



NORTH CAROLINA ENERGY REGULATORY PROCESS

*In Fulfillment of the North Carolina Clean Energy Plan B-1
Recommendation*

DECEMBER 22, 2020
SUMMARY REPORT AND COMPILATION OF OUTPUTS

AUTHORS & ACKNOWLEDGMENTS

AUTHORS

Josh Brooks¹, Dan Cross-Call¹, Heather House¹,
and Jessica Shipley²

¹Rocky Mountain Institute

²Regulatory Assistance Project

ACKNOWLEDGMENTS

The authors thank the North Carolina Department of Environmental Quality for initiating the process that led to the work represented in this report. We would also like to thank all NERP participants for their dedication to the work conducted in 2020 and for their review of this summary report.

This report is written by RMI and RAP to consolidate and record solutions explored by NERP in 2020. It does not necessarily represent consensus viewpoints or unanimously held positions of all participating organizations.

*Cover image courtesy of GYPSY FROM NOWHERE
IMAGES/ALAMY STOCK PHOTO*

ABOUT ROCKY MOUNTAIN INSTITUTE

Rocky Mountain Institute (RMI)—an independent nonprofit founded in 1982—transforms global energy use to create a clean, prosperous, and secure low-carbon future. It engages businesses, communities, institutions, and entrepreneurs to accelerate the adoption of market-based solutions that cost-effectively shift from fossil fuels to efficiency and renewables.

ABOUT THE REGULATORY ASSISTANCE PROJECT

The Regulatory Assistance Project (RAP) is an independent, non-partisan, non-governmental organization dedicated to accelerating the transition to a clean, reliable, and efficient energy future. RAP helps energy and air quality policymakers and stakeholders navigate the complexities of power sector policy, regulation, and markets.

ABOUT THE NORTH CAROLINA ENERGY REGULATORY PROCESS

Governor Cooper's Executive Order 80 mandated the development of a clean energy plan for the state of North Carolina. The Clean Energy Plan recommended the launch of a stakeholder process to design policies that align regulatory incentives with 21st century public policy goals, customer expectations, utility needs, and technology innovation. The stakeholder process was launched in February 2020 and has led to policy proposals on energy

Table of Contents

Foreword	5
Executive Summary.....	6
Background.....	8
NERP Overview	9
Purpose	9
Objectives.....	9
Process Overview	10
Convening Team.....	11
NERP Participants	12
Guiding Outcomes.....	12
Priority Areas	13
Performance-based Regulation	14
Background	14
Revenue Decoupling	15
Multi-Year Rate Plan (MYRP).....	15
Performance Incentive Mechanisms.....	15
Key Points of Discussion and Content Development.....	16
NERP Recommendations	17
Revenue Decoupling	17
Multi-Year Rate Plan (MYRP).....	17
Performance Incentive Mechanisms.....	18
Process Recommendations.....	18
PBR Outputs.....	19
Wholesale Electricity Markets	20
Background	20
Key Points of Discussion and Content Development.....	22
NERP Recommendations	24
Wholesale Market Outputs	24
Securitization for Generation Asset Retirement	25
Background	25
Key Points of Discussion and Content Development.....	26

NERP Recommendation 27
 Asset Retirement Outputs 27

Competitive Procurement 28

 Background 28
 Key Points of Discussion and Content Development..... 28
 NERP Recommendations..... 29
 Competitive Procurement Outputs..... 30

Conclusion 31

 Stakeholder Support for Reforms..... 31
 A Possible Package of Reforms 32
 Next Steps 33

Appendix 34

 Full List of NERP Participating Organizations 34
 Contact Information..... 35
 Study Group Outputs 35

Foreword

This summary report reflects the collaborative work of a committed group of North Carolina energy stakeholders, who dedicated themselves and their organizations to the NC Energy Regulatory Process (NERP) throughout the year of 2020. Building upon the foundational efforts of the 2019 North Carolina Clean Energy Plan, NERP is among a set of critical next steps to advance the state's energy transition. The regulatory reforms explored in NERP during the last year are critical topics that will shape North Carolina's electricity system for decades to come.

