BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of a Working Case to Consider Proposals to Create a Revenue Decoupling Mechanism for Utilities	)))	File No. AW-2015-0282

COMMENTS OF KANSAS CITY POWER & LIGHT COMPANY AND
KCP&L GREATER MISSOURI OPERATIONS COMPANY

COME NOW Kansas City Power & Light Company ("KCP&L") and KCP&L Greater Missouri Operations Company ("GMO") (collectively, the "Company") and hereby offer the following comments in response to the Missouri Public Service Commission's ("Commission") Order Opening a Working Case to Consider Proposals to Implement a Revenue Decoupling Mechanism for Missouri's Utilities ("Order").

BACKGROUND

1. On May 1, 2015 the Commission issued a Notice of New Proceeding.

2. On July 22, 2015 the Commission issued an Order which established File No. AW-2015-0282 as a repository for documents and comments regarding the Commission's consideration of the concept of a revenue decoupling mechanism.

3. The Commission invited interested stakeholders to submit comments as outlined in the Order by September 1, 2015. Additionally, on August 5, 2015 the Commission issued a Notice Scheduling Workshop and Requesting Responses which invited interested parties to submit responses to questions contained therein by September 1, 2015.

COMMENTS

4. The Company is interested in discussing revenue decoupling and other policies and practices as a means of aligning shareholder and customer interests in light of the evolving operating environment for electric utilities. To have a meaningful discussion of regulatory

policies and practices, it is essential to recognize the current environment facing electric utilities like KCP&L and GMO, including factors such as:

- Load growth has flattened considerably for a variety of reasons (including the economic downturn in 2008, lower national and regional economic growth rates, increasing efficiency standards, proactive implementation of MEEIA, increased installation of solar and other distributed generation facilities and new end-use technologies) such that whereas load grew on a 2-3% annual basis prior to 2008, current load growth forecasts show annual load growth of 1% or less annually, with flat or declining per capita residential consumption;
- The cost of providing electric service continues to increase due in large part to a variety of governmental mandates (from environmental regulators, FERC, NERC and state taxing authorities, among others) and ongoing increases in wages, health care costs and general operating costs;
- Customer expectations around service quality and reliability continue to rise, also increasing upward pressure on the cost of providing electricity; and
- New technologies are penetrating the electricity industry across the value chain (including, but not limited to, distributed generation, end-use appliances, Smartgrid at both the transmission and distribution levels, as well as third party service providers interacting with customers and electricity providers in virtually all of these areas), with the prospect of delivering higher value to our customers, but requiting capable and financially healthy utilities to manage their integration.

It is expected that this environment will continue for the foreseeable future, not just for the Company but also for electricity providers across the country. In this regard, the electric utility market has reached a level of maturity that requires a fundamental re-structuring of the regulatory construct. Revenue decoupling can stabilize utility revenues and customer bills, but utility financial health is also eroded by the inability of utilities to fully recover costs due to regulatory lag inherent in the current construct which has generally governed for over 100 years. It relies on historical test year ratemaking, long lead-time procedural schedules and very limited use of regulatory tools capable of keeping up with the continuously changing cost of providing electricity that will likely require electric utilities like KCP&L and GMO to file frequent rate cases to attempt to maintain a reasonable relationship between cost to serve and revenues. As the Commission is well aware, general rate cases are time consuming, resource intensive and expensive for all parties involved and do not allow for effective or timely response to changing conditions in the current dynamic environment. It is therefore wise to evaluate and give serious consideration to alternatives that could mitigate the need for frequent rate cases, better align the interests of customers and shareholders and improve outcomes for all stakeholders. Regulatory practices and policies that should be considered include the use of a forward test year, formula rate plans, performance-based rate plans and/or additional rate adjustment mechanisms, including revenue decoupling.

5. Utility regulatory commissions across the U.S. have recognized that changes in the electric utility operating environment require changes in the regulatory construct. Approximately 20 jurisdictions make use of forward test years, and formula rate plans are available in a number of jurisdictions (including Alabama, Arkansas, Georgia, Illinois, Oklahoma and the Federal Energy Regulatory Commission). More fundamentally, the performance-based approach to setting rates and creating incentives has been widely used both in the United States and internationally (e.g., Canada, Europe, Australia) as a framework for

explicitly aligning regulatory and utility goals. At least five state commissions are exploring how performance-based ratemaking could help address emerging issues in the electricity industry, and others are following that path. See, for example, Attachment 1 hereto which is a report of the e21 Initiative, a diverse stakeholder group in Minnesota. Rate adjustment mechanisms are also used extensively for electric utilities across the country; Schedules 1 and 2 of the white paper attached hereto as Attachment 2 show that:

- In non-restructured states, every utility regulatory commission makes use of a fuel adjustment clause-type mechanism to address changes in the cost of fuel and purchased power for electric utilities;
- 43 of 52 utility regulatory commissions in the U.S. have environmental cost adjustment mechanisms in place for electric utilities;
- 23 of 52 utility regulatory commissions in the U.S. have infrastructure cost adjustment mechanisms in place for electric utilities;
- 21 of 52 utility regulatory commissions in the U.S. have adjustment mechanisms in place for taxes for electric utilities;
- 18 of 52 utility regulatory commissions in the U.S. have transmission expense adjustment mechanisms in place for electric utilities; and
- 12 of 52 utility regulatory commissions in the U.S. have revenue decoupling mechanisms in place for electric utilities.

6. The Company understands that one of the issues that this docket would address is how revenue decoupling would operate. Below is the Company's understanding of revenue decoupling which focuses exclusively on revenues (and, as such, does not address changes in the cost of providing electricity):

- In general terms, revenue decoupling allows for the use of an adjustment factor which moves up or down based on increases and decreases in sales so that utilities continue to earn the amount of base or non-fuel revenues authorized by the Commission in a general rate case.
- Revenue decoupling eliminates the incentive to maximize sales, and removes much of the disincentive for utilities to promote energy efficiency.
- Decoupling stabilizes a utility's revenue stream because its revenues are no longer dependent on sales, while also stabilizing customer bills. Since decoupling adjusts actual revenues to align them with the authorized revenue requirement, it can effectively mitigate regulatory lag associated with revenue variability in some respects. Utilization of a timely and effective true-up mechanism ensures that this mitigation is symmetrical in that it can benefit customers by returning revenues exceeding the authorized revenue requirement, or it can benefit shareholders by recouping revenues falling short of the authorized revenue requirement.
- By truing-up actual revenues to the authorized revenue requirement, revenue decoupling would offer a more efficient and effective alternative to the "throughput disincentive-net shared benefits" concept currently utilized under MEEIA to recover revenues lost due to MEEIA programs. The MEEIA regulatory construct currently in place is too cumbersome, complicated, expensive, contentious and uncertain to be relied upon sustainably by customers, shareholders or businesses (such as HVAC contractors, etc.) involved in the provision of MEEIA programs.

7. To align customer and shareholder interests appropriately, the revenue decoupling mechanism must be structured properly. Obvious topics that must be considered include the following:

- To what rate elements should revenue decoupling apply?
- How should customer additions or losses be treated under revenue decoupling (as described above)?
- What impact, if any, does implementation of revenue decoupling have on other rate adjustment mechanisms (i.e., the fuel adjustment clause, demand side investment mechanism, renewable energy standard rate adjustment mechanism, etc.)?
- How does revenue decoupling impact customer rates and/or future rate predictability?
- What impact does the revenue decoupling mechanism have on a utility's ability to earn its authorized rate of return?

QUESTIONS/RESPONSES

a) Please comment on the legality of decoupling in Missouri.

Response:

Given the state of the law in Missouri, the Company would be hesitant to rely on a Commission order adopting a revenue decoupling mechanism involving rate adjustments between general rate proceedings as described herein for electric utilities absent a unanimous settlement or enactment of specific enabling legislation. Legislation would not be necessary to the extent that revenue decoupling is implemented as a tracker-type mechanism with rate adjustments associated with deferred balances addressed only in general rate proceedings along with all other relevant factors. State ex rel. Noranda Aluminum, Inc., v. Pub. Serv. Comm'n, 356 S.W.3d 293, 320 (Mo.App. S.D. 2011).

b) Please comment on your interests and preferences for any of the various aspects related to revenue regulation and decoupling contained in "Revenue Regulation and Decoupling: A Guide to Theory and Application, June 2011, The Regulatory Assistance Project". (A copy of that document is available in the EFIS file for this case.).

Response:

At this early juncture, the Company expects that it would lean toward either a full revenue decoupling approach (as described on pp. 11-12 of the RAP white paper) or a revenue per customer approach (described on pp. 16-19 of the RAP white paper). Of course, these expected preferences of the Company depend on the specifics of the revenue decoupling ultimately adopted and may change in the future.

c) For responding utility stakeholders, assuming that your preferred revenue regulation decoupling mechanism described in your response to b) will result in a change in the rates of certain, if not all, customer rate classes, what is your estimate of the change in residential rates and rate impact resulting from your preferred mechanism? Would you expect those changed rates to be collected through a customer charge or a usage charge?

Response:

The Company does not expect that implementation today of full revenue decoupling on a revenue per customer basis would require any immediate changes to existing rates or rate structures, although rate adjustments to amortize any under- or over-recovery of allowed decoupled revenues would be needed later at some point. Use of full revenue decoupling on a revenue per customer basis would not eliminate the need to maintain an appropriate balance between the level of fixed monthly rate elements and the level of variable rate elements, and the Company presumes that such rate design issues would continue to be addressed in periodic general rate cases in the future as they have in the past.

On a different but related point, the Company expects that implementation of full revenue decoupling on a revenue per customer basis would likely be facilitated by eliminating from base rates all fuel and purchased power costs and recovering all such costs through the fuel adjustment clause.

d) Please provide sources or papers on alternative rate mechanisms, revenue decoupling, or similar topics that will further the Commission's knowledge on the subject of this case.

<u>Response:</u>

The Company continues to research and seek understanding of decoupling and how it may be successfully applied. As part of that research, the following sources have been identified and have the potential to contribute to this proceeding:

a. Alternative Regulation for Evolving Utility Challenges: An Updated Survey, January 2013 prepared by the Pacific Economics Group Research LLC for the Edison Electric Institute.

b. State Electric Efficiency Regulatory Frameworks, December 2014, prepared by the Edison Foundation Institute for Electric Innovation.

c. Decoupling For Electric & Gas Utilities: Frequently Asked Questions (FAQ), September 2007 prepared by the The National Association of Regulatory Utility Commissioners.

d. The Impact of Revenue Decoupling on the Cost of Capital for Electric Utilities: An Empirical Investigation, March 20, 2014, prepared by the Brattle Group for the Energy Foundation.

e. The Theory and Practice of Decoupling, January 1994, prepared by the Energy & Environment Division of the Lawrence Berkeley Laboratory.

f. Decoupling Policies: Options to Encourage Energy Efficiency Policies for Utilities, December 2009, prepared by the National Renewable Energy Laboratory.

g. Revenue Regulation and Decoupling: A Guide to Theory and Application, June 2011, prepared by The Regulatory Assistance Project.

h. Decoupling Case Studies: Revenue Regulation Implementation in Six States, July 2014, prepared by The Regulatory Assistance Project.

CONCLUSION

8. Revenue decoupling, properly structured, offers a host of benefits to both customers and shareholders, but it is not a panacea. Fundamental changes to the regulatory construct also will be necessary to reduce persistent regulatory lag and align utility costs and revenues in the current environment of low load growth and rising cost to serve. Other structural changes in the regulatory construct may also be required to ensure that utilities can efficiently and effectively bring tomorrow's highest value energy solutions to their customers. The Company is encouraged that the Commission is examining these issues and looks forward to continued participation in this working docket.

Respectfully submitted,

/s/ Robert J. Hack

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CERTIFICATE OF SERVICE

I do hereby certify that a true and correct copy of the foregoing document has been hand-delivered, emailed or mailed, postage prepaid, this 1st day of September, 2015, to all parties of record.

/s/ Robert J. Hack
Roger W. Steiner

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December 22, 2014

– Via Electronic Filing –

Dr. Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
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St. Paul, MN 55101

Re: REQUEST FOR PLANNING MEETING AND DIALOGUE
ROADMAP FOR SUPPORTING THE E21 INITIATIVE

Dear Dr. Haar:

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission this letter offering a roadmap for implementing the recommendations of the e21 Initiative. To adapt to the evolutionary changes confronting the energy industry, e21 brought together a diverse group of stakeholders to create a vision for aligning Minnesota's regulatory framework with State policy goals, changing customer expectations, new technologies, and innovation.

We support this vision and would like to help make it a reality. Minnesota has long been a leader in energy policy; implementing the e21 recommendations would do much to take the state to the next level of accomplishment -- benefiting customers, shareholders, the state's economy, and the environment in the process.

To that end, we see exciting opportunities for Xcel Energy to enact various components of the e21 vision, including:

- *Lead the effort to achieve carbon reduction by 40 percent.* Confronting environmental challenges in the most economical way is one of the most significant challenges facing our industry. In our upcoming Resource Plan, we provide a path that could cost-effectively achieve a 40 percent or greater reduction in carbon emissions by 2030. Importantly, this path preserves and enhances the benefits of a diverse supply portfolio, thus offering significant price and risk mitigation that will benefit and protect customers during this period of rapid industry change.

- *Advance distribution grid modernization.* Distributed resources, for example solar, will play a more significant role in the future, while reliability will become even more important as our economy becomes increasingly electricity-driven. We would welcome the opportunity to take the lead in working with stakeholders to create a plan for evolving our distribution system to serve 21st century demands, such that we enable a more distributed energy future, maximize the value of the grid, and ensure and enhance reliability.
- *Provide our customers with a platform of innovative service and product offerings.* Our customers are interested in better managing their energy use and bills, and purchasing green or otherwise streamed energy while ensuring safety and reliability, among other things. We want to respond by offering products and services that align with those goals. New services, alternative rate structures and pilot programs will be needed, as well as potentially new standards and approval processes so as to encourage innovation and bring new services to market in a timely and effective manner.
- *Implement a new regulatory framework that provides both predictable rates for customers and a more timely and nimble review while retaining the key benefits of existing processes, thus freeing valuable time for regulatory agencies, stakeholders, and utilities to focus on achieving policy objectives.* The e21 Initiative highlighted the importance of developing a supportive regulatory framework to align achievement of policy objectives with business objectives. Minnesota has long been a leader in this effort, but the increasing complexity of our industry requires a rethinking of the current framework to ensure it is still aligned. We believe the rate setting process can improve by evolving to a model that allows us to recover the costs associated with implementing this roadmap with greater frequency, certainty and predictability while incenting us to manage our business in a competitive manner.

We are excited about the possibilities and would welcome the opportunity to help make the e21 vision a reality. To do so, we believe the collaborative spirit embodied by the e21 Initiative will need to carry forward and that additional dialogue with the Commission and stakeholders would be beneficial. We thus request that the Commission schedule a planning meeting for further exploration of the appropriate procedure advancing the e21 Initiative.

The remainder of this letter:

- Provides a brief background about the e21 Initiative,
- Discusses the guiding principles upon which we built our roadmap,
- Explains each element of our execution plan in more detail, and
- Outlines our proposed next steps.

We recognize the non-traditional nature of this request, and appreciate the Commission's consideration.

The Evolving Energy Industry and the e21 Initiative

The energy industry is at a pivotal point. While we have experienced periods of change in the past, the last several years point to a fundamental shift in what the energy system will look like, what it will be able to do, and how people will use it.

Earlier this year, the Company joined a diverse group of stakeholders, known as the e21 Initiative, to identify potential changes to the regulatory system that would better align utility revenue and business models with public policy goals and changing customer expectations. The group initially identified fundamental changes in the electric industry, including positive evolutionary shifts that have had impacts not fully reflected in historic regulatory norms. These include:

- *Environmental Policy Shifts* - Environmental policy changes have emerged over recent years, beginning in large part with Minnesota's Renewable Energy Standard.[1] In addition, this year the federal government released initial rules to limit greenhouse gas emissions from existing power plants, making long-term carbon reductions necessary. While it is not yet clear how the final federal rules will take shape, it is critical for electric utilities to not only respond to environmental mandates, but also to develop the investor support necessary for any utility to be a proactive environmental leader.[2]

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[1] Elisabeth Graffy & Steven Kihm, *Does Disruptive Competition Mean a Death Spiral for Electric Utilities?*, 13 Energy L.J. 1, 6-7 (2014) (discussing how state renewable portfolio standards have already significantly impacted utility obligations).

[2] Hal Harvey & Sonia Aggarwal, *Rethinking Policy to Deliver a Clean Energy Future*, America's Power Plan 1, 5 (citing changing "national security, public health, economics and climate change" policy concerns as a major factor driving change in America's power sector).

- *Impacts of Greater Conservation* - Years of successful conservation programs and increased awareness about the value of energy efficiency, as well as advancements in technology, have slowed and in some cases reversed the sales growth trends characteristic of the past century.[3]
- *Customer Demand for Choice* - Energy consumers are showing greater interest in receiving the same kinds of choices from their energy provider that they are offered in other areas of their lives, such as access to more detailed energy data, more advanced energy management capabilities, and a more customized energy mix.[4]
- *Competition and New Technologies* - Declines in the cost of distributed generation technologies, growing customer interest in expanded energy options, and supportive public policies have prompted a surge in the adoption of distributed generation, bringing increased competition.[5] Minnesota has the opportunity to be proactive and put a framework in place that will support continued expansion and potentially avoid the kinds of regulatory and operational challenges seen in places like Hawaii. Energy storage technologies will likely follow a similar path, as will energy management and other customer-facing technologies.[6]

The e21 Initiative spent months learning and discussing these topics, including how regulatory bodies in this country and abroad have tried to tackle adapting to the evolutionary change sweeping through the energy industry. An early point of consensus in the e21 Initiative was that the current regulatory framework is becoming increasingly incompatible with the State's energy policy goals and with industry trends, and could be improved to better serve the needs of customers and stakeholders.

On December 18, 2014, the e21 Initiative published its recommendations, which are attached as **Attachment A**. At the heart of the e21 Initiative's recommendations is a

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[3] Steven Nadel & Garrett Herndon, *The Future of the Utility Industry and the Role of Energy Efficiency*, ACEEE Report No. U1404, 1-4 (June 2014).
[4] Harvey & Aggarwal, *supra* note 2, at 4 (citing another major factor driving change in America's power sector as the "advent of competition").
[5] *Id.* at 4 (the first major factor driving change in America's power sector as the "large number of new technologies [that] are becoming commercially viable," such as renewable generation technologies and smart grid systems).
[6] Peter Kind, *Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business*, Edison Electric Institute 1, 3 (January 2013) (discussing how more emerging technology, such as battery storage, will place additional pressure on the traditional regulated utility model); Graffy & Kihm, *supra* note 1, at 15-16 (innovations in power storage "accelerating the potential for off-grid systems")..

shift to a more customer-centric and sustainable framework for utility regulation in Minnesota that better enables:

- Innovation and new customer options;
- Grid modernization and integration of distributed resources;
- Achievement of policy goals; and
- The financial health necessary for utilities to implement this vision.

While much work needs to be done, the e21 Initiative recommendations provides a commendable vision of potential changes to the State regulatory system that can better align utility business model and economic incentives with Minnesota's public policy goals and expanding customer expectations.

Guiding Principles

We are looking forward to participating in Phase II of the e21 Initiative, but instead of waiting for that effort to produce a concrete set of recommended next steps, we believe there are several recommendations from Phase I that we can further explore now to advance the goals of the State and our customers. We looked to four guiding principles to help us create our road map.

First, our customers and being responsive to them is our top priority. Our customers are changing from primarily valuing reliability to wanting to feel good about the energy they use and having greater choice in the service and products they purchase from us. While providing safe and reliable service will be a cornerstone of our business, we also want to be responsive to our customers' changing values.

Second, we believe it is in the best interest of the State and our customers to have a healthy vertically integrated utility today and into the future. For that reason, our ideas and vision build upon our existing infrastructure and regulatory platform instead of breaking those apart. We recognize some may think it best to concentrate our efforts on dismantling this utility. We respectfully disagree with that sentiment and believe we can spend this time now cooperatively evolving the Company into the utility this State and our customers want.

Third, the elements of our roadmap are interrelated and will work best to accomplish the goals of the State and our customers when kept together. Currently, resource and customer choice related policy, and ratemaking decisions happen in different proceedings, which the Commission may or may not decide near in time. We have seen this cause frustration and confusion from time to time. Reducing carbon emissions, modernizing the distribution grid and offering our customers diversified services and products will require the Company to make significant investments. We will have to recover the costs associated with these investments. We believe it would be an improvement to the existing process to make decisions about cost recovery at the same time as we decide whether to move forward with investments. Therefore, our roadmap keeps policy and ratemaking decisions connected.

