COMMERCE DEPARTMENT

April 22, 2020

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

RE: **Supplemental Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. E002/M-19-666

Dear Mr. Seuffert:

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

Xcel Energy's Integrated Distribution Plan (IDP) and Advanced Grid Intelligence and Security Certification Request.

The Department recommends that the Commission **accept Xcel Energy's IDP Report, require annual updates of a subset of IDP requirements, certify the Advanced Planning Tool and refer Xcel Energy's Advanced Grid Intelligence System Initiative certification requests to a contested case hearing**. The Department is available to respond to any questions the Commission may have on this matter.

Sincerely,

/s/ MATTHEW LANDI
Rates Analyst

/s/ TRICIA DEBLEECKERE
Planning Director

ML/TD/ja
Attachment

Before the Minnesota Public Utilities Commission

Supplemental Comments of the Minnesota Department of Commerce Division of Energy Resources

Docket No. E002/M-19-666

I. INTRODUCTION

On November 1, 2019, Northern States Power Company, d/b/a Xcel Energy (Xcel, Xcel Energy, or the Company) filed its 2019 Integrated Distribution Plan (IDP) as required by the Minnesota Public Utility Commission's (Commission) July 16, 2019 Order in Docket No. E002/CI-18-251 (the Order).[1] The Company's 2019 IDP included the Company's certification request of its proposed Advanced Grid Intelligence and Security (AGIS) Initiative and an Advanced Distribution Planning Tool (APT).[2] The AGIS Initiative includes Advanced Metering Infrastructure (AMI), a Field Area Network (FAN), Fault Location and Isolation Service Restoration (FLISR), an Integrated Volt-Var Optimization (IVVO).

The Company anticipates incurring capital expenditures totaling $582 million and operation and maintenance (O&M) costs totaling $152 million for the overall AGIS Initiative (exclusive of Advanced Distribution Management System or ADMS) from 2020-2029.[3] The APT is expected to cost $9.3 million in total, with $4 million attributed to Northern States Power-Minnesota (NSPM), and minimal ongoing costs for the annual software hosting fee and internal maintenance.[4]

On December 31, 2019, the Minnesota Public Utilities Commission (Commission) issued a *Notice of Comment Period* (Notice). The Notice reaffirmed the purpose of the Commission's IDP filing requirements:

- Maintain and enhance the safety, security, reliability, and resilience of the electric grid, at fair and reasonable costs, consistent with the state's energy policies;
- Enable greater customer engagement, empowerment, and options for energy services;
- Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies;
- Ensure optimized utilization of electricity grid assets and resources to minimize total system costs; and
- Provide the Commission with the information necessary to understand the utility's short-term and long-term distribution-system plans, the costs and benefits of the specific investments, and a comprehensive analysis of ratepayer cost and value.

[1] *Order Accepting Report, and Amending Requirements*, dated July 16, 2019, Docket No. E002/CI-18-251.
[2] Xcel 2019 IDP, dated November 1, 2019, Docket No. E002/M-19-666.
[3] IDP, at 153-154.
[4] IDP Executive Summary, at 11-12.

The Commission's Notice included the following topics related to Xcel Energy's 2019 IDP:

1. Should the Commission accept or reject Xcel Energy's Integrated Distribution Plan (IDP)?
2. Does the IDP filed by Xcel Energy achieve the planning objectives in the filing requirements approved in the Commission's July 16, 2019 Order [footnote omitted]?
3. What IDP filing requirements provided the most value to the process and why?
4. Are there filing requirements that are not informative and/or should be deleted or modified, and why?
5. Should the Commission accept Xcel Energy's request to file the next IDP no later than November 1, 2021? Should the Commission move from an annual to biennial IDP filing for the Company going forward?
6. Are there other issues or concerns related to this matter?

The Commission's Notice also included the following topics related to Xcel Energy's certification requests:

7. Should the Commission approve, modify, or deny certification of the following investments which are components of Xcel Energy's Advanced Grid Intelligence and Security (AGIS) Initiative at this time:
    a. Advanced Metering Infrastructure (AMI)
    b. Field Area Network (FAN)
    c. Fault Location, Isolation, and Service Restoration (FLISR)
    d. Integrated Volt-Var Optimization (IVVO)
8. Should the Commission certify the Advanced Distribution Planning Tool (APT) at this time?
9. What, if anything, should the Commission set as conditions or clarify if granting certification of these distribution projects?
10. What should the Commission consider or address related to realizing benefits of each of the investments in the Company's AGIS Initiative for ratepayers?
11. At the stage of certification, what consideration should the Commission give to subsequent cost recovery, via either the Transmission Cost Recovery rider or general rate case, for each of the AGIS investments?
12. Are there any other issues or concerns related to this matter?

On or before March 17, 2020, the following parties—including the Minnesota Department of Commerce, Division of Energy Resources (Department)—submitted Initial Comments in this proceeding:

- The Office of the Attorney General—Residential Utilities Division (OAG);
- The City of Minneapolis;
- Clean Energy Economy Minnesota (CEEM);
- Fresh Energy;
- Citizens Utility Board of Minnesota (CUB);
- Xcel Large Industrials (XLI);
- IPS Solar;
- Interstate Renewable Energy Council, Inc. (IREC); and
- Environmental Law and Policy Center (ELPC) and Vote Solar

On or before April 10, 2020, the following parties—including the Department—submitted reply comments in this proceeding:

- OAG;
- Xcel;
- ELPC and Vote Solar; and
- The Institute for Local Self-Reliance (ILSR).

The Department offers these supplemental comments in response to the initial and reply comments of the above-referenced stakeholders.

II. DEPARTMENT ANALYSIS

A. ANALYSIS OF IDP-RELATED RECOMMENDATIONS

The Department's analysis of other stakeholder recommendations related to Xcel's IDP requirements considers the larger picture of distribution system planning in Minnesota. The Department considers whether recommended modifications: (1) are reasonably likely to result in a benefit for ratepayers and the public interest; and (2) can be reasonably incorporated into other utilities' IDP requirements.

Based on the Department's initial comments and in review of Xcel's reply comments, the Department maintains its position to not support modifications of Xcel's IDP Requirements at this time.

The Department provides additional analysis related to ELPC and Vote Solar's recommendations below.

1. ELPC and Vote Solar Recommendations

ELPC and Vote Solar recommended modification of IDP Requirements 3.E.1 and 3.C.3, and the creation of a new IDP requirement. In addition to these IDP requirement recommendations, ELPC and Vote Solar recommended that the Commission take the following actions:

- Create a separate docket to address Xcel's non-wires alternatives (NWA) analysis and direct Xcel to form a NWA Stakeholder Advisory Group;
- Align the IDP process with the performance metrics framework by requiring Xcel to include a report of Xcel's performance on metrics related to Xcel's distribution system in the next IDP; and
- Compile Xcel's IDP requirements as amended by Commission Orders.

a.) Modification of IDP Requirement 3.E.1

ELPC and Vote Solar recommended modifications of IDP Requirement 3.E.1 that would require Xcel to provide additional granularity in its Non-Wires Alternatives (NWA) analysis to better determine when load relief was necessary, to consider all revenue streams associated with NWAs when comparing them to traditional projects, and to issue an RFP for NWA solutions for projects that involve N-0 risks.[5]

ELPC and Vote Solar explained that providing additional information regarding the hour(s) and day(s) during which an NWA would be called upon to deliver energy and demand would provide stakeholders and third-party developers with the information needed to evaluate Xcel's internally developed NWA solutions and enable third-party developers to propose NWA solutions through a Request for Proposal (RFP) process.[6]

Xcel responded and explained that additional granularity in its forecasting that better indicates when load relief is needed on a feeder by feeder level is a capability it does not have currently, and long-term forecasts generated by the Advanced Planning Tool (APT) will include hourly granularity based on linear regressions correlating historic loading with weather, economic, and customer behavioral trends, but that these forecasts will not be able to predict at which precise hours or on which precise days an NWA would be needed in the future.[7]

Xcel also explained that its internal processes and industry standards for NWA analysis preclude viable third-party solutions at this time, indicating that industry requires additional maturation, including: standardization of communications between and among devices, standardized control platforms across various technology types, and development of cybersecurity protocols before third-party solutions would be viable.[8] Xcel concluded that based on its internal level of process development and the lack of industry standardization, modifying the IDP Requirements to require an RFP for NWA analysis is premature.

[5] ELPC and Vote Solar Initial Comments, dated March 16, 2020, at 11.
[6] ELPC and Vote Solar Initial Comments, at 10.
[7] Xcel Reply Comments, Attachment A, at 34-35.
[8] Xcel Reply Comments, Attachment A, at 35.

Finally, with regard ELPC and Vote Solar's recommendation to require Xcel to consider all revenue streams available when developing NWA cost estimates, Xcel explained that "additional stacked benefits are difficult to quantify for specific applications – and in some cases, lack the means of monetary compensation for assumed benefits."[9]

The Department concludes that Xcel's response, while deficient in several regards, reinforces the Department's earlier position: the Department declines to recommend this modification to IDP Requirement 3.E.1 at this time, as IDP Requirement 3.E.1 currently contains language that could be interpreted to require Xcel to provide the specific information that ELPC and Vote Solar recommend be provided.

The current language of the IDP Requirement 3.E.1 can be reasonably interpreted to induce Xcel to provide that information in its NWA analysis. Further, there is nothing in the record to suggest that without the requested modification to IDP Requirement 3.E.1, Xcel would fail to provide such a discussion in future IDPs or in response to information requests.

The Department agrees that more refined analyses of the granularity of hourly forecasting and the potential benefits of an NWA solution would be helpful and is indeed a necessary component of performing a comprehensive evaluation of an NWA solution. Additionally, the Department agrees that there is likely to be significant merit in requiring Xcel to issue an RFP for NWA solutions at a currently indeterminate point in the future. However, it appears that requiring Xcel to do that now may be premature, given the current state of the industry.

ELPC and Vote Solar recommended that the Commission initiate a new regulatory proceeding to investigate this specific IDP-related issue in more depth.[10] The Department disagrees. Such an investigation could and should occur through the IDP proceedings, so that the Commission and stakeholders have a full and complete record of the development and evolution of Xcel's NWA analysis over time and within the context of distribution planning. This keeps the administrative record intact and the regulatory burden minimal. There also isn't a specific, cognizable basis why a new regulatory proceeding is needed in order to fully elucidate Xcel's NWA analysis and adjudicate these issues at this time.

For those reasons, the Department does not support ELPC and Vote Solar's recommendation to initiate a new regulatory proceeding focused on NWA alternatives, but does endorse the recommendation to require Xcel to create an NWA stakeholder advisory group to inform and enhance the Company's NWA analysis for future IDPs. The Department agrees that an NWA stakeholder advisory group may serve a helpful purpose and provide an opportunity for Xcel to work with stakeholders to improve its NWA analysis, including using more refined cost and benefit estimates and incorporating methodologies, expertise, and experience that other stakeholders and jurisdictions may have. The Department views

[9] Xcel Reply Comments, Attachment A, at 37.
[10] ELPC and Vote Solar Initial Comments, at 2 and 11-12.

NWA analyses as a path forward to potentially defray traditional distribution system capital spending, thereby providing benefits to ratepayers.

The Department recommends that the Commission require Xcel to form an NWA stakeholder advisory group to inform and enhance the Company's NWA analysis for future IDPs. This stakeholder advisory group should convene at least once before Xcel files its next IDP and Xcel should incorporate feedback and expertise from stakeholders and other jurisdictions that have experience with NWA analysis. (Recommendation 8)

b.) Modification of IDP Requirement 3.C.3

ELPC and Vote Solar recommended a modification of IDP Requirement 3.C.3 Distributed Energy Resource (DER) Scenario Analysis related to external control of smart inverters.[11]

ELPC and Vote Solar argued that Xcel's responses to information requests related to the Company's plans for a Distributed Energy Resource Management System (DERMS) did not establish a reasonable basis for its current plans to implement a DERMS in the 2024-2025 timeframe, noting that California does not require a DERMS system despite having higher levels of DER penetration today than Xcel projects to have in the 2024-2025 timeframe.[12]

Xcel provided more discussion of smart inverters in Attachment A of its reply comments, on pages 4 and 5, and again on pages 38 and 39. Xcel did not discuss its current plans for a DERMS in its reply comments, but did address ELPC and Vote Solar's recommended modification to IDP Requirement 3.C.3. Xcel concluded that it was not necessary at this time and suggested that its current IDP Requirements (3.A.7 and 3.A.33) provide an opportunity to discuss smart inverter technology as it relates to mitigating impacts from higher levels of DER integration.[13] Additionally, Xcel stated that it participates in the Electric Power Research Institute (EPRI) Integration of Distributed Energy Resource Program and is monitoring the latest research and industry experience in this area, as well as its own experience with solar gardens. Last, Xcel pledged to provide an update of the latest smart inverter developments and the role that they can play in integrating higher levels of photovoltaic (PV) and other DER on its system.[14]

While it is important to monitor this area in future IDPs and evaluate any proposed utility investments derivative of the issues that ELPC and Vote Solar raise, the Department does not see the need to modify Xcel's IDP requirements at this time. As the Department pointed out in reply comments, the current language of IDP Requirement 3.C.3 could reasonably be interpreted to require Xcel to consider the specific items that ELPC and Vote Solar recommend be considered. Further, there is nothing in the record to suggest that without this modification to IDP Requirement 3.C.3, Xcel would not provide such

[11] ELPC and Vote Solar Initial Comments, at 13.
[12] ELPC and Vote Solar Initial Comments, at 12-13.
[13] Xcel Reply Comments, Attachment A, dated April 10, 2020, at 38.
[14] Xcel Reply Comments, Attachment A, at 39.

a discussion in future IDPs or information requests. The Department affirms its position in reply comments and does not support ELPC and Vote Solar's recommended amendment to IDP Requirement 3.C.3 at this time.

c.) Creation of IDP Requirement 3.F

ELPC and Vote Solar recommended the creation of IDP Requirement 3.F Locational Reliability and Equity:[15]

3.F. Locational Reliability and Equity.

1. Xcel shall provide a map that illustrates the reliability of the Company's distribution system at a feeder-level.
2. Xcel shall describe how its proposed reliability investments will prioritize those portions of its system with poor reliability performance.
3. Xcel shall explain how its proposed reliability investments will advance equity across its service territory.

ELPC and Vote Solar argued that Xcel's description of its Incremental System Investment (ISI) Initiative and its general spending within the Asset Health and Reliability budget grouping does not enable sufficient review of Xcel's plans to target specific portions of its distribution system with poor reliability performance (as described in Xcel's annual service quality report filings[16]) such that stakeholders are unable to determine whether Xcel's proposed spending is reasonably tailored to address poor reliability performance.[17]

Xcel's reply comments did not address ELPC and Vote Solar's concerns regarding the transparency of Xcel's distribution spending plans related to the ISI Initiative and Asset Health and Reliability.

Xcel did, however, address the merits of ELPC and Vote Solar's recommendation for creating IDP Requirement 3.F. Xcel argued that it wasn't necessary or appropriate at this time, as the locational reliability and equity reporting requirements are topics that are being addressed in the Company's annual electric service quality report proceeding.[18] Additionally, Xcel noted that its electric service quality annual reports provide information on locational reliability, and Commission Staff proposed a map with feeder-level reliability detail and requested specific data points by feeder for all sustained outages.[19]

[15] ELPC and Vote Solar Initial Comments, at 15.
[16] Filed annually pursuant to Minn. Stat. § 216B.029, Standards for Distribution Utilities, and Minnesota Rules, Chapter 7826, Electric Utility Standards.
[17] ELPC and Vote Solar Initial Comments, at 14.
[18] Xcel Reply Comments, Attachment A, at 3.
[19] Xcel Reply Comments, Attachment A, at 4.

The Department agrees with Xcel's reasoning that the specific, additional IDP Requirement proposed by ELPC and Vote Solar is unnecessary at this time, as these topics are being appropriately considered in the service quality proceedings.

However, the Department is concerned with the Company's limited response to ELPC and Vote Solar's concerns, and the Department remains interested in the potential merit of targeted reliability spending to address poor-performing areas of Xcel's distribution system and the potential opportunity to advance equity by targeting investment to particularly vulnerable customers within Xcel's service territory. The Department expects that, going forward, Xcel will show that its discussion of targeted spending is consistent with the information filed in the Company's annual service quality reports.

At this time, the Department does not support ELPC and Vote Solar's proposed additional IDP Requirement regarding locational reliability and equity, but asks that Xcel link the information on these topics provided in Xcel's electric service quality annual report proceedings to the targeted spending reported in the Company's IDP, and respond to requests for additional information related to ELPC and Vote Solar's concerns in future IDPs.

2. Xcel Reply Comments

a). Biennial Filing Cadence and Annual Updates of Select IDP Requirements

In initial comments, the Department requested that Xcel explain whether providing baseline financial data required by IDP Requirements 3.A.26-30 and E.1-2 is feasible on an annual basis. Xcel indicated that preparing these two subsets of IDP requirements require the most effort.[20] Xcel then asked for clarification on how this data would be used in order to fully assess whether it can agree to the Department's request.

Taken together, the Department views these two subsets of Xcel's IDP Requirements as areas that are important to protect ratepayer interests, as they either directly involve expenditures of ratepayer resources and/or have the potential to lead to cost savings. Annual updates of these two subsets of financial data continues a process whereby the information asymmetry between utilities and regulators can be ameliorated. The Department responds to each subset of IDP Requirements separately.

IDP Requirements 3.A.26-30 require Xcel to report historical and projected distribution spending by certain cost categories. The Department envisions an annual update of IDP Requirements 3.A.26-30 as a means to inform the Commission and stakeholders of how Xcel's internal distribution system planning and budgeting functions over time and to help guard against the utility incentive for investing in capital assets. This information alone is helpful, but over time and on an annual basis can help stakeholders better understand the nature of distribution system budgeting. It helps provide information on the extent to which projected distribution system expenditures are accurate, provide

[20] Xcel Reply Comments, Attachment A, at 8.

an explanation or insight into why they are or are not accurate, and consequently, helps inform suggestions for how those projections can improve, if necessary. This type of insight allows stakeholders to assess whether Xcel is continually evaluating its distribution system planning and budgeting.