NERP was conducted in a collaborative, consultative manner, featuring nine workshops, multiple topic-focused webinars, and regularly occurring study group meetings among subsets of participants. In consultation with the NC Department of Environmental Quality, Rocky Mountain Institute (RMI) and the Regulatory Assistance Project (RAP) convened and facilitated NERP, providing direction, organizing support, technical expertise, workshop agenda design, and professional facilitation. Through that approach, stakeholders held open, wide-ranging dialogues exploring reform options and strove to advance proposals best suited to North Carolina's context, values, and public policy goals.

Throughout the 2020 NERP process, participants worked in good faith to identify broadly supported, meaningful reforms that balance stakeholder interests and state policy goals. The numerous outputs produced by NERP—fact sheets, guidance documents, and draft legislative language—reflect the collaborative work of the stakeholders and areas of general alignment for the State's energy transition.

This summary report is written by RMI and RAP to consolidate and record solutions explored by NERP in 2020. This report does not necessarily represent consensus viewpoints or unanimously held positions of all participating organizations. Throughout the report, we sought to reflect points of agreement and disagreement among participants, including areas for future attention by regulatory bodies or other processes, while also indicating where general agreement supports certain reforms moving forward—whether in the form of implementation, legislative direction for new regulations, or further study. The specific details of how reforms get advanced will be subject to pending developments and further dialogue among a diverse set of North Carolina stakeholders.

It is RMI and RAP's pleasure and honor to work with North Carolina on these important issues. The State's leadership, including its nationally recognized community of energy system leaders, showcase how critical North Carolina is to our nation's energy transition. Thank you for your good work, your leadership, and this opportunity to collaborate.

Executive Summary

North Carolina's 2019 Clean Energy Plan (CEP) established a goal to reduce greenhouse gas emissions in the state's electric power sector 70% below 2005 levels by 2030, and to attain carbon neutrality by 2050. It encouraged updates to energy system planning processes and regulations that achieve these goals, while maintaining long-term affordability and price stability for North Carolina residents and businesses, and also spurring innovation that grows the economy of the state.

From February to December 2020, a group of North Carolina energy stakeholders collaborated through the North Carolina Energy Regulatory Process (NERP) to consider updates to utility regulations and electricity market structures. NERP served as a platform for exploration and advancement of CEP recommendations, specifically fulfilling the "B1" recommendation to "launch a North Carolina energy process with representatives from key stakeholder groups to design policies that align regulatory incentives and processes with 21st century public policy goals, customer expectations, utility needs, and technology innovation." Through NERP, additional recommendations of the CEP were considered, including in-depth attention to:

- Adoption of a performance-based regulatory framework (B-2)
- Enabling securitization for retirement of fossil assets (B-3)
- Studying options to increase competition in the electricity system (B-4)
- Implement competitive procurement of resources by investor-owned utilities (C-3)

Participants engaged in extensive dialogue on these topics to investigate how each has been implemented in other parts of the country and to consider their potential application to North Carolina. Picking up where the CEP left off, NERP provided a venue for education and shared research on these topics, leading to development of policy proposals that are tailored for North Carolina's unique context.

Rocky Mountain Institute (RMI) and the Regulatory Assistance Project (RAP) convened and facilitated NERP, in consultation with the NC Department of Environmental Quality (DEQ). As independent, outside organizations, RMI and RAP supported NERP through process design and coordination, regulatory expertise and technical assistance, and national perspective to help compare reforms to approaches taken in other states.

This report summarizes key recommendations of NERP as of December 2020, along with context on how the content development evolved. The report has been prepared by RMI and RAP with input from NERP participants to provide a distillation of discussions that occurred throughout the past eleven months, in order to provide a common reference from which reforms can be carried forward in 2021.