Fourth, we need to consider a change in the way we approach the ratemaking process within the existing ratemaking framework. Rate cases take up a lot of resources and because of that make it challenging for us to talk to the Commission and our stakeholders about policy initiatives such as the ones outlined here. We concluded that our roadmap should suggest several evolutionary steps that could be applied to the existing ratemaking process so that the Company, Commission and our stakeholders can have an un-interrupted, non-distracted dialogue about the e21 Initiative recommendations and our roadmap for implementing them.

Achieving Forty-by-Thirty

The e21 Initiative has a vision that to align the regulatory model with the changing landscape, utilities need to be incented to be proactive environmental policy leaders. Our roadmap for this vision is to exceed the State's carbon emission goals by reducing carbon emissions by 40 percent, or more, by 2030.

Achieving such a historic reduction in carbon emissions provides a unique opportunity to create a partnership between the Company and the State. Environmental leadership is one of our core values and we have a strong track record of success. Likewise, the State of Minnesota has been a leader in environmental policy for many years. For example, recent legislation established a solar energy mandate and more accessible solar-based products, and set the goal for Minnesota to be the first state to use only renewable-based generation. By partnering together we believe we can cost-effectively achieve one of the State's key energy policy goals.

We will be laying out our preferred plan for achieving a 40 percent reduction in carbon emission in our next Integrated Resource Plan, which we will file in January 2015. In our upcoming IRP, we also present our thoughts and ideas about the future of Sherco 1 and 2. While the plan is still being prepared, we expect to take a multifaceted approach that meets several key objectives, including:

- Accelerating the pace of emissions reduction;
- Expanding renewable energy on our system;
- Preserving system diversity and flexibility; and
- Moderating rate impacts and keeping rates competitive.

Our preferred plan also allows for accelerating cost-effective investments and using other tools to achieve carbon reduction if renewable costs are higher than predicted.

The e21 Initiative did a laudable job in offering a forward-looking vision to help evolve the regulatory model. We believe there are success stories from our past that can also help guide us through these changing times. For example, with the Minnesota Metro Emission Reduction Project, the Company made significant investments in our metro area generating units to reduce carbon emissions with the assistance of an incentive base rate mechanism. We believe the interests of the State and our customers were furthered with the use of our suggested diversified ownership portfolio as part of complying with the Next Generation Act (NGA). As we look to the investments that will be needed to reduce carbon emissions by 40 percent, we believe our partnership with the State could be enhanced by using MERP-like creative rate recovery mechanisms, and value could be driven by encouraging the Company to be part of the growth in renewable resources through NGA-like diversified ownership portfolios.

We are excited about our carbon reduction plan, but note that not all states we serve have the same energy and environmental goals and policies. At this time, Minnesota and North Dakota are on diverging paths. Reconciling these differences is becoming increasingly difficult for the Company and regulators which may ultimately adversely affect our customers in each state. We are working on solutions and expect to present a proposal as part of our IRP filing in early January 2015.

Facilitating Grid Modernization

The e21 Initiative recognized existing distribution systems will be called on to do more in the future, such as accommodating higher levels of solar generation, as well as other distributed energy resources, optimizing system performance, and enabling emerging technologies. To accelerate progress on realizing a fully modern distribution grid, the e21 Initiative recommends a robust stakeholder process that results in a plan describing the steps and investments needed to be responsive to 21st century demands. This process could document the current capabilities of the distribution system and explore a range of planning and investment issues, including:

- Foundational communications and control technologies to create a more intelligent grid;
- Strategies for optimizing distributed resources on the system, including *locational value mapping;*
- Evaluation of the role of energy storage and micro-grids; and
- Requirements for a secure and resilient grid.

Through this process, the Company can share what we have done and are doing to develop a more intelligent and integrated grid. For example, we are developing an advanced distribution management system, which will enable additional system automation and support intelligent electric field devices. Additionally, our distribution engineers are actively involved in industry efforts to research and test new technologies and operational models. In the past, we partnered with the Electric Power Research Institute (EPRI) on a solar-to-battery research project and are now working with the Midcontinent Independent System Operator (MISO) on a broad-based system monitoring and control project using synchrophasors to improve power system reliability and visibility. These efforts allow us to experiment with new technologies and practices in a low-risk and low-cost environment and learn from the experience of other industry partners.

We believe there may be a greater role for pilot and demonstration projects going forward. As part of the continued dialogue on grid modernization, we will explore launching a pilot project that assesses the impact of a stand-alone micro-grid on our distribution system and will consider others identified through the stakeholder process.

Because some of what we do may be new and based on evolving technologies, it will be important to receive input and cost recovery guidelines upfront. Investment in and modernizing of the distribution grid in a thoughtful, comprehensive manner based on established policies, actual customer needs, and understood technological capabilities will focus resources and save money.

A Platform for Creating Customer Optionality

We agree with the e21 Initiative that a more responsive customer choice tariffing platform is needed; a platform which allows us to work with and even anticipate the kinds of new products and services our customers want, resolve customer requests for new tariff provisions, and develop clean energy partnerships.

While we agree with the e21 Initiative on creating more customer optionality, not all of our customers want the same thing, and we are continuing to learn what our customers want. For that reason, our roadmap offers a number of pilots and test-offerings. This will allow us to better understand the needs, wants and desires of our customers before implementing products and services that are permanently part of our tariff.

Specific examples of products, services and pilots making up our roadmap are as follows:

- Develop and if the interest further matures, offer a carbon-free or sustainability rate to our residential customers;
- Develop and offer a pilot program to our energy intensive trade exposed customers that offers different, more tailored, rate options;
- Develop and offer a pilot program that provides a streamed renewable offering;
- Provide additional supply-side options, including renewable rate options that price renewable energy close to existing General Service and Time-of-Day rates to interested communities and commercial customers;
- Develop and offer a pilot which provides more detailed data on energy use, and the ability to better control how and when they use energy, to our interested residential customers.

Evolving Rate Recovery

The last element of our intertwined roadmap is evolving the rate recovery process. The e21 Initiative recognized that utilities should be incented to pursue outcomes sought by stakeholders, should not be financially harmed for doing so, and drive cost excellence within the aspects of the existing rate recovery framework that works. As we reflect on the current ratemaking process and mechanisms, the e21 Initiative findings and recommendations and our roadmap, we believe there are opportunities for evolving what we are doing today both within and beyond the existing statutory framework.

We believe a place to start is transitioning the rate recovery process to one that creates a tie between our investment plan, the cost of the plan, and a path for the rate growth needed to address the costs of the plan. We believe this is a good place to start based on our experience in our recent rate cases. Our recent cases were driven by significant capital investments we have made into our system. We decided to move forward with many of these investments several years ago during a period of growth. We are now recovering the costs during a period of sluggish growth. What we are seeing with the current ratemaking process is that many years pass from the time we decide to pursue an investment and when we recover the costs in rates. During that time changes occur that make it harder to create ties between the policy rationale supporting an investment and rate recovery.

Another key evolutionary point is creating efficiencies and predictability within the process. Rate cases take a significant amount of resources and can take a year or more to complete. As we look to the immediate horizon, we are still working through our current investment cycle during a period of sluggish growth. We believe the rate case cycle will continue for a few more years. In fact, we are currently forecasting a sizeable deficiency over the next few years. This means we will likely have to file for rate increases, which will consume significant resources from the Company, state agencies and other stakeholders. Evolving the current ratemaking process to create efficiencies and predictability could make future rate cases less resource intensive and create opportunities to have more un-interrupted discussions about policy initiatives.

The last evolutionary point is balancing affordable, competitive rates with preserving our financial health as we execute this roadmap. The roadmap we have laid out in this letter will result in significant capital investment in renewables, distributed technologies, and our distribution grid. We also expect to see changes to our revenue structures as we provide more optionality to our customers. Furthermore, our customers will continue to expect we provide safe and reliable service, which means on-going investments in existing and new infrastructure. Cost-effectively, and cost-consciously working through this roadmap while allowing us the opportunity to recover all of our costs and earn our authorize return should help strike the right balance between competitive, affordable rates, and preserving our financial health.

Other commissions have taken steps to evolve their traditional rate making processes and mechanisms to be more incentive and performance based, and efficient. For example, the Alberta Utilities Commission uses performance based or incentive regulation as part of multi-year rate plans. The primary objective of performance-based rates is to improve cost efficiency and efficiency within the regulatory process. Another model that was studied is "going-in" rates. With this model, which is used as part of a multi-year rate plan, the case is expedited since the starting rates are based off the most recently approved rates, subject to minor adjustments. The Washington Utilities and Transportation Commission used this model in the Puget Sound Energy case.

We have considered a few high-level models that could work well in this State. One approach is to expand the scope of the existing multi-year rate plan construct to allow for the recovery of O&M as well as all capital. Consistent with the e21 Initiative Findings and Recommendations, O&M expense could be pegged to an inflationary index to create an incentive for us to more competitively manage our business. Another approach is to use an annual rate recovery mechanism, which allows us to recover the investments made in carbon-free energy, grid modernization and providing customer optionality. Since this mechanism does not address O&M or investments made to preserve safe and reliable service, we believe incorporating efficiencies and incentives into the existing rate case process would be necessary.

Our plan is to bring forward a straw man proposal to the Commission planning meeting so that we may share more details about several of the models discussed above.

Next Steps

At the outset we recognize the spirit of collaboration that was embodied within the e21 Initiative will be needed as we embark on the roadmap we have outlined in this letter. We look forward to facilitating that collaboration as best as we can.

We also recognize this is a non-traditional filing but believe it is appropriate considering the way in which the energy industry is changing. We request that this letter follow a different procedural path than would be used for a typical filing. By submitting information that is more conceptual in nature, our intention is to offer a roadmap for moving forward with the e21 recommendations and to use this document as a guide for further stakeholder conversation. Thus, we respectfully request that the Commission delay initiating a comment period to allow for additional collaboration prior to the start of a formal proceeding.

Instead, as a first step, we request the opportunity to discuss this letter with the Commission at a planning meeting in January or February. Our goal for that meeting is to be available to answer questions and address comments the Commission may have and elaborate on our roadmap as appropriate.

We also note that there is a high likelihood that our roadmap will become disjointed right away. We are filing our IRP in early January 2015, which means discussions regarding achieving 40 by 30 will likely begin before we can substantively discuss the other intertwined elements of our roadmap. For instance, it will be hard to substantively discuss evolving the rate recovery process until our currently pending rate case and prudence review are addressed by the Commission. We look forward to obtaining the Commission's guidance at our planning meeting as to its thoughts about moving through our roadmap in a connected manner.

Ultimately, to make the e21 vision a reality we believe we will need to implement our roadmap through our upcoming integrated resource plan, as well as, our next rate case.

At the same time, we intend to work with stakeholders to consider Minnesota legislation in 2015 that would further clarify and encourage the Commission's use of these approaches and provide additional authority or rate making tools as necessary. We believe this will provide greater certainty, if needed.

Conclusion

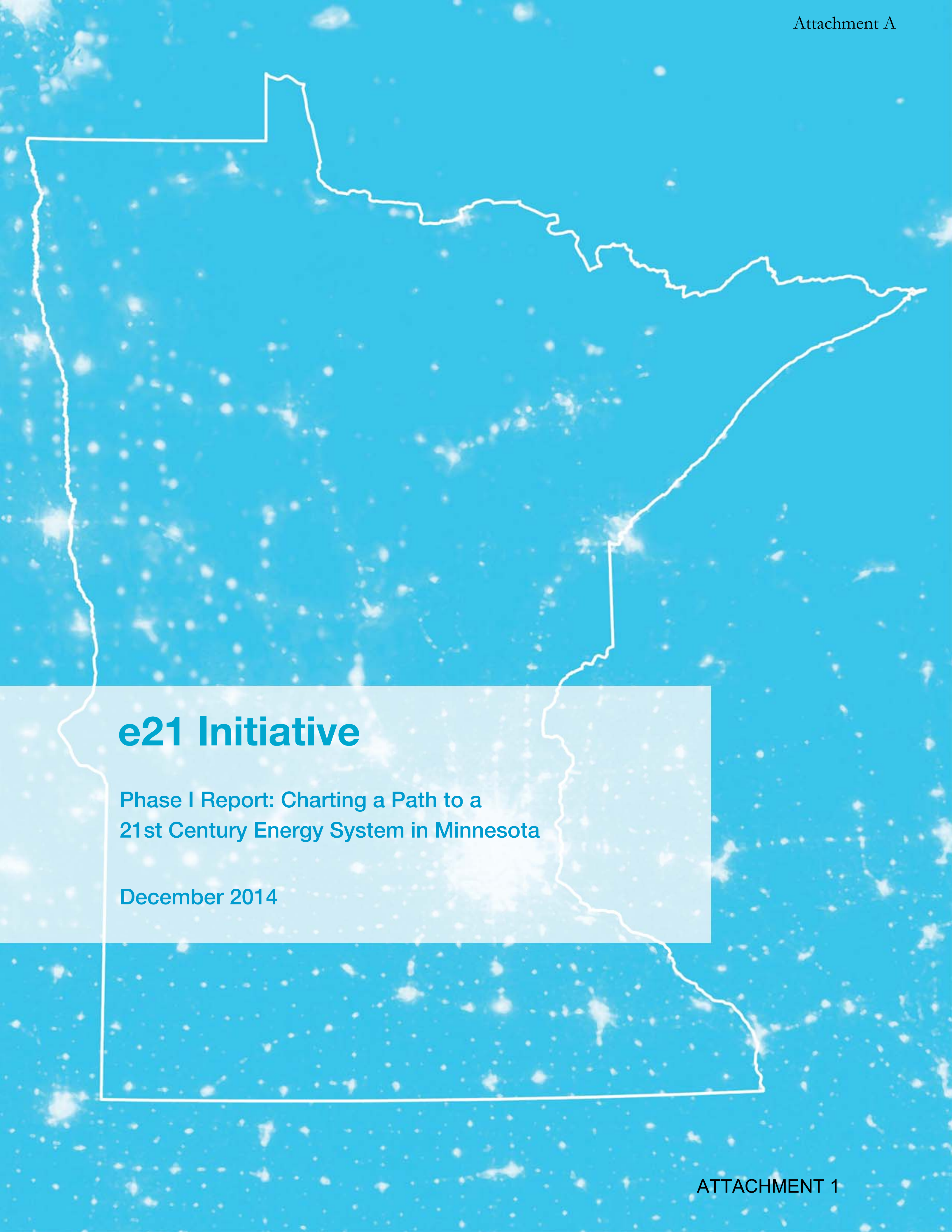
We have appreciated the opportunity to work with stakeholders in the e21 process and look forward to continued dialogue and implementation of a regulatory framework best suited to meet Minnesota's evolving energy landscape. We believe this approach will serve as a model of collaborative, fruitful development of regulatory processes and mechanisms that will benefit from the advance input of stakeholders with varying interests and needs.

If you have any questions regarding this filing, please contact me, or Aakash Chandarana at 612-215-4663 or email aakash.chandarana@xcelenergy.com

Sincerely,

/s/

CHRISTOPHER B. CLARK
PRESIDENT – ELECT
NORTHERN STATES POWER COMPANY MINNESOTA



e21 Initiative

Phase I Report: Charting a Path to a 21st Century Energy System in Minnesota

December 2014

About the e21 Initiative

The e21 Initiative aims to develop a more customer-centric and sustainable framework for utility regulation in Minnesota that better aligns how utilities earn revenue with public policy goals, new customer expectations, and the changing technology landscape. The Initiative brings together key interests including utility, consumer advocate, energy technology, business, environmental, academic, and government to accomplish this goal and enable Minnesota to continue to lead in shaping an energy system for the 21st century.

The Great Plains Institute (GPI), Center for Energy and Environment (CEE), Energy Systems Consulting Services (ESCS), George Washington University Law School (GWU), Xcel Energy, and Minnesota Power convene the e21 Initiative.

The Energy Foundation, the Joyce Foundation, Xcel Energy and Minnesota Power have funded the e21 Initiative, with in-kind contributions from CEE, ESCS, and GWU.

Learn more at: www.betterenergy.org/projects/e21.

Cover page adapted from a NASA Earth Observatory image by Robert Simmon (2012), using Suomi NPP VIIRS data provided courtesy of Chris Elvidge (NOAA National Geophysical Data Center). The image is available here: http://earthobservatory.nasa.gov/Features/NightLights/.

About the Phase I Report

This report is written primarily for Minnesota's electric utility regulators, policymakers, organizations representing ratepayers, and others who have a stake in the direction of Minnesota's future energy system, and includes specific recommendations for statutory changes and regulatory action.

It is also e21's hope that this report is useful to others outside of Minnesota who are grappling with similar issues, albeit in their own context. Please refer to Appendix C to view a map of other efforts working on the 'utility of the future' in the United States.

To learn more about the e21 Initiative and how the recommendations were developed, please refer to the e21 Process section in Appendix A of this report.

When reading the e21 consensus recommendations, please note that these are intended as a cohesive *package* of ideas rather than as disparate options from which to pick and choose. In other words, the recommendations relate to and support one another, and only as a package do they reflect the consensus recommendation of e21 Participants. The Recommendations Background section provides detailed context and examples to describe the rationale and purpose of each recommendation.

Finally, since each utility in Minnesota is unique, the state's implementation of e21's recommendations should recognize the attributes and context within which each utility in Minnesota operates.

The report can be downloaded here: www.betterenergy.org/projects/e21

About the Authors

The preparation of this report was every bit as collaborative as the e21 process itself. It was primarily written and edited by Jennifer Christensen and Rolf Nordstrom at the Great Plains Institute, but based entirely on content developed by the e21 group.

Various portions of the report were written by e21 participants and synthesized by GPI. The report also benefitted from significant edits and refinements from many e21 participants and observers. The final product was co-created in the best possible sense and we are grateful to all who lent their time, experience, expertise, and resources to charting this new course.

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Executive Summary

A growing and fundamental misalignment exists between the traditional utility business model (and the regulatory framework that supports it), and the realities of today's marketplace and Minnesota's public policy goals. This is unsurprising since we have regulated utilities more or less the same way since roughly 1900, when the first state regulation of electric utilities emerged, just 20 years after Thomas Edison established the first centralized electric utility in New York.[1]

The e21 Initiative ("e21" stands for 21st Century Energy System) is a highly diverse and collaborative group of Minnesota leaders assembled by the Great Plains Institute to recommend ways to fix this misalignment and update the way we regulate utilities in two fundamental ways:

> *1) Shifting away from a utility 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; and*
>
> *2) Shifting away from a regulatory system that rewards the sale of electricity and building large, capital-intensive power plants and other facilities toward one that rewards utilities for achieving an agreed-upon set of performance outcomes that the public and customers want (e.g., energy efficiency, reliability, affordability, emissions reductions, predictable rates, etc.).*

In short, new customer expectations, public policy goals, and the changing utility marketplace are driving the need for a modern electric system that can support new ways for electricity to be generated, delivered, and used. These and other drivers will require the electric system to continue to be reliable, as well as become cleaner, more flexible, secure and resilient against attack and natural disaster, and able to empower customers to manage and reduce their energy costs. It will also become more distributed, flexible, intelligent, efficient, real-time controlled, and open to more participants. These technology, market, and policy forces are inexorable and will continue to transform the energy economy and technology landscape, impacting utilities and their customers in profound ways, both in Minnesota and elsewhere.

> ***In the face of this rapid change, e21 presents Minnesota with an opportunity to act in advance of any particular crisis and lead the nation in demonstrating how a new customer-centric, performance-based regulatory approach and utility business model can enable both economically viable utilities and achievement of public policy goals.***

Readers should view the consensus recommendations in this Phase I report as a cohesive *package* of ideas rather than as disparate options from which to pick and choose. In other words, the recommendations relate to and support one another, and only as a package do they reflect the consensus recommendations of e21 Participants.

[1] Jim Lazar (March 2011), "Electricity Regulation in the U.S.: A Guide," Regulatory Assistance Project, available from: www.raponline.com.

Together they provide a broad framework, describing the overall arc of change needed, while acknowledging that there are many implementation details to be worked out in 2015 and beyond through stakeholder collaboration, outreach to policymakers, regulators and the public, and legislative and regulatory action.

e21 Guiding Principles

The e21 Initiative established the following consensus principles and e21 participants recommend that these principles guide any regulatory or statutory changes:

- *Align an economically viable utility model with state and federal public policy goals.*
- *Provide universal access to electricity services, including affordable services to low-income customers.*
- *Provide for just, reasonable, and competitive rates.*
- *Enable delivery of services and options that customers value.*
- *Recognize and fairly value grid services and "distributed energy resource" services.*
- *Assure system reliability, and enhance resilience and security, while addressing customer privacy concerns.*
- *Foster investment that optimizes economic and operational efficiency of the system as a whole.*
- *Reduce regulatory administrative costs where possible (e.g., results in fewer rate cases or otherwise reduce the burden of the regulatory process).*
- *Facilitate innovation and implementation of new technologies.*

e21 Consensus Recommendations

e21's recommendations for a new regulatory framework fall into four main categories:

- Performance-based Ratemaking;
- Customer Option and Rate Design Reforms;
- Planning Reforms; and
- Regulatory Process Reforms.

