and third-party services and products.

- **Explanation:** This outcome relates to customer engagement and the availability of a broader range of customer options. e21 is interested in enabling greater innovation and flexibility for utilities and third-parties to offer new products and services to customers, similar to the current Conservation Improvement Program process. The desired outcome is a broader menu of offerings available to customers, with care taken to being inclusive of low-income customers and ensuring appropriate customer protections. The metrics tie to utility actions that increase offerings and increase convenient customer access to third-party services, products, and new technologies. e21 is also interested in improving existing services offered by utilities.

- **Examples of Metrics:**
    a. Increased customer awareness of utility offerings
    b. Implementation of new technologies and services
    c. Number of available product and service options
    d. Customer adoption of specific new service or product
    e. Increased availability of information that facilitates expanded customer offerings
    f. Customer satisfaction with access to customer and system information from the utility
    g. Customer satisfaction with the availability of third-party services

- **Notes:** Utilities are currently permitted to propose new offerings, but there could be process improvements at various stages to better achieve this goal, recognizing the need to balance expediency with due process and regulatory resources. On the topic of third-party products, e21 participants also recognize the past docket where the Minnesota PUC made decisions limiting aggregation of retail customers by third parties (docket no. 09-1449).

Outcome 6: Development of efficient, low/no carbon loads (e.g., electric vehicles) is promoted.

- **Explanation:** Energy conservation and other demand-side management programs can reduce utility system costs; however, increased sales allow the system's fixed costs to be spread across a greater number of kilowatt hours, lowering volumetric rates. Therefore, it is appropriate to encourage development of selected new loads. In order to avoid violating other e21 guiding principles, such as carbon reduction, it is important that there are incentives for new load to be efficient and served in a way that meets customer needs while balancing the goal to reduce the carbon intensity of the electric system overall. Examples include the electrification of the transportation system and creation of renewable microgrids to serve new customer loads.
- **Example of a Metric:** Adoption of rates supporting electric vehicles
- **Notes:** The creation of a carbon benefit is dependent on the electricity powering the electric vehicle having a lower carbon intensity than gasoline or diesel. Additional metric development would be needed to identify other metrics within the utility's control.

Outcome 7: High levels of reliability are ensured as driven by customers, as and where needed.

- **Explanation:** Not all customers require, or would want to pay for, greater reliability than they already have; but in an increasingly digital economy more customers do need—and would be willing to pay for—higher levels of reliability. e21 argues that meeting this need is a matter of economic competitiveness. Because e21 also sees maintaining good reliability more generally as important, it recommends that any performance system continue measuring the System Average Interruption Duration Index, the System Average Interruption Frequency Index, and any other established reliability metrics under the PUC's rules. Other metrics may be added as appropriate and possible with newly installed technology.
- **Examples of Metrics:**
    a. System Average Interruption Duration Index
    b. System Average Interruption Frequency Index
    c. Momentary Average Interruption Frequency Index
    d. Number of validated power quality or voltage complaints to the PUC
    e. Number and percentage of distribution lines with voltage and volt-ampere reactive controls
- **Notes:** None.

Outcome 8: Customer satisfaction is increased.

- **Explanation:** Customer satisfaction has been and will continue to be a key indicator of a utility's success. As utilities become more customer-centric, it is important to enhance the focus on high customer satisfaction, which could include utility facilitation of third-party offerings.

- **Examples of Metrics:**
    a. Electricity customer satisfaction indices, or third-party surveys, for residential and business customers
    b. Transaction surveys
        i. Percentage of customers satisfied with their recent transaction with the utility
        ii. Percentage of contacts resolved on the first call
    c. Number of call-center calls received and the answer speed
    d. Number of customer complaints received
    e. Number of service appointments made and fulfilled
    f. Utility's offering of a variety of ways to obtain outage or emergency information
    g. Utility's delivery of accurate, relevant, and timely information about outages
    h. Utility's delivery of convenience and choice for customers' bill-paying
    i. Percentage of bills that do not need to be rebilled
    j. Percentage of bills produced by actual meter reads

Notes: Measuring achievement of some of these metrics may require employing independent third-party evaluators.

Outcome 9: Customers are ensured access to basic electricity service that is affordable.

- **Explanation:** Particularly in light of the many expected changes in the electric sector e21 participants wanted to highlight the necessity of customers' access to affordable, basic electricity service.

- **Examples of Metrics:**
    a. Percentage of eligible customers signed up for affordability programs, such as low-income discounts and payment plans
    b. Number of avoided disconnections due to customers' enrolling in payment plans

- **Notes:** No additional metrics are proposed for this outcome beyond what regulators already require. However, allowing customers to self-certify low-income eligibility could be considered.

Section VI: Conclusion

A central recommendation of the e21 Initiative's phase I report is the shift to a more performance-based compensation framework, where some portion of utility earnings are linked to utilities' performance on outcomes valued by customers and supportive of state energy policies. It became clear through e21's discussions that there are diverging views about how quickly and how extensively that shift should take place. While this white paper outlines three stages, it does not offer a judgment or recommendation on where the regulatory framework should land along that spectrum. Instead, its aim is to offer principles, guidelines, and potential outcomes and metrics to support Minnesota's incremental movement toward a more performance-based model, irrespective of the final destination.