The report is accompanied by a set of "outputs" produced by NERP participants, through their work in four study groups: performance-based regulation, wholesale markets, asset retirement, and competitive procurement. Those outputs were developed to aid briefings to decision-makers on the detailed findings for each of the four focus areas of NERP. Due to the multi-stakeholder nature of NERP with organizations and individuals comprising differing viewpoints and priorities, policy positions and recommendations described in this report do not necessarily reflect full consensus or unanimous support for a reform. In authoring this summary report, RMI and RAP have made every effort to communicate areas of alignment and to identify issues for continued consideration in future work.

NERP Recommendations

In support of the Clean Energy Plan and B1, B2, B3, B4 and C3 recommendations, NERP participants have recommended regulatory changes in four key reform areas. Those are summarized here, with additional detail provided in the relevant sections of the report as well as in topic-specific briefing documents and other outputs produced by NERP study groups.

NERP participants recommend the following:

- The General Assembly and the North Carolina Utilities Commission (NCUC) pursue a comprehensive package of PBR reforms to include a multi-year rate plan (MYRP), revenue decoupling, and performance incentive mechanisms (PIMs).
- The General Assembly direct the NCUC to conduct a study on the benefits and costs of wholesale market reform and implications for the North Carolina electricity system.
- The General Assembly expand securitization to be an available tool for electric utilities to retire undepreciated assets, in addition to the current authorization related to storm recovery costs.
- The General Assembly expand existing procurement practices to utilize competitive procurement as a tool for electric utilities to meet energy and capacity needs defined in utility Integrated Resource Plans (IRPs) and where otherwise deemed appropriate by the NCUC.

Many participants expressed a desire to combine above recommendations into a “package” of legislation in the 2021 legislative session that also includes other provisions related to climate and clean energy. That is, there was agreement to combine NERP produced policy concepts into one piece of legislation, and that such legislation should also include other enabling policies not discussed in NERP. Agreement was not reached on what that additional enabling policy ought to be. Multiple participants believe an enabling policy specifically directed at increasing clean energy deployment beyond currently authorized levels or reducing carbon emissions is a necessary complement to the NERP reforms. A handful of participants expressed that legislation to study a wholesale market should be considered separately.

While the bullets above represent general agreement among NERP participants regarding components of a suggested reform package, no one reform enjoys the full support of every NERP participant and there are nuances to participants’ views. Those nuances are explored more fully in this report. In addition, study groups produced detailed outputs to help advance respective reforms, which are attached in the Appendix.

Advancement of the identified reforms will require continued dialogue and negotiation between North Carolina energy stakeholders. To that end, participants agreed at the completion of the 2020 NERP process to remain in dialogue with each other and carry forward these recommendations to brief North Carolina lawmakers, decision makers, and constituents, in an effort to support their passage in the 2021 legislative session.

Background

North Carolina Governor Roy Cooper’s Executive Order 80 (EO 80) laid out an emission reduction goal for North Carolina of 40% by 2025 and DEQ to develop the CEP for the state.¹ The CEP was meant to encourage the use of clean energy resources and technologies and to foster the development of a modern and resilient electricity system. In response to EO 80, DEQ launched a multi-month public stakeholder process to collect input and conduct analysis of North Carolina’s energy systems. This input and analysis was used to identify policies and strategies to guide policymakers and decision-makers on ways to implement a clean energy vision for the state. The resulting CEP, released in October 2019, contains short, medium, and long-term recommendations in five strategy areas. It lays out a vision that includes the following overarching goals:

1. Reduce electric power sector greenhouse gas emissions by 70% below 2005 levels by 2030 and attain carbon neutrality by 2050.
2. Foster long-term energy affordability and price stability for North Carolina’s residents and businesses by modernizing regulatory and planning processes.
3. Accelerate clean energy innovation, development, and deployment to create economic opportunities for both rural and urban areas of the state.