A new performance-based, more forward-looking approach to ratemaking and incentives. In place of today's frequent, costly—and by design adversarial—rate cases, e21 proposes that Minnesota provide an alternative option in which utilities that "opt in" are allowed to submit a forward-looking, performance-based business plan covering up to five years. This length of time will provide more predictable rates for customers and give utilities sufficient time to achieve the public outcomes they commit to in the plan.

This approach will also enable Minnesota utilities and stakeholders to work together to envision, plan for, and pay for the electric system they want versus the current framework that assesses, in an audit-like fashion, whether customers are paying the right amount for what utilities delivered (see Text Box 1 below).

As its name suggests, a performance-based approach would tie a portion of a utility's revenue to achieving an agreed-upon set of performance metrics (e.g., measuring such things as energy efficiency, customer service, environmental sustainability, affordability, and competitiveness) so that utilities have a natural financial incentive to produce the outcomes customers want.

Both are explained in more detail in the full report, but in brief the ***Business Plan*** would describe the investments the utility needs to make in order to operate effectively, how it will accomplish the agreed-upon performance metrics, and how costs will be allocated and recovered over the plan's term. It would also outline how the utility will modernize the grid, plan for and manage the addition of Distributed Energy Resources (e.g., solar PV, demand response, electric vehicles), optimize the system's overall efficiency, and the expenditures required to do so.

The proposed ***Integrated Resource Analysis (IRA)*** would replace the current Integrated Resource Plan (IRP). Still looking out 15 years or more (as with the current IRP), the IRA would capture all the informational benefits of the traditional IRP, but improve the process by fundamentally changing the way all parties to the regulatory process use the information the IRA contains. Instead of adjudicating every detail of the IRP (as is done now), the IRA would guide the five-year Business Plan and focus everyone's time and resources on getting that right, rather than arduously perfecting a 15-year IRP that is often out-of-date by the time state regulators finally approve it. The shift from preparing an Integrated Resource "Plan" to producing an "Analysis" may seem subtle, but the overall idea behind the IRA is to make resource planning more useful to regulators, utilities and intervenors, reduce overall regulatory burden and cost, and tie resource decisions more closely to the actual costs of maintaining the electric system and achieving the agreed upon performance outcomes.

Box 1. The e21 recommendations represent a new approach to ratemaking:

- **Current approach:** A cost-by-cost accounting to determine **whether we are paying the right amount for what utilities delivered.**
- **Proposed approach:** A performance-based, more forward-looking regulatory framework that determines **what we should pay to achieve the outcomes society wants.**

Customer Option and Rate Design Reforms

e21's recommendations support a shift to a more customer-centric framework that meets growing expectations of customers regarding service, product, and technology options by enabling:

- Delivery of services and options that customers value, while providing universal access to affordable service.
- Rate design reform, such as a review and adjustment of time-varying rates.
- Flexibility for utilities to offer tailored rate and service options that respond to unique customer needs and interests.
- Pilot programs or other methods to test, evaluate, and bring to market more quickly new service options, products, and technologies for customers.

Reforms to Regulatory Processes

In order to transition toward a performance-based regulatory framework, Minnesota regulators will need sufficient authority, resources, and tools. This includes, but is not limited to, exercising more fully their existing quasi-legislative authority where appropriate, engaging stakeholders in more collaborative and forward-looking processes, and initiating generic dockets on issues of statewide concern. e21's recommendations for reforming the regulatory process are intended to support more nimble and flexible decision-making that allows regulators to:

- Put forth policy solutions that are not entirely one party's position or another;
- Encourage proactive exploration of critical and emerging issues; and
- Support the development of forward-looking solutions through more collaborative stakeholder processes in advance of the quasi-judicial hearings that most often characterize regulatory proceedings and that will remain necessary for making official decisions and ensuring due process rights.

Planning for a Modern & Efficient Grid

e21's first phase raised many questions yet to be answered. One is how best to modernize Minnesota's electric grid, particularly the distribution system (as opposed to the bulk transmission system), since that is where many new technologies, such as solar, energy storage, and electric vehicles, will plug in.

The current electric grid—with its large centralized power plants and miles of transmission and distribution lines—relies on many technologies that originated more than a century ago with Edison and Westinghouse. The rapidly emerging modern grid looks much more distributed and decentralized, with many actors on the system sending electricity and data back and forth.

Proactively planning for an intelligent, flexible, nimble, efficient, open, and secure distribution system over the next several decades that can handle new distributed energy technologies and the complexity of many more actors on the system will require a coherent strategy. To develop this strategy, e21 recommends that Minnesota establish a distribution planning and grid modernization stakeholder process much like e21 itself. Such a process will help us understand where on the electric system new distributed energy technologies can provide the most value, how best to coordinate which technologies get put on the distribution system and when, and which distribution management systems and advanced control and communications technologies we will need to enable seamless integration and interoperability of a wide variety of energy technologies and systems.

Desired Outcomes of the e21 Recommendations

The e21 recommendations presented in this report should position Minnesota to fix the misalignments described above and address key challenges, enabling our state to better achieve a wide range of desired outcomes (see table below).

ISSUE AREA	CHALLENGES TO THE CURRENT SYSTEM	DESIRED OUTCOMES
Utility Business Model	• The current model is leading to more frequent rate cases, higher rates for customers, and arguably insufficient revenue for utilities. The current model is not sustainable. • The current framework requires the utility and the regulators to engage in long, protracted, time and resource intensive quasi-litigation about how much a utility should spend or has spent to provide service. This framework is inefficient, opaque and expensive, not just for those two primary participants, but for everyone (e.g., intervenors, policymakers, customers). • Increasing energy efficiency and the falling costs of new technologies (e.g., solar) are eroding utilities' traditional sources of revenue. • The electric system requires significant reinvestment at a time when electric demand is flat or declining. • The current framework inhibits innovation by requiring long regulatory processes to bring new service options to customers.	• An economically viable utility business model that focuses on performance outcomes we want utilities to achieve on behalf of customers and the public. • A utility business model that supports energy efficiency, renewable energy, distributed energy resources, and advanced energy technologies. • A regulatory framework that enables a fair return for energy producers, an equitable allocation of costs for all customer classes, with as few stranded assets as possible during the transition. • Timely and predictable recovery of utilities' fixed costs that are not necessarily dependent on commodity sales, and more predictable rates for customers. • A regulatory framework that allows for collaborative, flexible approaches that puts the interests and expectations of customers at the heart of the business model.

ISSUE AREA	CHALLENGES TO THE CURRENT SYSTEM	DESIRED OUTCOMES
Customer Access, Options & Engagement	• A growing number of customers want to make decisions about their energy use, management, and in some cases, source of energy (wind, solar, coal). The current system offers customers few options or control. At the same time, other customers do not have the capacity or the desire to take a more active role in making energy decisions. • As electric customers become more efficient and some choose other sources of electricity (such as producing their own via solar), under the current utility business model, eroding sales could lead to higher charges for customers as utilities have fewer resources to cover fixed costs. • Rates for commercial and industrial customers are becoming increasingly uncompetitive.	• Delivery of services and options that customers value. • Universal access to electricity services that provide affordable service to low-income customers, while providing, where desired, more options. • Electricity users are encouraged and enabled to take advantage of all cost-effective energy efficiency and other opportunities to reduce demand for electricity. • Commercial and industrial customers are encouraged to partner with utilities on competitive rate options while leaving the Commission with discretion to ensure just and reasonable rates for all customers.
Customer Rates	• Flat or declining sales of electricity, the falling costs of alternatives to traditional grid power, and the need for significant reinvestment in the electric system create a "perfect storm" for frequent and unpredictable changes to rates.	• Customer rates are competitive, equitable, predictable, affordable, and transparent. • Cost-recovery mechanisms are stable and transparent, attracting capital at competitive rates.
System reliability, resilience, and security	• The electric system needs reinvestment in order to maintain and improve reliability; it will require additional investment to ensure that it can bounce back from increasingly frequent harsh weather and remain secure from cyber and physical attacks.	• A cleaner, more flexible grid that is reliable, resilient, and secure and enables customers to manage and reduce their energy costs.

ISSUE AREA	CHALLENGES TO THE CURRENT SYSTEM	DESIRED OUTCOMES
Public Policy	• The current utility business model is misaligned with achieving many local, state, and federal public policy goals. • State public policy calls for increasing energy efficiency, ramping up renewable energy, reducing greenhouse gasses (GHG's) by at least 80% by 2050, and encouraging a more "distributed" system that gives customers more options, but the current regulatory framework and grid itself are not yet designed to deliver those things. • The existing regulatory framework may make the U.S. EPA's proposed rule to reduce GHGs from power plants and other federal environmental regulation more difficult for utilities to meet.	• Minnesota is better positioned to meet state and federal public policy goals. • Utility and customer interests are aligned with the pursuit of Minnesota's goal of at least an 80% reduction in GHGs by 2050 and the transition to a sustainable, carbon-neutral energy system. • Reduced regulatory administration costs and resources, resulting in fewer rate cases or otherwise reducing any regulatory burden. • A "systems approach" to coordinating planning, operations, and energy markets across transmission, generation, distribution, and end use. • Maintain competitiveness of energy-intensive, trade-exposed industries.
Cost allocation & Recognition of value	• The current system is not set up to compensate actors on the system for the full range of benefits they offer (energy, capacity, voltage support, etc.) or charge them for the legitimate cost of the grid services they use. Without this "two-way street" being established, utilities will find it difficult to maintain the system and remain financially healthy. Moreover, the current system presents barriers to development and deployment of new technologies.	• Utilities, customers and service providers are compensated for the full range of services they provide. • Payments to and by participants on the system are aligned with the costs and benefits they impose and provide.
Innovation	• The existing utility business model and regulatory framework make it difficult to keep pace with technological change.	• Innovation is facilitated and new technologies are implemented to provide customer and system value.

e21 Recommendations

The e21 Initiative proposes shifting to a more customer-centric and sustainable framework for utility regulation in Minnesota that better enables innovation, new customer options, modernization of the grid, and achievement of policy goals.

The following recommendations, taken as a package, provide the blueprint for this new regulatory approach, and suggest a new utility business model that places less emphasis on selling an increasing amount of electricity and more on providing the energy services and options that meet customer expectations. The recommendations cover four broad areas of reform: performance-based ratemaking, customer options and rate design, planning, and regulatory processes.

(A) Allow a multi-year, performance-based regulatory framework for utilities that wish to opt-in. The e21 Initiative recommends that Minnesota should provide utilities the option of a multi-year, performance-based regulatory framework that bases a portion of a utility's revenue on the achievement of identified performance metrics that are quantifiable, verifiable, and align with e21's Guiding Principles and Outcomes. Performance metrics would measure such things as: total system efficiency, reliability, customer service, environmental sustainability, affordability, and competitiveness. In 2015, the e21 Initiative plans to flesh out the details of what these metrics are, how they can be measured, and what portion of a utility's revenue will depend on achieving them. Some of these metrics may be tied to utility revenue, and others not.

The main components of the multi-year, performance-based regulatory framework would be a utility Business Plan covering up to five years, guided by a 15-year (or longer) Integrated Resource Analysis (IRA) as outlined below:

(B) ***Require utilities that opt into a multi-year, performance-based framework to file a comprehensive Business Plan (covering up to 5 years) consistent with a 15-year (or longer) Integrated Resource Analysis (described in (C) below).*** This comprehensive Business Plan, filed with the Minnesota Public Utilities Commission, would replace the traditional rate case. Components of this business plan would include, but not be limited to:

1. *Resource adequacy and customer needs*. How the utility expects to meet resource adequacy requirements and customer needs.
2. *Investments and expenditures*. A description of the investments and expenditures a utility proposes to make in order to operate effectively and reliably, satisfy established policy goals, and accomplish the agreed-upon performance metrics over the years covered by the business plan.
3. *Performance metrics*. Proposed performance metrics and award and penalty mechanisms to be in effect during the plan's term, and the associated measurement and verification process.
4. *Cost recovery*. A description of how the utility will recover identified costs, including the process for annual rate adjustments and any additional adjustment mechanisms. Utilities should have the option of proposing fixed or formula-based annual rate adjustments or a combination of the two.
5. *Cost allocation*. How the utility proposes to allocate costs across classes and segments.

6. *Earnings-sharing*. Description of potential “earnings-sharing” opportunities in which both the utility and ratepayers could benefit.

7. *Grid modernization and system efficiency.* How the utility will enhance the distribution grid, plan for and manage the addition of distributed energy resources (DERs) to the system, and other investments needed to optimize the energy system’s efficiency as a whole.

8. *Other information.* Other information the Commission deems necessary to approve the business plan.

Within the business plan, a utility should have flexibility to manage its spending and investments as it deems necessary to meet the established policy goals and performance metrics of the plan. This includes allowing utilities to add, cancel, and/or replace projects within a business plan.

(C) ***Revise Minnesota statutes to allow utilities that opt into a multi-year, performance-based framework to replace the current Integrated Resource Plan (IRP) with a 15-year (or longer) Integrated Resource Analysis (IRA) that guides the utility business plan; and allow utilities to coordinate the filings of the Business Plan and IRA.*** The IRA would consider all system resources and strategies for achieving state and federal regulatory and policy goals, setting the stage for and informing the business plan to be submitted simultaneously by the utility. Although the IRA would not be subject to the full regulatory process required of resource plans currently, the five-year action plan that is currently part of the Integrated Resource Plan would be included in the business plan and subject to full regulatory review. Utilities would update the IRA as the Commission deems necessary. Utilities would integrate an advisory committee of key stakeholders representing the broad public interest in the development of the IRA prior to filing, and/or develop other mechanisms for these stakeholders to have access to the same planning tools and information as the utility, while respecting confidentiality and trade secret issues, so that they can help shape the analysis and propose alternatives.

(D) ***The Commission should encourage the use of pilot programs or other methods for testing and evaluating components of a multi-year, performance-based framework,*** *including service options, products, and technologies. This approach would allow, for example, utilities to test what new service options customers want before going through lengthy, expensive regulatory proceedings.*

(E) ***The Commission should establish clear methods for determining the value of grid services and DER services, and set rates to:***

1. Fairly compensate customers;
2. Cover utilities’ fixed costs of maintaining the system;
3. Provide clear price signals to encourage economically efficient choices; and
4. Send appropriate price signals to achieve the e21 Principles and Outcomes.

(F) ***The Commission should review and adjust time-varying rates for energy services so that they send more accurate and effective price signals.*** Customers currently have “on peak” and “off peak” options, but moving toward additional time-varying and location-based rates for some customers would improve the accuracy of price signals they receive and better reflect true costs. In keeping with e21 Principles and Outcomes, providing more options that signal actual time-of-day prices should not disadvantage low-income ratepayers.

(G) ***Enable innovative product and service options and technologies by revising Minnesota statutes and regulations.*** Utilities should be allowed, through streamlined statutory and/or regulatory means, the flexibility to offer tailored rate and service options that respond to unique customer needs and interests, where doing so brings economic and/or system efficiencies. Examples include, but are not limited to:

1. *Maintain competitiveness of energy-intensive, trade-exposed industries.* Keep energy-intensive, trade-exposed industries competitive, while ensuring just and reasonable rates. This could be accomplished through changes in statute that:
    a. Allow greater flexibility to establish special tariffs between these industries and utilities. Examples include fixed rates or market-based rates, which could include, for example, time, location, or other circumstance-based pricing.
    b. Facilitate partnerships among utilities and customers that foster initiatives beneficial to the system, such as on-site generation via elimination of certificate of need requirements where appropriate.
2. *Expand services and develop markets.* Empower utilities to expand services and develop additional markets that can be demonstrated to be in the public interest, such as electrification of transportation.

(H) ***The Commission and Department of Commerce should use their existing authorities to achieve e21 Principles and Outcomes; and review and recommend revisions to their authorities where needed.*** For example, in order to enable more proactive, nimble, and flexible decision-making, the Commission should make greater use of its existing authority to fashion policy solutions from the procedural record that are consistent with legislative direction but are not entirely one party’s position or another’s. The Commission and the Department should also identify areas where they may need more explicit legislative authority to accomplish e21 Principles and Outcomes, and should flag those issues for consideration by the Legislature and the Governor.

(I) ***The Minnesota Legislature should appropriate the resources necessary for the Commission and the Department to implement e21’s recommendations*** and enable both agencies to carry out their respective duties in a timely and cost-effective manner.

(J) ***The Commission and the Department should institutionalize the practice of using a collaborative regulatory process*** where appropriate, while preserving due process protections, including the right to appeal to a regulatory or judicial decision maker. A more collaborative, multi-interest process may be lower cost, faster, and lead to better outcomes. This recommendation is linked to the need for adequate resources. The Commission and Department should:

1. Encourage the use of, and give additional weight to, settlement agreements among parties, as long as the Commission determines that the agreements are in the public interest.

2. Establish guidelines for what the Commission wants to see in any kind of negotiated settlement among interested parties.

3. Routinely use transparent dispute resolution processes facilitated by staff or others. An example includes technical conferences designed to reach consensus on some or all potentially disputed facts or policy issues in a given situation in order to narrow the issues in contention before entering the more formal docket process.

(K) ***The Commission and the Department should look for opportunities to initiate generic dockets*** in cases where doing so would enable more consistent policies statewide on issues of common concern to many. Using generic dockets could reduce the transaction costs of participating in the regulatory process for both intervenors and government agencies (which are required by statute to participate in dockets).

(L) ***Initiate forward-looking stakeholder processes.*** The Commission and the Department should use existing authorities to encourage and/or initiate forward-looking stakeholder processes, such as technical conferences and workshops, to address issues that merit deeper exploration and stakeholder dialogue, understanding that resources to do this are a constraint.

(M) ***Develop a transparent, forward-looking, integrated process for modernizing the grid.*** This should include identifying how to achieve a more flexible distribution system that can efficiently and reliably integrate cost-effective distributed energy resources (e.g., efficiency, demand response, distributed generation, distributed intelligence, etc.).

(N) ***Identify and develop opportunities to reduce customer costs by improving overall grid efficiency.*** In Minnesota, the total electric system utilization is approximately 55 percent (average demand divided by peak demand), thus providing an opportunity to reduce system costs by better utilizing existing system assets (e.g., generation, wires, etc.).

Recommendations Background

This section provides detailed context and examples to describe the rationale and purpose of each e21 recommendation.

(A) A multi-year, performance-based regulatory framework. This core recommendation addresses the need to shift from a regulatory system that rewards utilities for selling more electricity and building capital-intensive facilities and infrastructure (e.g., large, central station power plants) toward one that rewards utilities for achieving an agreed-upon set of performance outcomes.

After serving Minnesota well for more than 100 years, it has become clear that the way we regulate utilities—and the two main ways they earn revenue—have become increasingly misaligned with both customer demands (e.g., for more choice in how and where their energy is produced) and with public policy goals calling for more energy efficiency (i.e., lower sales of electricity) and a cleaner, more distributed energy system. The way we regulate utilities made sense when growing electricity use was seen as an indicator of a healthy economy and the focus was on serving vast geographic areas with large centralized plants.

But today, one can have robust economic growth without necessarily using more electricity. This is driven partly by public policy and partly by technological innovation such as LED lights and increasingly efficient appliances and by the dramatic reduction in the costs of new more decentralized technologies, such as solar. As a result, a growing number of customers are interested in managing – and even producing – their own electricity.

These increases in energy efficiency and distributed energy technologies are translating into even lower sales of electricity and less need for capital-intensive, central station power plants—again, the two principal ways utilities currently earn revenue.

At the same time that utilities are faced with this inexorable erosion of their traditional sources of revenue, they are obligated to continue to invest in the electric system, much of which is in need of replacement and upgrades. Utilities will also need to make significant investments to enable new capabilities and technologies, particularly in the distribution system. It has been estimated that by 2030, the U.S. electric utility industry will need to make a total infrastructure investment of $1.5 trillion to $2.0 trillion.[2]

Left unchanged, the current regulatory framework and utility business model will become increasingly unsustainable, yielding more frequent rate cases, unpredictable rates for customers, and likely insufficient revenue for utilities.

Frequent rate cases are not only time-consuming and expensive for everyone involved—utilities, intervenors, and regulators (and ultimately ratepayers) — but also reduce the amount of time and resources utilities can devote to developing the products and services that customers are increasingly demanding. In this way, rate cases impose an opportunity cost.

Instead of rewarding performance, the current framework assesses in an audit-like

2 Marc W. Chupka, Robert Earle, Peter Fox-Penner, Ryan Hledik, the Brattle Group (November 2008), "Transforming America's Power Industry," prepared for Edison Electric Institute, available at: www.edisonfoundation.net.

fashion whether customers are paying the right amount for what utilities delivered.

This recommendation recognizes that what is needed is a new regulatory framework that rewards utilities for achieving agreed-upon performance outcomes.