The Department is open to suggestions of an annual filing requirement that achieves those goals and that level of insight, and suggested a maintenance of IDP Requirements 3.A.26-30 as a means by which those goals are best served. For instance, assuming the Company's next IDP is filed in 2021, a 2020 annual update could include: actual 2019 distribution system spending compared to the forecasted 2019 distribution system spending, a narrative explanation of why the projections were different (assuming that they are), what processes can be improved to better anticipate the inherent mismatch between actual and forecasted distribution system spending, and whether Xcel has evaluated different solutions to its capital and operational needs that allay the need for investments in capital assets.

The Department's goals for an annual filing of IDP Requirements 3.E.1-2[21] are similar: to help the Commission and stakeholders understand what alternatives exist to traditional capital investments in the distribution system, especially due to the paradigm shift in the technology available for distribution system operations and the seemingly rapid advances in technology made.

Again, here, the Department is open to alternatives that fulfill the same goal of these IDP Requirements but are less administratively burdensome. Coupled with the Department's recommendation to convene an NWA stakeholder advisory group, perhaps the annual update of this subset of IDP Requirements could include a report on industry advancements in NWA analysis, lessons learned from other jurisdictions and utility practices with NWAs, Xcel's own experience with NWAs, and an annual update on the work of the NWA stakeholder advisory group.

The Department is open to suggestions on how best to provide an annual update of these subsets of the IDP Requirements that serves the broader goal of ameliorating the information asymmetry without being administratively burdensome. The Department amends Recommendation 2 to read as follows:

The Department recommends that the Commission require Xcel to file its next IDP no later than November 1, 2021 and move from an annual to biennial IDP filing going forward, but to file an annual update of baseline financial data and non-wires alternatives analysis. (Modified Recommendation 2).

This more general language provides Xcel with an opportunity to fulfill the intent of the Department's goals with additional flexibility.

[21] IDP Requirements 3.E.1-2 concern the NWA alternatives analysis.

b). Narrative Explanation of IDP Differences

In the Department's initial comments, the Department requested that Xcel explain whether it is reasonable to provide a narrative explanation of the differences between the new IDP filing and the previous IDP filing to help focus stakeholder review.

Xcel responded in reply comments and indicated that it believed it was not reasonable given: (1) the substantial time it takes the Company compile each IDP Report; (2) the IDP already contains an executive summary which includes highlights of the IDP and other high-level information; and (3) the IDP includes a compliance matrix that maps the location of all content of the IDP Requirements and compliance with the Commission's Orders and the Commission's advanced grid principles.[22]

The Department continues to believe that a narrative explanation of the differences between the new IDP filing and the previous IDP filing would be helpful to stakeholders, the Department concedes that such a narrative is not essential, and thus withdraws this recommendation.

c). Annual Certification of Grid Investments

Xcel requested the ability to submit advanced grid certification requests on an annual basis.[23] Xcel cited "the rapid pace and changes underway with respect to grid advancement" as the only support for this request, and noted that the Commission allowed the Company to file a grid modernization report and certification request in Docket No. E002/M-17-776.[24]

At this time, the Department does not support Xcel's request to submit distribution grid project certification requests on an annual basis due to the lack of justification for accelerating the opportunity to request rider recovery, particularly in light of the biennial cadence allowed by Minn. Stat. § 216B.2425. Therefore, the Department recommends that the Commission deny, without prejudice, Xcel's request that it be allowed to file annual certification requests. (Recommendation 9)

B. ANALYSIS OF STAKEHOLDERS' RECOMMENDATIONS REGARDING XCEL'S CERTIFICATION REQUEST OF THE AGIS INITIATIVE AND THE APT

1. Overview

To start, the Department reiterates its support for Xcel's forward-looking view of the distribution system, its efforts to enhance the customer experience, lead a clean energy transition, and keep bills low. We agree that a more dynamic and connected distribution system will be a significant and necessary part of the future. The AGIS Initiative proposal put forth by Xcel is leading in the state, and in some aspects, nationally. Xcel has broad support from stakeholders to proceed with modernizing its

[22] Xcel Reply Comments, Attachment A, at 2-3.
[23] Xcel Reply Comments, Attachment A, at 8.
[24] Xcel Reply Comments, Attachment A, at 8.

distribution system, but—importantly—that support *is conditional on ensuring there is sufficient customer protections and risk sharing*. Unfortunately, throughout this comment and reply process, Xcel appears unwilling to compromise or agree to ratepayer protections that guard against the risk that the benefits, capabilities, and services may not materialize in the future.

In response to Xcel's initial AGIS Initiative proposal, and through this comment process, the Department has sought to find a process or terms that allow for sufficient ratepayer protections, through increased transparency and record development or the development of sufficient conditions. However, Xcel objected to the proffered options. In its reply comments, Xcel continued to resist taking a share of the responsibility for the risk that the claimed investment benefits, which are only in Xcel's control to produce, would not materialize. These benefits include both quantified and unquantifiable benefits including enhanced DER integration, improved customer choice, advanced rate structures, improved safety, improved environmental benefits, among others outlined in the IDP.[25] Essentially, it appears that Xcel prefers not to assume any financial risks, and therefore opposes the following ratepayer safeguards proposed by the Department and other stakeholders:

1) direct conditions that provide sufficient ratepayer protections,
2) requirements to file proposals that outline methods to establish customer benefits, or
3) requirements to develop 'frameworks for proposals' to enable Xcel to be held accountable for materialization of the customer benefits.

Therefore, the Department continues to support its recommendations laid out in initial and reply comments, and as further discussed below. The Department limits its comments here to address arguments made by Xcel in reply comments as well as stakeholder reply comments, as relevant.

2. Background on Utility Cost Review and Rider Use

A cornerstone of public utility regulation in over a century of governance in Minnesota, and codified in Minnesota statute, is that utilities have the burden to prove that their investments and expenditures are reasonable.[26] Utilities also have the obligation to make prudent investment decisions on behalf of ratepayers, deploy technology effectively and efficiently, and in a cost-effective manner. Typically, investments and expenditures that have occurred in the past (and/or will continue in a future test year) are recovered through rates set in a general rate case. The utility must demonstrate to the regulator that those investments were prudent before being allowed to include those investments/expenditures in customer rates, which creates an incentive for the utility to make prudent investments on behalf of the customer, and to minimize costs between general rate cases.

[25] IDP, at Attachment O2.
[26] Minn. Stat. 216B.16.

Sometimes, a state allows an extraordinary recovery mechanism (a rate rider), that allows a utility to recover certain expenditures, often related to a particular policy preference, as they are expended and occur outside a general rate case. In both cases (general rate case and rate rider), prudency *is a fundamental condition and must be demonstrated by the utility*. In a rate rider proceeding, an investment or project must be determined to be eligible for rider inclusion (it meets the statutory requirements for the rider), and second, that the costs incurred are prudent for recovery. In most cases, that statutory eligibility process is relatively clear and/or rigorous: an investment may have received a certificate of need[27] or has been vetted through an integrated resource plan (both rigorous), or, the project is a renewable resource that will count toward the state's mandated renewable energy standard (clear). In the immediate instance, in the certification process, the basis for eligibility for rider recovery is not rigorous nor clear and therefore, the weight of this decision is not similar to other rider eligibility processes.

In rider mechanisms, cost caps are often used so that, even if the project type and the associated expenditure estimates for a project are deemed reasonable, any cost overruns need to be shown to be prudent in a general rate case. In this case, the Commission is put in the position of having to determine whether the investment selection and estimated project expenditures have been sufficiently vetted such that rider recovery is appropriate, without concrete assurances that the assumed benefits of the projects will be realized. Based on the current record, and given the narrow cost/benefit analysis results, it is impossible to assess with certainty whether the planned projects are in the public interest, or whether some alternative would be a more cost effective pursuit (more rudimentary AMI meters, other system investments). While Xcel's internal business decisions, such as Xcel's decision to expand the traditional definition of electric service by enabling greater customer options, are not typically subject to regulatory second-guessing, regulators are responsible for establishing ratepayer protections from the risks of those decisions, even when the business decision has broad stakeholder support. Additionally, the Commission cannot micro-manage the implementation of the system, overseeing potential cost overruns and interoperability of the new systems with the old, issues that are only within Xcel's control. Without cost caps, even at the certification stage, proving internal (unforeseen) costs as unreasonable later would be difficult for stakeholders.[28]

3. Certification and Use of Riders for Recovery

Xcel argued that that 1) certification, and later rider recovery, allows for regulatory review and oversight of costs through regular [future] filings, and 2) that recovery of advanced grid investments is consistent with public policy, authorized by statute, and falls within an established regulatory framework that works in concert with rate case proceedings.[29]

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[27] Through a contested case proceeding if Xcel is proposing a facility: see the Commission's May 31, 2006 Order in Docket E002/M-04-1052.
[28] See the recently released, National Association of Utility Regulatory Utility Commission's *Smart Grid Interoperability: Prompts for State Regulators to Engage Utilities.* Published April 21, 2020.
[29] Xcel Reply Comments, Attachment A, at 33.

First, as the Department outlined in reply comments, the Department disagrees with Xcel's characterization of this certification process: Xcel minimizes the magnitude of and the level of risk associated with the certification of the AGIS Initiative investments and alludes to a greater level of oversight at the cost prudency stage than actually exists. If the Commission certifies the AGIS Initiative, it has agreed with Xcel's determination that the project is "necessary to modernize the … distribution system,"[30] and, it follows, that it is the best alternative to meet Xcel's long-term goals. Without identifying up front the benefits that make the investments "necessary," the burden to demonstrate prudency is shifted to stakeholders to prove that any costs associated with the project are unreasonable, i.e., there is no framework in place to measure the point at which expenditures may be deemed imprudent.[31]

Xcel argued that the eligibility determination is a minimal threshold[32] since cost prudency would be reviewed at the time the Company requests cost recovery. Xcel indicated that the eligibility determination is so imperative to them, that they cannot proceed without it. Further, Xcel argued that it will be forced to pursue imprudent investments if certification is not granted at this time.[33] This is discussed in more detail below.

As to Xcel's second argument that recovery of advanced grid investments is consistent with public policy, authorized by statute, and falls within an established regulatory framework that works in concert with rate case proceedings, the Department notes that the existence of a certification process does not mean all projects that could qualify are good candidates for the rider. That decision is exactly the one before the Commission, as CUB noted in initial comments, one to be made with the totality of the circumstances in mind.[34] The Commission can determine whether use of a rider is in the public interest, again, as outlined by the Department in reply comments, and as noted above, in the context of the rider parameters outlined in statute.[35]

In initial comments, CEEM cited a useful primer for regulators regarding when use of pre-approval authorizations are appropriate and what should be considered when doing so (Pre-Approval Primer).[36] The Pre-Approval Primer supports many of the outcomes advocated by stakeholders and it explains that pre-commitments for investments are an important tool to marry the interest of the utilities and the public, but any approval needs appropriate alignment of rewards and penalties and responsibility and risk. The Pre-Approval Primer discusses both instances where there are direct cost implications and indirect cost implications (both of which are present in this case).[37]

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[30] Minn. Stat. § 216B.2425, subd. 2(e).
[31] See Department's Initial Comments at 16-19 regarding ADMS certification and rider recovery requests, which include project cost increases of 155% between certification and rider recovery, and also Xcel Transmission Cost Recovery Rider Petition, dated November 15, 2019, and Compliance Filing, dated February 26, 2020, Docket No. E002/M-19-721.
[32] Xcel Reply Comments, at 3.
[33] Xcel Reply Comments, at 2 and 26.
[34] CUB Initial Comments, at 5.
[35] Department Reply Comments, at 15-16.
[36] See DOC Attachment 1, *Pre-Approval Commitments, When and Where and Under What Conditions Should Regulators Commit Ratepayer Dollars*. Hempling, 2010.
[37] DOC Attachment 1, at 12.

> regulatory action at an early pre-cost stage may identify areas in which private and public interests diverge and create opportunities for interest matching – identified through the development of an evidentiary record and implemented through, for example, conditional approval.

No stakeholder concluded that Xcel's proposal struck the right (or any) balance between ratepayer and shareholder interests; however, because of general support, stakeholders attempted to aid the proposal through recommendations for conditions (roadmap, frameworks, future filings, cost caps, etc.) or process suggestions (review in the Multi-Year Rate Plan or a contested case hearing) in an attempt to strike that balance. Xcel agreed to none of the recommendations. Therefore, the Department concludes that the current process for project certification does not appear to contemplate the uncertainties and complexities of a distribution project proposal such as the AGIS, since it does not allow sufficient time for broad public input on the future of Xcel's distribution system, business model, and its relationship with its customers, nor for an evidentiary proceeding to enable Xcel to fully develop, and remain accountable for, both the costs and benefits, and to develop conditions that would manage risks and protect ratepayers. The current process, which remains appropriate for transmission projects and more limited distribution projects, allows for only a very limited review and evaluation of a project's costs, risks, and benefits.

Alignment of responsibility of risk in this proceeding (regardless of where the effect of the conditions play out, via a different docket, later in time, or in conjunction with an on-going proceeding) should be articulated here in the context of this approval and should not be referred to another docket or delayed. Xcel argued in many aspects how each of the conditions or processes proposed are unnecessary, untimely (too early), misplaced (wrong dockets), or simply unreasonable.[38] The Department disagrees for the reasons outlined in its reply comments. The benefits included in the cost benefit analysis depend on use of advanced rate design, data provisions, customer involvement, among other proposed system benefits, and therefore processes or commitments to ensure that they implemented in a manner timely and commensurate to the benefits must be included in this proposal in order to make a public interest determination and ensure that ratepayers are protected.

Xcel argued that if some level of increased rate design information was sought, it should be included in conjunction with Docket No. E002/M-20-86, which is Xcel's *Petition for Approval of a General Time-of-Use Service Tariff*. The Department agrees that alignment with that docket is reasonable, but disagrees with the limited scope of information Xcel proposed for reporting into that docket. The Department concludes that a more comprehensive rate design plan is needed to tie the commitments Xcel has made in this proceeding, including methods to ensure accountability on the part of Xcel.[39] Significant rate design modifications need to be in place by 2024 to achieve the benefits that Xcel claims are a part of the AGIS Initiative; therefore, additional accountability is required to ensure work is on track to achieve those benefits.

[38] Xcel Reply Comments, at 23-28.
[39] Xcel Reply Comments, at 25.

The Department's initial and reply comments noted that the Commission should be conscientious in how it words any potential certification order: both in the description of what is certified (investment, cost, technology type, functions) and the wording of any conditions imposed. [40] Both will have long-lasting and tangible ratepayer impacts. The Pre-Approval Primer contains support for the need for clarity in any pre-approval decision:[41]

> What purpose does the pre-approval serve and does the action constrain future regulatory decisions? To what extent does approval of a non-cost mechanism constrain a commission's future cost recovery decisions? The short answer to this question is that it *depends on what the commission says in its approval order*. Some utilities have sought, prior to the incurrence of major costs, … findings that the construction of a specific project is prudent. Such findings can vary in their degree of regulatory commitment to eventual cost recovery. At one end, a ruling on a specific project might not promise cost recovery at any particular cost level, but would insulate the utility from a subsequent finding that its project selection was imprudent. [*Emphasis added*]

The Department continues to have concerns that the proposal submitted did not have a more balanced approach in terms of ratepayer protections and plans for assurance of realized benefits up front, and instead, stakeholders are left to recommend conditions in order to salvage Xcel's proposal through a relatively brief (in the context of the proposal's complexities) comment process. Again, as advocated earlier by the Department, if the Commission certifies the AGIS Initiative, the Department strongly recommends an additional comment period to allow further development and refinement of certification conditions that are designed to create additional layers of accountability for Xcel's proposal and better assure ratepayer protections.

As noted by the Department discussion in reply comments, the rider process inherently allows for the disjointed review of project costs, a facet of the cost recovery process that should be considered at the time of approval of rider use.[42] The Department's concerns regarding this issue of allowing an investment of this size and complexity to proceed through a rider process , particularly if approved without additional conditions and ratepayer protections, has not been allayed by Xcel in reply comments: Xcel's only new rebuttal is that since the rider framework exists, its use (for any project) would be consistent with public policy (ignoring the need to review the eligibility determination with a totality of the circumstance).[43]

[40] Department Initial Comments, at 21; Department Reply Comments, at 15.
[41] DOC Attachment 1, at 13-14. See also discussion of burden shifting at 8-9.
[42] Department Reply Comments, at 22.
[43] Department Reply Comments, at 4; DOC Attachment 1, at 14.

Last, the Department has concerns that Xcel attempted to absolve itself from its requirement and responsibility to make prudent decisions on behalf of ratepayers. Xcel noted the following.[44]

> [T]he plan that we have proposed for Minnesota benefits from broader Xcel Energy AGIS efforts, as it incorporates efficiencies from AGIS work Xcel Energy is doing in other jurisdictions. For example, the plan contemplates engaging centralized subject matter experts in design decisions and implementation of common components, such as the AMI headend and its interfaces with Company systems. It also relies on using the same contractors for portions of the work. A schedule delay would mean that these parts of the work cannot be done in parallel, leading to a loss of resource and cost efficiencies and potentially knowledge base, in the case of contractors.

The Department applauds Xcel's efforts to coordinate the AGIS Initiative projects with the same project efforts in other jurisdictions. However, unlike Xcel's assertions, this prudent, coordinated, and cost-efficient approach should move forward regardless of the Commission's certification decision. Pursuing the projects as planned would allow Xcel to fulfill its burden to show prudency at the time of a future cost recovery request. Any decision to pursue a less prudent and cost-efficient path would jeopardize Xcel's ability to support full recovery. Xcel's stance reveals Xcel's reluctance to bear any of the risks inherent in pursuing its proposed advanced distribution system projects.