The stakeholder process conducted as part of the CEP development sought input on the key issues that need to be addressed in order to make the CEP vision a reality. The process of developing the CEP’s analysis and recommendations involved extensive stakeholder engagement including six large workshops attended by a cross-section of diverse North Carolina energy stakeholders, nine public meetings, and hundreds of pages of written comments and online engagement by the public. Stakeholders were asked to identify ways in which the current policy and regulatory framework in the state is working to accomplish their goals, and ways in which it needs to be modified in order to accomplish those goals.

The CEP stakeholders prioritized three recommendations that would move the state forward toward achieving the goals above:

1. Develop carbon reduction policy designs for accelerated retirement of uneconomic coal assets and other market-based and clean energy policy options.
2. Develop and implement policies and tools such as performance-based mechanisms, multiyear rate planning, and revenue decoupling, that better align utility incentives with public interest, grid needs, and state policy.
3. Modernize the grid to support clean energy resource adoption, resilience, and other public interest outcomes.

Among the CEP’s many insights, it found that new policy priorities and current and emerging trends in the electricity industry are forcing a reconsideration of traditional regulation and utilities’ responsibilities. Stakeholders generally agreed that the existing electricity regulatory system has been successful at accomplishing historical policy goals, but that it is not set up to support 21st century policy goals such as enhanced customer access to energy choices, rapid expansion of clean energy deployment, and environmental outcomes. The CEP stated that these responsibilities are “expanding to include new expectations for environmental performance, carbon reduction, customer choice, resilience, equity, and adapting to (or enabling) sector-wide innovation, among others, while retaining long-standing responsibilities such as reliability and affordability.”

The CEP identified multiple trends in the electricity industry that necessitate updating North Carolina’s energy regulatory framework. In light of this, the CEP identified a need for a deeper, sustained engagement

¹ <https://files.nc.gov/ncdeq/climate-change/EO80--NC-s-Commitment-to-Address-Climate-Change---Transition-to-a-Clean-Energy-Economy.pdf>

from stakeholders outside of traditional legislative and regulatory forums to “design policies that align regulatory incentives and processes with 21st Century public policy goals, customer expectations, utility needs, and technology innovation.” The CEP identified topics such as regulatory incentives, integration of distributed generation, transparent and efficient regulatory processes, and holistic resource planning as being ripe for consideration. In addition, other sections of the CEP identified the introduction of more competition into the North Carolina energy market, possible wholesale electricity market reform, and coal power plant retirement as needing further analysis and discussion. The CEP identified the need for such a process to build on, not duplicate, the work that dedicated North Carolina stakeholders accomplished in the CEP process.

NERP Overview

The CEP B-1 recommendation, “launch a North Carolina energy process with representatives from key stakeholder groups to design policies that align regulatory incentives and processes with 21st century public policy goals, customer expectations, utility needs, and technology innovation,” led to the creation of the North Carolina Energy Regulatory Process (NERP) in 2020. NERP was formed to advance components of the CEP that could accomplish the B-1 recommendation. Several other CEP recommendations were explored in NERP due to strong interest from participants, including recommendations around wholesale market reform, securitization for fossil asset retirements, and competitive procurement (CEP recommendations B-2, B-3, B-4, and C-3).

Purpose

NERP worked to produce recommendations for policy and regulatory changes that can be delivered by the participants to the North Carolina General Assembly, North Carolina Governor, NCUC, and other entities as appropriate. These take the form of issue briefs, policy proposals, and draft proposed legislation developed by participants during the process.