The two main requirements for a utility that decides to opt in to the proposed performance-based framework will include filing with the Minnesota Public Utilities Commission (Commission) the following:

- *A Business Plan.*
- *An Integrated Resource Analysis.*

(B) Business Plan. The business plan would provide a comprehensive picture of a utility's expected investments and expenditures, how it will meet resource adequacy requirements, customer needs, agreed-upon performance metrics, and how costs would be allocated and recovered over a term of up to five years. The plan will also detail how a utility intends to invest in the distribution system and otherwise support and optimize an increasingly modernized grid. In other words, the business plan describes what specific outcomes a utility would deliver over a five-year term, and how it proposes to achieve and pay for those outcomes.

The business plan would serve as a replacement for the conventional rate case, but would contain all the information necessary to appropriately set rates.

The benefits of a longer, multi-year term are several and include, but are not limited to:

- Increased "marketing flexibility"[3] for utilities that can result in tailored rates, new services, and innovative products that meet customer needs, provide more customer options, and support achievement of agreed-upon performance metrics.
- Reduced regulatory burden – and associated costs – by replacing the need for frequent rate cases with a more predictable, longer-term plan for rates.

Given its benefits, using a multi-year term for rates is the most common approach to alternative regulation used across the world.[4]

To account for changes within the multi-year term of the business plan, the Commission will need to establish a process for rate adjustments (e.g., annual rate adjustments to account for changes in costs). The Commission should allow utilities to propose fixed or formula-based annual rate adjustments or a combination of the two. If a formula is used, it should incent operational efficiency and allow for appropriate Commission review.

Furthermore, the regulatory approach should allow rate adjustments for capital investment and/or expenses that cannot be otherwise accommodated within the framework, including significant costs incurred as a result of exogenous events (e.g., natural disasters, changes in law, etc.). For example, adjustments are commonly used to address material cost impacts from exogenous events that cannot be accommodated within an approved plan.[5]

Under the multi-year, performance-based ratemaking approach envisioned, utilities would participate voluntarily. The approach would provide clear incentives to Minnesota utilities that opt in to deliver on desired outcomes, including those related to customer needs, public policy goals, and innovation.

3 Dr. Mark Newton Lowry, Pacific Economics Group Research LLC (September 2014), "PBR for the Electric 'Utility of the Future'," presented to the e21 Initiative, available here: http://www.betterenergy.org/publications/lowry-e21-pbr

4 Ibid.

5 This is often referred to as a 'Z-factor' adjustment.

This approach can be designed to encourage utilities to maximize cost efficiency, enhance customer products and service, and deliver on a range of other performance outcomes by tying a portion of utility revenue to achieving them, in areas such as: reliability, total system efficiency, customer service, environmental sustainability, affordability, and competitiveness.

In 2015, the e21 Initiative plans to specify the important details of what these metrics are, how they can be measured, and what portion of a utility's revenue will depend on achieving them (see details in 'Next Steps'). Some of these metrics may be tied to utility revenue, while others would not.

To protect ratepayers against the potential for utilities over-earning within this framework, regulators can put in place an earnings-sharing mechanism in which both utilities and ratepayers benefit.[6] A useful historical example of this is the Metropolitan Emissions Reduction Plan (MERP) proposed by Xcel Energy, supported by an e21-like group of stakeholders, and approved by the Commission in 2002. The final MERP plan included a specific incentive for the utility to complete the project under its proposed capital budget for converting two coal plants to natural gas. When the utility in fact achieved that outcome, ratepayers paid less and the utility received a higher return.

Taken as a whole, the business plan will enable utilities to anticipate and deliver on the performance outcomes Minnesota wants utilities to achieve that are in the public interest.

(C) Integrated Resource Analysis (IRA). Under the existing system, utilities file Integrated Resource Plans (IRPs) that provide a 15-year (or longer) look at the utility's expected load forecast (future demand for electricity) and resources planned to meet that demand, plus a five-year action plan that details the investments and actions the utility plans to undertake to ensure that it can meet electricity demand in the nearer-term.

While the traditional IRP contains valuable information, it often takes so long to adjudicate all the details that it is either obsolete or has changed multiple times by the time the Commission considers and approves the Plan. Through no fault on the part of any one actor in the system, utilities, regulators, ratepayer advocates, and other intervenors spend large amounts of time on the IRP, only to re-litigate the same details in subsequent dockets (e.g., rate cases, certificate of need proceedings, rate rider requests).

The proposed Integrated Resource Analysis (IRA) is meant to capture all the informational benefits of the traditional IRP, but improve the process by fundamentally changing the way all parties to the regulatory process *use* the information the IRA contains, so that relevant facts are hammered out, and then used to guide a utility's business plan and the Commission's rate-setting.

To ensure appropriate stakeholder and regulatory evaluation of the IRA, a utility that opts in to this framework would be required to engage a broad group of stakeholders up front, prior to filing the IRA, so that all interested parties have the opportunity to inform and shape the analysis.

The shift from preparing an Integrated Resource "Plan" to producing an "Analysis" may seem subtle, but the overall idea behind the IRA is to make resource planning more useful to regulators, utilities, and intervenors, reduce overall regulatory burden, and tie resource decisions more closely to the actual costs of maintaining the reliability of the electric system.

Utilities that opt in to a performance-based, multi-year regulatory framework would still prepare the five-year action plan component of current IRPs and it would be part of and

[6] Regulatory Assistance Project at 17 (Dec. 2000), "Performance-Based Regulation for Distribution Utilities," available at: www.raponline.org.

inform its multi-year business plan. Sales forecasts, load and capability projections, and RES/EE compliance over that time would be included in the business plan filing, and would still follow the regulatory process and be subject to Commission approval.

The IRA would still be scrutinized by regulators for completeness, but would not be subject to the full discovery and approval process that traditional IRPs currently undergo.[7]

(D) Pilot programs. The rationale behind this recommendation is that both customers and utilities would benefit from a new regulatory framework in which regulators give their support up-front for utilities to pilot, test, and modify new customer options more quickly, and see what new service offerings are successful with a test group of customers before expanding to all customers. This does not mean giving utilities a blank check to develop whatever products they choose, but rather it means establishing a framework within which utilities can innovate. This approach would allow utilities to be more responsive to customers and more nimble in response to changing market demands.

The existing Conservation Improvement Program (CIP) offers a useful example of the type of regulatory flexibility the e21 Initiative contemplates and what the regulatory system could do more of. The regulatory requirements that govern CIP make it relatively quick and easy to add new programs and features or change existing ones. Offering a new product under CIP takes just 2-3 months, as opposed to a year or more for a typical regulatory proceeding.

e21 participants understand that for some new products (e.g., the creation of solar gardens), extra time may be warranted; but for things such as new tailored rates for particular customer segments or renewable energy-only options, everyone would benefit from allowing utilities to bring those to products to market more quickly—within certain pre-established guidelines.

Examples of the kind of pilot programs, demonstration projects, or accelerated deployments that a more CIP-like approach could enable include:

- Renewable energy rate options that provide renewable energy at prices close to existing General Service and Time-of-Day rates.
- Providing interested customers more detailed data on their energy use and the ability to better control how and when they use energy.
- Accelerated LED street lighting, in which there is growing community interest.

In this more nimble approach, if utilities offer a new option that customers like and demand is significant, the Commission could add additional oversight if deemed necessary. If customers don't respond to a new service offering, the utility should be allowed to withdraw it from the marketplace. Without this space for testing ideas that other innovative businesses have, utilities and customers will both lose out.

(E) Value of grid and DER services. A fundamental shift in the way the electric grid works is already underway. The conventional electric grid we have all come to know moves electricity in one direction—from centralized power stations through transmission lines, substations and distribution lines to Minnesota's homes and businesses. The modern grid that is quickly emerging looks much more distributed and decentralized, with many actors on the system sending electricity and data back and forth. This new electric grid is being driven largely by changes in consumer preferences, improvements in energy technology, and sharp declines in their cost —for example modular solar technologies that enable households and institutions to produce their own power.

[7] Available at: https://www.revisor.mn.gov/rules/?id=7843.0400

Distributed energy resources (DERs) are supply and demand side resources that can be used throughout an electric distribution system (i.e., on either the customer side or on the utility side of the customer meter) to meet energy and reliability needs of customers. They include end-use efficiency, distributed generation (solar PV, combined heat and power, small wind), distributed flexibility and storage (demand response, electric vehicles, thermal storage, battery storage), and distributed intelligence (communications and control technologies).

An integrated system of distributed resources can provide new and not yet recognized values as well as new and not yet resolved challenges to distribution systems and regulatory approaches that were designed for conventional resources.

To encourage the installation of distributed generation, “net metering” programs credit customers for the electricity they export, often at retail rates. The certainty and simplicity of retail net metering has led to its adoption in forty-three states. Some supporters of DER technologies are strongly in favor of net metering, believing that it makes the financial proposition of distributed electricity generation more attractive since customers are guaranteed to sell any excess electricity at the going retail rate. However, others have argued that net metering raises a fairness question about whether (and how much) producers of their own electricity should continue to pay for maintaining the existing electric grid that benefits everyone.

In Minnesota, investor-owned utilities may apply to the Public Utilities Commission for a Value of Solar (VOS) tariff as an alternative to net metering for distributed solar PV. The VOS tariff compensates the customer through a bill credit for the value of electricity produced (to the utility, its customers, and society) using the established Minnesota VOS methodology, and the customer is charged for all electricity usage under the existing applicable tariff. As technologies continue to evolve, the challenge of valuing grid and DER services will expand beyond distributed solar.

Energy storage provides an example of the need to appropriately compensate services provided by both the grid and forms of DER. Energy storage technologies have potential to provide the grid with a wide range of services for which there is a value but often no current way to compensate those who might deliver these services, including so-called spinning or non-spinning reserves, fast ramping when electricity demand goes up or down, peak load shaving and demand shifting, frequency regulation and voltage support, black start capability, the ability to store renewable energy and deliver it later, when needed, and more. On the flip side, providers of energy storage or any other distributed energy resource (e.g., rooftop solar) benefit from the existence and function of the electricity grid itself.

The grid not only provides reliable back-up power should the customer’s own system fail, but it provides the means for the customer to sell excess electricity. The grid can also act as a kind of shock absorber, smoothing out the voltage and frequency disturbances that might otherwise be caused by hundreds or thousands of actors taking and delivering electricity at any given time.

The e21 stakeholder group recognizes—as stated in the guiding principles—that society still needs the services that the electric grid provides and should help pay for them; and that providers of various kinds of DERs also provide quantifiable benefits that should be compensated.

A key step in e21’s Phase II will be to develop greater clarity on who should pay for what, and be compensated for what on both ends of the economic transactions that will inevitably take place as part of a more decentralized electric system with many more actors and complexity.

As part of this, e21 recognizes and will learn from the significant work done on the value of solar in Minnesota.[8]

(F) Time varying rates. Economics 101 dictates that the price of any good or service should reflect the true costs of providing it—if the price is artificially low then people will over-consume and if the price is artificially high they will under-consume. Thus, by providing more accurate price signals to customers, time-varying rates are an important tool for managing an increasingly complex electric grid with many more participating actors on it.

Of particular benefit are peak-pricing rates that apply for only a short period of time when electricity demand is highest. If applied fairly and with some advance notice to customers, such rates can significantly reduce the system's peak demand, leading to more efficient use of the system's existing capacity and avoiding the need for new power plants just to meet peak demand.[9] Similar to sizing parking lots to accommodate a small number of high-volume shopping days per year, the existing regulatory framework and rate structure leads to a system design that results in some units only being used during the few peak demand hours of the year. Not having to build additional gas-fired, traditional "peaking plants" will simultaneously save customers money and reduce emissions.

Influencing the amount and timing of electricity use (often called load management) through such means as time-varying rates provides a wide range of benefits, from saving money for the system as a whole to enable increasing amounts of renewable resources onto the grid to reduce greenhouse gases. This is because load management, when it can be relied upon to deliver, can be used as an alternative (at least in part) to peaking plants as a means to keep both demand for electricity and generation of electricity in balance when the output of intermittent renewable resources changes.[10]

Time-varying rates may also expand customer options and facilitate desirable customer participation in energy markets. For example, time-varying rates can alert customers to opportunities for lowering their current cost of power or signal when is the best time to plug an electric vehicle or sell electricity or other ancillary services back to the grid in order to fetch the best price. Technological advances can assist customers in responding appropriately to time-varying rates. For example, thermostats and appliances that can accept price signals from the grid are increasingly available to residential customers. Time-varying rates may not be suitable for all customers, such as those with low usage or limited ability to adapt and shift load. But advanced metering makes it feasible within different classes of customers to identify sub-groups that have similar characteristics and design rates applicable to those sub-groups.

This recommendation could enable the utility to make time-varying rates available to suitable customers, particularly those open to innovative, technology-driven adaptation of their usage patterns, while preserving simpler rate options for customers who use little power or have limited options for adaptation.

8 Minnesota Value of Solar tariff methodology, available at: http://mn.gov/commerce/energy/topics/resources/energy-legislation-initiatives/value-of-solar-tariff-methodology%20.jsp

9 Carl Linvill, John Shenot, Jim Lazar (November 2013), "Designing Distributed Generation Tariffs Well," Regulatory Assistance Project at 39, available at: www.raponline.com.

10 Jim Lazar, "Teaching the Duck to Fly," Regulatory Assistance Project (January 2014), available at: www.raponline.com.

(G) Innovative product and service options and technologies. Energy technologies and customer demands are evolving quickly. To keep pace, utilities need to be better equipped to offer tailored products and service options and technologies to meet the unique needs and interests of their customers. e21's recommendations highlight some examples, described below, that illustrate how tailored rate and service options would provide significant benefits to Minnesota customers.

Competitiveness of energy-intensive, trade-exposed industries. Since 2007, industrial rates in Minnesota have gone from below the national average to above it. According to the U.S. Energy Information Administration, Minnesota ranks 31st out of 50 states for industrial electric utility rates as of 2012. In 1990, Minnesota was ranked 15th out of 50 states.

This precipitous drop in competitiveness, which will likely continue absent attention by policymakers, is not sustainable for energy-intensive, trade-exposed industry. For these businesses, the cost of energy is a factor that influences investment and operation – the cost of energy for some Minnesota businesses is roughly 25% of their overall cost of production. This is not a cost that businesses operating in a global marketplace can pass on to customers.

Fair, predictable, and competitive utility rates are therefore critical to job retention, business development, and job growth in Minnesota. This is especially true as we grapple with aging electric plants and other infrastructure and new and existing federal and state regulations – all of which is fueling a utility investment cycle at a time of low to no sales growth.

Two statutes – the Competitive Rate Statute and the Area Development Statute – were designed to keep rates competitive and incentivize economic development. However, neither has been an effective tool, especially in controlling the sharp increase in electric rates - some customers have experienced a 60% increase in rates since 2007.

Minnesota Statutes § 216B.162 (the Competitive Rate Statute) provides for competitive rate schedules for customers with connected loads of at least 2MW, but they are rarely if ever used. The idea is that if a large-load customer had an alternative to meet its energy requirements from a non-rate regulated energy supplier at a more affordable rate, the utility could offer the competitive rate, but only under certain conditions after the Commission makes required findings. Among them, the Commission, after considering the environmental and socioeconomic impacts, must determine that offering the competitive rate is in the best interests of all other classes of customers. Given utilities' exclusive service territories and the lack of customer options when it comes to who provides their electricity, meeting the burden required for implementation of the Competitive Rate Statute is arduous.

Minnesota Statute § 216B.161 (the Area Development Statute) allows utilities to incorporate area development rates into their tariffs. But such a tariff can only apply to new or expanding customers. In effect, neither the Competitive Rate Statute nor the Area Development Statute provides the intended relief to existing and captive customers that do not have plans for expansion.

Generally speaking, energy-intensive, trade-exposed customers are significant employers, providing tax base and ancillary employment to their respective communities and regions. But this value can be lost if these customers are forced to shift production to other locations around the country and world due to the ever-increasing cost of production.

To help ensure this value remains in Minnesota, e21 proposes modification of existing law to provide energy-intensive, trade-exposed industries the flexibility to negotiate tailored rates with the utility providing service to those customers. These rates would be subject to approval by the Commission, thereby ensuring the rates remain just and reasonable.

Examples of such a statutory change would be to specifically allow energy-intensive, trade-exposed industry to negotiate fixed rates or market-based rates (e.g., time, location, or other circumstance-based pricing). While such an option may appear to provide for a discount to existing or future generally applicable tariff rates, any discount would reflect the risk the energy-intensive trade-exposed customer is willing to accept via a fixed or market-based rate.

Another example of an innovative service option, e21 recommends that Minnesota law and regulation should encourage utilities and customers to explore on-site generation partnerships that are beneficial to the electric system as a whole. To make this possible, e21 recommends modifying existing law to eliminate the Certificate of Need requirements and streamline other regulatory requirements for such installations. Such a statutory change could provide a platform for utilities and customers to construct new generation facilities that take advantage of economies of scale and manage load on a utility's system to better accommodate new and increasingly variable forms of generation.

Expand services and develop markets. The Commission and Department of Commerce should look for opportunities to allow utilities to expend some ratepayer funds, along with shareholder funds, to develop new socially beneficial markets for electricity.

While e21's recommendation is technology agnostic, one of the biggest opportunities for Minnesota may be the electrification of transportation, including EV passenger cars, light rail, and fully electric buses (now being researched by Metro Transit). e21 recommends that regulators allow utilities to identify and propose ways to encourage adoption and use of technologies and new markets that offer the greatest net social benefits.

Enabling utilities to be partners in developing new markets for electricity-using products may not only provide greater financial stability for utilities but also deliver societal benefits including jobs, economic multipliers, healthier air, quieter transit (in the case of electric buses and light rail) and perhaps retention of some of the $18 billion sent out of state for energy each year.

(H) Regulatory authorities. The Commission has both quasi-judicial and quasi-legislative powers. It uses its judicial powers to make decisions in proceedings that have complex factual disputes, such as rate proceedings and certificates of need. The Commission has in the past used its quasi-legislative powers to develop rules that guide its processes and decisions.

In recent years, however, the Commission has been faced with many unique issues and requests from regulated utilities and stakeholders that may not fit neatly into existing Commission rules and processes. Many of these instances call for policy decisions (made within the legal framework the Commission is given by the Legislature) rather than strict determinations of fact.

Issues that don't fit neatly into existing Commission rules and processes crop up regularly in utility resource planning and resource cost recovery proceedings. An example of this is the miscellaneous tariff filings required to implement new programs driven by legislation.

What is typically, by design, an adversarial hearing process often doesn't lend itself to dealing effectively with such policy-oriented issues. For example, deciding how best to handle the implementation of renewable energy or low-income programs is usually not well served by simply choosing one position or another. As issues become more complex, a better role for the Commission may be in fashioning compromise solutions that balance the interests of all parties, a practice which the Commission has encouraged on occasion, but sporadically.

Developing these "highest common denominator" solutions more frequently will require a more active role on the part of Commissioners and staff. The Commission could, for example, hold informal hearings where all stakeholders present their positions and the Commission provides guidance and direction for the parties to take away and either revise their proposals or attempt to find common ground. Staff could facilitate settlement discussions or propose creative solutions for Commission consideration, keeping in mind that a record to support a Commission decision must always be created and maintained.

In some cases, this could be done with more generic policy proceedings where the Commission provides general direction on how it would like utilities to handle a new issue. Other times, it could apply to more specific proposals that need additional shaping to meet public interest standards.

Through this recommendation, e21 intends to promote a more interactive process of Commission decision-making that facilitates "win-win" solutions, as opposed to the current more linear, one-side-wins approach.

(I) Appropriation of Resources. Evolving the 100-year-old-plus regulatory framework from one in which customers have few options toward a more customer-centric paradigm will place new demands on Minnesota's regulatory agencies, particularly during the transition.

Both the Commission and Department will need additional resources if they are to guide this transition to a new framework and carry out their duties in a timely and cost-effective manner.

To that end, the Minnesota Legislature should appropriate additional resources to the Commission and Department beyond amounts appropriated in the previous biennium.

(J) Collaborative regulatory process. This recommendation seeks to strengthen the regulatory structure while saving resources, time, and money, minimizing the potential for litigation, and maximizing the potential for universal support of policies that are in the public interest and mutually beneficial to utilities, ratepayers, intervenors, and other stakeholders.

The current regulatory system is predominantly adversarial, and not designed to be a collective, problem-solving process. Although in some instances, a few parties in a proceeding might enter into a settlement, these are typically not inclusive, and global settlements among all parties reached through a collaborative process have not been encouraged and therefore rarely, if ever, occur.

The current regulatory framework has layers upon layers of process, regulatory oversight, and interventions, with the vast majority of information sharing being conducted via written arguments. Disgruntled parties may appeal for reconsideration and, subsequently, judicial review, and issues solved via the current process are often reargued in subsequent cases.

This framework was deemed necessary both for the protection of ratepayers against being taken advantage of by monopoly utilities and to ensure development of an appropriate record for Commission decisions.

However, in today's quickly changing environment, over-reliance on a regulatory process that, by its current design, is adversarial, may not always produce the best outcomes or support utilities in delivering new, innovative service offerings to customers in a timely way.