Xcel further indicated that a delay in a certification decision would put the whole project at risk:[45]

> [W]ere a decision on certification substantially delayed, the Company's planned implementation schedule would, at best, be compressed, potentially increasing costs for customers, and, at worst, portions of the projects would need to be abandoned altogether.

This is new information, and there are no ratepayer protections proposed by Xcel that deal with the potential for project abandonment and stranded costs for a project.

The Department has attached an essay by Scott Hempling, which addresses timing concerns generally, among other useful considerations when determining approval or certification of a project. The essay provides an example of a Baltimore Gas and Electric (BGE) proposal, which included a bill surcharge proposal in order to proceed with an investment:[46]

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[44] Xcel Reply Comments, at 2, 6, and 26.
[45] Xcel Reply Comments, at 26.
[46] See DOC Attachment 2, *"Smart Grid" Spending: A Commission's Pitch-Perfect Response to a Utility's Seven Errors*, Hempling, 2010.

> [Marbles Argument] A utility's obligation to serve includes an obligation to deploy technology to its best use, cost-effectively. The obligation is unconditional. But BGE, viewing innovation as voluntary, told the Commission, in a nutshell, "No surcharge, no deal." Opinion at 3-4 (but see fn. 5—no "line in the sand" concerning alternative cost recovery). When the game is voluntary, the dissatisfied can take his marbles home. Utility service—excellent service—is not voluntary.

4. Lack of Criteria and Proposal to Establish Criteria

Xcel's reply comments acknowledged the lack of clarity regarding certification requirements. The Department notes that Xcel's reply comments on this topic support our position that the criteria are unclear and are being evaluated on a case-by-case basis. Xcel asserted that the Commission's August 7, 2018 Order in Docket 17-776 provides direction.[47,48] However, the referenced order clearly describes the information referenced by Xcel as 'filing requirements' and was not characterized by the Commission (or any stakeholder) as a threshold for certification.

If certified, the Department continues to agree with other parties that criteria should be established for either 1) this decision, or 2) future certification requests.[49] This could be completed via a comment period (for Xcel only) or rulemaking to establish rules for any utility that seeks distribution project certification under Minn. Stat. § 216B.2425, Subd. 7.

5. Conditions are Appropriate and Necessary at the Certification Stage

Xcel objected to certification with any conditions that relate to cost recovery, including specific cost caps, consumer protections, conditions on cost recovery, or development of additional metrics – as well as the Department's proposal to further record development by referring the matter for a contested case hearing. Again, the Department finds this telling: if Xcel is able to fully support its proposal, it would be willing to assume the conditions proposed to ensure the claimed benefit (since Xcel is the only entity able to materialize the purported benefits). However, Xcel stressed the preliminary nature of the cost benefit analysis at this stage and indicated that its cost benefit analysis is only an estimate. Such preliminary cost-benefit data weakens Xcel's certification request, and highlights the need for specific criteria or metrics the Commission can reply upon in making a certification decision:[50]

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[47] *Order Approving Pilot Program, Setting Reporting Requirements, and Denying Certification Request*, dated August 7, 2018, Docket No. E002/M-17-775 and E002/M-17-776, at 9.
[48] Xcel Reply Comments, at 2 and 26.
[49] Department Reply Comments, at 20.
[50] Xcel Reply Comments, Attachment 1, at 27.

> While we thoughtfully prepared the CBAs that were part of our IDP and AGIS certification proposal and believe they are reasonable estimates, the specific benefit and cost amounts are from the point in time we began our analysis, and rooted in specific deployment plan, scope and timing that we proposed. … Any changes to that plan could significantly affect the identified benefits (and costs).

Additionally, the conditions proposed by stakeholders are even more important to establish now, as Xcel is already seeking to establish parameters around the process surrounding the Transmission Cost Recovery Rider proceeding (and challenging the potential use of a contested case in that proceeding).[51] If there was not an inherent shifting of risk to ratepayers at this step, then Xcel would be willing to accept cost caps and the assurance that all benefits would flow to the customer until otherwise approved by the Commission, as it would be standard course.

The Department does not recommend that the Commission approve these investments (by certifying), given the uncertain facts and significant lack of assurances before it.

6. Public Input

The Department reiterates its concern regarding the lack of advance public input on the proposed investments; the Department proposed public input as part of the referral to the Office of Administrative Hearings, to which Xcel objects in its entirety. As noted by the Institute for Local Self-Reliance in its reply comments, "the utility needs customers to help prove the value of the distribution system improvements."[52] Public hearings are a required part of rate cases and of large energy facility proposals before the Commission; this proposal is an approval for Xcel to advance with the largest infrastructure and distribution-system level change in Xcel's history, one that, in part, *depends on public participation* for success. As proposed, it would not allow for public input until after the Commission certifies the course of action. The Department has concerns with this approach and believes it is shortsighted; the Department continues to recommend that public hearings (or at a minimum, customer notice and opportunity for comment) be included as part of the referral to the Office of Administrative Hearings.

7. Incremental System Investment Initiative and Increased Distribution System Spending

Xcel proposed significant increased spending on the distribution system in the near term (of roughly $2.5 billion not inclusive of the AGIS Initiative or APT proposals). The Department recommends referral to the OAH to evaluate project costs related to the AGIS Initiative investment, and to include the ISI Initiative and increased distribution system spending, generally, as related to the AGIS Initiative proposal. Additionally, due to the significant increase in distribution spending over the next 5-10 years, coupled with the lack of specific criteria to provide a framework for review and approval of

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[51] Xcel Reply Comments, at 26 and 28.
[52] ILSR Reply Comments, dated April 10, 2020, at 3.

certification requests, the Department notes these costs will need to be closely scrutinized when they are proposed for recovery. The Department notes there is no related eligibility determination or other pre-approval mechanism for early review of these costs.

8. APT Certification

Last, the Department recommends the Commission certify the APT with hard cost caps. Notwithstanding the concerns regarding the certification process and the lack of accountability for performance; the Department believes there is 1) enough experience with the APT in the industry for the functions and uses so that Xcel's use of the tool will be able to be monitored and reviewed, 2) benefits of LoadSEER (industry-wide) have been proven by other utilities, and 3) the investments aid in resolving known limitations in several dockets - largely surrounding DER forecasting - and the resulting benefits are expected to be near term.

The Department recommends that the Commission certify the Advanced Planning Tool, and limit cost recovery to a hard cost cap of $4 million and further, that the Commission detail in its order the specific scope and functionality expected from the Advanced Planning Tool (consistent with the description in Xcel's filing). (Modified Recommendation 5)

9. Certification Conclusion

The Department continues to recommend the process set out in its reply comments: a contested case hearing, or some other stakeholder process that aligns with the scope and risk of the proposed AGIS Initiative investment, that continues this evaluation with the goals of inviting more public participation and protecting ratepayers by ensuring Xcel is accountable to both costs and benefits it articulates.

The Department shares the desire to use advanced grid technologies as soon as possible, but however desirable new technology and services may be, the public interest demands assurances of reasonable and sound investments. Any certification should include sufficient ratepayer protections and clear plans for accountability to achieve system benefits. No other entity, other than Xcel, can ensure that benefits materialize and ensure that investing in the project was the least-cost, best-fit solution. Moving forward without protections puts significant risks on ratepayers, misaligning the risk and incentives that should be placed on Xcel to achieve the benefits claimed.

III. DEPARTMENT RECOMMENDATIONS

Again, the Department appreciates the opportunity to further comment on Xcel Energy's 2019 IDP and certification request and looks forward to the review of other stakeholder comments. The Department makes the following recommendations (new or modified recommendations are emphasized in bold):

- The Department recommends that the Commission accept Xcel Energy's 2019 IDP compliance with reporting requirements. (Recommendation 1)

- **The Department recommends that the Commission require Xcel to file its next IDP no later than November 1, 2021 and move from an annual to biennial IDP filing going forward, but to file an annual update of baseline financial data and non-wires alternatives analysis. (Modified Recommendation 2)**

- The Department recommends that the Commission refer Xcel's AGIS Initiative proposal (AMI, FAN, FLISR, IVVO) to the OAH for a contested case hearing for further record development. The referral should include consideration of the proposed costs associated with the Incremental System Investments and increased distribution system spending, as necessary, and as they relate to the AGIS Initiative. The evaluation should consider, under any criteria that may be established by the Commission, at a minimum:
  1. Public interest determination for the AGIS Initiative
  2. Public input
  3. Delineation of project costs, scope, and expected functions, including but not limited to:
     a. Clearly identified costs, including the following subcategories of Company costs:
        i. Total revenue requirements on total-company and MN-jurisdictional bases (including identification of the MN jurisdictional allocator used)
        ii. Incremental/new capital costs and depreciation lives and support for the depreciation lives
        iii. Incremental expenses and revenue (all expenses and revenues not already in rates, including expenses that are in rates that will be reduced (i.e. all changes in expenses and revenues)
        iv. Identification of any future AGIS Initiative-related investment costs that would be needed to maximize the potential of the AGIS Initiative as outlined in the IDP
     b. Fixed cost recovery caps for AMI and FAN capital costs (no more than the lower of actual costs incurred or costs as proposed in Xcel's 2019 IDP)
     c. Variable cost recovery caps, including O&M and labor, for AMI and FAN (no more than the lower of actual incurred costs or Xcel's variable costs as proposed in the 2019 IDP, applied on a per-meter basis)
  4. Impacts of distribution investments on transmission-level customers
  5. Cost allocation options, including outline of bill impacts for each customer class over an initial five-year period
  6. Pass-through methodology and/or development of a process or mechanism to pass the savings and revenues associated with the AGIS Initiative on to the Company's customers in a reasonable timeframe
  7. Other necessary conditions for customer value and ratepayer protection

8. Specific plans and timelines for future customer offerings and system capabilities and their implications, including recommendations on whether Commission approval is required or warranted. Plans or timelines should include at a minimum, the following:
    a. Service Tier Plans: potential new options and pricing options for levels of system service expected to be enabled by the AGIS Initiative, including identification of the impacts on non-participant ratepayers, opt-out provisions, etc.
    b. Remote Connect/Disconnect Procedures
    c. Customer Notice Plan for AMI Installation
    d. Customer Data Access Requirements and Rights, including Xcel's intentions regarding:
        i. Customer data rights and terms for inadvertent data release
        ii. Green Button Connect My Data after smart meter deployment
        iii. Home Area Network functionality issues
        iv. Format for providing customers with customer usage data and rate schedules
        v. Potential enhancements to Saver's Switch, and the timing of any enhancements
        vi. Third-Party Service and Data Sharing Plans including whether such plans would result in revenues that would offset costs or reduce rates;
    e. Distributed Generation Interconnection Agreement and Process Modification
    f. Metrics, Baselines, and Targets for System Performance: including baseline data for performance evaluation and reporting plan (or proposal for how advanced grid metrics will be tied to or incorporated into to the Commission's Performance Incentives Mechanisms proceeding) including a minimum 1.5% reduction in customer energy consumption from IVVO technologies
    g. Advanced Rate Design Roadmap that offers a specific timeline and implementation strategy for advanced rate offerings to customers (including the 400 MW of demand response by 2023 as noted in Xcel's current Integrated Resource Plan, Docket No. E002/RP-19-368). The Advanced Rate Design Roadmap should include:
        i. Xcel's current advanced rate designs and demand management programs
        ii. A summary of industry best practices
        iii. A timeline and implementation plan (including education and outreach) for the Company to offer updated dynamic rates for all residential and commercial customers (including, the introduction of time-varying rates), which should include demand response offerings
        iv. Potential low-income rate reform options
        v. Enrollment mechanisms for convenient customer participation
        vi. Evaluation plans for monitoring, verifying, and improving the effectiveness of advanced rate designs
        vii. Opportunities for utilizing distributed energy resources and/or beneficial electrification technologies in conjunction with planned dynamic rates and/or demand management programs
        (Recommendation 3)

- If the Commission certifies all or a portion of the AGIS Initiative, inclusive of the costs as represented by Xcel in its certification request, the Department recommends strong cost caps and clear descriptions of what is certified to protect ratepayers from cost exceedances, changing project descriptions, and in the event that the capabilities, functionalities, and benefits that Xcel represented in the certification request do not materialize. The Department also recommends that any certification should be conditioned on a presumption that all revenues from the AGIS Initiative belong to ratepayers unless otherwise approved by the Commission. (Recommendation 4)

- **The Department recommends that the Commission certify the Advanced Planning Tool, and limit cost recovery to a hard cost cap of $4 million and further, that the Commission detail in its order the specific scope and functionality expected from the Advanced Planning Tool (consistent with the description in Xcel's filing). (Modified Recommendation 5)**

- If the Commission declines to adopt the Department's recommendation to refer the AGIS Initiative to the OAH, the Department recommends conditioning certification on the outcome of a short comment period that allows stakeholders to propose and respond to proposed (or potentially new) conditions regarding ratepayer protections. (Recommendation 6)

- The Department recommends that the Commission require Xcel to file the ADMS annual compliance filing from Docket No. E002/M-17-797 on November 1 of each year in the most current IDP and TCR dockets. (Recommendation 7)

- **The Department recommends that the Commission require Xcel to form a NWA stakeholder advisory group to inform and enhance the Company's NWA analysis for future IDPs. This stakeholder advisory group should convene at least once before Xcel files its next IDP and Xcel should incorporate feedback and expertise from stakeholders and other jurisdictions that have experience with NWA analysis. (Recommendation 8)**

- **At this time, the Department does not support Xcel's request to submit distribution grid project certification requests on an annual basis due to the lack of justification for accelerating the opportunity to request rider recovery, particularly in light of the biennial cadence allowed by Minn. Stat. § 216B.2425. Therefore, the Department recommends that the Commission deny, without prejudice, Xcel's request that it be allowed to file annual certification requests. (Recommendation 9)**

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National Regulatory
Research Institute

Pre-Approval Commitments: When And Under What Conditions Should Regulators Commit Ratepayer Dollars to Utility-Proposed Capital Projects?

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Executive Summary

Until the last quarter of the 20th century, utility regulators commonly made cost recovery decisions concerning new capital projects only after construction was completed and the facility had entered commercial operation. The key aspect of this traditional approach is timing -- *i.e.*, that whatever regulatory decision is made with respect to the rate-making treatment of construction costs occurs "after-the-fact," *i.e.*, after the utility has incurred the costs at issue. Deciding only after a project is completed whether to allow rate recovery means that (1) cost recovery does not begin until the utility seeks and obtains a rate increase; and (2) during construction, the utility has to obtain outside (*i.e.*, non-ratepayer) sources of funds to finance the project.

Some state commissions, based on traditional statutes or recent amendments, are breaking from this traditional approach, thereby providing some level or form of cost recovery assurance prior to commercial operation (and sometimes prior to commencement of construction). Stimulating these new approaches are multiple factors: growing demand, aging infrastructure, environmental requirements, an increasing call for the construction of renewable projects, and shrinking credit markets. These considerations have led utilities to seek upfront regulatory commitments before expressing a willingness to pursue even much needed major capital projects.

This paper addresses the many and conflicting considerations raised when a utility asks a commission to commit to cost recovery in advance of the regulated utility's completion -- or, perhaps, even the initiation -- of construction of a major capital project. For shorthand purposes, we term these commitments as "pre-approvals," and define them as:

> ***An official government declaration that constrains future government decision-making, issued (a) by the commission pursuant to state statute, or (b) by statute directly. The declaration is issued at some point in time before (a) the utility obligates itself to incur project costs, or (b) the project enters commercial operation. The declaration provides that the utility (a) will receive, or (b) will have an opportunity to assert that it should receive, at some point or points in time, dollars from ratepayers, with some level of certainty, to cover some or all of the project costs.***

In evaluating whether to make a pre-approval commitment, there are many potential options and real-life examples to consider. These include state commission determinations that a specific capital project is a prudent choice, that pre-construction costs can be recovered in rates, or that some of the costs to be incurred in constructing a project can be included in rates, on either a contemporaneous or post-completion basis. Any of these approaches involves some upfront shifting, from regulated utilities to ratepayers, of the economic and timing risks associated with implementing a major capital project.

Examples of these mechanisms, which are not mutually exclusive, include:

- Recovery of construction costs during, rather than only after, construction;

- Approval of specific projects in advance of completion (sometimes, though not always, subject to conditions such as meeting scheduled milestones or imposing cost recovery caps);

- "Adjustment clauses" (allowing for recovery of specified costs as incurred, *e.g.*, on a monthly or annual basis);

- Approval of "formula" rate structures, which allow for automatic recovery of certain types of costs, including capital costs;

- Single issue rate increases (*e.g.*, involving consideration of only a capital improvement) rather than general rate cases (involving consideration of all of a utility's costs, whether increased or decreased since the last general rate case);

- Riders and surcharges, allowing for the recovery of pre-approved, specific cost increases without the need for a general rate case; and

- "Securitization" (a rock-solid, often statute-based, government guarantee of cost recovery, which is intended to reduce financing costs by eliminating the risk of non-recovery).

While the paper contains a review of these and other possibilities, its larger purpose is to identify the considerations that the regulator should take into account before moving forward with any form of an in-advance -- rather than after-the-fact -- approval of utility actions or costs. Consideration of advance commitments requires that the commission determine the terms on which risks may be shifted as between a utility's shareholders and its customers, and the benefits provided in response to any approved risk-shifting. In addressing these issues, the regulator must weigh multiple, and occasionally conflicting, concerns, including those involving management effectiveness, regulatory effectiveness, and rates. Some of the considerations involved in addressing pre-approval issues are arrayed sequentially in Figures 1 and 2 to this paper.