Objectives

The work of stakeholders was set to focus on priority items of the CEP which were identified as actionable in 6-12 months, through an ongoing, policy-oriented convening process. In particular, NERP applied the following process objectives to advance CEP goals on electricity market design and utility regulatory reform:

1. Build expertise and trust among North Carolina energy stakeholders through shared principles, foundation setting, education, and identification of priority action areas
2. Examine alternatives to the traditional utility regulatory model and incentives, carbon reduction policies, and as needed, energy market reforms identified by stakeholder group
3. Produce specific policy proposals that participants can work to implement

The objectives of the NERP process were meant to build upon the work already completed in the CEP process and to address the substantive issues identified by the CEP B-1 recommendation, as well as other related CEP recommendations.

The policy proposals and other work products that NERP participants created can be found in the Appendix and at the DEQ’s Clean Energy Plan website.² They are also being distributed directly to decision-makers throughout the State.

² <https://deq.nc.gov/CEP-NERP>

Process Overview

NERP included nine workshops during 2020, supplemented by four webinars, and extensive study group research and discussion. Workshops were intended to be in-person, but due to limitations on travel and in-person meetings imposed by the COVID-19 pandemic, all workshops were held virtually with the exception of the February kickoff workshop.

NERP proceeded according to three phases: foundation setting, topical deep dives, and policy development. Foundation setting took place during the first workshop to align stakeholders around the purpose and objectives of the process. At this workshop, participants identified priority outcomes for attention in future NERP work, reviewed CEP recommended topics, and gave input on which topics should be the focus of future work. In the second phase of NERP, spanning workshops 2 through 5, topical deep dives provided dedicated time for participants to learn about priority topics of CEP and stakeholder interest:

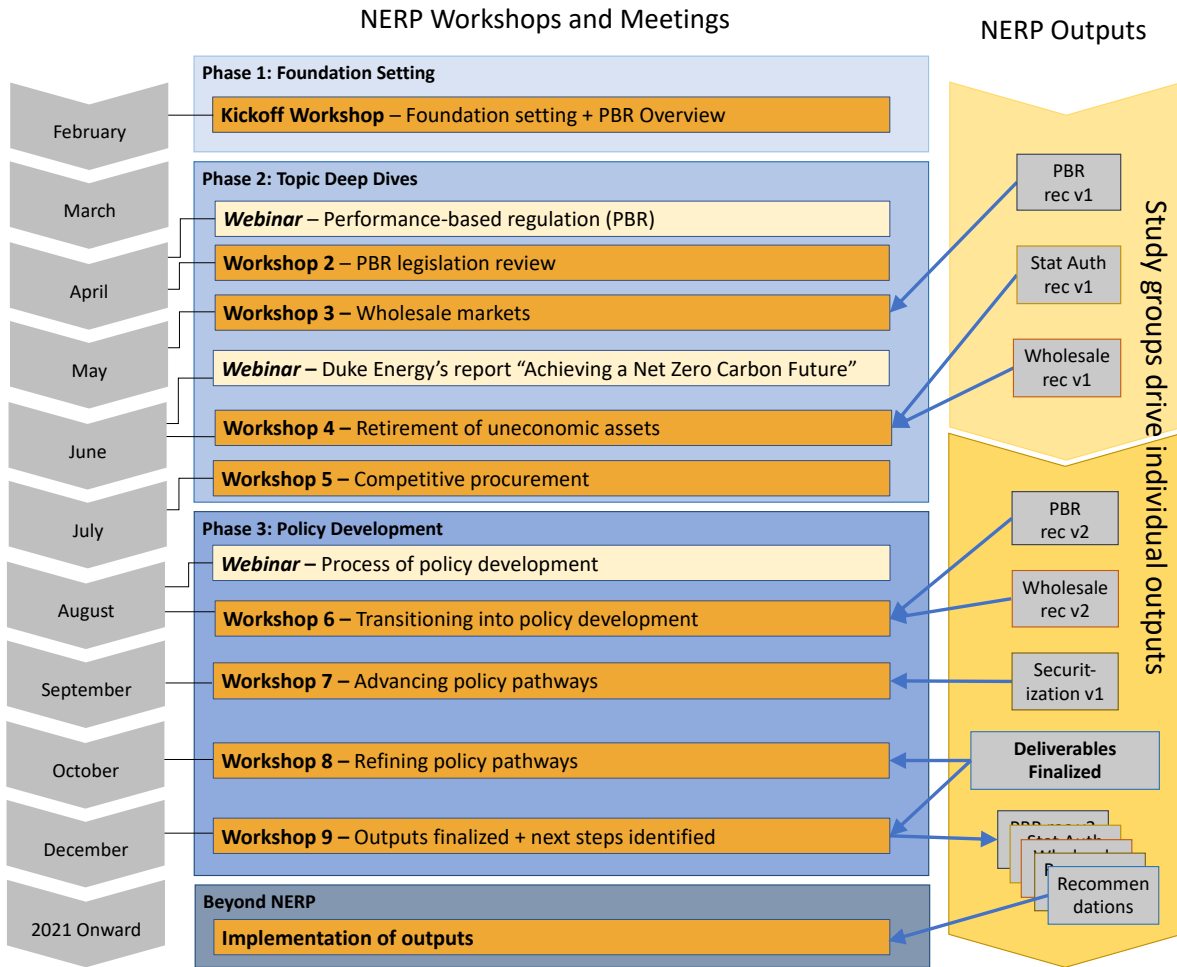
- Performance-based regulation (PBR),
- Accelerated retirement of generation assets including through securitization,
- Wholesale market design and competition, and
- Competitive procurement for resource acquisition.