Providing an alternative regulatory path that is more collaborative and consultative up front may make the transition that e21 is proposing smoother. The thrust of e21 is to shift to a more customer-centric, outcome-based regulatory approach, which lends itself to a collaborative process wherein all parties agree on outcomes, measurements, and methodologies.

(K) Generic dockets. The Commission and Department should look for opportunities to initiate generic dockets in cases where the practices of one utility affect other interests in the state. Doing so would enable more consistent policies statewide on issues of common concern to many, and reduce the transaction costs of participating in the regulatory process for intervenors.

Under the current regulatory system, issues that affect all utilities and all ratepayers statewide infrequently result in the opening of a docket that addresses the generic matter and involves all utilities and stakeholders.

This recommendation seeks to institute a more regular process to involve all affected parties in broad issues that may be raised formally by a single party. It rests on the presumption that issues affecting utilities, ratepayers, and stakeholders statewide might be best solved through an inclusive, collaborative, problem-solving process that reaches a resolution which all parties can support.

(L) Forward-looking stakeholder processes. Implementing this report's recommendations will require proactive exploration of emerging issues and developing forward-looking solutions with stakeholders.

Developing this new regulatory approach will require just such stakeholder processes that enable regulators, customers, utilities, and others to spend more time learning from one another in collaborative forums and allowing creative solutions to specific issues to arise and be implemented. This will increase customer satisfaction with both utilities and their regulators.

(M) Grid Modernization Process. The current electric grid relies on many technologies that originated centuries ago with Edison and Westinghouse.

This recommendation seeks to initiate the development of forward-looking distribution planning and timely grid modernization through a robust, well-informed stakeholder process, which could include workshops and technical conferences.

Customer demands and public policy requirements are driving the need for a modern grid that will support new ways in which electric energy will be generated, delivered, and used. The modern grid will be cleaner and reliable, more flexible, and will enable customers to manage and reduce their energy costs. This will also require the electric system to become more distributed, intelligent, efficient, real-time controlled, open *and* secure, and resilient against attack and natural disaster.

Proactive, forward-looking planning of the distribution system over the next several decades will include evaluating the extent to which the system can reliably and cost-effectively:

- Integrate a high level of distributed energy resources (both supply- and demand-side);
- Accommodate and support active participation by customers;
- Manage two-way flows of electricity and data; and,
- Ultimately provide seamless integration and interoperability of varied systems and components.

All of the above will require implementing modern distribution management systems including advanced control and communications.

(N) Grid Efficiency. The basic design of the electric grid has remained largely the same throughout its history. Electricity is generated remotely at large central stations, transmitted large distances with high voltage lines, and then reduced in voltage for local distribution system delivery to the customers.

The system is planned and operated to meet the instantaneous demand of customers plus an additional reserve for unexpected power plant and/or transmission line outages.

This historical approach has developed due to a combination of limited generation technologies, inelastic customer demand and, in the pre-digital era, very minimal information, communications, and control technology.

Thus the grid is designed to meet retail peak demand, which is nearly twice the average load. This results in significant underutilization of much of the grid most of the time.

In Minnesota, the total electric system utilization is approximately 55 percent (average demand divided by peak demand), providing opportunity to reduce system costs by better utilizing existing system assets (e.g., generation, wires, etc.).

There are a number of potential opportunities to improve the overall grid efficiency. For example, more responsive demand would improve grid efficiency and reduce overall costs. One approach could be, in areas with advanced metering technology, to transition to time-varying rates.

e21's Next Steps - The Plan for Phase II

e21 participants understood from the beginning of the project in February 2014 that evolving Minnesota's 100-year-old-plus regulatory framework would be neither simple nor fast. The initial recommendations outlined in this Phase I Report propose a new blueprint for regulating utilities in Minnesota. But as with any blueprint, the building still needs to be built. That is what e21's second phase will be about. Phase II begins the hard work of "sweating the details" to place Minnesota on a predictable, step-wise path toward implementing e21's recommendations.

The precise timeline of the e21 Initiative's second phase depends on several factors, including:

1. Endorsement of the process by the Minnesota Public Utilities Commission;
2. The willingness of participants to continue devoting time and energy to the effort;
3. Funding to support the process; and
4. The speed with which e21 participants—and others to be engaged during Phase II—are able to work out the details of implementing a multi-year, performance-based regulatory approach.

Expected Activities & Outcomes

In its second phase, the e21 Initiative expects to work with the Commission, Department, e21 stakeholders, and others to further develop the implementation strategies and details for Phase I recommendations and tackle issues raised in Phase I but not yet fully addressed by e21. Multi-interest stakeholder processes, such as e21, should be used in the near-term to work out the details of implementing the multi-year, performance-based regulatory framework recommended in this report, including but not limited to:

1. Identification of performance metrics that are quantifiable, verifiable, and align with e21 Principles and Outcomes;
2. The percentage of a utility's revenue that should be tied to achieving these performance metrics, and any penalties for failing to achieve them, or additional incentives for exceeding them;
3. Additional questions raised by the proposed Integrated Resource Analysis;[11] and
4. The planning needed to identify grid modernization investments or new services that would facilitate achieving e21 Principles and Outcomes.

e21 expects to leverage the diversity of the e21 stakeholder group to build an even broader and more diverse coalition of interests to support and advocate for e21's recommended changes to the policy and regulatory framework in a stepwise fashion over time. This would include engaging participants in the Citizens League's electricity project.

As part of this broadening of the process, e21 may also:

1. Organize and host a "roll-out event" in Minnesota that shares more broadly with key interests what the e21 process produced.

[11] See Appendix B for the list of questions.

2. Conduct smaller, targeted meetings with key constituents who were not directly represented in the e21 stakeholder process, but who are affected by the recommendations and important to effective and timely implementation of the results.

3. Organize other outreach activities in Minnesota and nationally.

We look forward to discussion with the Commission, Department and other stakeholders to determine the most appropriate forum, timeline, and audience for continued dialogue.

Conclusion: Toward a Modern Energy System

Minnesota has an opportunity to lead the nation in preparing for a more modern, customer-centric, cleaner energy system. e21's performance-based regulatory framework will enable new technology and deliver more options and value, while protecting those who simply need and want electricity at an affordable price.

Instead of rewarding utilities for selling more electricity and building capital-intensive facilities, the proposed regulatory framework would allow utilities to earn revenue by delivering the outcomes Minnesotans want.

Minnesota is not alone in this quest.[12] Establishing a regulatory framework and utility business model that can keep up with technological change in the energy sector and maintain secure, reliable, sustainable, and affordable energy is a truly national and global challenge.

[12] See Appendix B: Map of US Projects Working on the Future of Electric Utilities.

Appendix A: The e21 Process

Launched in February 2014, a diverse set of stakeholders have met monthly to develop recommendations for evolving the regulatory system in Minnesota so that it better aligns how utilities earn revenue with new customer expectations and public policy goals. The e21 Initiative project team, participants, and observers represent key Minnesota interests including utility, consumer advocate, energy technology, business, environmental, academic, government and others.

A shared understanding of the current state and plausible futures

To identify what changes might be necessary to Minnesota's legal and regulatory framework, the e21 Initiative went through a process called 'transformative scenario planning.'[13] This helped e21 participants think through the threats, opportunities, and choices presented by energy scenarios that could plausibly occur in the future (not necessarily what any one interest would want to happen). This process enabled participants to understand how others viewed the current state of affairs and what potential futures they envisioned, and the associated challenges and opportunities of different futures.

Grounding the process in a common base of knowledge

As part of developing a shared understanding of "the current state," the e21 Initiative developed a series of working papers to provide detailed background information and cultivate a common base of knowledge on which to build. These foundational documents include the following:

- *Overview of the Current Utility Business Model in Minnesota.* Provides an overview of Minnesota utilities' business models, which operate in a regulated market under a cost-of-service regulatory framework.

- *Challenges and Misalignments with the Current Regulatory Model.* Lays out the challenges that are driving the need for change in the current regulatory model.

- *Summary of Complementary Utility Regulatory Reform & Business Model Initiatives.* This surveys and summarizes significant efforts underway in other parts of the US and abroad, from both research-focused projects to business model initiatives, on developing the utility of the future.

- *Legal and Regulatory Framework for Energy Utilities in Minnesota.* Provides an overview of Minnesota's legal and regulatory framework for energy utilities.[14]

e21 participants also learned about a range of issues through presentations from e21 stakeholders and in-state and national experts including Minnesota Power, Xcel Energy, the Minnesota Department of Commerce's Division of Energy Resources, the Minnesota Public Utilities Commission, George Washington University School of Law, Rocky Mountain Institute, the Regulatory Assistance Project and Pacific Economics Group.

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[13] This is a derivative of traditional scenario planning made famous by Royal Dutch Shell and now used regularly by many institutions to adapt to an uncertain future. Transformative scenario planning helps to understand and change complex systems where one cannot simply derive the answers by looking at history or at "best practices" because often none exist. It was popularized by Adam Kahane and used effectively in South Africa after apartheid (and elsewhere) as a way to actively shape and transform the future, not just adapt to it.

[14] All of these working papers are available at: www.betterenergy.org/projects/e21.

Using a Consensus-Based Approach to Develop Recommendations

The e21 Initiative developed its recommendations on a consensus basis, which means that the participants support the recommendations, taken as a package, as a framework for moving Minnesota on a path toward achieving the e21 principles and desired outcomes. Consensus does not mean that each party is equally enthusiastic about every idea, but *rather that all participants support the package as a whole.* Importantly, consensus does not require participants to give up their right to object to future implementation details that they feel do not reflect the original agreement. While reaching consensus is neither fast nor easy, it can lead to solutions that—if implemented together—are more effective and durable than a “majority rule” or single-issue result.

Phase II of the e21 Initiative will focus on implementing the recommendations identified in Phase I, including a more detailed examination of questions raised during this first Phase. See the ‘Next Steps’ section of this report for more details.

Engaging Others

The e21 project team and participants have engaged other stakeholders and the public through several venues and media outlets, including presentations to the Minnesota Legislative Energy Commission, Minnesota Public Utilities Commission, Minnesota Chamber of Commerce, Solar Energy Industries Association Conference, the Citizen’s League, and members of the Minneapolis City Council. An e21 team also participated in the Rocky Mountain Institute’s eLab Accelerator, a national ‘innovation boot camp’ for those exploring how a 21st century electricity system might work, where they had the opportunity to interact with, and learn from, eleven other related efforts from around the country.[15]

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[15] To learn about e21’s experience at the eLab Accelerator, see Rolf Nordstrom (July 2014), “e21 Initiative Eyes a Sustainable, Carbon-Neutral Energy System for the Land of 10,000 Lakes,” available at: http://www.betterenergy.org/e21-RMI-blog.

Appendix B: Issues & Questions for Phase II

In its second phase, the e21 Initiative expects to work with the Commission, Department, and e21 stakeholders to further develop the implementation strategies and details for Phase I recommendations and tackle issues raised in Phase I but not yet fully addressed by e21. Multi-interest stakeholder processes, such as e21, should be used in the near-term to work out the details of implementing the multi-year, performance-based regulatory framework recommended in this report, including but not limited to:

1. Identification of performance metrics that are quantifiable, verifiable, and align with e21 Principles and Outcomes;
2. The percentage of a utility's revenue that should be tied to achieving these performance metrics, and any penalties for failing to achieve them, or additional incentives for exceeding them;
3. Precisely what a Business Plan must contain for utilities that opt in to a performance-based approach; and
4. Additional questions raised by the proposed Integrated Resource Analysis:
    A. How to integrate and address the impacts of federal policies such as the U.S. Environmental Protection Agency's proposed rule to reduce greenhouse gases (GHGs) under Section 111d of the Clean Air Act?

    B. The potential value of developing a statewide resource analysis rather than a utility-by-utility evaluation? This may lead to better coordination across utilities, facilitate development of more economically sized projects and shared resources, and reduce the time commitment and workload of the Commission in developing and reviewing analyses. Uniformity across the state could also make execution of the analysis more efficient.

    C. Whether or not the tools (e.g., methodologies, software packages) used to identify and compare options in an IRA are taking into equal consideration all supply and demand-side resources? This includes:

        i. Distributed energy resources (DERs) such as efficiency, storage, distributed generation, demand response, and demand-side management;

        ii. Bulk electric system/centralized generation and storage;

        iii. Integration of electric vehicles, and other technologies,

        iv. Distribution and transmission alternatives; and,

        v. Non-traditional solutions, such as customer-sited solutions that provide net benefits to the system.

    D. How should utilities that prepare IRAs coordinate them with planning done by the Midcontinent Independent System Operator (MISO) and neighboring states? Do there need to be protocols that facilitate regular communication and, to the extent possible, coordination of state and regional plans to achieve optimal investments end-to-end across the entire regional electric system?

5. Other questions e21 plans to explore in Phase II include:

   A. How to better incorporate the growth of DERs and other distribution-level technologies on the system, enabling better evaluation of their costs/benefits, and their ideal locations on the system?

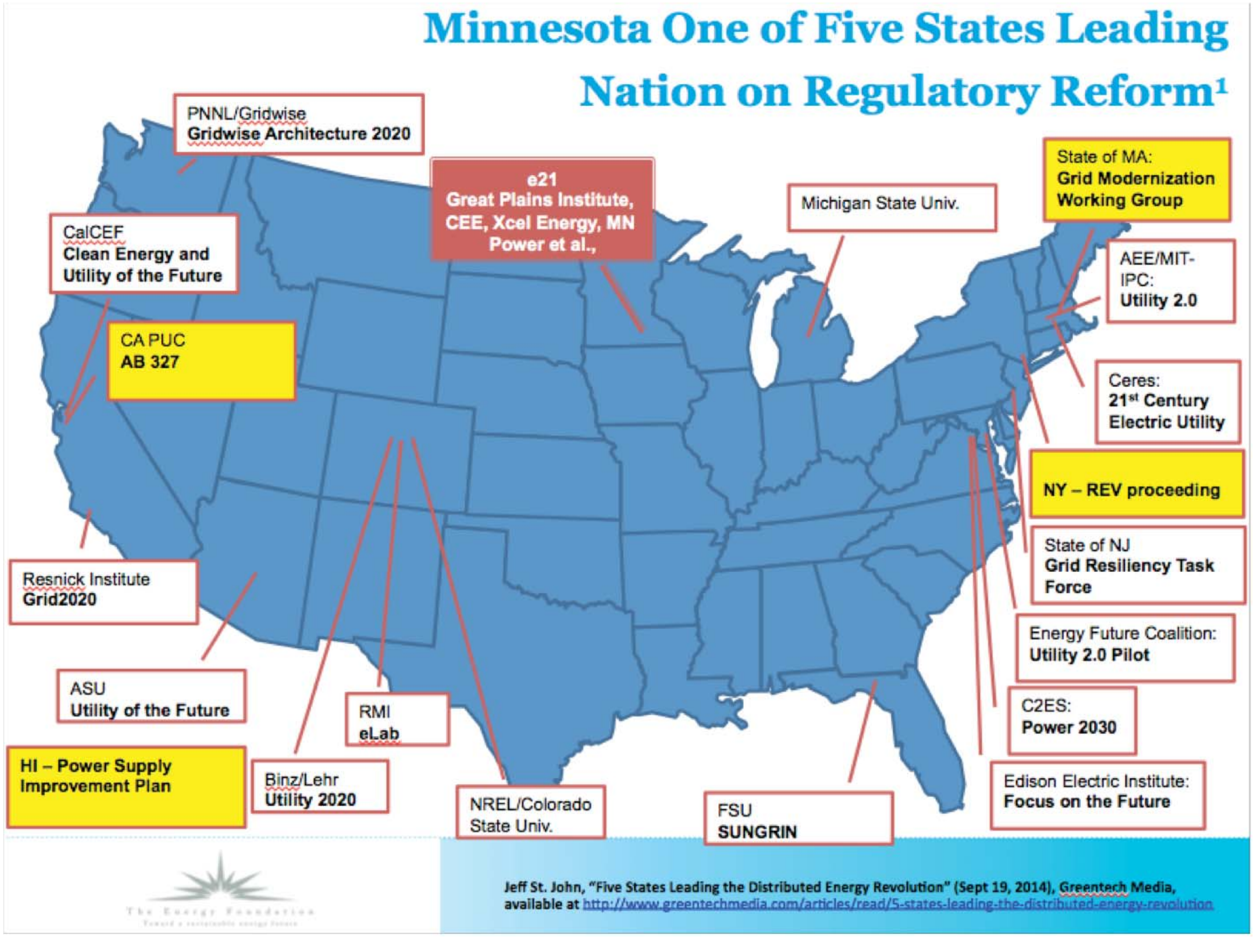
   B. What planning is needed to identify grid modernization investments or new utility services that would facilitate achieving e21 Principles and Outcomes? That might include allowing utilities to invest in efficiency improvements or other solutions at their customers' sites if and when doing so is a more cost-effective way of meeting demand consistent with other policy objectives.

   C. What energy products and service options need to be regulated, even if provided by a non-utility?

   D. What mechanisms (e.g., aggregation of load) could be allowed and encouraged to better reflect customer's load and improve billing efficiency for customers with multiple meters?

   E. What customer-side utility investments might go in the rate base?

Appendix C: Map of US Projects Working on the Utility of the Future



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e21 Initiative Phase I Report

December 2014

To learn more about the e21 Initiative,

please visit: www.betterenergy.org/projects/e21

CERTIFICATE OF SERVICE

I, Tiffany Hughes, hereby certify that I have this day served copies or summaries of the foregoing document on the attached list(s) of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States Mail at Minneapolis, Minnesota

xx electronic filing

Xcel Energy Miscellaneous Electric Service List
Docket No. E002/GR-13-868; Electric Rate Case
Docket No. E002/RP-10-825; Resource Plan

Dated this 22nd day of December 2014

/s/

____
Tiffany Hughes

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MODERNIZING UTILITY RATEMAKING PRACTICES IN A CHANGING INDUSTRY

BLACK & VEATCH PROJECT NO. 187810

PREPARED FOR

Kansas City Power & Light Company

7 MAY 2015

BLACK & VEATCH
Building a world of difference.

ATTACHMENT 2

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Introduction

Kansas City Power & Light Company (KCP&L) requested that Black & Veatch Corporation (Black & Veatch) prepare a report to assist it in evaluating utility ratemaking practices that could be adopted to address a continuing financial concern for KCP&L's management - the inability to earn its allowed rate of return on investment for its Missouri jurisdiction.

This report is structured to address the most significant issues related to modernizing electric utility ratemaking in response to the evolving business conditions utilities face. The utility industry is experiencing significant changes affecting virtually every part of the traditional utility business model. These changes are recognized by a broad spectrum of industry stakeholders, including a growing number of state utility regulators. In recent times, numerous trade journals and other industry publications have provided extensive comments expressing a wide range of viewpoints on this important subject.

In some states, utility regulators are also recognizing these fundamental changes to the utility industry, and have initiated comprehensive investigative proceedings to identify and analyze the changes occurring in the energy markets and to develop regulatory and ratemaking solutions that are supportive of the desired changes. For example, the New York Public Service Commission (NYPSC) has initiated a comprehensive docket[1] to investigate ways the energy industry and regulatory practices should be modified to address future industry changes. The NYPSC recently issued a major order in its proceeding that adopted a policy framework and implementation plan for the changes that will be made to its regulatory model and related policies.[2] In that order, the NYPSC found that, "Reforming the Commission's ratemaking practices will be critical to the success of the REV vision."

The current utility regulatory models and methods have been in use for well over a century. Over that period, fundamental changes to energy markets and the operating environment for utilities have occurred that the utility regulatory model has gradually adapted to in light of both regulatory policy and legislative changes. This section of the report provides a brief discussion of the changes in the utility industry that make it more difficult in the current environment to maintain the integrity of both the regulatory compact and the regulatory requirement for just and reasonable rates. The paper then discusses how the operating changes impact the various elements of the utility ratemaking process and provides some necessary policy considerations for addressing these changes. Details of the relevant issues and the regulatory/ratemaking solutions being implemented across the U.S. electric utility industry are discussed in the subsequent sections of the report. The last section of the report provides Black & Veatch's conclusions on the need for change in the utility regulatory area and specific recommendations on the ratemaking changes that KCP&L should consider to create a better alignment of interests among its customers and shareholders.

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[1] NYPSC Case 14-M-0101, Proceeding on Motion of the Commission to Reforming the Energy Vision (the "REV Proceeding").

[2] Order Adopting Regulatory Policy Framework and Implementation Plan (Issued and Effective: February 26, 2015).