While the issues are, of course, fact-specific, the paper presents certain general guidelines that the regulator can apply in evaluating potential pre-approval opportunities. In general, the regulator should ensure that:

- Any pre-approvals are granted only upon a supported showing that regulatory action will benefit customers.

- Regulatory actions are based on full review of the relevant facts, and are supported by evidentiary showings.

- Whatever regulatory action is taken is appropriately limited or conditioned. Approval of an option as a "prudent" choice is not the same thing as approving the inclusion in rates of whatever dollars are expended to pursue it. Approving the recovery of "preliminary" or "planning" costs should not construed as approving the recovery of later-incurred dollars. The key is to be certain that regulator flexibility and discretion are retained to the greatest extent possible.

- The regulator has adequate resources to conduct appropriate reviews of whatever is requested. The commission will need assured access to sufficient technical resources if it is inclined to consider the request of a utility seeking, for example, a determination that building a new nuclear plant is a "prudent" response to the need for new capacity.

- The roles of the regulator and the utility remain properly defined. While it may be appropriate to require that a utility provide periodic reports on the progress of a construction project, the regulator's oversight should not leave it as the party with responsibility for managing the project.

Consideration is given to offsetting adjustments. If pre-approval will reduce the utility's going-forward risk profile, consider whether an adjustment to the utility's return on equity should be ordered in connection with whatever pre-approval is granted.

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Pre-Approval Commitments: When And Under What Conditions Should Regulators Commit Ratepayer Dollars to Utility-Proposed Capital Projects?

I. Introduction

Every regulated public utility has a statutory obligation to satisfy its customers' needs, reliably and cost effectively. To meet that obligation, the utility must, among other things, forecast demand accurately and commit to appropriate capital projects. Those projects must then be completed on time and constructed in a prudent and cost-effective manner.[1]

Achieving these public interest objectives — accurate forecasts, prudent capital project commitments, cost-effective and timely project implementation — requires a number of decisions by both the regulated utility and the regulatory commission. Common to these decisions is the commitment of dollars. Using its legal powers to approve projects, sites, and rates, the regulatory commission commits ratepayer dollars to the project. Using its legal powers to enter contracts, the regulated utility condemns land, borrows money, issues stock, and commits corporate resources — and ultimately shareholder dollars — to the project.

Taken together, these corresponding commitments present a multi-billion dollar, multi-part question: When a public utility proposes to undertake a major capital project, at what point in time should a commission provide assurance that the utility will recover its investment? What conditions, if any, should be placed on whatever assurance is provided? Phrased differently, how much ratepayer money should regulators commit, when should regulators commit it, and under what conditions should such commitments be made?

This paper focuses on commitments made by regulatory commissions in advance of the regulated utility's completion — or, perhaps, even the initiation — of construction of a major capital project. When faced with a request for approval of a project-related regulatory commitment in advance of project completion, a commission will face several basic questions:

a. What types of regulatory commitments should be considered?

b. At what point in the construction process should the regulator make a commitment to a new capital project?

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[1]In this paper, "public utility" or "utility" refers to an entity having a legal obligation to serve. This obligation can arise from legislative or commission mandate. The policy origins of such a mandate are normally a determination that (a) the service is essential to the public welfare and (b) the provider is a monopoly or near-monopoly, such that customers have few alternatives and thus need regulation to ensure high-quality service. The application of this term will vary across states and across industries. At the state level, a regulated utility's obligation to serve typically amounts to a responsibility to provide a defined product (*e.g.*, reliable electric, gas, or water service) in a quantity sufficient to satisfy all demand within an assigned service territory. We do not address the more complex issue of utility obligations where there is competition for the right to supply customers.

c. Assuming the commitment involves cost recovery, should the commitment be bounded through the imposition of conditions, and, if so, how should those conditions be structured?

Consideration of advance commitments requires that the commission determine the terms on which risks may be shifted as between a utility's shareholders and its customers, and the benefits provided in response to any approved risk-shifting. In answering the questions presented above, the regulator must weigh multiple, and occasionally conflicting, concerns, including those involving management effectiveness, regulatory effectiveness, and rates.

While these questions can be considered sequentially, real-world decision-making is not so orderly. In a given set of circumstances, the answers to each of the questions posed will be interrelated and interdependent. For this reason, it is important for a regulator to observe the entire array of choices systematically, before making commitments at any particular stage.

Some of the considerations that may be posed by a request for a regulatory commitment are reviewed in this paper, are displayed in Figures 1 and 2 to this paper, and are applied in the "examples" presented below in Section III.

A. The Situation: Needed New Investment in Capital Projects Poses Challenges for Utilities and Regulators

Facing a combination of growing demand, aging infrastructure, environmental requirements, an increasing call for the construction of renewable resources, and shrinking credit markets, utilities are seeking upfront regulatory commitments before expressing a willingness to pursue even much needed major capital projects.

Consider the situation currently facing service providers in the electricity, gas and water industries:

a. Electricity

Infrastructure needs are growing for electric utilities. Some utilities are seeing capacity margins shrink as demand continues to grow in the face of plant retirements. Others have deferred investments in aging transmission and distribution systems. Utilities are voluntarily (or by mandate) investing in advanced metering and data management systems while facing the need to comply with new renewable energy and energy efficiency directives. Some utilities are considering investing in a new generation of nuclear plants, while others are proposing to meet customer needs by entering into long-term purchase power agreements. Those involved in construction projects have seen increases in the cost of raw materials used as project inputs. Licensing remains a challenge for any major project in an era of NIMBY (not in my backyard) and NIMTOO (not in my term of office). Utility financial capabilities and the availability of capital in today's markets also constrain capital investment projects.

b. Gas

During the past five years, gas utilities spent roughly $5 billion per year on capital investments. This spending trend is on the upswing. The American Gas Association (AGA) estimates that during the next twenty years, annual capital expenditures will increase to $6.5-$9 billion,[2] with funds expended on new main and service pipes, replacement pipes, and compliance with new federal safety regulations.[3]

In some states, gas utilities are petitioning their state commissions to approve accelerated recovery of capital expenditures.[4] As of the end of 2007, eleven state commissions allow gas utilities to "use expense trackers or accounting deferrals to recover costs expended to replace infrastructure in a timely manner."[5] Similar mechanisms are pending before other state commissions.

c. Water

In the years immediately following World War II, the unprecedented industrial, business, commercial and residential development experienced in the U.S. was accompanied by water and wastewater infrastructure to support that development. Many of the water and wastewater facilities constructed during that period are now at the point where they must be upgraded or replaced. Absent action, communities risk adverse economic consequences, such as unplanned system failures, increased maintenance costs, and unbudgeted repair and replacement costs. Water and wastewater utilities are also facing increasingly stringent water quality regulations, which will require large capital investments in water treatment facilities and processes. United States Environmental Protection Agency surveys indicate that over the next two decades, the level of needed investment in water and wastewater infrastructure improvement and replacement is between $500 billion and $1 trillion.[6]

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[2] Cynthia J. Marple, Facilitating Energy Efficiency and Conservation: Non-Volumetric Rate Designs, Presentation Before the Virginia SCC and LDC Conference (Oct. 1, 2008).

[3] For example, the Pipeline Safety Improvement Act of 2002 (Pub. L. No. 107-355, 116 Stat. 2985 (codified as amended in scattered sections of 49 U.S.C.)) and the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 (Pub. L. No. 109-468, 120 Stat. 3486 (codified as amended in scattered sections of 49 U.S.C.)) require gas utilities to increase their pipeline maintenance and safety investments. The latter legislation requires gas utilities to spend additional money on excavation damage prevention, distribution integrity management, excess flow valves and pipeline control room operations. In addition, state regulators can impose standards that are more stringent than federal safety mandate minimums.

[4] In general, state public utility commissions approve the construction of distribution facilities and intrastate pipelines, which include main distribution lines and service lines, metering systems, and storage facilities located within a utility's service area. Commissions review the economics and need (*e.g.*, requirement for meeting federal safety regulations) for these facilities before issuing a certificate. Moreover, state commissions may require that gas utilities under their jurisdiction provide reliable and safe service, which can include, for example, imposition of the obligation that a utility replace some of its existing pipes to comply with safety standards or construct new service lines to accommodate new customers.

[5] American Gas Association, "Infrastructure Cost Recovery Mechanisms," *Natural Gas Rate Round-Up*, December 2007. Commissions have approved trackers for pipeline integrity management programs and pipeline replacement costs.

[6] David Denig-Chakroff, Nat'l Regulatory Research Inst., The Water Industry at a Glance (2001), http://nrri.org/pubs/water/Water_industry_at_a_glance.pdf.

B. The Traditional Approach: Determine Cost Recovery at Project Completion

Until the last quarter of the 20th century, regulators commonly made cost recovery decisions concerning new capital projects when construction was completed and the facility had entered commercial operation.[7] Under this traditional approach, referred to as the "prudent investment rule," cost recovery was available only on satisfaction of two conditions: costs were prudently incurred, and the project was "used and useful," *i.e.*, providing actual benefits to the public.[8]

The mechanics of the traditional approach are straightforward: once the plant enters commercial operation, the utility, for accounting purposes, puts its construction and associated financing costs into its rate base and books associated depreciation. The utility then seeks a rate increase to pay for the plant. In computing its proposed new rates, the utility includes the net book value (*i.e.*, original investment less booked depreciation) in its proposed rate base and includes annual depreciation of the investment in its proposed annual expenses. The depreciation expense gives the utility the return of its investment, while the cost of capital applied to the rate base gives the utility a return on its investment.[9]

In connection with the proposed rate increase, the regulator engages in several assessments, the aim of which is to determine whether the costs proposed for inclusion in rates were prudently incurred and whether the resulting utility plant is used and useful for serving the public. Those assessments include: (1) examining the utility forecasts that supported the decision to build the project, thereby satisfying itself that the project was, in fact, needed; (2) assessing the project choice, including reviewing whether potentially less expensive alternatives were considered and, if so, why they were not pursued; (3) evaluating whether the methods and sources of plant financing reflect prudent decision-making; and (4) conducting a review of the reasonableness of construction costs and the timeliness of completion. Upon completing this review, the regulator disallows costs that it finds were caused by the utility's imprudence.

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[7] In setting utility rates, Commissions typically do not guarantee cost recovery, but rather provide a reasonable opportunity for recovery. That reasonable opportunity exists when the regulator includes the designated costs in the utility's revenue requirement when setting rates. Whether the utility actually collects that full revenue requirement depends on the extent to which its actual expenses and sales volumes match the levels assumed in the Commission-approved revenue requirement. Guaranteed cost recovery, which is the exception but not unprecedented, requires a distinct device, such as a fixed line item amount on each customer's bill, or a "pass through clause" that allows for periodic true-ups, or, most formally, a statutorily-defined "securitization" mechanism in which the state government promises full payment.

[8] For background on this concept, see Justice Brandeis's dissenting opinion in *Missouri ex rel. Southwestern Bell Telephone Co. v. Public Service Commission*., 262 U.S. 276 (1923); and James Bonbright, Principles of Public Utility Rates 159-61 (1961).

[9] In a state which defers cost recovery until construction is complete, the technical accounting works like this: While construction is ongoing, the utility records its construction costs as Construction Work in Progress, or CWIP. It also records an Allowance for Funds Used During Construction, or AFUDC, which represented the cost of financing the outstanding CWIP. The AFUDC rate varies: it may be the utility's weighted average cost of capital, or it may be the cost of debt, or the cost of short-term debt. When the plant is complete, the utility stops recording CWIP and AFUDC, moves the CWIP to plant-in-service accounts, and begins depreciating the plant and including it in rate base. For purposes of this discussion, the important point is that during construction the utility does not obtain a cash return of or on the investment, but books the costs for later recovery in rates.

For purposes of this discussion, the key aspect of the traditional approach is *timing* — *i.e.*, that whatever regulatory decision is made with respect to the rate-making treatment of construction costs occurs "after-the-fact," i.e., after the utility has incurred the costs at issue. Deciding only after a project is completed whether to allow rate recovery means that (1) cost recovery does not begin until the utility seeks and obtains a rate increase;[10] and (2) during construction, the utility has to obtain outside (*i.e.*, non-ratepayer) sources of funds to finance the project.

Supporters of the traditional approach assert that it offers customers important benefits, including encouraging utility management to complete the project on schedule and on budget (if not sooner than forecast and less expensively). Moreover, in an after-the-fact cost recovery review, regulators have access to all relevant construction facts before making prudence and rate recovery decisions.

C. Is the Traditional Approach Optional Where Needed Financing is Difficult to Obtain?

Beginning in the 1970s, the factual bases for the traditional approach began to change. In the electric industry, for example, until the 1970s, the combination of economies of scale and increasing demand growth permitted utilities to size facilities to a level that would both meet expected demand and reduce unit costs, while also allowing for additional sales. However, the combination of inflation and fuel cost increases meant that internal utility funds were less available for use on construction projects. Moreover, access to needed capital became more difficult as construction projects grew larger, employed new technologies, required longer construction periods, and had to meet new and uncertain regulatory requirements (such as those emanating from the Nuclear Regulatory Commission for electric utilities and the Environmental Protection Agency for water utilities). These facts made capital markets less optimistic about whether, and when, ratepayers would pay up. In response, capital — both shareholder capital and debt capital — became more expensive and less available.

State law and practices concerning the timing and processing of rate increase requests subjected utilities to additional financial stress. Some states had statutory "stay-out" provisions, limiting the frequency of the utility's general rate increase requests. Regulators also had a non-statutory preference for infrequent rate cases, due to resource limits and public relations challenges. For small utilities, the transaction costs of a full rate case could compare unfavorably to the size of the revenue increase associated with the likely outcome.

Critics of the traditional approach have asserted that this combination of circumstances has had negative effects, including: delays in needed utility investments (thereby increasing the risk of shortages, blackouts, brownouts and other service concerns); decreasing the frequency of rate filings (and conditioning customers to unchanging (meaning below-cost) utility rates even as other costs of

[10] One clarification of the phrase "seeks and obtains": some states allow the utility to institute some or all of its proposed rate increase before the commission has decided the case. Practitioners label such rates "interim subject to refund." If the Commission ultimately approves rates lower than those placed into effect, the utility must refund the excess amounts.

living rose)[11]; and deferring projects until "crisis" conditions prevailed (leaving insufficient time for commission examination of potential alternatives).

Regulators have responded to these concerns by considering certain modifications to the traditional approach, many of which are short-term and project-specific. Examples of these mechanisms, which are not mutually exclusive, include:

1. Recovery of construction costs during, rather than only after, construction (known as recovery of Construction Work in Progress or "CWIP");

2. Approval of specific projects in advance of completion (sometimes, though not always, subject to conditions such as meeting scheduled milestones or imposing cost recovery caps);

3. "Adjustment clauses" (allowing for recovery of specified costs as incurred, *e.g.*, on a monthly or annual basis);

4. Approval of "formula" rate structures which allow for automatic recovery of certain types of costs, including capital costs;

5. Single issue rate increases (*e.g.*, involving consideration of only a capital improvement) rather than general rate cases (involving consideration of all of a utility's costs, whether increased or decreased since the last general rate case);

6. Riders and surcharges, allowing for the recovery of pre-approved, specific cost increases without the need for a general rate case; and

7. "Securitization" (a rock-solid, often statute-based, government guarantee of cost recovery, which is intended to reduce financing costs by eliminating the risk of non-recovery).

Some of these mechanisms were mandated by legislative action, which might single out a particular technology or cost category for favorable (*i.e.*, certainty-enhancing) treatment. However, approval of any of these cost recovery mechanisms could unreasonably shift risk from shareholders to ratepayers if not limited (*e.g.*, by imposing a cap on cost recovery, which could be exceeded if certain showings were made).

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[11] Eventual – and generally substantial – rate cases could engender customer and media attention that undermined public trust in both the commission and the utility. Bonbright, in his *Principles of Public Utility Rates*, *supra*, at 291 (bullet point 5), emphasizes the value of rate stability (including gradual rate increases) over sudden, large rate increases.

D. The Framework for a New Approach

The present regulatory landscape at the state commission level features an apparent mismatch between (a) the magnitude of investment dollars necessary for essential infrastructure expansion and replacement essential to the nation's well-being, and (b) the clarity and predictability of the regulatory treatment of those investment dollars. These concerns are present regardless of the perspective from which the situation is viewed. For example:

Regulators and utility executives are unclear about largely the same things: what decisions are theirs to make, which decisions will be mandated or guided by legislators, what risks they incur in taking particular actions, and, therefore, how best to identify and balance the managerial, financial, technical, economic, and political factors that affect construction of needed large capital projects.

Investors are unclear about when regulatory commitments will be made, how those regulatory actions will allocate responsibility for project costs and risks, when dollars will flow, through what ratemaking mechanism, and how regulatory commitments might change with unanticipated events.

Customers are unclear about (a) what to expect in terms of the cost consequences of utility investments on their behalf; and (b) whom to hold accountable — legislators, regulators, utility executives, capital markets, or all of the above — for outcomes that vary from these expectations.

In short, there is a need for clarity and predictability, in the form of systematic, but not rigid, decision-making. Systematic decision-making seeks clarity and predictability, the prerequisites for which include alertness to all relevant facts, identification of all legitimate values, attention to both long-term and short-term consequences, and analytic transparency. A framework embodying these features will allow for improvisations, changes of heart and mind, and creative modifications.

In considering how and when to approve the recovery of the costs associated with large capital projects, achievement of the public interest requires at least three ingredients:

- First, whatever regulatory commitments are made should be well-founded, *i.e.*, based on a substantial evidentiary record.
- Second, the commission must have the capacity (including skills, experience and resources) to evaluate anticipated utility performance, to monitor performance throughout the course of the project (including a review of utility rationales for schedule slips and cost overruns), and to take actions in response to unanticipated events.
- Third, whatever regulatory action is taken must be designed to both motivate the utility to excel (*i.e.*, operate efficiently) and to penalize the utility for poor performance.