The third phase of NERP focused on turning topics of interest into policy proposals. Four study groups formed, one for each of the topical deep dive focus areas. Study groups consisted of 5-15 members of NERP who self-selected to participate in the development of policy ideas within each topic area. Study groups each had two co-chairs that helped organize and lead the advancement of policy proposals. Study groups were responsible for proposal development, presenting to the full stakeholder group on their progress, and for soliciting feedback and incorporating that feedback into proposals. Study groups shared drafts of their proposals and other outputs in NERP workshops 6, 7, and 8 where they received substantive feedback and incorporated the views of other stakeholders not involved in the study group deliberations. Study groups produced proposals that were presented at the final workshop in December 2020.

Stakeholders were not required to endorse final recommendations. While work products and final recommendations received broad support and general agreement on the elements contained within them, there is not full consensus on all details. RAP and RMI sought to include areas of disagreement in this report, noted in the “Key Points of Discussion and Content Development” sections of each topic.

2020 North Carolina Energy Regulatory Process Workplan

Last updated on December 18, 2020



Convening Team

The Regulatory Assistance Project (RAP) and Rocky Mountain Institute (RMI) partnered to convene NERP. RMI and RAP served in two primary roles through the process. The first role was as convener and facilitators of the process. The organizations collectively designed the year-long process and the individual workshops. In addition, RMI and RAP provided technical expertise and assistance to guide NERP activities and support output development. This was necessary to design effective workshops, design the content for the topical deep dives, and to invite additional content experts to serve as presenters. RMI and RAP also provided technical expertise to study groups when requested by participants.

NERP Participants

To support the most constructive stakeholder process, participation at meetings was limited to 30-40 individuals spanning North Carolina organizations representing a wide variety of interests. This multi-stakeholder approach allowed broad and diverse representation among participants while promoting progress on the specific topic areas within the scope of NERP. Based on review of organizations and individuals that participated in the CEP process, the North Carolina DEQ helped identify the organizations to invite to participate in NERP. A list of participant organizations can be found in the appendix.

In limited cases, organizations were allowed to send additional observers to attend meetings in order to support learning and product development. After NERP settled on its ambitious agenda and scope of topics, the convening team offered delegates to include additional participants from their organizations to support study group content development.