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KEY BUSINESS CHALLENGES FACED BY THE UTILITY INDUSTRY

The electric utility industry faces numerous challenges as a result of both internal and external factors driving the utility business model and the ability of the utility industry to respond to the changes that it faces. Regulatory models and policies contribute significantly to the impact of these factors on utility economics. Importantly, it should be recognized that a one-size fits all approach to addressing utility issues cannot be applied because even the overriding issues do not have the same impact on each individual utility. In part, the differences are driven by the economics of the utility and of its service area. Utilities have different market models with some operating in markets with competitive energy providers. Some utilities operate in high cost regions. Some utilities are currently more exposed to change than others, but all utilities will eventually have to address the issues driving change. Five broad issues are discussed that are fundamental to the changes occurring to the utility business model:

1. Low customer growth;
2. Low or negative growth in energy consumption;
3. Requirements to replace or retrofit aging infrastructure;
4. New infrastructure demands associated with renewable resources and Distributed Energy Resources (DER); and
5. Disruptive cost changes for the infrastructure supporting technological innovation (e.g., grid modernization) and cyber security.

Within each of these issues are subsumed the factors most effecting the utility business and regulatory models under which utilities operate.

For much of the first 100+ years of utility regulation, customer growth and energy (kWh) growth was rapid as electric service expanded quickly by adding new customers and by adding load for existing customers. Customer and consumption growth provided utilities with opportunities for substantial economies of scale as unit costs declined overall with the addition of new facilities, growing rate base and earnings growth. Even with inflation, the economies of scale were large enough in some cases to offset those impacts and rates actually declined or remained flat as utilities had a reasonable ability to earn their allowed rates of return even with historically-based test years. Until the 1970s, utilities were strong financially with over 90% of utilities' bond ratings at A or above, and over 50% of the industry rated AA or higher.

From the 1970s to today, the utility industry has faced financial challenges of customer growth and growing investment in infrastructure in an ever-changing economic environment. Early in that time period, the robust growth required investment in new capacity for generation, transmission and distribution facilities. Over time, the growth moderated and the challenges required utilities to operate in a period of low growth with a need to address infrastructure issues including retrofit and replacement of the infrastructure developed prior to and during the earlier part of the past 40 years. During this period, both regulators and legislative bodies have recognized the constitutionally required need to provide for the financial health of utilities and have accomplished this financial health through changes in regulatory tools and policies. Even with changes designed to improve

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utility financial ratings, the number of A- or higher rated utilities had declined to just below 27% by 2011. The dual problems for utilities of customer growth and low or zero sales growth (and even negative growth in some cases) impacted the reasonable opportunity to earn their allowed rates of return and to operate effectively under the existing regulatory model. These problems directly impact the revenue side of the utility financial equation at a time when other issues are impacting the cost side.

Given the average age of utility systems, many assets are at or near the end of their useful physical life. Some assets are also at the end of their useful economic life as new technologies have changed the cost structure of utility service. Aging infrastructure creates substantial demand for new capital resources to replace the aging infrastructure without new customers or new energy uses to defray the cost of the new infrastructure investment. These non-revenue producing investments in infrastructure increase utility rates at the same time new DER technology, conservation and energy efficiency create additional reductions in revenues. Infrastructure investments are also needed to meet new operating requirements resulting from new environmental regulations and other new regulations; such as Order 1000 issued by the Federal Energy Regulatory Commission (FERC) dealing with electric transmission planning processes and North American Electric Reliability Corporation (NERC) compliance. The result is that utility rate bases are growing faster than they have since the end of the new plant construction eras of the 1970s and 1980s. This investment growth is occurring during a period when revenue growth is low or non-existent.

There also are new demands for infrastructure to accommodate renewable energy resources on the distribution grid and to develop new renewable energy products. The infrastructure investments for renewable resources range from the new utility scale renewable energy sources; new transmission facilities to deliver renewable energy from remote areas to load centers: distribution system upgrades to accommodate DER; and developing a more efficient mix of generation resources to protect the utility's system reliability and stability. As with other infrastructure requirements, these costs challenge the utility to recover new investments through rates: (1) without the addition of new loads; (2) with DER creating lower kWh loads, but without an equivalent decrease in the utility's peak loads; and (3) with no change in the peak loads on transmission and distribution for some utilities.

One final issue that represents a large investment to safeguard the utilities infrastructure is cyber security. The types of costs associated with cyber security range from hardware and software costs to operating expenses for data collection and analysis. Today's utility operations are highly dependent on integrated systems to manage complex network resources in order to capture data, as well as to deliver, bill and service millions of customers. New emphasis is being placed on information related to the operation of the distribution grid. The need to protect all assets, components and data within a finite physical and logical boundary is critical to the daily operations of every utility. Cyber security requirements are based on Critical Infrastructure Protection (CIP) regulations issued by the FERC and managed through the NERC. These regulations and the administration of the regulations is a constantly evolving process. This adds cost directly to both capital and expense as utilities create and implement solutions to meet and maintain the security of their infrastructure.

Each of these issues represents a new business challenge for electric utilities as they seek to operate efficiently, reliably and cost-effectively in this new operating environment. At the same time, utilities have new operational challenges in an environment with substantial growth in DER creating a new

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and significant class of "partial requirements service customers" who do not use the system in the same historical way.

THE NEED FOR CHANGES TO TRADITIONAL UTILITY RATEMAKING PRACTICES

Each of these issues also directly impacts the following utility ratemaking practices:

- The regulatory compact;
- Test year determination for setting rates;
- Treatment of volatile cost elements that are not subject to meaningful control by the utility and cannot reasonably be matched with corresponding revenues when rates are set only through a traditional historic based test year in a rate case consistently biasing a utility's earnings above or below its allowed return; and
- Treatment of unpredictable, uncertain, recurring, and material cost elements included in the utility's revenue requirement.

As discussed in detail below, the regulatory compact describes the system of legal rights and obligations of the utility and state public utility commissions that define the environment in which utility ratemaking occurs. The regulatory compact protects the interests of various stakeholder groups including a utility's customers and investors. The issues that are fundamentally changing the utility business model require that regulatory policies, and potential legislative mandates, change with the changing business model to assure safe, reliable and cost-effective utility services are provided to customers at compensatory rates. The alternative regulatory mechanisms required by these industry changes protect the core regulatory compact in a new environment. Importantly, the changes in the regulatory environment are critical for meeting requirements related to just and reasonable rates that provide the utility a reasonable opportunity to earn the allowed return.

The historical test year is only legitimate to the degree it acts as a reasonable indicator of future revenues and expenses. With slow customer growth and little or negative sales growth, it is important that the utility's test year revenue projections portray a reasonable expectation of future revenues. Likewise, the additional infrastructure investment occurring annually together with other expense items should be estimated consistent with the future period during which rates are effective. This suggests that attention should be given to the ability of the selected test year to properly reflect costs if regulation is to provide the utility with a reasonable opportunity to earn its allowed rate of return. Reexamination of the test year concept will be a necessary element of any review of the utility regulatory model, and is discussed below.

Historical costs are only a good prediction of future costs when the costs are not subject to volatility or a systematic bias (upward or downward) as the result of inflation or other cost drivers. To understand the upward bias of costs, it is only necessary to understand that the costs of new facilities are substantially higher than the cost basis for a utility's rates – which is historical, embedded costs less accumulated depreciation. Effective utility regulation recognizes the need to allow for adjustments to expenses that occur outside the reasonable control of utility management particularly when those changes threaten the reasonable opportunity to earn the authorized return set by the utility regulator. These exogenous cost changes may represent both increases and decreases in the

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utility's total revenue requirement. Utilities should not profit from, or be denied recovery of, cost changes that are beyond management's control.

Regulatory control of the utility industry has existed for over a century. During that time, utility regulators have faced changes in the entities they regulate and the environment in which those entities operate. As a result, there are now many more ratemaking practices to support utility regulation implemented to address the changing environment. Both federal and state ratemaking have evolved to address the types of issues faced today with models from telecommunications, railroads, pipelines (both natural gas and liquids), water, and so forth. These models have explicitly addressed changes in the determination of test years, the design of utility rates, the widespread adoption of adjustment clauses, and other innovative ways to enhance cash flow in the face of utilities' growing rate base requirements.

A utility's test year has evolved from a fully historical basis to a fully forecasted basis, and all variations in between depending on the particular state or federal jurisdiction. Some utility regulators have recognized the value of setting rates for more than one year based on multiple test years, or have utilized formula rates that are reset annually. Formula rates may be based on actual costs or on a price or revenue cap formula in the case of Performance-Based Regulation (PBR). There are different ways of determining the revenue requirements including alternative rate base treatments. For example, some regulators permit Construction Work in Progress (CWIP) in rate base to improve cash flow and to reduce the future cost of plant in the utility's rate base. The FERC has adopted trended original cost for determining the rate base of oil pipelines. Some regulators allow for adjustment clause formulas to adjust rate base between rate cases to reflect the impact of infrastructure capital additions made pursuant to approved, long-term infrastructure replacement plans. These types of tools have been used to address some of the critical issues related to the test year concept.

Rate structure modifications such as rate adjustment mechanisms (RAMs), trackers and formula rates are being used to provide utilities with more reasonable opportunities to earn their allowed rates of return. Rates are being restructured to accommodate a mixed monopoly/competitive model. Rates have been developed to recover costs from customers who purchase only some portions of the utilities' services. These partial requirements customers may need services such as supplemental service or standby service with inherently different load shapes compared to the former full requirements load. The use of adjustment clauses has become a universal tool as part of the rate design process to improve the matching of cost and revenues. These tools exist and are used under all forms of cost of service regulation from traditional cost of service regulatory models to alternative regulatory models such as PBR and formula rates.

RAMs go well beyond the typical fuel and purchased power adjustment clauses and address revenue stabilization through weather adjustment clauses, revenue decoupling adjustments, and formula-based mechanisms designed to adjust rates to accommodate unforeseen cost changes between utility rate cases. Adjustment clauses have been designed to recover costs associated with both capital and expense components. For example, some adjustment clauses recover environmental costs including both a capital component and the variable cost of chemicals where those costs are not already recoverable through the utility's fuel adjustment clause. With the advent of RTOs or ISOs, regulators authorized adjustment clauses to pass through federally approved transmission costs based on

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formula rates and with the new FERC policy statement permitting gas pipelines to establish mechanisms to recover infrastructure replacement costs likely for gas transmission as well. The importance of these adjustment clauses differs from utility to utility since not every utility has the same operating circumstances.

The important point is that each utility must have the regulatory tools in place to ensure a reasonable opportunity to earn its authorized return on equity given the circumstances unique to its service territory and its operating environment. The regulatory tools will be unique even for utilities operating in the same jurisdiction. Each utility will face its own combination of factors that drive the fundamental requirements embodied in the regulatory compact. In each case, the fundamental objectives of just, reasonable and non-discriminatory rates must be satisfied by the public utility commission and that judgment must be safeguarded in a rapidly changing cost-environment to ensure the regulatory compact functions as constitutionally required.

The remainder of this report will discuss useful regulatory tools in accommodating the business challenges caused by the fast evolving energy industry environment.

The Regulatory Compact and its Role in Modernizing Utility Ratemaking

The concept of the regulatory compact is often discussed in the context of regulatory policy decisions. Despite the widespread use of the term, it has not been broadly used in the academic literature related to utility regulation. In our view the regulatory compact represents a shorthand reference to the system of obligations and rights that underlie the regulatory process. These rights and obligations result from the legislative and judicial processes as they relate to utility regulation and are administered through the regulatory process. Our aim is to provide an overview of the elements of the regulatory compact as a basis for assuring safe, reliable and cost effective utility service in the ever changing economic environment facing energy utilities today.

The foundation of the regulatory compact is the system of utility obligations and rights that can be summarized as follows:

Figure 1 Summary of the Regulatory Compact

UTILITY OBLIGATIONS	UTILITY RIGHTS
Obligation to Serve	Right to a Reasonable Rate of Return
Safe and Reliable Service	Service Subject to Reasonable Rates, Rules, and Regulations
Non-Discriminatory Rates	Protection from Competition
Just and Reasonable Rates	Eminent Domain

Both the obligations and rights are constrained by the regulatory process. Thus, there is no unlimited obligation to serve, but rather an obligation constrained by a variety of legislative and regulatory policies such as line extension rules, policies related to payment, and so forth. Similarly, the utility's right to a reasonable rate of return is constrained to a return on assets that are considered to be used and useful, and whose costs have been prudently incurred. The list of constraints on the regulatory compact for both obligations and rights requires an in-depth analysis of statutory issues and judicial decisions that have interpreted their statutory meanings. It is not the purpose of this discussion to provide an opinion on these legal issues, but rather to note specific aspects of the regulatory compact as they impact the utility ratemaking process with the changing energy market.

In Black & Veatch's view, the fundamental shift occurring in the utility business model occasioned by the issues previously discussed has created a new model of mixed monopoly and competition as the result of the small scale implementation of DER. This trend has become a major factor in the need for new utility regulatory models. Nevertheless, these new models must continue to meet the requirements of providing the utility with a reasonable opportunity to earn its allowed rate of return.

Put another way, the regulatory obligation must still provide the utility with timely cost recovery. That is, the regulatory process should set rates as close as practical to the costs expected to be incurred in the period rates are to be effective. There are several implications for matching revenues and costs. First, for costs that are beyond the control of the utility, there should be the availability of cost tracking mechanisms. Second, for planned rate base additions that are part of a multi-year capital investment plan (such as infrastructure replacement), utility regulators should provide a method for cost recovery between rate cases for these approved plant additions. This should not be in the form of a blank check, but should consist of a carefully reviewed process to assure that new facilities are consistent with the approved plan, and that the costs are prudent. Third, the regulatory process should recognize that the utility must have a reasonable opportunity to actually earn its allowed rate of return. Failure to provide an opportunity to earn the allowed return will result in further detriment to the financial health of the utility even if the approved rate of return equaled the market-based return. Simply, investors respond not to the allowed return but to the return actually earned by the utility. By improving the utility's actual financial performance, regulators ensure that the costs for customers will be lower in the future as the result of lower capital costs over the life of the assets and lower regulatory costs from the prospect of less frequent rate proceedings.

Maintaining balance in the regulatory compact given the economic environment necessitates the regulatory tools and processes for utilities and regulators that assure full recovery of prudently incurred investments and operating costs that are deemed to be used and useful, and that provides a reasonable opportunity to recover prudent and efficient operating costs. This recovery of operating costs must recognize that certain costs can only be fully recoverable on a reasonable basis when the costs are recovered through adjustment clause or cost tracking mechanism used in some jurisdictions that permit automatic recovery of the tracked costs. Properly designed RAMs assure all parties that no more or no less than actual costs are recovered and those recoveries precisely match the portion of costs excluded from base rates as part of the underlying adjustment formula.

To find the balance necessary in the regulatory compact to provide returns for utility investors consistent with the financial marketplace and to protect the interests of customers from excessive rates requires a careful balancing of interests. There is always a danger that the economic environment will disrupt the regulator's careful balancing of interests. The symptoms of this imbalance are more frequent (even annual in some cases) rate cases to correct for the utility's chronic under-earning of its allowed rate of return. Persistent over-earning would also be a symptom of this imbalance. There may be reasons that over or under earnings occur related to a systemic bias in the utility's revenue requirement formula. Addressing any systematic bias is a prerequisite to restoring the balance established by the regulator as part of the regulatory compact.

The Ratemaking Formula: A Fundamental Building Block

The fundamental ratemaking formula is deceptively easy to understand, but much more difficult to implement. The formula is as follows:

$$RR_t = O_t + M_t + D_t + T_t + (GP_t - AD_t + ORB_t) * ROR_t$$

Where:

- RR_t = Revenue Requirement for test period t
- O_t = Operating Expenses for test period t
- M_t = Maintenance Expenses for test period t
- D_t = Depreciation Expenses for test period t
- T_t = Taxes for test period t
- GP_t = Gross Plant for test period t
- AD_t = Accumulated Depreciation for test period t
- ORB_t = Other Rate Base for test period t
- ROR_t = Rate of Return for test period t.

This equation and its components will be used to discuss various issues in the following section and will be referred to as the test year ratemaking formula.

The test year ratemaking formula seems simple enough. Yet, issues typically are raised in utility rate cases relative to every element of the formula. There are issues on the determination of the test year; the level of expenses to be included in base rates; what adjustments, if any, should be made to the test year; the determination of depreciation expense and taxes; the level of gross plant to be used in the determination of rate base; the determination of accumulated depreciation; the definition of the other rate base items that may be either positive or negative values; and the rate of return on rate base that includes the appropriate capital structure and the cost of each component of that structure.

TEST YEAR DETERMINATION

The issues associated with test year determination differ among jurisdictions. At its core, the purpose of the test year is to serve as an estimate of what a utility's costs will be to provide service in the *Rate Effective Period* or *Rate Year* so that new rate revenues will exactly match the indicated costs. The concept of the *Rate Year* is the first twelve months after the new rates take effect. Ideally, the relationship can be expressed as follows:

$$RR_t = RR_{t+1}$$

Where:

RR_{t+1} is the Revenue Requirement for the Rate Year.

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Ideally, it would also be true that the rate revenues in the Rate Year would equal the actual revenue requirement for that year.

Regardless of the basis for the test year, its purpose is to provide a reasonable estimate of the costs to be incurred and the revenues to be produced in that Rate Year. The efficacy of different forms of the test year concept has evolved over time to reflect the circumstances of the utility. As a result, there are many different forms of the test year. The following alternative definitions of a utility's test year have been used by regulators to estimate the utility's costs in the Rate Year:

- *Historical Test Year* - a 12-month period in which actual costs are known (based on per book amounts) and contained in the utility's accounting records.
- *Normalized Historic Test Year* - a 12-month period in which actual known costs from the accounting records of the utility are normalized for weather or other non-recurring expenses.
- *Normalized and Annualized Test Year* - a 12-month period in which actual known costs are normalized (as described above) and other costs are annualized for changes in costs that occurred in the historic period that result in higher or lower costs when applied over a full 12-month period.
- *Normalized, Annualized and Pro-Forma Test Year* - a 12-month period that is normalized and annualized (as described above) with pro-forma adjustments for changes that have occurred after the end of the test year. Pro-forma adjustments may be known and measurable at some point during the rate case process, or they may be known to occur during the Rate Year.
- *Hybrid Test Year* - a 12-month period of which a part is actual and part is forecast that may or may not be subject to a full true-up during the rate case process.
- *Forecasted Test Year* - a 12-month period that is fully forecasted at the time the utility's rate case is filed. In some forecast test years the forecast may be for the actual Rate Year period, whereas in other cases the forecast is at least partially known and measurable before the Rate Year occurs.

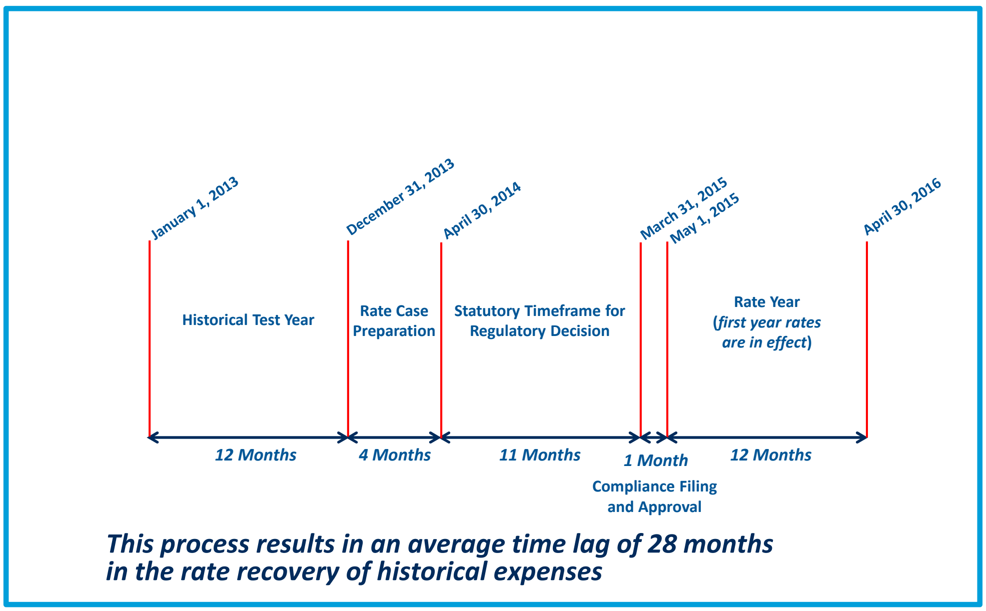
Each of these test years represents fundamentally different assumptions about the costs and revenues in a future Rate Year period. The assumptions used are most easily illustrated with a historic test year. That type of test year assumes that actual costs in the future period will be matched by rates developed on the basis of historical cost data. Essentially, a historic test period assumes that growth in electric load will generate revenues to offset the growth in costs resulting in full cost recovery (including both return of and on the utility's full rate base) in the Rate Year. During the growth period after World War II, this test year alternative produced reasonable outcomes as the combination of technological change and rapid growth permitted declines in nominal rates despite the effects of inflation. In fact, in some years, utility rates actually declined even though the utility's total revenue requirement increased.