In regulatory dialogue, these concepts can be captured in the term "pre-approval." This term has been given multiple meanings. Here is a suggested definition that covers many of them:

> ***An official government declaration that constrains future government decision-making, issued (a) by the commission pursuant to state statute, or (b) by statute directly. The declaration is issued at some point in time before (a) the utility obligates itself to incur project costs, or (b) the project enters commercial operation. The declaration provides that the utility (a) will receive, or (b) will have an opportunity to assert that it should receive, at some point or points in time, dollars from ratepayers, with some level of certainty, to cover some or all of the project costs.***

The concept can be viewed with more clarity when the description's separate components are parsed:

> ***a. An official government declaration that constrains future government decision-making, issued (a) by the commission pursuant to state statute or (b) by statute directly,***

Whether the commission issues an order or the legislature enacts a statute, the action is "official" because it declares rights and obligations. The declaration, the content of which is addressed below, can issue from the commission, acting pursuant to statutory authority, or directly from the legislature (which can either direct or authorize a result). However, unless the declaration constrains future government decision-making, it is legally meaningless.

> ***b. at some point in time before (a) the utility obligates itself to incur project costs, or (b) the project enters commercial operation,***

Utilities seek "pre-approval" to reduce the risk non-recovery of costs, and also to reduce the time lag between expenditure and cost recovery. "Pre-approval" can address one or both of these goals. Risk reduction occurs if a government makes a cost recovery commitment before the utility incurs a cost. Time lag reduction occurs if cost recovery under a pre-approval structure occurs sooner than would be the case if the utility has to file an after-the-fact rate case.

> ***c. that the utility (a) will receive, or (b) will have an opportunity to assert that it should receive,***

This phrase goes to the heart of what the government is, in fact, approving. If the government approves cost recovery, then it is promising that the utility "will receive" some amount of dollars at some point, predicated on the fulfillment of certain conditions (such as prudent conduct, timely completion of construction, or completion within a specified budget).

Another, and more limited type of "approval" does not commit to cost recovery specifically, but somewhat constrains future commission decisions on cost recovery. Assume, for example, that a commission determines that a utility's demand forecasts are accurate and that new capacity is necessary to meet those forecasts. If action is taken by the utility based on that finding, then the commission presumably cannot — absent a material change in factual circumstances — find later that the capacity addition was unnecessary. This type of pre-approval constrains the regulator to stick to its original "need" finding. However, depending on the scope of the action, the regulator remains free to question (a) the utility's choice of a particular project as the means of meeting the acknowledged need; (b) the reasonableness of the costs incurred in constructing the additional capacity; and (c) the utility's continuation of the project despite material changes in underlying facts.

d. at some point or points in time

In the context of pre-approvals, the point in time when the utility receives ratepayer dollars can vary widely. Dollars can flow either as or after the utility incurs costs, and each of these options themselves involve multiple choices. "As incurred" can mean in each monthly bill or pursuant to an annual true-up. "After incurred" could be at the next rate case if the costs were "deferred" (meaning that the commission has allowed the utility to preserve the right to argue later for recovery of costs incurred in the past).

e. dollars from ratepayers,

This portion of the description reflects that the main purpose of "pre-approval" is either to (a) create a government-authorized flow of dollars from ratepayers to the utility as compensation for utility service, or (b) have the commission bless a particular option (thus precluding a later finding that the option was imprudent), while leaving the specific dollar amount for subsequent determination.

f. with some level of certainty,

A regulatory approval granted prior to project completion may shift, but does not necessarily eliminate, cost recovery risk. Cost recovery certainty depends on several factors, including the scope of the regulator's decision. The regulator might determine that a particular project selection is prudent, but remain silent on the prudence of particular project costs. Such a decision creates certainty, in that prudent costs associated with the decision will be recoverable, but leaves uncertain what level of costs is prudent. The regulator might find that the utility's forecast of future needs is accurate but not address the type of project (*e.g.*, power plant vs. demand-side management) that will meet that need prudently, leaving that important question for later determination.

g. to cover some or all of the project costs.

The certainty of cost recovery is distinct from the amount of that recovery. A regulator could find, in advance, that all costs up to a stated amount are deemed prudent and therefore recoverable. On the other hand, as concerns additional costs, the regulator may find that costs above that limit (a) are not recoverable (making the stated amount a ceiling), or (b) the utility may argue later that the costs should be recovered because they were prudently incurred (making the stated amount a floor).

Having now set forth, in conceptual terms, the parameters of a pre-approval approach, we turn to a review of how various state commissions are putting these concepts into action.

II. Pre-Approval Mechanisms in Action: Examples from across the Nation

Pre-approval opportunities are typically triggered by a specific action taken by the utility, which results in a request for some type of imprimatur from a regulator. We begin by reviewing potential pre-approval triggers and then move into a discussion of specific regulatory actions that might be taken. This discussion will address the considerations that may be weighed in reviewing a specific request and provide examples of how regulators and state legislatures across the country are dealing with these issues.

A. Triggering Actions

1. Forecast customer requirements

The utility forecasts customer peak demand and annual consumption requirements. In order to do so, the utility measures economic trends and customer behavior (including price responsiveness and propensity to adopt efficiency opportunities). The utility may ask the regulator to "approve" the forecast or to bless actions to be taken in response to it.

2. Incur specific pre-commitment costs

Prior to committing to a capital project, a utility may incur costs necessary to preserve the option. Examples are paying a fee to an equipment supplier to reserve a place in its queue, initiating site development or seeking a construction license from the NRC. Such steps are time consuming and involve cost incurrence; their purpose is not to initiate a project, but to ensure that if the utility subsequently selects that option, it can move forward without undue delay. The utility might seek approval, in advance of the commencement or completion of a project, to recover such "pre-commitment" costs in rates.

3. Commit to a project and initiating construction

After assessing supply and demand options, the utility might ask the commission to approve the utility's commitment to an option that it asserts best matches the forecasted customer requirements (whether from the perspective of size, timing, reliability, environmental or siting effects) and cost (whether construction cost, running cost over its useful life, or decommissioning cost). In this context, "commitment" means that the utility binds itself contractually to the contractors and suppliers of the equipment, technology and other cost drivers required to construct the project.[12]

[12] For a detailed discussion of the multiplicity of generation choices, organized according to their characteristics, *see* J. McGarvey et al., Nat'l Regulatory Research Inst., *What Generation Mix Suits Your State? Tools for Comparing Fourteen Technologies across Nine Criteria* 3 (2007), http://nrri.org/pubs/electricity/07-03.pdf.

4. Continue construction

While a utility's commitment to a project may create some unavoidable cost obligations, there will always be avoidable costs as the project moves through various stages of development. Before committing to each stage of cost commitment, a prudent utility will compare the project's prospective costs and benefits, taking into account factors like cost escalations beyond those assumed in original projections, changes in forecasted customer requirements, and alternate options. The utility may ask the commission to approve continued (or modified) efforts.

5. Change in project plans

During construction, changes in circumstances may warrant project changes. Examples include: downsizing or upsizing to reflect changes in forecasted customer requirements, design changes to comply with new regulatory requirements, and modifications to fuel supply arrangements due to changes in availability or price. Any such change might shift the project's cost-benefit ratio, and may lead to the utility seeking commission approval of associated project modifications.

6. Abandon a project

Prior to completion, circumstances may change the cost-benefit ratio so drastically as to justify project abandonment.[13] Abandonment itself may cause the incurrence of new costs (*e.g.*, decommissioning, attorney fees to renegotiate supplier costs, payment of liquidated damages to shed contract commitments). The utility could seek authorization to recover abandoned plant costs before any such decision is made, or seek abandonment cost protection in advance of a decision whether to pursue a particular project.

B. Pre-Approval Regulatory Commitments that Constrain Future Decisions but Do Not Commit Ratepayer Dollars to Immediate Cost Recovery

For major capital projects, cost recovery is not the only regulatory decision. Under most state statutory schemes, a utility must obtain approvals relating to need, suitability, and environmental effects — often before incurring projects costs. Examples of these approvals include obtaining:

(1) A Certificate of Public Convenience and Necessity ("CPCN"), demonstrating that the proposed project is necessary to serve the public;

(2) A determination that a proposed project is consistent with an integrated resource plan;

[13] Factors leading to an abandonment decision may include: decline in forecasted customer requirements; emergence of new alternatives; unanticipated cost increases relating to fuel supply or regulatory requirements; and unavailability of key equipment components.

(3) Permission to exercise the power of eminent domain (*i.e.*, the taking of private property for utility purposes);

(4) Permission to site utility facilities in particular locations, including (in some states) permission to preempt local zoning restrictions;

(5) Approval of compliance with federal or state environmental restrictions, such as installation of pollution control equipment or other actions associated with electric generating plants, transmission lines, gas and oil pipelines;

(6) Approval of a plan to address reliability problems arising from insufficient resources;

(7) Approval of critical infrastructure protection plans in response to national security challenges;

(8) Approval of plans for repair and replacement of aging facilities;

(9) Approval of bidding or procurement programs; and

(10) Permission to issue debt and equity securities.

Consideration of any of these actions raises at least two questions: (a) What purposes does the approval action serve?, and (b) Does the action constrain future regulatory decision-making, including cost recovery decisions?

1. What are the purposes of an approval that does not directly involve cost recovery?

Any of the above-listed approvals may serve several purposes.

Action at an early stage may provide the regulator with an opportunity to better match the utility's private interest with the public interest. There are plenty of opportunities for mismatch. A utility may prefer to build its own facilities (so as to earn a return on the investment), rather than relying on purchases from others (which might be lower cost, but will not produce a profit for the utility). A utility may seek to maximize sales of its product, even if promoting actions to reduce consumption would be a better choice for the public. Considering regulatory action at an early, pre-cost stage may identify areas in which private and public interest diverge and create opportunities for interest matching – identified through the development of an evidentiary record and implemented through, for example, conditional approvals.

Similarly, consideration of pre-approval actions that do not directly involve cost recovery give the regulator the opportunity to balance multiple factors besides cost. In the specific context of integrated resource planning, project choices involve multiple options with varied possible impacts on the consuming public – including cost, environmental, and economic development impacts — all on both a short-term and potentially longer-term basis. An early open planning process, culminating in some type of regulatory commitment, facilitates a public investigation of these effects and a weighing of the many public preferences and values.

Even where the issue before the regulator does not involve cost recovery, a pre-approval process can create a useful template for future consideration of cost recovery issues. In the case of pollution control infrastructure, some state statutes authorize their jurisdictional electric utilities to file compliance plans for meeting with state or federal emissions requirements. By approving the plan, the commission may effectively be committing to cost recovery of utility funds spent carrying out the plan, assuming a subsequent showing by the utility that such funds were prudently incurred.

Consider Indiana Code 8-1-27-8(1)(A), which directs the Indiana Utility Regulatory Commission to consider an electric utility's Clean Air Act Amendment compliance plan in terms of whether it is efficient, reliable, economic, and constitutes a reasonable least cost strategy over the life of the investment. The electric utility can seek recovery of its original cost estimate for the plan, an approved revised cost estimate, or additional costs, if it can show that they were necessary and prudent. The commission also has authority to modify or withdraw its original pre-approval if there have been substantial changes in the need for, or estimated cost of, an approved environmental compliance plan.[14] A similar arrangement is in place in Pennsylvania.[15]

2. To what extent does approval of a non-cost mechanism constrain a commission's future cost recovery decisions?

The short answer to this question is that it depends on what the commission says in its approval order. Some utilities have sought, prior to the incurrence of major costs, commission or legislative findings that the construction of a specific project is prudent. Such findings can vary in their degree of regulatory commitment to eventual cost recovery. At one end, a ruling on a specific project might not promise cost recovery at any particular cost level, but would insulate the utility from a subsequent finding that its project selection was imprudent. The North Carolina Commission has ruled, for example, that it has authority to issue a declaratory, pre-expenditure ruling regarding the prudence of a proposal.[16] However, some commission orders state expressly that approval of a project choice is not an approval of any cost recovery.[17]

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[14] Ind. Code §§ 8-1-27-18,-19. *See, e.g., In re Indianapolis Power & Light Co.*, 145 P.U.R.4th 513 (Ind. Util. Regulatory Comm'n 1993); *In re S. Ind. Gas & Elec. Co.*, 137 P.U.R.4th 231 (Ind. Util. Regulatory Comm'n 1992). *See, e.g., In re Indianapolis Power & Light Co.*,145 P.U.R.4th 513 (Ind. Util. Regulatory Comm'n 1993); *In re S. Ind. Gas & Elec. Co.*, 137 P.U.R.4th 231 (Ind. Util. Regulatory Comm'n 1992).

[15] *See* Pennsylvania statutes, Pa. Stat. Ann. § 530(d)(2) (requiring utility to show that amounts spent to fulfill the plan were reasonable in amount and prudently incurred as determined in an appropriate rate or other proceeding, for costs to be reflected in rates).

[16] *In re Duke Power Co.*, 256 P.U.R.4th 215, 232 (Commission finds authority to issue declaratory ruling providing "general assurance" concerning nuclear plant assessment activities), *clarified*, No. E-7, Sub 819, 2007 WL 2790658, *clarified*, No. ID 153282, E-7, Sub 819, 2007 WL 3273546 (N.C. Utils. Comm'n 2007); and *In re Duke Energy Carolinas LLC*, No. E-7,

That said, the initial "approval" may constrain later regulatory decisions to the extent that actions the utility takes on the basis of that approval. In other words, the regulator can criticize a utility's implementation of an approved plan, but cannot simply announce after-the-fact that it is reversing that approval absent finding that the relevant facts have materially changed and that the utility should have taken the fact changes into account.[18] However, the commission's approval does not authorize the utility to take imprudent and unnecessarily costly actions to obtain the needed capacity, or to ignore changes in facts that undermine the basis for the original approval. The utility has a continuing obligation to act in a cost-effective manner, and the commission should remain free to enforce that obligation. For this reason, some states require utilities to file periodic updates of demand forecasts and project progress, allowing for a continuous reassessment of project premises.

C. Moves toward Pre-Approved Cost Recovery: "Deferral" of Costs for Later Consideration

Under traditional, embedded cost ratemaking, commissions use a "test year" to match utility cost and revenue increases and decreases. A "historic test year" is a 12-month period experienced by the utility, in which test year costs and revenues are those actually incurred by the utility during that period. Along with adjustments for inflation and other predictable changes (called "known and measurable changes"), these costs and revenues become the basis for the utility's new rates. A "future test year" approach bases rates on expected costs and revenues, rather than adjusted historic costs and revenues. The extent of any difference between the historic test year and future test year approaches depends on the nature of the predictions and adjustments.

After rates are set, if the utility incurs costs not anticipated in the test year, some commissions will permit the utility to "defer" these costs, meaning the utility records them on its books and thereby preserves the opportunity to request recovery in future rates. By definition, such cost deferrals are

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Sub 819 (N.C. Utils. Comm'n 2008), *available at* http://ncuc.commerce.state.nc.us/cgi-bin/webview/senddoc.pgm?dispfmt=&itype=Q&authorization=&parm2=EAAAAA36180B&parm3=000125794.

[17] Consider this 1999 Idaho PUC ruling:

> The Commission further finds that the general purposes to which the proceeds will be put are lawful purposes under the Public Utility Law of the State of Idaho and are compatible with the public interest. However, the Commission finds that this general approval of the general purposes to which the proceeds will be put is neither a finding of fact nor a conclusion of law that any particular program of Rockland which may be benefited by the approval of this Application has been considered or approved by this Order, and this Order shall not be construed to that effect.
>
> Further, the issuance of an Order authorizing the proposed loans does not constitute agency determination/approval of the type of financing or the related costs for ratemaking purposes, which determination the Commission expressly reserves until the appropriate proceeding.

In re Direct Commc'ns Rockland, Inc., Order No. 27914, No. ROK-T-99-1, 1999 Ida. PUC LEXIS 36, at *6-*7 (Idaho Pub. Utils. Comm'n 1999).

[18] For example, if the regulator finds that the utility needs to install or otherwise procure 500 MW of new capacity, then utility actions taken to obtain that capacity cannot be imprudent on the sole ground that the utility does not need the capacity. On other hand, the utility does not get a "free pass" if it continues to pursue the 500 MW in the face of later evidence that it no longer needs the capacity.

deviations from the typical test year approach; deferral preserves the utility's option to argue for later recovery, even though costs were incurred prior to the test year. In permitting the deferral, the commission order makes no promise about cost recovery.[19]

Some state commissions are authorized to permit cost recovery deferrals for capital projects, but only where the project meets certain identified criteria. For example, under Nevada regulations, Nev. Admin. Code § 704.9484, the Commission may designate a "critical facility," thus making the utility eligible for special incentives for its construction, operation and maintenance, including authority to "defer" construction costs in a regulatory asset account for possible later cost recovery.[20] During the deferral period, the utility also can include put into rates "construction work in progress" (which is addressed separately below) associated with the designated facility.[21]

D. Options for Implementing Pre-Approved Cost Recovery

The most immediate, certain form of cost recovery is to permit a utility to include costs in rates contemporaneous with expenditure incurrence. Regulatory options are reviewed below.

1. Construction Work In Progress ("CWIP")

Under the traditional approach, a commission addresses cost recovery of a capital project in the utility's general rate case, submitted when the project enters commercial operation. If the costs are prudent, the commission allows them in rate base and establishes a depreciation rate, allowing for the gradual recovery of the investment.[22] Thus, cost recovery commences only when the plant enters

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[19] *See*, for example, *In re Idaho Power Co.*, Order No. 29904, No. IPC-E-05-21, 2005 Ida. PUC LEXIS 225 (Idaho Pub. Utils. Comm'n 2005) (clarifying the conditions under which a utility can treat preliminary survey and investigation costs as construction work in progress); *Phila. Elec. Co*., 57 Pa. P.U.C. 114 (Pa. Pub. Util. Comm'n 1983). Similarly, in approving a Settlement that provided for a cost recovery deferral, the Pennsylvania Commission noted that in exchange for this treatment, the Settlement provided for early flow-through to consumers of the benefits derived from certain off-system transactions. *See In re Metro. Edison Co*., Nos. G-900240, P-900485, P-910502, C-913373, P-910502C001, 1992 Pa. PUC LEXIS 87, at *73 (Pa. Pub. Util. Comm'n 1992) ("Affiliated Interest Agreements").