Expectations of Participants

- Due to restrictions on attendance, participants were asked to represent a broader set of stakeholders and/or constituents at meetings. This required additional outreach and engagement between meetings to solicit input.
- Participants (or a pre-determined designee) were expected to attend every session of the process.
- Participants were asked to work together between meetings to develop presentations for the broader group and materials that support the summary report.
- Participants were expected to work in good faith to achieve process objectives. This included bringing a collaborative spirit, and a willingness to challenge assumptions and consider new ideas to support North Carolina energy goals.
- Participants were not required to explicitly endorse final written products or policy ideas that emerge from NERP.

Guiding Outcomes

At the February kickoff workshop, participants identified outcomes that they would like to see for the process and for resulting energy reforms. The list of outcomes is shown below, grouped by the following outcome categories: improve customer value, improve utility regulation, improve environmental quality, and conduct a quality stakeholder process. When asked to prioritize three outcomes, affordability, carbon neutrality, and regulatory incentives aligned with cost control and policy goals rose to the top and became the agreed upon priorities of NERP. Outcomes are seen categorized below, with the top three priorities highlighted. These outcomes served as a guiding framework for NERP's work, against which energy reform options were considered.

Outcome Category	Outcome
Improve <u>customer value</u>	Affordability and bill stability
	Reliability
	Customer choice of energy sources and programs
	Customer equity
Improve <u>utility regulation</u>	Regulatory incentives aligned with cost control and policy goals
	Administrative efficiency
Improve <u>environmental quality</u>	Integration of DERs
	Carbon neutral by 2050
Conduct a quality <u>stakeholder process</u>	Inclusive
	Results oriented

Priority Areas

After the second phase of NERP that consisted of topical deep dives on PBR, wholesale markets, accelerated retirement of generation assets, and competitive procurement, the group decided not to narrow the list of reforms, believing that all four topics were important for the state of North Carolina to consider to fulfill state clean energy goals. Thus, study groups were formed for each topic. In workshops 8 and 9, NERP considered how the priority areas could interact or be combined as a package of reforms.

The following sections summarize the work of the four study groups and related NERP discussions.

Performance-based Regulation

PBR In Brief

- Performance-based regulation was a significant focus of NERP stakeholder work, following its identification in the CEP as a key tool to realign utility financial incentives with social and policy goals.
- A PBR study group conducted extensive research of PBR mechanisms and their applicability to North Carolina utilities, including multi-year rate plans, revenue decoupling, and performance incentive mechanisms. In combination with other updates to utility regulations, these PBR mechanisms can motivate utility achievement of key outcomes while balancing customer costs with utility financial considerations.
- The primary recommendation on PBR from NERP is for the legislature and the NC Utilities Commission to pursue a comprehensive package of PBR reforms to include a multi-year rate plan (MYRP), revenue decoupling, and performance incentive mechanisms (PIMs).

Background

Performance-based (or outcome-based) regulation is intended to motivate utilities to accomplish outcomes that customers or society deem desirable. In doing so, PBR can help shift utility focus away from certain outcomes that may be inadvertently incentivized by traditional ratemaking.

In the current system, utilities increase their revenues by increasing electricity sales in the short term (known as the throughput incentive) and increase their profits by favoring utility capital spending over other options as the method by which to solve identified grid needs (known as the capital expenditure, or capex, bias).

The *throughput incentive* arises from the fact that, in traditional ratemaking, prices are set primarily on a volumetric basis based on a historic level of costs and sales, normalized and adjusted for known and measurable changes. After prices are set in the rate case, if utilities sell more electricity than was estimated in the rate case they increase their revenues and therefore profits (assuming costs do not fluctuate significantly based on sales volume in the short term). This incentive leads utilities to be reluctant to pursue activities and programs that lead to a decrease in sales throughput, such as energy efficiency measures or enabling customer installation of distributed generation.

The *capex bias* originates from the fact that utilities are typically allowed to earn a regulated rate of return (profit percentage) on shareholder capital that they invest in physical assets, such as power plants, transmission wires, distribution grid assets, company trucks, computers, buildings, etc. This results in utility preference for capital expenditures as solutions for grid needs, whereas many cost-saving or emissions-reducing opportunities result from program innovations, such as customer efficiency programs, that fall into the category of operating expenditures (opex), on which no rate of return is earned.