Changes such as rapid inflation and rising demand for fuels caused this test year alternative to no longer be a practical choice. New alternatives were created to achieve the desired balance in the regulatory compact. These solutions included adoption of refined formulas for ratemaking where the cost of fuel and purchased power became subject to a different formula that allowed for adjustment to reflect actual cost changes outside of the utility's test period. In addition, both regulators and sometimes legislators also sought alternatives to address cost differences between the test year and rate year. For example, the FERC amended the definition of the test year in 1980 to include the right of a utility to use a forecast test year for the Rate Year. Over the years, a number of state regulatory commissions have adopted the concept of a future test year to allow for matching of costs and revenues in the Rate Year and to provide an opportunity for the utility to earn the allowed return.

THE CONCEPT OF REGULATORY LAG

In its simplest form, regulatory lag is the time between the incurrence of a cost by the utility and when those costs are recovered in rates. As a result, the amount of regulatory lag that a utility experiences is impacted by how the test year is defined in the utility's rate case and the timing of regulatory decisions in those rate cases. The factors impacting the level of regulatory lag are illustrated below.

Figure 2 Illustrative Example of Regulatory Lag



Regulatory lag is measured from the utility's test year to the rate year and is expressed in months. The time lag is also a function of some of the elements of the test year. For example, if rate base is determined as a thirteen month average of net plant, the regulatory lag as calculated above would be six months longer than if rate base was determined at the end of the test year adjusted for known and measurable adjustments beyond the test year. Essentially, the historical test year becomes "stale" relative to actual conditions in the Rate Year as the test year is further lagged from the Rate Year. Mathematically, the relationship between the Test Year and the Rate Year is a biased estimate of costs given by the equation (during periods of rising costs):

$$RR_{t} < RR_{t+1}$$

The result of this bias for a utility is to consistently earn rates of return lower than the allowed rate of return (on a weather normalized, test year basis). This is the most likely result of using an historical test year in any form.

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While it is theoretically possible, of course, for regulatory lag to result in a bias for a utility to consistently earn rates of return higher than the allowed return, given the environment in which utilities currently operate as discussed in this paper, that phenomenon is not expected to occur in the foreseeable future. Periodic general rate case filings would provide ample opportunity for regulatory authorities to become aware of such a consistent bias should it come to pass.

EARNINGS ATTRITION

Regulatory lag results in earnings attrition when there is general inflation. Earnings attrition is the deterioration of a utility's actual rate of return on equity below its allowed rate of return on equity that occurs when the relationship between revenues, costs, and rate base used to establish rates (i.e., using a historical test year) have changed by the time rates go into effect. For example, if external factors are driving costs to increase more than revenues, then the rate of return will fall short of the allowed return, even if the utility is operating efficiently. Similarly, when growth in the utility's investment outstrips the rate base used in its test year, the earned rate of return will fall below the allowed return through no fault of the utility's management.

Regulatory lag also results in earnings attrition when the rate of capital additions (infrastructure replacement, growth capital and compliance capital investments) exceeds the annual level depreciation expense because under these conditions rate base grows and will be higher than the rate base level used to set rates. Earnings attrition also results from growth in expenses that depress earnings with fixed rates that cannot reflect cost changes. Attrition may result from both the cost and revenue side of the utility ratemaking process. The concept of attrition is the ultimate reason that regulation must address the issues related to the test year determination.

Since customer usage impacts earnings attrition as well, the low growth or no growth (and in some cases even negative growth) in revenues currently being experienced no longer provides a cushion for mitigating the issue of regulatory lag sufficient to prevent earnings from consistently falling below the allowed level. Additionally, regulatory lag has a more severe impact on efficient utilities than it does on inefficient utilities. This means that utilities that operate efficiently see reduced earnings simply because they have exhausted economically efficient productivity improvements. Less efficient utilities have more opportunities to save costs because of improved productivity and would likely have better earnings than efficient utilities in the face of regulatory lag. This is the opposite of the result that should occur under the regulatory model where efficient utilities should see higher returns for efficiency.

THE PRINCIPLE OF MATCHING COSTS AND REVENUES

An essential element of sound ratemaking is the principle of matching costs and revenues. Under this "matching principle", the utility's customers are charged with the costs of producing the service they receive. Without this principle, current customers would not be paying for the costs they cause the utility to incur. This is particularly important when evaluating costs that are uncontrollable, variable, unpredictable, and recurring. For costs that meet these criteria the test year revenue requirements equation compared to the rate year above may be expressed as follows:

$$RR_{t} \neq RR_{t+1}$$

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As an inequality, there is no matching possible of costs and revenues. The absence of matching results from a test period that cannot be the basis for a reliable forecast of the rate year. In fact, in order to provide for a matching principle, certain costs must be treated separately from the utility's base revenue requirement. These costs, instead of being determined based on a test year, are established based on a formula independent of the test year revenue requirements formula. Although the costs are set under a separate formula, the ultimate recovery of those costs adheres to the matching principle and results in much more efficient cost recovery from the customers who cause those costs. The adoption of separate formulas for recovery of costs is fully consistent with the comprehensive rate case determination of the costs to be incurred in the Rate Year. Thus, the combination of formula based costs and test year determined costs in the rate case preserves the regulatory lag incentive for costs that management can control and costs that are reasonably projected by the historic test period. Properly designed formulas are an essential part of the test year cost determination. Importantly, the use of formulas as part of the revenue requirement determination meets all the tests of just and reasonable rates and providing the utility an opportunity to earn its allowed rate of return. The principle of matching costs and revenues in the rate year occurs only when historic test years are coupled with full tracking RAMs for costs such as fuel and purchased power which cannot be reasonably projected based on the results in a historic test period.

It is also important to note that the failure to match costs and revenues does not meet policy goals such as rate efficiency and the creation of appropriate price signals. Absent tools to mitigate cost mismatches between the test year and the rate year, both investors and customers are impacted negatively. The ultimate result from a continued mismatch of costs and revenues is either higher bills for customers in the near-term when revenues exceed costs, or higher bills for customers in the long-term when revenues are less than costs. The first result is obvious because when a utility over earns, it is the customer who has paid more than necessary. The second result is less obvious but nevertheless is a real outcome. Higher bills result over time as the utility's cost of capital rises and as the utility chases revenues through more frequent and administratively costly rate cases. Failure to match costs and revenues may also have the effect of signaling customers to use more utility service because bills are lower than the actual cost to provide the service. To the extent that better price signals provide customers with the proper information to make better energy choices, the economy is more efficient. The second outcome of matching costs and revenues is the lower long-run cost of service for all classes of customers through lower financing costs for the utility.

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The Role of Adjustment Clauses in Utility Regulation

Adjustment clauses represent an important ratemaking practice to provide a utility with the proper matching of costs and revenues consistent with the regulatory principle discussed above. The typical adjustment clause is approved by the regulator so that changes in the costs specified by regulation are reflected in rates as either increases or decreases to the price paid by customers. As such, the adjustment clause becomes part of each rate schedule applicable to the classes of service. The adjustment clause, as a form of formula rate, remains an integral part of the test year revenue requirements determination. However, the adjustment clause allows for an explicit rate adjustment outside of a general rate case in response to a change in the particular cost element for which the adjustment clause is designed.

Returning to the basic revenue requirements formula above, it may be modified as follows for the existence of an adjustment clause (the fuel adjustment clause is used as an example):

$$RR_t = O_t - FC_t + M_t + D_t + T_t + (GP_t - AD_t + ORB_t) * ROR_t$$

Where:

FC_t is the cost of fuel to be removed and recovered through a fuel adjustment clause – which is the most common form of adjustment clause. In this example, the fuel adjustment clause is a separate element of each rate schedule that is comprehensive in that it fully recovers 100% of the prudently incurred costs of providing energy (commodity) to customers and none of those costs are included in base rates. The result is that the cost recovery in the Rate Year is defined as follows:

$$R_{t+1} = RR_t + FC_{t+1}$$

Where:

R_{t+1} is the revenue in the Rate Year and FC_{t+1} is the actual fuel cost incurred by the utility in the Rate Year. The formula for calculating the fuel adjustment clause above is defined in a manner consistent with the costs removed from the operating expense in establishing base rates. For example, the formula for FC_{t+1} might be as simple as referencing the specific accounts to be used in the calculation such as the sum of accounts 501-Fuel, 547-Fuel and 555-Purchased Power Expense. Typically, a fuel adjustment clause is much more comprehensive than the simple version and includes a variety of other variable costs associated with the production of energy. Each fuel clause is likely to be different based on the volatility of costs associated with power production or other operating considerations such as being a member of a regional power coordinating group. The key component is that the formula for the fuel clause matches the costs removed from the test year revenue requirements and provides for full recovery of all prudently incurred costs for the rate year. Absent the full recovery of these prudently incurred expenses, the utility's rates could not be considered just and reasonable under the regulatory standard of full recovery of prudently incurred costs.

FUEL ADJUSTMENT CLAUSES

The provisions for recovery of a utility's fuel costs are defined in detail either specifically for the utility or broadly for all jurisdictional utilities through a standard regulatory rule. For example, the FERC uses a rule codified as 18 CFR 35.14 - Fuel cost and purchased economic power adjustment clauses. This rule specifies the costs to be recovered and the formula to be used to in determining the

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fuel adjustment. Exhibit 1 provides a copy of the FERC Rule, a Kentucky Public Service Commission rule and several sample adjustment clauses related to fuel and purchased power as well as other types of adjustments. It is important to recognize that in a mixed monopoly/competition model, the fuel adjustment clause must be redesigned as part of the utility's unbundled rate structure. The redesign of the fuel adjustment clause is discussed below.

The first step in developing a modern fuel adjustment clause is to remove all fuel and related costs from the utility's base rates. Fuel costs include fuel, fuel transportation and handling, purchased power, carrying costs on deferred balances; uncollectible fuel cost recovery, variable generating costs such as environmental chemicals, transmission costs and, so forth. Removing the fuel costs from base rates results in more efficient rates for customers by signaling customers when the cost of fuel and purchased power changes, and by allowing for a more accurate reflection of seasonal and Time-of-Use (TOU) cost differences. By removing all fuel costs from base rates, the fuel clause tracks cost causation more accurately by customer voltage level of service, by season and, where appropriate, by on-peak and off-peak periods. The resulting cost-based price signals promote economic efficiency. The customer's bill is now properly unbundled because all of the variable production costs are reflected in the separate fuel rate. This gives the customer the ability to clearly understand how the utility's costs of power change by season and by the times when power is used – as well as when the changing market conditions affect the cost of fuel and purchased power.

Finally, placing all such costs into the fuel clause permits easier review by the utility, regulatory, and other interested parties. The resulting change means that the utility will be able to recover its fuel costs on a more accurate and timely basis throughout the year and to adjust the seasonal charges when significant fuel cost or market changes occur.

The second step in modernizing the fuel adjustment clause is to determine if costs vary by season or time of use and, if so, to which classes such variations should apply. When costs differ significantly from one season to another during the year, it is appropriate to reflect those differences for all customer classes since there is no need to change meters to bill seasonally differentiated costs. This is referred to in utility ratemaking as the "seasonal differential." The seasonal differential recognizes that system operating conditions and, therefore, marginal costs may differ in a predictable pattern that needs to be reflected in rates to improve efficiency and economic price signals. There are a number of reasons for cost differences to arise based on seasons of the year.

The appropriate costs to analyze are marginal costs – costs affected by changing demand ("Megawatts" or "MW") and energy ("Megawatt hours" or "MWH"). By contrast, average embedded costs do not change with changes in load, and are sunk costs by definition. The existence of seasonal cost differences is most often driven by the utility's mix of fuels used to produce energy to meet the peak demands of the system, as well as the intensity of those peak demands. In addition, as load on the system increases, the marginal costs for a given generation unit also change based on the heat rate curve of the unit. The heat rate curve shows the relationship between the fuel input per unit of rated-load and the output per unit of rated-load. The heat rate curve can show when and if changes in marginal costs are significant. Where the maximum demand on capacity of the system differs significantly from one month to another, there may also be seasonal capacity cost differentials. But one must recognize that demand on the system also includes scheduled outages, unit de-ratings and unit forced outages – in addition to customer load. These other factors generally represent a smaller

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total impact than load, but must also be considered in evaluating seasonal differentials related to a capacity cost component.

The practical requirements of utility systems associated with the other demands on capacity cause a leveling of the total system demands. For example, a system may be winter peaking for load, but summer peaking for reliability, because of lower capacity ratings of generators in the summer. High load factor systems may find that the total demand on capacity resources is the same year round because of the need to schedule plant maintenance in the spring and fall. By analyzing the cost patterns, it is possible to determine if seasonal and TOU rates provide better price signals and if the magnitude of the price differentials warrant reflection in rates.

Most utilities are members of a wholesale market ("Market") and, therefore, the marginal cost is not driven solely by the resources of the utility. This occurs because the utility operates to minimize the cost of power delivered to customers. The utility will purchase power from the Market at times when power from the Market is less expensive than that from running its own generation resources. In this case, marginal cost for the utility in any hour depends not only on its own generation but on generation in the interconnected Market. Essentially, utility marginal cost is based on the lower of its own marginal costs or the Market's marginal cost. The net result is that the analysis of marginal cost for a utility depends on much more than the utility system and is impacted by factors such as unit availability and transmission loading for a much larger and more diverse set of generation resources than owned by the utility. All of these characteristics are best reflected in an unbundled fuel adjustment clause. The unbundled fuel adjustment clause is also a key element in promoting conservation, DSM and DG.

Finally, the rationale for a fuel adjustment clause is not merely about the volatility of input prices such as the cost of coal or natural gas; it is about the volatility of the total costs of fuel and level of sales that make the unit cost of fuel volatile. For example, weather may impact the cost and sales and significantly change the unit costs of fuel because of the changes resulting from plants operating at different points on the heat rate curve, from different fuel mix or from different levels and prices for off-system sales. The end result is a different cost per kWh than would have been calculated on a weather normalized test year basis.

OTHER TYPES OF ADJUSTMENT CLAUSES

While fuel cost adjustment clauses are the most common type of adjustment clause in the utility industry, there are other adjustment clauses designed to match costs and revenues during the rate year for costs that are volatile, unpredictable or highly uncertain and beyond the reasonable control of the utility management.

Each type of adjustment clause is based on a formula approved either in a rate case or a separate proceeding for establishing cost recovery independent of current rate levels. Adjustment clauses take one of two general forms: (1) a comprehensive adjustment clause designed to separately recover all of the costs subject to the clause (none of which are included in base rates) as shown in the equation above for the full tracking fuel adjustment clause; or (2) an adjustment clause may be an incremental adjustment clause recovering (or returning as the case may be) changes from cost levels included in base rates as given by the following equation:

$$RR_t = XFO\ t + BFC_t + M_t + D_t + T_t + (GP_t - AD_t + ORB_t) * ROR_t$$

Where:

XFO_t is the operating cost in the test year (less the base fuel costs in the test year) and BFC_t is the base fuel cost established in the test year. The revenue recovery in the rate year is given by the following equation:

$$R_{t+1} = RR_t - (BFC_t - FC_{t+1})$$

Each of these formulas is based on the assumption of a perfect match in costs and revenues for the fuel adjustment clause for illustrative purposes. Practically, there would also be a reconciliation account for fuel costs to ensure that costs and revenues match over time based on the actual results.

Adjustment clauses are designed to allow the utility to adjust its rates to recover in a timely fashion cost changes for significant expense items or for items where the utility has little or no control over the costs. The adjustment clause seeks to mitigate the impact of volatile or uncertain costs that are otherwise prudently incurred on the utility's ability to earn its allowed rate of return. Essentially, an adjustment clause should match costs dollar for dollar in the rate year so as to avoid either windfall gains or losses in the return component of the utility's revenue requirement. The end result of a properly designed adjustment clause is to have rates that more closely match the rate year cost of service. A key point in reviewing the concept of an adjustment clause is that the utility does not earn any more or less as a result of the operation of the adjustment clause. The utility only has an opportunity to earn its allowed rate of return consistent with prudent management of the costs that it must incur to serve customers in the rate year.

To emphasize, the use of adjustment clauses is an important and significant practice in providing the utility with a reasonable opportunity to earn its allowed rate of return by allowing timely recovery of prudently incurred costs. Without the existence of adjustment clauses, utilities would be faced with more volatile earnings based on factors beyond management's control. The regulatory lag issue creates an unreasonable barrier to earning the allowed rate of return. This earnings volatility impacts not only shareholders but also all customer classes. When cost recovery is inadequate, the utility's cost of capital increases. Higher borrowing and equity costs have a large impact on customers because of the capital intensity of the utility industry. As a general proposition, customers are always better off if regulators mitigate earnings volatility rather than to leave earnings volatility unmitigated and fairly compensate the utility for that volatility. The reason is simple. When revenues and earnings are volatile, utilities adjust the costs they can control (including the elimination of discretionary capital expenditures from which customers would otherwise benefit) to minimize that volatility. These adjustments could impact reliability, service quality and the financial flexibility of the utility. Importantly, providing a reasonable opportunity to earn the allowed rate of return on an annual basis will result in lower long-run costs for customers as the result of lower capital costs and the administering of less frequent rate cases. Proper recognition of the lower costs as it relates to the equity return in modern utility regulation only requires that the comparable companies operate under a RAM similar to that of the utility requesting the adjustment.[3]

As noted above, there are different types of adjustment clauses approved for utilities in the U.S. Figure 3 below provides a partial list of these adjustment clauses. As the list indicates, there are numerous adjustment clauses in use for different utilities based on the circumstances each utility faces and the ability of the rate case process to address timely cost and revenue matching for specific identifiable costs subject to review and periodic true-up. As a practical matter, the variety of adjustment clauses recognizes the importance of a proper understanding of the components of the utility revenue requirement formula and the ability of those cost components to provide a reasonable estimate of the actual rate year cost of service. Each adjustment clause reflects either full tracking of costs not otherwise included in the utility's base rates or smaller incremental adjustments for cost elements that cannot be reasonably determined using historic period data as the basis for a future period estimate of costs.

Figure 3 Types of Adjustment Clauses Approved for Utilities in the U.S.

ADJUSTMENT CLAUSE DESCRIPTION	
Fuel and Purchased Power	Vegetation Management
Infrastructure Cost	Revenue Decoupling
Transmission Cost	Smart Grid/AMI Costs
Environmental Cost	Property Taxes
Renewable Energy Cost	Pension/OPEB Costs
DSM/EE Cost	Bad Debt/Uncollectible Expense
Annual Cost of Capital	Weather Normalization
Nuclear Construction Cost	Bill Stabilization
Transmission Costs for ISO/RTO Charges	Construction Work in Progress (CWIP)

The large number of different adjustment clauses reflects a trend both legislatively and in regulatory proceedings to acknowledge that numerous changes occurring in the utility business environment l have significant, uncontrollable and unpredictable impacts on the utility. These impacts, if left un-addressed, can have negative financial consequences for utilities and long-run implications for higher cost and a decrease in the quality of utility service. Infrastructure cost adjustment clauses represent a good example of the trend. For many of the growth years of the utility industry, the issue of replacing (including retrofits of) infrastructure was far less of an issue for two reasons. First, there was not a great amount of infrastructure that needed to be replaced and when replacement was required, it usually was part of the business solution for serving the utility's growing customer base. The replacement also generated revenue from this customer growth to help pay for the replacement

[3] As a practical matter, for a fuel adjustment clause there is a virtual certainty that comparable companies will have an FAC or the equivalent so the market return will already be adjusted to reflect the lower capital costs associated with and FAC.

assets. The second reason is that the replacement typically reduced costs because it was a better technology and provided services more efficiently.

Today, the electric utility industry's low or no growth in customers and load generate little or no additional revenues to support replacement. Even though the replacement may be more efficient, the costs savings cannot come close to paying for the assets because of the substantial impacts of inflation on capital costs for the new assets. A significant portion of many utility systems have reached a point where replacement is the only option for maintaining a safe and reliable system. In addition, there are far more external influences that impact replacement costs. These may include environmental issues, government policy issues at all levels of government, and regulatory or other government mandates.

The widespread acceptance of adjustment clauses has resulted from one of several specific utility requirements. These requirements include the costs incurred by the utility to:

- Meet government mandates;
- Respond to exogenous factors such as changing accounting standards or NERC standards;
- Accommodate the changing market model by changing the distribution system from a pure energy delivery to a delivery and generation interface; and
- Implement revenue or margin decoupling approaches to make the utility indifferent to load growth or conservation, to stabilize earnings, or to reflect changes in revenue requirements through a pre-established formula.

Some adjustment clauses have been in effect for select utilities for many years as part of the particular jurisdictional regulatory model. Other adjustment clauses have a more recent history as utilities are transitioning to different business and regulatory models.