[20] The recovery would occur pursuant to subsection 3 of Nev. Admin. Code § 704.9523 (costs may be deferred between rate cases, and must include application of a carrying charge at the rate of 1/12 the authorized overall rate of return; account balances may be recovered via amortization over a period determined by the Commission in a general rate case, with a return at the authorized return plus 5 percent). Nev. Admin. Code § 704.9484(3)(cross-reference explanation supplied).

[21] In order to be eligible for these special cost recovery protections, the Commission (under Nev. Admin. Code § 704.9484(2)) must find that the facility will

1. protect reliability,
2. promote diversity of supply and demand side sources,
3. develop renewable energy resources,
4. fulfill specific statutory mandates,
5. promote retail price stability, or
6. fulfill any combination of the above.

[22] For example, if the plant cost $900 million and has an expected useful life of 30 years, and if the commission uses a straight line depreciation rate, the rates will recover a depreciation expense of $30 million, as well as a return on the

commercial operation. By contrast, some states allow rate recovery of construction costs during the construction process. Known as "construction work in progress," the technique involves a commission finding that the utility's project selection decision, and the costs incurred to date, are prudent. This regulatory action eliminates the risk of non-recovery, and allows for recovery earlier. The technique both reduces non-recovery risk and aids in cash flow during construction. Providing CWIP may also reduce a utility's finance costs, as construction financing will be provided by ratepayers rather than lenders or shareholders.

Until the investment is moved from CWIP to a plant-in-service account, the utility is permitted to apply a rate of return to the investment amount (which covers its financing costs, *i.e.*, a return on investment). The utility is not permitted, however, to apply a depreciation rate to the investment amount, meaning that the shareholders will not start to see a return of their investment until the plant enters service and satisfies the commission's prudence review.[23] When a utility completes construction and the plant enters operation, accounting rules require the utility to (a) cease accruing an AFUDC on the investment; (b) place the CWIP associated with the plant into a plant-in-service account; and (c) begin amortizing (*i.e.*, reducing) that plant-in-service account by treating a portion of it as depreciation expense. Of course, there are limits to the impact of a decision to allow CWIP in rate base. While the action provides a current return during construction, it does not necessarily preclude the regulator from reviewing the prudence of the underlying investment once the project begins operation.

Proponents have argued, and some commissions have found, that permitting a utility to recover CWIP funding can reduce a project's total net present value cost, compared to booking construction costs as AFUDC and then placing those costs in rate base upon commercial operation.[24] CWIP has been justified on the ground that it removes any utility incentive to rush completion of a nuclear plant imprudently (so as to get its costs into rates) and in doing so risks errors and safety lapses.[25] On the other hand, including CWIP means that customers pay for a plant before it provides benefits, raising intergenerational inequity issues. Some states ban it. *See, e.g., Barasch v. Pa. Pub. Util. Comm'n*, 532 A.2d 325 (Pa.1987), *aff'd sub nom. Duquesne Light Co. v. Barasch*, 488 U.S.

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undepreciated $870 million.

[23] In other words, putting CWIP in rate base does not allow the utility to recover the CWIP costs themselves. The utility instead recovers only the financing costs associated with the CWIP. The CWIP amount earns a return at the utility's Weighted Average Cost of Capital ("WACC"). Further, where CWIP is put in rate base with an AFUDC offset, the only dollar cost recovery created is CWIP times the excess of the allowed return over the AFUDC rate. This amount is substantial only where the AFUDC rate is based primarily on debt, particularly short-term debt, rather than a measure of the utility's WACC.

[24] *See* also the Oklahoma Commission's recitation of the competing views of witnesses in the Red Rock pre-approval case. *In re Okla. Gas & Elec. Co.*, Order No. 545240, No. PUD 200700012, 2007 Okla. PUC LEXIS 249 (Okla. Corp. Comm'n 2007) (utility's early approval request denied on other grounds).

[25] *See, e.g., Phila. Elec. Co.*, 103 P.U.R.4th 430 (Pa. Pub. Util. Comm'n 1989)("early window" treatment allowed when the Company filed for rate increase just before fuel was loaded into the Limerick 2 Nuclear Unit); and *Pa. Power & Light Co.*, 47 P.U.R.4th 274 (Pa. Pub. Util. Comm'n 1982)("early window" treatment allowed where the Company filed two months before receiving an operating license for Susquehanna Nuclear Unit I).

299 (1989).[26] Similarly, the Pennsylvania Commission denied "early window" treatment in a case in which the utility sought such authority three years before it acquired its proposed ownership interest in one plant and five years before it began construction of a related transmission line.[27]

2. Riders, surcharges and "single issue" rate increases

A commission's inclusion of costs in the utility's revenue requirement rates does not *guarantee* recovery (because other cost increases, or declines in sales, can leave the utility earning less than its authorized return on equity). One method for increasing the probability of cost recovery is the use of a rider or surcharge, added to each customer's bill on top the "normal" charges (*i.e.*, charges based on the revenue requirement). These riders or surcharges are typically applied to the quantity consumed; thus, as actual consumption may vary from estimates, the utility is still subject to some revenue recovery uncertainty. The probability of full cost recovery is greater if the charge is a fixed, per customer charge (meaning, it does not vary with the customer's consumption). While the typical forum for addressing surcharges is the utility's general rate case, some commissions have established them in so-called "single-issue" rate proceedings, in which recovery of a particular investment is the sole issue.

Certain surcharges are designed to increase over time through automatic "step increases" according to a pre-determined schedule or, as the utility's project costs rise, with periodic adjustments to avoid under- or over-recovery. For example, since 1997 Pennsylvania's water utilities have been allowed by statute to recover the costs of certain system improvements through a "Distribution System Infrastructure Charge" or "DSIC."[28]

The New Hampshire Commission has, in specific circumstances, granted step increase pre-approvals to gas and water utilities to recover the costs of infrastructure remediation, while providing certain safeguards to limit cost recovery. The gas utility filed a plan for gas main replacement under which the utility, operating under an approved schedule, would replace bare steel

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[26] Alternatively, some state commissions developed standards for inclusion of CWIP in rate base. *See*, *e.g.*, Nev. Admin. Code § 704.9484(3). In allowing CWIP for a portion of the construction costs associated with the North Valmy coal-fired plant, the Nevada Commission supported its decision by citing to intangible benefits associated with higher quality earnings, a federal policy of promoting coal over oil and natural gas, and the assertion that completion of the plant would advance the goal of fuel diversity. *In re Nev. Power Co.*, No. 06-06051, 2007 Nev. PUC LEXIS 22, at *114-15 n.11 (Nev. Pub. Serv. Comm'n 2007).

[27] *See* earlier discussion of Affiliated Interest Agreements. The Commission also denied "early window" treatment where neither size nor safety were important considerations. *Re W. Penn Power Co.*, 66 P.U.R.4th 337 (Pa. Pub. Util. Comm'n 1985) and *Re Pa. Power Co.*, 68 P.U.R.4th 357, 361 (Pa. Pub. Util. Comm'n 1985).

[28] *See* Section 1307(g) (66 Pa. Stat. Ann. § 1307(g)) to the Pennsylvania utility code, which states:

> **[Q]uality, fire protection reliability and long-term system viability**.—Water utilities may file tariffs establishing a sliding scale of rates or other method for the automatic adjustment of the rates of the water utility as shall provide for recovery of the fixed costs (depreciation and pretax return) of certain distribution system improvement projects, as approved by the commission, that are completed and placed in service between base rate proceedings. The commission, by regulation or order, shall prescribe the specific procedures to be followed in establishing the sliding scale or other automatic adjustment method.

gas mains (bare steel pipes lacking cathodic protection) with either cathodically-protected steel pipes or PVC piping. The purpose was to avert ongoing corrosion and gas main leaks associated with the unprotected bare steel pipe.[29] Similarly, the New Hampshire Commission awarded step increase treatment to address local water utilities' difficulties in financing improvements needed to address long-developing infrastructure deficiencies.[30] At the same time, the Commission, in each instance, provided for review and audit of construction costs incurred under the plan and review of the prudence of such costs, before the step increases would take effect.[31]

California has allowed water utilities to obtain step increases pursuant to an approved water infrastructure development plan. Once the plan is approved, the utility implements related annual rate increases by filing so-called "advice letters." In each letter, the utility notifies the Commission that investments that are required as preconditions for the step increase have been made and files the resulting new rates for application in the next year.[32]

In Washington State, the Commission gave Puget Sound Energy, Inc. authority to recover the costs of new power sources in the utility's reconciling Power Cost Adjustment, upon the approval of the new source in a so called Power Cost Only Rate Case (or PCOCR).[33]

Similarly, a Florida statute encouraging construction of new nuclear and Integrated Gasification Combined Cycle ("IGCC") plants, and the Commission regulations implementing the statute provide for annual construction cost recovery based on estimates of upcoming construction activities, together with a reconciliation of the most recent year's expenditures against the estimates upon which the earlier charges were based.[34]

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[29] *See*, *e.g.*, *Re N. Utils.*, *Inc.*, Order No. 20,546, No. DR 91-081 (N. H. Pub. Utils. Comm'n 1992) and *Re N. Utils.*, *Inc.*, Order No. 23, 052, No. DR 98-169 (N.H. Pub. Utils. Comm'n 1998) (approving the sixth step increase under Northern Utilities' bare steel main replacement plan).

[30] In that case, the Commission found that the deficiencies at issue

> pose a threat of backflow and cross-contamination to the drinking water supply. [The utility's witness] explained that this threat exists because much of the infrastructure is greater than 100 years old and consists of unlined cast-iron pipe which is subject to corrosion and failure. In addition, over 78% of the system has no post-treated storage. Also, increased traffic on the roadways, under which much of the distribution system is located, exerts additional pressure on these already weak pipes.

In re Hanover Water Works Co. Order No. 23,007, No. DF 98-076 (N.H. Pub. Utils. Comm'n 1998). Hanover Water Works serves approximately 8500 customers. Citydata.com, http://www.city-data.com/city/Hanover-New-Hampshire.html (last visited Oct. 3, 2008).

[31] The review proceedings differ from full rate cases in that they do not look at any other potential changes in revenues, costs and rates of return.

[32] *See*, *e.g.*, *In re San Gabriel Valley Water Co.*, 258 P.U.R.4th 65 (Cal. Pub. Utils. Comm'n 2007).

[33] Twelfth Supplemental Order, *Wa. Utils. & Transp. Comm'n v. Puget Sound Energy* , Nos. UE 011570, UG 011571, (Wa. Utils. & Transp. Comm'n 2002), *available at* http://www.wutc.wa.gov/rms2.nsf/vw2005OpenDocket/CB033A64A4C98B5688256BDE007D6AAE?OpenDocument .

[34] *See* Div. of Policy Analysis & Intergovernmental Liaison, Fla. Pub. Serv. Comm'n, Distribution System Improvement Charges for the Florida Water and Wastewater Industry 1 (2001), http://www.psc.state.fl.us/publications/pdf/pai/dsic4ww.pdf.

3. Formula rates

The traditional test year approach to determining a utility's revenue requirement allows for a consideration of all cost increases and decreases. Regulators have designed a method for preserving the integrity of the test year while expediting analysis of a proposed rate increase necessitated by a capital addition. The approach allows the utility to update its rate base with increments of completed capital investment by filing an annual update of the inputs to a rate formula. The utility supplies the new cost data in accordance with the accounts of costs and revenues filed with the Federal Energy Regulatory Commission on the annual FERC Form 1, with (perhaps) some particular pre-approved adjustments. Because the regulator has approved the formula (and the input form) in advance, the regulatory review is confined to scrutiny of the prudence of particular input items or to arguments that the utility has misapplied the formula (*e.g.*, by including inaccurate or erroneous formula inputs).

4. Securitization

Securitization attaches a statutory commitment to cost recovery, thereby eliminating all risk of non-recovery. Reducing risk reduces the cost of capital to the customer.

E. Conditions That Can Accompany Pre-Approval Mechanisms to Ensure Consistency with the Public Interest

To ensure that risk-shifting pre-approval regulatory commitments promote the public interest, regulators have conditioned such commitments, including through the application of screening mechanisms. We review examples of such conditions below.

1. Consistency with regulator-approved resource plans

An integrated resource planning process identifies the public's needs and the investment options that may satisfy them cost-effectively. Once the plan has been approved, a commission will be more inclined to grant some form of pre-approval to projects that are consistent with the terms of the plan. Conversely, denying pre-approval to projects that are inconsistent with the plan properly leaves project risk with the utility.

2. Cost cap

Imposing a cost cap on the pre-approved amount limits the economic risk to ratepayers and shifts that risk to the utility. Similarly, some states have permitted the inclusion of CWIP or accelerated cost recovery only up to a defined dollar cap.[35] A cap can be set as a dollar amount or as a percentage of forecasted costs.

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[35] *See*, *e.g.*, *Ariz. Pub. Serv. Co.*, Decision No. 54247, at 19-20 (Ariz. Corp. Comm'n 1984). In this case, the utility was rapidly accruing CWIP because of its construction of the Palo Verde nuclear power plant. The Commission allowed

While a cap encourages utility cost-control measures, it can also have unintended and potentially adverse consequences. For example, a strict cap can induce the utility to cut corners or even abandon a project prematurely. Some regulators avoid this problem by making the cap a floor — *i.e.*, approving a cost level as prudent and leaving the utility free to argue for recovery of additional expenditures, if prudent. To protect ratepayers, the regulator might subject above-cap costs to some form of heightened scrutiny or require an enhanced demonstration of need and prudence before approving recovery.

3. Project must be near completion

Since pre-approval provides some cost recovery certainty, commissions may seek to ensure ratepayer benefits by implementing corresponding performance conditions. One approach is to limit pre-approval to projects that have a high probability of completion. An indicator of likely success is whether the project has met certain milestones.

The Oklahoma Commission authorized a rider for early recovery of the costs of a wind farm, providing a completion condition was met.[36] Similarly, a rider might be authorized only where the project will likely enter service within a short period of time (*e.g.*, six months). Or the commission (or the legislature) could require that a specified percentage of the costs of the project be incurred before the early recovery mechanism takes effect.[37]

4. Regulatory "oversight" of project activities

Where early cost recovery is authorized, the commission can keep track of the course of construction by requiring the utility to provide detailed status reports. The Florida Commission, by rule, requires utilities seeking current cost recovery for nuclear or IGCC plants to submit periodic reports on:

(a) the feasibility of finishing the plant;

(b) the technology selected by the utility including, but not limited to, a review of the technology and the factors leading to its selection;

(c) contracts executed in excess of $1 million, including the nature and scope of the work, the dollar value and term of the contract, the method of vendor

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approximately $200 million of the utility's $600 million CWIP balance to go into rate base, before the plant was complete, to address the utility's cash-flow deficiency, and also to soften the rate increases that would occur if the entirety of the nuclear plant entered in rate base at one time.

[36] The condition was that at least 73 of the 80 contemplated required turbines had to be operational. *See In re Chermac Energy Corp.*, Order No. 524078, Nos. PUD 2005-00059, PUD 2005-00177 (Okla. Corp. Comm'n 2006).

[37] *See, e.g.*, Ohio Rev. Code. Ann. § 4909.15 (allowing the commission to approve CWIP in rate base if the plant is at least 75 percent complete, and the investment represents a defined percentage of the rate base).

selection, the identity and affiliation of the vendor, and current status of the contract;

(d) monthly expenditures incurred for major tasks performed within site selection, pre-construction and construction categories, and annual variance explanations, comparing the current and prior period to the most recent projections for those periods filed with the Commission; and

(e) monthly expenditures for major tasks performed within site selection, preconstruction and construction categories.[38]

5. Limit approval to specified investments

Some capital investments, such as pollution control equipment, are mandated by law. Where required by statute, and where no additional evidentiary showing is needed, the commission might grant pre-approval of cost recovery (at least up to a cap) or take other actions to reduce the risk of non-recovery.[39]

For example, Indiana's Environmental Compliance Plan Pre-Approval Act, Ind. Code § 8-1-27, allows the Commission to limit challenges to Commission-approved environmental compliance costs to issues of fraud, concealment or gross mismanagement. The Commission will grant pre-approval for these costs if they are part of an Environmental Compliance Plan that will "constitute[] a reasonable and least cost strategy over the life of the investment consistent with providing reliable, efficient and economical electric service."[40]

6. Preliminary project investments only

A commission (or legislature) may wish to encourage preliminary steps towards undertaking a capital project, while declining to commit ratepayer dollars to the full cost of the project before the completion of needed planning, investigation or engineering activities.

In 2008, the North Carolina Legislature enacted a statute providing for early recovery of so-called "project development" costs for potential nuclear power plants.[41] The legislation includes

[38] Fla. Admin. Code Ann. r. 25-6.0423(5)(c)(5), (8)(b)-(e).

[39] These cases arise most frequently where a state requires the utility to file a pollution control or environmental compliance plan for commission review and approval. Such plans may include additions to infrastructure, as well as retrofits to existing infrastructure. Other examples are scrubbers on generators, leak detection programs for gas utilities, and treatment plants for water utilities, and post-9/11 security enhancements.

[40] The Florida Legislature enacted Section 366.93, Fla. Stat. § 366.93, providing early cost recovery for the siting, design, licensing, and construction of nuclear and integrated gasification combined cycle power plants.