With the growing number of adjustment clauses, an important question relates to the standard of regulatory review for adjustment clauses. In other words, how should parties review the results of the utility's application of an adjustment clause? First, it must be recognized that an essential purpose of all adjustment clauses is to match costs and revenues in a timely manner so that the utility has a genuine opportunity to earn its allowed rate of return. The matching principle is an important concept because it often is more important than the nature of the costs themselves that are to be matched with revenues. The infrastructure cost adjustment clause discussed above is not as much about volatile or uncertain costs as it is about a systematic process of permitting cost recovery for a class of investments that would not be matched over time in the traditional rate case process. This traditional process would discourage the utility from systematically renewing its infrastructure as its financial condition between rate cases would deteriorate. The most significant rationale for any adjustment clause is found in the matching principle that leads to timely cost recovery and a reasonable opportunity to earn the allowed rate of return.

The second consideration that supports the concept of an adjustment clause is the good faith business intentions on the part of utility management that must be presumed by the regulator. The precedent for this is found in basic ratemaking where it is not the purpose of regulation to manage the utility. Utility management has an obligation to act prudently in running the business, incurring costs, and in

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managing the timing of those costs. Utilities go to great lengths to analyze their decisions in a way that demonstrate well-conceived, supportable, and reasonable approaches to the business.

The third consideration relates to prudence upon review of these decisions. Any party should be free to raise the issue of prudence upon a showing calling prudence into doubt relative to the costs recovered by the utility through its adjustment clause. Prudence standards are an important part of the review process related to the timely matching of costs and revenues since imprudent costs should not be included in recovery, and should be promptly refunded to customers through rates if there is a final determination of imprudence.

For the prudence standard to be meaningfully applied, the fourth consideration should be regulatory and public oversight of the utility's actions on a regular and timely basis. This implies that the utility, under the terms of the adjustment clause, should file regular reports with the regulator for review that presents operating results of the adjustment clause. In some cases, these reports are required on a monthly or quarterly basis. The reports are also typically subject to periodic audit by regulatory staff. Audit reports are typically available for review by any interested party. As needed, the operation of the adjustment clause may also be subject to a public hearing process.

The fifth consideration is designed to minimize the potential for dispute among parties about cost recovery. Adjustment clauses should be free from conflict over their interpretation. This requires either a clear and comprehensive regulatory rule or an agreed upon definition of the terms and conditions under which the adjustment clause will operate as part of the utility's tariff. The clause should delineate the costs to be recovered under the adjustment clause with clear definitions for each type of cost to be included. The adjustment clause should be subject to periodic review to make sure that changing market circumstances have not changed the definition of costs to be included in the adjustment clause.

As suggested above, the final consideration for an adjustment clause requires the filing of detailed and auditable cost and revenue reports. The use of full tracking adjustment clauses makes the detailed reporting of costs and revenues associated with the clause more transparent for the audit. The required information for filing should be specified in a regulatory rule or in the applicable tariff for the adjustment clause. This type of detail is typically specified in a regulatory rule since it would apply to multiple utilities within a particular jurisdiction. The regulatory rulemaking may also be required to address a legislative mandate that gave rise to the need for the adjustment clause.

Application of these six principles provides the necessary regulatory oversight and gives credibility to the costs and revenues recovered under the clause. The participation of parties assures that the results of application of the matching principle assure that there is a dollar for dollar matching and that there are no excess cost recoveries to the detriment of the customers.

Utility Ratemaking Practices in Other States

The discussion above identified the trends in the use of adjustment clauses by regulators and utilities in the U.S. There are many different types of regulatory policies and locational circumstances across the states relative to the use of adjustment clauses. At the core of adjustment clauses is the need to match costs and revenues under the prevailing regulatory model and the state of regulatory reform within the particular state.

With respect to the use of fuel adjustment clauses (including purchased power), every state in the U.S. where the utility generates some of its own power requirements has some form of a fuel adjustment clause. There is at least one state where the only regulated electric utility has no generation and, therefore, has only a purchased power adjustment clause. There are also a number of states where competitive markets have been established. In those markets the utility typically has a standard offer service (SOS) or provider of last resort obligation (POLR). In these markets, there is no longer any type of fuel adjustment clause, but the matching principle for the energy costs incurred by the utility to provide SOS or POLR operates on the same principle as a fully tracking, unbundled adjustment clause.

Based on Black & Veatch's review of states where energy deregulation has not been implemented, every utility in these states has some form of fuel adjustment clause except for KCP&L and one other utility in a jurisdiction that is a predominately hydroelectric based generation utility (Washington). States where energy deregulation has been implemented have an adjustment clause that recovers the costs of SOS and POLR. In addition, fuel adjustment clauses are common for non-regulated municipal and cooperative utilities as a means of recovering their fuel and purchased power costs. This also includes some electric cooperatives in the state of Missouri that have power cost adjustment clauses. Schedule 1 provides a listing of each state regulatory commission that permits recovery of a utility's fuel and purchased power costs through the operation of a fuel adjustment clause.

In addition to fuel adjustment clauses, numerous utilities across the U.S. have other types of adjustment clauses in operation. Schedule 2 provides a listing of other adjustment clauses approved by state regulatory commissions. Most regulators allow recovery of environmental-related costs in adjustment clauses. These adjustment clauses differ in that some costs may also be included in the fuel adjustment clause while other costs (including capital costs) are recovered in a separate adjustment clause. About half of the states have some type of infrastructure cost adjustment clause. Some are limited to a specific type of asset such as smart grid/AMI, while others may reflect costs associated with specific plant additions. Some adjustment clauses relate to specific assets classes such as transmission facilities or assets approved for construction by a pre-approved capital investment plan. These adjustment clauses and tracker mechanisms operate in the same manner as the fuel adjustment clause in most cases. The changes in costs, either up or down, are passed through to customers in the Rate Year, or are subject to reconciliation and true-up.

It is also common to find a variety of tax related adjustment clauses. In these adjustment clauses, utilities are able to recover various types of taxes and fees including franchise taxes. Property tax recovery is also a common tax that is recovered under tax adjustment clauses. Full revenue

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decoupling adjustments are less common than the other types of adjustment clauses.[4] Other states have different regulatory models related to recovering changes in costs from year to year to provide the utility with a reasonable opportunity to earn its allowed rate of return. Examples of this type of program include Rate Stabilization and Equalization (RSE) in Alabama that changes rates annually based on changes in annual costs under a formulaic approach whenever the utility's earned return falls outside of a dead band related to the allowed rate of return. Vermont has an Alternative Regulation Plan (ARP) that allows rates to change annually subject to a base rate price cap and specifically includes adjustments outside the cap for large capital projects, exogenous cost changes and an adjustment to the Return on Equity based on a formula. The Vermont ARP has features of both revenue decoupling and multi-year rate plans.

For transmission cost recovery, nearly half the states have adjustment clauses to recover the costs associated with participation in a Regional Transmission Organization (RTO) or an Independent System Operator (ISO). Transmission cost adjustment clauses have become a recent trend in utility rates based on the FERC approval of RTO/ISO operations in states that are not restructured into competitive retail markets. For states with competitive retail markets, SOS costs are fully recovered by the utility providing the service. These rates are based on nodal pricing and include the transmission costs in rates. For each of these states, a transmission cost recovery adjustment clause is not required. In addition, in jurisdictions where the local utility is its own Balancing Authority (i.e., not a member of an RTO/ISO), transmission costs are allocated between the Open Access Transmission Tariff (OATT) and retail customers on a jurisdictional basis and recovered fully in the utility's base rates. The states that permit transmission cost recovery through an adjustment clause represent most of the remaining states where utilities provide bundled services with an RTO/ISO to coordinate and facilitate a formal wholesale market for power.

Under the terms of these markets, many utilities have formula rates that change annually under FERC regulation and the RTO/ISO charges are also subject to FERC jurisdiction. These costs are essentially all pass-through cost items that are beyond the control of the utility. The costs are also deemed to be prudently incurred because they represent the FERC approved rates for the services provided. These organized markets also have impacts that relate directly to the fuel adjustment clause as well. The markets change both the physical operation of member utilities generation fleet and the marginal cost for the utilities energy requirements. Both of these factors impact the fuel adjustment clause.

Although Black & Veatch has not attempted to identify all of the types of adjustment clauses that are currently in operation in the U.S., it is obvious that adjustment clauses have become an important ratemaking practice for regulators to adopt to provide the utility with a reasonable opportunity to earn its allowed rate of return. A growing number of regulatory and legislative bodies have recognized the need to modernize the regulatory and ratemaking process to accommodate a dynamic and changing business environment. These adjustment clauses are valuable tools to ensure a well-balanced regulatory compact that align the interests of the utility's customers and shareholders.

[4] There are other states where partial revenue decoupling adjustment clauses have been approved (e.g., designed to recover lost revenues related to the utility's DSM/EE programs).

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Conclusions and Recommendations

This report has discussed the ratemaking formula used to establish a utility's rates and the concepts of regulatory lag and earnings attrition. As noted previously, the policy of using regulatory lag as an incentive for improved performance by a utility is not a sound regulatory policy since it serves as a blunt tool that effectively punishes all utilities whether or not they are operated efficiently. Since regulation should be structured to provide the right incentives to utilities to manage their businesses in a responsible manner, it is critically important to recognize when the prevailing ratemaking practices detract from this primary objective.

While the traditional ratemaking practices of the past have served the utility industry and customers well, they have fallen short in more recent times to provide the desired balance between a utility's customers and shareholders that is a foundational concept under the regulatory compact. In today's energy marketplace, the ability to recover costs and earn a reasonable rate of return on investment often pits the interests of utility shareholders directly against the interests of consumers who are impacted by increased rates. It is the responsibility of state regulators to balance these competing needs. Yet, some regulators continue to move cautiously on cost recovery and rate requests by utilities as a result of challenging economic conditions that still linger in some parts of the U.S. This cautious approach by regulators often conflicts with an industry that recognizes the need to operate efficiently and reliably by investing in new and retrofitted infrastructure. Despite the wider acceptance of regulatory practices that streamline the ratemaking process – as evidenced by the increased use of capital-based adjustment mechanisms – some industry observers still believe that the utilities' interests are favored much less by the regulator than those of the consumer.

This perspective is evidenced in the deteriorating financial health of some utilities that do not have the modernized ratemaking practices described earlier that are designed to address regulatory lag and earnings attrition while enabling utilities to invest wisely in assets which will provide customers with safe, reliable, and cost-effective service, and the new energy choices they desire.

Black & Veatch believes there are a number of ratemaking practices that should be considered for adoption by KCP&L's regulators to restore the balance in the regulatory compact for KCP&L. Specifically, it has become essential that KCP&L should be granted regulatory approval to implement a comprehensive fuel adjustment clause that includes all of the costs for fuel, purchased power, the net effect of off-system sales, and SPP transmission costs associated with power delivery. This adjustment clause should also include the costs of chemicals and other variable costs to meet emission requirements, the cost of any other variable costs of generation, and any charges resulting from SPP for KCP&L's market participation. Ideally, all fuel costs would be recovered in the resulting fuel adjustment charges and removed from KCP&L's base rates so that customers will actually know what portion of their electric bills are for recovery of energy-related costs.

The type of fuel adjustment clause recommended for KCP&L will benefit both its customers and shareholders by assuring that there is a dollar-for-dollar matching of costs and revenues during the Rate Effective Period associated with its current rate case, and during subsequent annual periods. The adoption of a comprehensive fuel adjustment clause together with other ratemaking practices we recommend will reduce, but not eliminate regulatory lag, improve KCP&L's opportunity to earn its

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allowed rate of return, protect customers from paying higher than actual fuel costs and result in lower long-run costs for its customers. Symmetry in treatment of cost changes either increases or decreases is an important element of a sound RAM or tracker.

In addition to the fuel adjustment clause just described, KCP&L should identify other expenses included in the determination of its revenue requirement that should also be subject to recovery through other adjustment clauses. Besides its fuel adjustment clause (FAC) proposal, KCP&L has identified three other types of potential adjustment mechanisms[5] for which it seeks regulatory approval in its current rate case. Each of the proposed "trackers" is designed to match costs and revenues during the rate year for particular cost elements through a pre-approved deferral accounting process. Trackers represent another ratemaking alternative for matching costs and revenues for earnings purposes, while allowing for the utility's eventual recovery of prudently incurred costs through their amortization in a future rate case. However, unlike an adjustment clause, a tracker as defined by KCP&L makes no adjustment to the utility's actual rates. Instead, it is an accounting mechanism which sets a "baseline" expense level in the utility's current rate case and then "tracks" the difference between the actual expenses incurred by the utility over time (for that cost element) and the baseline amount as a deferred regulatory asset or liability for future recovery or customer credits.[6] The regulatory asset created by the tracker is then considered for recovery in the utility's next general rate case through a multi-year amortization process.

The trackers proposed by KCP&L include: a Property Tax Tracker, a Vegetation Management Tracker, and a Critical Infrastructure and Cyber Security Tracker. Individually and collectively, these ratemaking proposals are consistent with the kinds of adjustment clauses that are being adopted by regulators in other parts of the U.S. to provide for cost matching and to permit utilities to have a reasonable opportunity to earn their allowed rates of return. The difference between KCP&L's proposed tracker concept and an adjustment clause is there is no longer a real time matching of the utility's costs and revenues. Rather, as just described, the deferred accounting treatment creates a regulatory asset or liability over time for later inclusion in rates after a full review and hearing as to the deferred account amounts. As such, KCP&L's tracker concept which ensures that it has an opportunity to fully recover its costs while protecting customers from paying higher than actual costs should be viewed as a very modest change to the way utility rates are traditionally set in Missouri relative to the manner in which an adjustment clause operates.

As noted above, property tax adjustment clauses are in operation in twenty-one (21) states. As with the other adjustment clauses discussed above, there are other regulatory models that permit the utility to adjust rates that would include these costs in the periodic rate adjustments (e.g., RSE in Alabama, attrition adjustments in California, and ARP in Vermont). Thus, even though there is no specific adjustment clause for this cost element in these states, the basic regulatory policy is such that

[5] In its current rate case filing, KCP&L uses the term "tracker" (as distinguished from an adjustment clause) to represent the deferred accounting treatment and eventual rate case recovery of particular expenses that have been approved by the Missouri Public Service Commission for utilities under its jurisdiction. Under this definition, a tracker is distinct from an adjustment clause because rates do not change as costs increase or decrease under a tracker. Rather KCP&L is permitted to defer changes in costs for review and recovery in a subsequent rate case.

[6] Including carrying costs accrued on the deferral account balance.

a matching of costs and revenues is achieved. That type of cost treatment is generally consistent with KCP&L's tracker proposals.

The matching principle is also recognized in the design of the other two trackers proposed by KCP&L. Indeed, for the particular ratemaking mechanism to be efficient, it must accurately match costs dollar-for-dollar subject to subsequent regulatory audit and prudence review. For KCP&L's tracker proposals, that review would occur in the utility's next rate case and would result in the amortization of the approved level of prudently incurred costs through future rates.

The basic point related to adjustment clauses is that some clauses like the fuel adjustment clause have near universal applicability while other clauses have cost elements that are unique to the requesting utility and its operating jurisdiction(s). The conceptual and economic support for adequate cost and revenue matching is compelling. This matching only occurs when the regulatory lag created by the preference for a particular test year (i.e., an historical test year) is minimized and adjustment clauses and trackers are available to track the most volatile components of a utility's costs - the costs that utility management cannot control or costs that cannot be predicted adequately by reference to historic trends.

The combination of utilizing future test years and the responsible application of adjustment clauses and trackers form the basis for modernizing the utility ratemaking process to best accommodate the challenges of a fast changing energy marketplace. The regulatory balance restored through such changes will once again provide KCP&L with a reasonable opportunity to achieve its Commission-allowed return as well as the financial performance expected by its shareholders and to provide customers with safe, reliable, and cost-effective utility service in the years ahead.

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Schedules

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SCHEDULE 1
Fuel Adjustment Clauses for Electric Utilities by State

STATE REGULATORY COMMISSION	FUEL ADJUSTMENT CLAUSE	RECOVERY OF PURCHASED POWER EXPENSE
Alabama	Yes	Yes
Alaska	Yes	Yes
Arizona	Yes	Yes
Arkansas	Yes	Yes
California	Yes	Yes
Colorado	Yes	Yes
Connecticut	(1)	
Delaware	(1)	
District of Columbia	(1)	
Florida	Yes	Yes
Georgia	Yes	Yes
Hawaii	Yes	Yes
Idaho	Yes	Yes
Illinois	Yes (2)	Yes
Indiana	Yes	Yes
Iowa	Yes	Yes
Kansas	Yes	Yes
Kentucky	Yes	Yes
Louisiana (PSC)	Yes	Yes
Louisiana (New Orleans)	Yes	Yes
Maine	(1)	
Maryland	(1)	
Massachusetts	(1)	
Michigan	Yes	Yes
Minnesota	Yes	Yes
Mississippi	Yes	Yes
Missouri	Yes	Yes
Montana	Yes	Yes
Nebraska	No electric utility regulation	Yes
Nevada	Yes	Yes
New Hampshire	(1)	
New Jersey	(1)	
New Mexico	Yes	Yes
New York	(1)	
North Carolina	Yes	Yes

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STATE REGULATORY COMMISSION	FUEL ADJUSTMENT CLAUSE	RECOVERY OF PURCHASED POWER EXPENSE
North Dakota	Yes	Yes
Ohio	(1)	
Oklahoma	Yes	Yes
Oregon	Yes	Yes
Pennsylvania	(1)	
Rhode Island	(1)	
South Carolina	Yes	Yes
South Dakota	Yes	Yes
Tennessee	Yes	Yes
Texas	Yes (2)	Yes
Utah	Yes	Yes
Vermont	Yes	Yes
Virginia	Yes	Yes
Washington	Yes	Yes
West Virginia	Yes	Yes
Wisconsin	Yes	Yes
Wyoming	Yes	Yes

Footnotes:
(1) State with restructured utilities that recover these costs through default utility services
(2) State with a mixture of competitive and default utility services

Source:
SNL/RRA State Profile Data

SCHEDULE 2
Other Adjustment Clauses for Electric Utilities by State

STATE REGULATORY COMMISSION	RECOVERY OF ENVIRONMENTAL COSTS	RECOVERY OF INFRASTRUCTURE COSTS	RECOVERY OF TAX EXPENSE	RECOVERY OF TRANSMISSION EXPENSE	REVENUE DECOUPLING
Alabama	Yes	Yes	Yes	No	No
Alaska	No	No	No	No	No
Arizona	Yes	No	Yes	Yes	Yes
Arkansas	Yes	Yes	Yes	Yes	Yes
California	Yes	No	No	No	Yes
Colorado	Yes	Yes	No	No	Yes
Connecticut	No	No	No	Yes	Yes
Delaware	No	No	No	No	No
District of Columbia	No	Yes	No	No	No
Florida	No	Yes	Yes	No	No
Georgia	Yes	Yes	No	No	No
Hawaii	No	Yes	No	No	Yes
Idaho	No	No	No	No	Yes
Illinois	Yes	No	Yes	Yes	No
Indiana	Yes	No	No	Yes	No
Iowa	Yes	No	Yes	Yes	No
Kansas	Yes	No	Yes	Yes	No
Kentucky	Yes	No	Yes	No	No
Louisiana (PSC)	Yes	No	No	No	No
Louisiana (New Orleans)	Yes	No	No	No	No
Maine	Yes	No	No	No	No
Maryland	Yes	Yes	Yes	No	No
Massachusetts	Yes	Yes	No	Yes	Yes
Michigan	Yes	Yes	No	Yes	No
Minnesota	Yes	No	No	Yes	No
Mississippi	Yes	Yes	No	No	No
Missouri	Yes	No	Yes	No	No
Montana	Yes	No	Yes	No	No
Nevada	Yes	No	No	No	No
New Hampshire	Yes	No	No	Yes	No
New Jersey	Yes	No	Yes	No	No
New Mexico	Yes	No	Yes	No	No
New York	Yes	No	No	No	Yes
North Carolina	Yes	No	No	No	No

STATE REGULATORY COMMISSION	RECOVERY OF ENVIRONMENTAL COSTS	RECOVERY OF INFRASTRUCTURE COSTS	RECOVERY OF TAX EXPENSE	RECOVERY OF TRANSMISSION EXPENSE	REVENUE DECOUPLING
North Dakota	Yes	Yes	No	No	No
Ohio	Yes	Yes	Yes	No	No
Oklahoma	Yes	Yes	Yes	Yes	No
Oregon	Yes	No	No	No	Yes
Pennsylvania	Yes	Yes	Yes	Yes	No
Rhode Island	Yes	Yes	No	No	Yes
South Carolina	Yes	Yes	No	No	No
South Dakota	Yes	Yes	Yes	Yes	No
Tennessee	No	No	No	No	No
Texas	Yes	Yes	Yes	Yes	No
Utah	Yes	No	No	No	No
Vermont	Yes	No	No	No	No
Virginia	Yes	Yes	Yes	Yes	No
Washington	Yes	No	No	No	Yes
West Virginia	Yes	Yes	Yes	Yes	No
Wisconsin	Yes	Yes	Yes	No	No
Wyoming	Yes	Yes	No	No	No

Source:
SNL/RRA State Profile Data

Exhibits

Exhibit 1 has been intentionally omitted.