[41] N.C. Gen. Stat. § 62-110.7 (effective January 2, 2008) states:

> § 62-110.7. Project development cost review for a nuclear facility.
>
> (a) For purposes of this section, "project development costs" mean all capital costs associated with a potential nuclear electric generating facility incurred before (i) issuance of a certificate under G.S. 62-110.1 for a facility

two conditions on recovery. First, the costs must be for preliminary activities in connection with a nuclear generating plant. Second, the costs must be incurred before certain dates or events have occurred. The statute also contains a non-exclusive list of examples of the types of activities that are included in the term "preliminary activities."[42]

The North Carolina Commission has approved Duke Power Company's requests for early approval of nuclear power development costs. The Commission approved a cost cap consistent with Duke's estimate of the costs it would incur in the relevant year for development efforts recoverable under the statute.[43] The Commission found that if Duke did not incur those expenses now, then long-lead time items needed to build the facility might not be available to Duke in a timely manner.[44]

7. Reduced ROE to reflect risk reduction

Some commissions have allowed early recovery where the utility's weakened financial condition would otherwise preclude projected completion or trigger certain specific adverse financial events, such as a bond rating reduction below investment grade, reduction in interest coverage ratios below a specified level, or insufficient cash flow to ensure adequate service.[45] In other cases, early recovery has been denied.[46] Any approval based on claimed financial weaknesses should be based on specific evidentiary showings, including the likelihood that the requested relief will alleviate the utility's financial problems.

Because pre-approvals reduce utility risk, commissions awarding some form of pre-approval cost recovery should consider whether a corresponding reduction in the utility's authorized return on equity is appropriate.

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located in North Carolina or (ii) issuance of a certificate by the host state for an out-of-state facility to serve North Carolina retail customers, including, without limitation, the costs of evaluation, design, engineering, environmental analysis and permitting, early site permitting, combined operating license permitting, initial site preparation costs, and allowance for funds used during construction associated with such costs.

[42] As set out in the North Carolina statute, these can include the costs of evaluation, design, engineering, environmental analysis and permitting, early site permitting, combined operating license permitting, and initial site preparation costs, among others.

[43] These include: review by, and responses to, the NRC, purchases of land and rights-of-way, site preparations, project planning and engineering, and payments to fabricators to hold the utility's place in line for obtaining long-lead-time material and equipment such as reactor coolant pumps, containment vessel, reactor pressure vessel, steam generators, control rod drive mechanisms, and condenser circulating water piping.

[44] *In re Duke Power Co*., 256 P.U.R.4th 215 (N.C. Utils. Comm'n 2007).

[45] In *Sierra Pacific Power Co.,* Docket No. 959, Order issued July 21, 1977, the Nevada Commission allowed SPCC to include CWIP associated with the Valmy generation project in rate base once the capital costs exceeded $27.7 million, in part on the theory that cash earnings would be higher quality earnings for the utility. In 1979, the Nevada Commission authorized SPPC to include $ 31.966 million of Valmy 1 and any common facilities CWIP in to rate base. *In re Nev. Power Co.*, No. 06-06051, 2007 Nev. PUC LEXIS 22, at *114-15 n.12 (Nev. Pub. Serv. Comm'n 2007).

[46] See Affiliated Interest Agreements (Pennsylvania Commission denies request for early approval and cost recovery where the estimated expenditure was no more than 15% of the total capital expenditures of the utility applicants over the next ten years).

F. Criteria for Selecting among Pre-Approval Mechanism Options

As shown, a regulator considering some form of pre-approval commitment has many options. Indeed, even where the state legislature has already made certain choices, there will likely remain room for commission discretion.[47] We here offer criteria that a regulator may consider applying in making choices among competing options. The application of these criteria requires the regulator to match subjective concepts to the facts at hand.[48]

[47] *E.g.*, Fla. Stat. § 366.93 (providing for cost recovery for certain changes relating to nuclear or IGCC plants, but leaving PSC free to "establish … cost recovery mechanisms.")

[48] The criteria are an outgrowth of questions developed by James Bonbright, and set forth in Principles of Public Utility Rates. Bonbright, *supra*, at 152-58, articulated five criteria for judging the appropriateness of a utility's rate:

1. The capital-attraction criterion: "[P]rinciples of rate control are best designed to permit well-managed, soundly financed public utility companies to attract needed capital."
2. The management-efficiency criterion: "[D]esigned, not just to enable a company to attract capital but also to reward efficiency and discourage inefficiency of management.
3. The rate-level stability criterion: "[W]hether or not an attempt to secure cyclical flexibility in the right direction is desirable and feasible remains a highly controversial question."
4. The consumer-rationing criterion: "[E]ach rate should be designed to encourage all consumption for which consumers are ready to pay escapable, marginal costs, and so as to deter any consumption for which consumers are not prepared to pay these costs."
5. The fairness-to-investors criterion: "Market acceptability may thus be thought to become, at one and the same time, the test of fairness and of corporate financial need….But…the principle is subject to serious qualifications…."

Bonbright (*supra*, at viii) noted the impossibility of meeting all five criteria at one time with any on rate-making approach:

> Reasonable public utility rates, like reasonable prices in general, are rates designed to perform with reasonable effectiveness multiple functions as instruments of social control. But a system of rates that would be best designed to perform any one of these functions is unlikely also to be the best that could be designed to perform any of the others. Hence, to a substantial extent, sound ratemaking policy is a policy of reasonable compromise among partly conflicting objectives.

Commissions and legislatures have added to Bonbright's list. *See, e.g.*, Michael Dworkin et al., *The Environmental Duties of Public Utility Commissions*, 18 Pace Envtl. L. Rev. 325 (2001). And *see* 2 Alfred E. Kahn, The Economics of Regulation xii (1971) (stating a regulatory goal of encouraging a utility to "engage in product or service innovation with an intensity" the same as its pursuit of efficiency).

1. Utility effectiveness criteria

(a) **Alignment of public and private interest:** The regulator should assess whether a proposed commitment will align the utility's commercial interest with the public interest. The utility must satisfy the multiple customer needs of reliable, safe and timely service at reasonable cost, while earning a reasonable return. Whatever pre-approvals are granted by the Commission should provide clear signals, in the form of both rewards and penalties, and should avoid conflicting messages. The regulator should consider whether pre-approval will promote broader objectives, such as construction of renewable resources.

(b) **Efficient utility management:** The regulator should consider whether granting the incentive will promote efficient utility management and discourage inefficient management. Will regulatory reduction of shareholder risk, through advance approval, reduce management's incentive to act cost-effectively? Conversely, if the regulator refrains from commitment, will the utility choose shorter-term, smaller, or more conventional projects over possibly more efficient but larger projects that involve greater risk?

(c) **Alignment of responsibility and risk:** Does the regulatory decision allocate responsibilities, risks, and benefits logically? Does it align decisional responsibility with management knowledge? Does the decision involve regulatory approval of a detailed, technical solution where the detailed regulatory knowledge is locked within utility management? Do the regulatory conditions involve the regulators so deeply in project management as to relieve the utility's project management experts of responsibility and risk? To the extent regulatory approval is conditioned on the commission oversight of the construction process, does the commission have the requisite technical expertise?

(d) **Sound planning and timely investment:** Will the decision encourage sound planning and timely investment? Some argue that the traditional regulatory practice of giving the utility no cost assurance until a plant is complete causes conservatism, lack of innovation, reliance on "what everyone else is doing." Others argue that the traditional practice, which includes not only no cost assurance but also no cost expectations, encourages a utility to overspend, because if the project cost is large enough, a "too big to fail" situation will pressure regulators to disallow no costs. Still others argue that without cost assurance upfront, the utility will tend to "wait until the last minute" to propose a project, in the hopes that the surrounding urgency will induce the regulator to approve the project for cost recovery without examining alternatives. All these tendencies, if the facts support them, deserve attention as regulators design approval methods. A useful approach is the integrated resource plan, approved well in advance of a project request, containing general guidelines about need, appropriate resources, and timing. A process allowing pre-authorization of a project consistent with a plan ensures two opportunities – the first one conceptual, the second one practical, to ensure utility effectiveness.

(e) **Access to capital:** How does the regulatory decision affect the utility's ability to attract necessary capital on reasonable terms? If the regulatory has refrained from promising cost recovery, will capital be available on reasonable terms? Conversely, if the commission has promised cost recovery, has the commission accurately reflected that risk reduction in the authorized return on equity?

(f) **Pre-approvals versus utility errors:** Is the request for a pre-construction commitment the result of utility errors or inappropriate delays? In other words, to what extent is the utility itself at fault for the need to consider a pre-approval commitment? Would granting the approval create a "moral dilemma" by rewarding (and encouraging for the future) sub-optimal practices?

2. Regulatory effectiveness criteria

(a) **Clarity:** "Pre-approval" encompasses a range of regulatory commitments. Choose your metaphor – palette of colors, symphony of sounds, tool chest of tools, algebraic equations with multiple variables – the regulator has choices about the level of certainty, the timing of decision, the depth of detail, and the intensity of oversight. Common to all the options is clarity: A regulatory commitment should be express as to its limits, thereby avoiding any later claim that the commission has "implicitly" approved recovery of subsequently-incurred costs.

(b) **Information and expertise:** A regulatory commitment can be no more detailed than the regulator's mastery of the details. In reaching a decision, the regulator should have access to information and expertise, including delaying or qualifying a decision, where feasible, until needed facts are available. Data concerns are increasingly prevalent as utilities operating in competitive markers have sought protection from public disclosure of cost data and other key information concerning proposed capital projects.

(c) **Timing affects information:** Pre-approvals are, by definition, approvals that precede knowledge about outcomes. In response to that informational gap, the regulator must focus its limited resources on a myriad of hypothetical concerns. Opponents of pre-approval object that this focus on hypotheticals produces less informed decisions than after-the-fact reviews: knowing the events that precipitated excess costs, the regulator can better assess management's handling of those facts. An argument against after-the-fact review is the risk that the regulator improperly imputes to utility management knowledge of facts that were not known when management made decisions.

(d) **Do precedents and consistency matter?** Regulatory statutes do not require identical, or even comparable, treatment of different projects. Provided the commission has a rational, evidentiary basis for each decision, treatments can vary, generally in accordance with material factual differences. But in sending signals to an investment community considering financing utility projects across four industries (electricity, gas, telecommunications, water), consistency has a value. The importance of consistency should be weighed against the need to address individual projects on the basis of the specific facts that are presented. Amplifying this tendency are legislative enactments that single out a particular industry, or even a particular expenditure, for pre-approval opportunity.[49]

(e) **Post-approval oversight:** How deeply does the regulatory commitment involve the commission in project oversight? Is the commitment an efficient use of commission resources? Does

[49] *See* earlier discussions of Fla. Admin. Code Ann. r. 25-6.0423; and N.C. Gen. Stat. § 62-110.7.

the commission possess the technical resources to monitor and enforce its conditions? Will the commission need to curtail other regulatory activities to free up the necessary resources? Will the utility cooperate in the commission's efforts to obtain the necessary resources?

3. Rates criteria

(a) **Economic efficiency:** Prices that reflect the cost of consumption induce consumer and producer behavior that maximizes benefits for the economy. In choosing the timing and type of pre-approval, and the method of cost recovery, regulators should seek rate solutions that send proper price signals.

(b) **Gradualism:** Sudden jumps in rates for a commodity product produced through large fixed costs with long lives make customers skeptical of the sellers and the regulators. Methods of pre-approval and cost recovery that give weight to gradualism without distorting economic efficiency deserve regulatory attention.

(c) **Investor risk:** As discussed throughout this paper, pre-approval is about identifying and allocating risk of uneconomic results. More sophisticated but clearer methods and procedures for calibrating the proper debt-equity ratios and authorized returns on equity for various types of pre-approvals may be necessary. This is an area deserving additional research.

(d) **Intergenerational equity:** Will the regulatory decision create a cost-benefit mismatch among generations of ratepayers? Early cost recovery requires customers taking service during the period of construction work in progress to pay for plant investments, the use of which they may never enjoy, or will enjoy for only part of the project's life. It also means that customers paying towards the investment during the construction period may pay more for the plant than customers who paid nothing during the construction, even if they are on the system for the same length of time. Yet this problem is not unique. A city collects taxes from today's parents for buildings that will benefit future students. Taxpayers pay today for mass transit projects that will benefit tomorrow's riders. Intergenerational equity need not be a requirement for each project if there is intergenerational sharing overall.

III. Application of the Framework to Hypothetical Examples

The criteria and other considerations addressed in Sections I and II are summarized in a chart entitled, "Pre-Approval: Options and Considerations," which is appended to this paper.

Here we illustrate how these criteria/considerations can be applied in the context of three hypothetical situations that may come before a state commission. We do not examine these examples to explain how they should be resolved. Our purpose is to identify the types of questions and considerations that may be weighed in deciding whether to provide some form of pre-approval, including cost recovery authorization. Specific answers will depend on the specific facts at issue and the weight commissions give to different considerations in the particular circumstances.

A. Example #1: A relatively small water utility seeks pre-approvals in connection with a relatively large — but otherwise routine — investment

Assume that a small water utility is required by statute or regulation to undertake a relatively large capital investment. The investment concerns a program that, while substantial for the utility, is routine for the industry. An example could be the development of a leak detection and mitigation program, which may include the removal and repair or replacement of a large portion of the utility's underground plant. The utility asserts that it needs upfront assurances that would not be available under the traditional approach of cost recovery after-the-fact.

The small utility might request two kinds of pre-approvals: one involving cost recovery and one involving approval without addressing cost recovery. An example of the former would be the utility arguing that it has no access to the level of financing required to complete the project, and that it cannot proceed absent assurance of contemporaneous cost recovery. An example of the latter would be seeking the regulator's blessing of the proposed program as a prudent course of action. Given the commission's statutory obligation to support any decision with substantial evidence, it must require that the utility document the specific challenges. If a utility wants advance approval, it must demonstrate that the program is the best option available. Identifying a statutory mandate, state or federal, would serve this purpose if the mandate specifies the solution.

The commission will need to consider whether conditions should be imposed on pre-approval, including these questions:

- Should the pre-approval, if granted, be contingent on the receipt of periodic progress reports?
- Should any cost recovery be capped at no more than the estimated price tag for the program? Should that cap be a hard cap, or one that the commission can raise or lower depending on future facts?
- Does the small utility have the technical resources sufficient to undertake a major capital project? If not, should the commission condition pre-approval on the utility procuring engineering and project management assistance? To what extent should or must the commission become involved in monitoring project progress? [50]
- Will a pre-approval aimed at shifting regulatory risks involve other associated adjustments? For example, should the utility's return on equity be adjusted if assurances are provided that result in changes in the utility's risk profile?

Each of these questions have a common theme: cost-benefit analysis. The commission should be satisfied that the risks associated with providing approvals in advance — including the constraints on the commission's ability to take action after the fact because of approvals granted

[50] To the extent the commission is involved in monitoring progress, the commission staff or an outside consultant will have to examine the progress of the project, measure it against whatever standards are available, and help the commission render a judgment as to whether the job is being done adequately.

before-the-fact — are outweighed by the benefits derived from the timely implementation of the infrastructure upgrade. Then the commission should ensure that those benefits arrive.

B. Example # 2: A utility with reasonable access to capital seeks pre-approvals in connection with a routine investment

In this example, the utility has ready access to capital on reasonable terms, and the needed capital project presents few new or unusual challenges. Unlike the first example, there is no reasonable claim that, absent pre-approvals, the project cannot be financed. As in the first example, the project will provide substantial benefits for customers, assuming efficient implementation.

The utility here seeks the same two types of pre-approvals: one that directly involves cost recovery and one that does not. For the pre-approval that does not directly involve cost recovery, the utility must demonstrate that its selected project is the best feasible option.

As to pre-approval of cost recovery, the utility's access to capital requires assessment of at least the following issues:

- The utility can make the investment without a pre-approval commitment. One question is whether pre-approval of cost recovery will lower the cost of capital while having no effect on management's incentive to act efficiently.

- The commission can address the efficiency issue directly by considering whether any advance authorization should be capped at the estimated cost of the project and, if so, whether the cap is hard (no later adjustments) or soft (later adjustments, up or down, possible based on fact changes). If the authorization is entirely "upside" for the utility, it may lack sufficient incentive to manage the project efficiently.

- As in the first example, the commission might consider conditioning cost recovery commitments on the submission of periodic project status reports. Continued regulatory supervision should encourage management to conduct construction of the project in a cost-efficient manner. Moreover, regulatory oversight can readily catch and prevent glaring inefficiencies and errors, especially as concerns routine infrastructure repair and replacement projects.

- The commission should consider why a utility with access to capital needs pre-approval of cost recovery. Is the utility seeking pre-approval to rectify prior management neglect? Was this project, for example, something that should have been pursued several years ago? Is early approval and cost recovery in such situations merely a reward to a utility that may have unreasonably delayed making necessary repairs and improvements to its system? To the extent there is evidence of management imprudence, the commission might consider combining early approval and cost recovery with reductions to the allowed return on equity to reflect (a) the lower risk to the utility where its costs are approved or recovered before project completion, as well as (b) management imprudence in delaying necessary investments.

C. Example #3: A utility seeks pre-approvals in connection with a risky and discretionary investment intended to serve its customers

In this example, a utility seeks pre-approvals in connection with a potentially risky capital project, such as a nuclear plant or "clean coal" facility that is needed to meet load (but for which there are other more conventional, proven technology options). The utility might be pursuing this option in a partnership, thereby spreading the risk.[51] Given the uncertain nature of project costs and timelines, it will be difficult for the commission to marshal sufficient facts to support upfront cost recovery. And the request for approval might not involve cost recovery directly, but might still have substantial cost recovery implications (*e.g.*, a determination that the decision to build a nuclear plant instead of pursuing other options is "prudent"), as well as daunting cost recovery requests (*e.g.*, recovery of planning costs, or costs to maintain the project as an option that could be pursued on a timely basis).

If the commission believes the utility would pursue this risky investment absent some form of pre-approval, there is not a clear basis for commission assistance. But if the project could benefit ratepayers yet is too uncertain for the utility to bet its own money, the commission faces a hard question: To what extent should it devote ratepayer money to experiments where, in the absence of ratepayer commitment, the experiments will not occur? To insist on never betting ratepayer money is to risk continued dependence on yesterday's technology. While new technologies can receive stimuli from Congressional authorizations, universities and ratepayer-funded joint research organizations like the Electric Power Research Institute, the involvement of local utilities and their state commissions can also influence technological development. Still, in these situations, the commission can insist that the utility first seek private sources.[52]

A commission may be asked to bless a potentially risky option as a "prudent" choice under the circumstances. This determination will involve both evidentiary showings and policy considerations. The resources identified as potential means to meet forecasted electricity needs for electricity, including energy efficiency, are all characterized by some level of uncertainty. The public may or may not prefer to take on the uncertainties of future carbon mitigation costs, generation construction cost overruns, safety and health consequences, and other risks affecting nuclear and IGCC generation, rather than the uncertainties as to the extent of achievable energy efficiency, or cost-competitive renewable power. Either way, and absent express intervention by the legislature, in addressing a pre-approval proposal, the commission will have the responsibility to make a policy call.[53]

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[51] On the regulatory treatment of joint venture investments in demonstration projects, see S. Hempling, *Joint Demonstration Projects: Options for Regulatory Treatment*, 21 Electricity J. 30, 30-40 (2008).

[52] The mere fact that such projects are estimated to have very high costs does not necessarily render them incapable of attracting private capital. Paul D. Phillips et al., *Financing the Alaskan Project: The Experience at SOHIO*, 8 Fin. Mgmt. 7, 7-16 (1979).

[53] Analysts have observed the somewhat symbiotic relationship at issue in the context of large and risky capital projects, highlighting the need for ratepayer support of such projects in order for the financial markets to make investments in such technologies. *See, e.g.*, Ellen Lapson, Managing Director, Utilities, Power & Gas, FitchRatings, Construction of Coal-Fired Generation: Evaluating the Utility Credit Implications, Presentation Before the National Association of Regulatory Utility Commissioners (July 17, 2007) (presentation available at

Depending upon the evidence, a regulator could determine that the decision to go forward with an expensive and risky generation option was not the product of sound planning, and that the plant was not needed to serve the public. Utilities proposing nuclear, IGCC, and similar plants will presumably have the expertise, staff, and external resources needed to carry out forecasting, construction management, commissioning, and operation of the plants. Compared to the huge firms involved in nuclear and IGCC plant development, regulators will lack sufficient resources to make the myriad decisions involved in the development process. Thus, additional (internal and external) resources may be needed to conduct extensive reviews of such utility proposals. Of course, this concern is not unique to pre-approvals and would be equally applicable present under the traditional approach.

Even where the commission restricts early approval and cost recovery to pre-construction costs, or to costs incurred within a single year, such decisions must be drafted carefully to avoid to constraining subsequent decision-making flexibility. If, for example, the commission is limiting recovery to "preliminary" or "pre-construction" costs, it must define these terms tightly. For emphasis, the commission could consider including in its approval order a specific definition and/or an express dollar amount.

Unlike routine infrastructure replacements, nuclear and IGCC projects (for example) are enormously complicated undertakings, dealing with technologies that may still be in experimental phases. In such circumstances, the commission must retain the flexibility to address changing conditions. This can be accomplished in part by requiring periodic reports from the utility and by retaining staff with sufficient technical expertise to review them and to advise the regulator. However, and as mentioned earlier, care should be taken to make clear that the provision and review of reports does not leave the commission in the role of supervising day-to-day project construction activities.

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http://www.narucmeetings.org/Presentations/Construction%20of%20Coal-Fired%20Generation.ppt); Michael Degernes, Aberdeen Asset Management, Integrated Gasification Combined Cycle: Financing the Next Generation of Coal Plants, Presentation Before the Oregon Advanced Coal Workshop (May 24, 2006) (presentation available at http://www.oregon.gov/PUC/meetings/pmemos/2006/052406/Degernes.pdf); Kevin Genieser, Managing Director, Morgan Stanley, Putting Capital to Work to Achieve CO_2 Reduction¸ Presentation before the Electric Power Research Institute (Aug. 7, 2007) (presentation available at http://mydocs.epri.com/docs/SummerSeminar07/Presentations/EPRI_Summer_Seminar_07_Geneiser.pdf); and Ari Kagan, Director, Global Power Group, FitchRatings, Presentation Before the National Association of Regulatory Utility Commissioners Energy Resources and the Environment Committee: Credit Rating: Issues Associated with Nuclear Investment (July 27, 2005) (presentation available at http://www.narucmeetings.org/Presentations/ERE_Kagan_s05.pdf).

IV. Conclusions: Recommendations for Regulators

This paper has examined options a regulator can consider when faced with a "pre-approval" request — *i.e.*, an upfront request for approval of a utility's proposed course of conduct or for rate recovery of the costs that it plans to incur. The purpose of the paper has not simply been to provide a catalogue or description of potential options, though such a listing can be quite useful. The larger purpose has been to identify the considerations that the regulator should take into account before moving forward with any form of in-advance – rather than after-the-fact — approval of utility actions or costs.

The advice presented in this paper can be summarized as follows:

Where empowered to do so, the regulator can consider breaking from the traditional approach to rate recovery and shifting toward the provision of some in-advance security to the utility. That security can take many forms, including rulings that an option is prudent, that pre-construction costs can be recovered in rates, or that some of the costs to be incurred in constructing a project can be included in rates, on either a contemporaneous or post-completion basis. Any of these approaches involve some upfront shifting, from regulated utilities to ratepayers, of the risks associated with implementing a major capital project. Thus, in considering such approaches, the regulator should ensure that:

- Any pre-approvals are granted only upon a supported showing that regulatory action will benefit customers.

- Regulatory actions are based on full review of the relevant facts. For example, if a utility seeks the commission's blessing that a particular project is "prudent," require the applicant to explain why other options were rejected (and not simply why the applicant's option is appropriate).

- Whatever regulatory action is taken is appropriately limited or conditioned. Approval of an option as a "prudent" choice is not the same thing as approving the inclusion in rates of whatever dollars are expended to pursue it. Approving the recovery of "preliminary" or "planning" costs should not construed as approving the recovery of later-incurred dollars. The key is to be certain that regulator flexibility and discretion are retained to the greatest extent possible.

- The regulator has adequate resources to conduct appropriate reviews of whatever is requested. The commission will need assured access to sufficient technical resources if it is inclined to consider the request of a utility seeking, for example, a determination that building a new nuclear plant is a "prudent" response to the need for new capacity.

- Roles remain properly defined. For example, while it may be appropriate to require that a utility provide periodic reports on the progress of a construction project, the regulator's oversight should not leave it as the party with responsibility for managing the project.

- Consideration is given to offsetting adjustments. If pre-approval will reduce the utility's going-forward risk profile, consider whether an adjustment to the utility's return on equity should be ordered in connection with whatever pre-approval is granted.

Figures 1 and 2

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Figure 1

Pre-Approval:
Options and Considerations

What utility action is being proposed?

- Forecast customer requirements
- Incur specific pre-commitment costs
- Commit to a project and initiate construction
- Continue construction
- Change project plan
- Abandon project

For each proposed action:

What are possible regulatory commitments?

- Approve for purposes other than cost recovery (e.g., financing, siting)
  - What are the purposes of these regulatory actions?
  - Does an approval action constrain the commission's future recovery decisions?
- Approve for purposes of cost recovery, with varying certainty
- Approve deferral of costs for later consideration

When might a regulator make a commitment?

- Before utility commits to any costs
- At one or more points in time during construction
- After the project has entered commercial operation

At what points in time, and over what time period, might cost recovery occur?

- As incurred (monthly)
- As incurred (annually)
- Upon commercial operation

What cost recovery devices are available?

- CWIP
- Riders, surcharges, and "single-issue" rate increases
- Formula rates
- Securitization

What conditions might the commission impose?

- Consistency with regulator-approved resource plan
- Cost cap
- Project must be near completion
- Regulatory oversight of project activities
- Limit approval to specified investments
- Preliminary project investments only
- Reduced ROE to reflect risk reduction

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Figure 2

Pre-Approval:
Options and Considerations

Utility Effectiveness

- Alignment of public and private interest: Is the utility's interest aligned with the public interest in all relevant respects?
- Efficient utility management: Will the proposed regulatory action (or inaction) add (or subtract) certainty; to what extent, if any, will the utility have less incentive to act cost- effectively?
- Alignment of responsibility and risk: Does the approval allocate responsibilities, risks and benefits logically?
- Sound planning and timely investment: Will the decision encourage sound planning and timely investment?
- Access to capital: Will the decision allow the utility to attract necessary capital on reasonable terms?
- Pre-approvals versus utility errors: Would granting the approval create a "moral dilemma" by rewarding (and encouraging for the future) suboptimal practices?

Regulatory Effectiveness

- Clarity: Is the regulatory commitment express as to its limits, thereby avoiding any later claim that the commission has implicitly approved recovery of subsequently-incurred costs?
- Information and expertise: Does the regulator have effective access to the information and expertise necessary to make an appropriate decision?
- Timing affects information: To what extent does a pre-approval require the regulator to focus on hypotheticals and produce decisions based on imperfect information?
- Precedents and consistency: Will the regulatory decision create a precedent favoring a particular type of action and disfavoring others?
- Post-approval oversight: Does the regulatory action make efficient use of commission resources?

Rates

- Economic efficiency: What rate solutions will send proper price signals?
- Gradualism: Does the decision avoid unnecessary jumps in rate levels?
- Intergenerational equity: Will the regulatory decision create a cost- benefit mismatch among generations of ratepayers?

General Concerns

- Has the utility demonstrated that a pre-approval will benefit customers?
- Is the decision based on a full review of relevant facts?
- Is the regulatory action appropriately limited or conditioned?
- Does the regulator have adequate resources to conduct appropriate reviews of whatever is requested?
- Are the roles of the utilities and the regulator properly defined?
- Are there any offsetting adjustments that should be made?

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Effective Regulation of Public Utilities

The essential fact of life—for regulation as well as for antitrust—is that data about the past, predictions about the future, and judgments about anything are not always extant, costless, reasonably obtainable, or very reliable. Furthermore, decision-makers everywhere are of mixed quality and sometimes of no quality at all.

Phillip Areeda, "Antitrust Laws and Public Utility Regulation," *The Bell Journal of Economics and Management Science* (Spring 1972)

"SMART GRID" SPENDING: A COMMISSION'S PITCH-PERFECT RESPONSE TO A UTILITY'S SEVEN ERRORS

June 2010

The Proposal asks BGE's ratepayers to take significant financial and technological risks and adapt to categorical changes in rate design, all in exchange for savings that are largely indirect, highly contingent and a long way off.

— Maryland Public Service Commission, Case No. 9208, Order No. 83410 (June 21, 2010).

* * *

Like many two-word phrases ("competitive markets," "rate relief," "fiscal integrity," "light-handed regulation," "social compact," "adjustment clause," any word-pair containing "reform"), "smart grid" has a simple sound but multiple meanings. Baltimore Gas & Electric's 2010 proposal, costing $835 million, had four main components: (1) replace or upgrade all existing electric and gas meters with "smart" meters; (2) install a two-way communication network linking utility-to-meter-to-customer-appliances; (3) implement mandatory residential time-of-use rates for June through September; and (4) recover all associated costs through a surcharge, prior to completion.

In its June 2010 Order, the Maryland Commission rejected the proposal, without prejudice. Climate change proceedings bring out everyone's passions, but the Commission was dispassionate. Its Order (1) aligned risk with reward, (2) required facts rather than hopes, (3) reframed the issue as customer service rather than cost recovery, and (4) prevented politics from obscuring objectivity. The Order exemplifies effective regulation. (A subsequent order, dated August 13, 2010, approved a revised proposal, with conditions.)

The Utility's Seven Strategies

Verbal packaging (who opposes a "smart grid"?) can help sell a product, but in regulation, the product's benefits must match the costs. The utility failed this test. Its seven errors were both typical and archetypal. Commissions see them all the time.

Bridge halfway: Eager to get going, BGE failed to plan—or reveal—the full route. The Commission had to fill out the picture, detailing the need "to deploy an advanced automated distribution control system that utilizes embedded sensors, intelligent electric devices, automated substations, 'smart' transformers, analytical computer modeling tools, high-speed integrated communications, and reconfigured distribution circuits"—all omitted from the Company's cost proposal. Opinion at 2-3.

Cost understatement: The utility claimed a benefit-cost ratio of 3:2. But its cost category skipped over items essential to success: (1) "the approximately $100 million in undepreciated value of existing, fully operational meters that would be retired before the end of their useful lives"; (2) "the estimated $60 million [for] ... the new billing system necessary to implement" the new time-of-use rates; (3) "the cost of in-home display devices, which easily could exceed another $100 million"; and (4) the cost of new customer appliances that can communicate with the new meters. Why omit costs from a cost-benefit calculation?

MONTHLY ESSAYS BY TOPIC

MONTHLY ESSAYS BY YEAR

Benefit overstatement: Smart grid investments can produce two types of benefits: operational savings (e.g., substituting remote for manual meter reading), and power supply savings (e.g., reducing future capacity and energy needs as customers change their behavior). Almost 80% of BGE's claimed savings (that is, 80% of the "3" in the 3:2 benefit-cost ratio) came from the "power supply savings" category—a category pervaded by uncertainties about future market prices and customer responses.

Excess optimism: Excess optimism is optimism-minus-risk: "My upside exceeds my downside, I think, but you cover the bet." BGE claimed confidence but avoided risk. ("Although BGE claims that the assumptions underlying its business case are sound, the Company would have its customers bear all of the risk in the event those assumptions prove incorrect." Opinion at 7.) Consumers would guarantee costs-plus-profit but receive no promise. This tactic, "betting with other people's money," shares features with Wall Street's 2009 wreckage.

New customer rates without new customer education: The success of time-of-use rates depends on behavioral change by millions who have known only average rates. "Yet the Proposal contains no concrete, detailed customer education plan, includes no orbs or other in-home displays, and provides for grossly inadequate messaging, in our view, to trigger the behavior changes contemplated under the Proposal." Opinion at 5.

Payment before performance: The customers' cost responsibility was clear, but the utility's accountability was not. Absent were metrics: specific commitments to cut demand and usage measurably. BGE forgot what every teenager learns when lawn-mowing: cut the grass, cut it well, then get paid. At bottom was an optical error: seeing ratepayers rather than consumers, pocketbooks rather than people. Peter Drucker, the leading scholar of management and leadership, a deep believer in capitalism, had it right: "Business exists to supply goods and services to customers, rather than to supply jobs to workers and managers, or even dividends to stockholders," *The Effective Executive*.

Marbles: A utility's obligation to serve includes an obligation to deploy technology to its best use, cost-effectively. The obligation is unconditional. But BGE, viewing innovation as voluntary, told the Commission, in a nutshell, "No surcharge, no deal." Opinion at 3-4 (but see fn. 5—no "line in the sand" concerning alternative cost recovery). When the game is voluntary, the dissatisfied can take his marbles home. Utility service—excellent service—is not voluntary.

The Commission's Response

Cost-effectiveness before cost recovery: BGE conditioned its willingness to innovate on assured cost recovery; the Commission conditioned cost recovery on cost-effectiveness. The purpose of regulation is to induce performance that serves the customer, cost-effectively. To induce that performance, the Commission must use the leverage provided by its statute. By pre-approving cost recovery, the Commission would lose its leverage; by conditioning cost recovery on cost-effectiveness, the Commission kept its leverage.

The dog that didn't bark—"future sunk costs": The Commission looked beyond BGE's plan, asking, "What's missing here"? It didn't take Sherlock Holmes to find out: Several hundred millions in future costs, unstated, unexamined, and unplanned for. The risk was this: After spending the first $800 million, BGE could argue that a few more hundred millions would be small relative to the benefits—the classic argument to "ignore sunk costs." The Commission got it right: There are no sunk costs before costs are sunk. Place all future costs on the table now, then compare that total to the benefits.

Not snowed by non-verifiable financial claims: Like many utilities, BGE cited the "financial community" and "the rating agencies" to support its insistence on a surcharge. Referring to these "now predictable" arguments, the Commission's arrow hit its target: "[W]e are not in the business of attempting to predict rating agency reactions, nor of calibrating our decisions to what the utilities say the agencies want or expect." Opinion at 30.

Open door, with conditions: The Commission expressed "hopes, even enthusiasm" for some type of "smart grid" initiative. But it refused to accept uncertainty over facts. It "invited" BGE to return, but only if the company backed its confidence with commitment—commitment to bear the risks of confidence misplaced. At the same time, the Commission recognized that (1) future benefits are always less certain than current costs, and (2) insisting on certainty undermines innovation. Ratepayers will share some risk, the Commission said, if we know the risks up front.

Just and reasonable decisionmaking: The phrase "just and reasonable" experiences so much repetition it almost loses its meaning. The Maryland Commission gave the phrase content: "just" aligns benefits with cost bearers; "reasonable" requires cost-effectiveness.

Conclusion

2009

2008

2007

There's a form of regulation known as "If you do that again we'll clobber you—but go ahead this time." (Thanks to regulatory legend Peter Bradford.) The Maryland Commission did the opposite: "The answer is 'no,' until you get it right." Bradford has a boxing-based metaphor for three levels of regulatory willpower: "Rocky," "Rope-a-Hope," and "Canvasback." Maryland chose Rocky.

Mark Twain, in his autobiography, wrote: "The happy phrasing of a compliment is one of the rarest of human gifts, and the happy delivery of it another." I hope this essay qualifies. Congratulations to the Maryland Commission.

CERTIFICATE OF SERVICE

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

Minnesota Department of Commerce
Supplemental Comments

Docket No. E002/M-19-666

Dated this **22nd** day of **April 2020**

/s/Sharon Ferguson

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