PBR offers a set of tools that can create utility incentives that are more aligned with customer and societal goals. For example, PBR can make it more likely that clean energy, energy efficiency, and carbon reduction goals are achieved by rewarding utilities for making progress on these outcomes. There is no one uniformly adopted combination of PBR tools. Some states have implemented one or two reforms; others are examining comprehensive measures. Many states have been using revenue decoupling for quite some time and are more recently considering the addition of multi-year rate planning and performance mechanisms.

NERP primarily discussed three PBR mechanisms: revenue decoupling, multi-year rate plans, and performance mechanisms. A brief description and explanation of these three mechanisms is provided below.

Revenue Decoupling

Decoupling breaks the link between the amount of energy a utility delivers to customers and the revenue it collects, thus minimizing the throughput incentive described above. Allowed revenue is set in a rate case as usual. Rather than setting prices in the rate case and leaving them unchanged until the next rate case, under revenue decoupling prices are set in the rate case but adjusted up or down over the course of the rate effective period to ensure that collected revenues equal allowed revenues (no more and no less). Decoupling goes a step further than NC's existing "net lost revenue" mechanism, which targets only approved efficiency or demand-side management (DSM) programs, by removing the disincentive to reduce sales in all situations. This would include reduced sales from distributed energy resource (DER) deployment, reduced sales from efficiency and conservation efforts by customers that are not part of a utility program, and reduced sales from certain rate designs or other utility programs that may not qualify as an approved DSM/energy efficiency (EE) program.

Multi-Year Rate Plan (MYRP)

A MYRP begins with a rate case that sets the utility base revenues for the test year, based on the normal ratemaking process. Under a MYRP, the revenue requirements necessary to offset the costs that are contemplated to occur under an approved plan would be set for multiple years in advance (typically 3–5 years). Utility compensation would be based on forecasted costs that are expected under the approved plan, rather than the historical costs of services. Customer rates would be reset annually through NCUC review under the terms set out for the MYRP.

Performance Incentive Mechanisms

Introduction of carefully designed performance incentive mechanisms (PIMs) into ratemaking procedures could create new incentives for utilities to accomplish new policy goals by linking a portion of utility revenues to utility performance in achieving those goals. PIMs provide positive and/or negative incentives to utilities to perform certain tasks or accomplish certain outcomes. If a significant portion of a utility's revenues is tied to performance, PIMs can begin to shift a utility's investment or management focus away from increasing capital assets and toward the accomplishment of the public policy objectives reflected in PIMs, potentially mitigating the utility's capex bias.

In 2007, North Carolina passed Session Law 2007-397 ("Senate Bill 3"), which encourages renewable energy and energy efficiency. That legislation authorized the NCUC to approve performance incentives for utilities related to adopting and implementing new DSM and EE measures. The PBR proposal by NERP would expand that to include performance incentives for other areas of public policy interest. In the rules adopting Senate Bill 3, the NCUC stated that recovery of net lost revenues could be included as an incentive for DSM/EE programs, and the NCUC subsequently approved the recovery of net lost revenues for DSM/EE programs for utilities within the state, effectively decoupling sales from utility profits for reductions in sales caused by utility DSM/EE programs. As discussed above, the PBR proposal by NERP goes a step further by removing the disincentive to reduce sales in all situations.

Key Points of Discussion and Content Development

NERP participants generally agreed that a package of PBR reforms as described above is desirable for the state of North Carolina, and that the reforms should be implemented together.³

Some stakeholders believe that individual PBR mechanisms could be successfully implemented in isolation. As described above, each of the mechanisms studied in NERP has the ability to address different challenges identified in the current regulatory framework. NERP participants tended to agree that the three mechanisms are complimentary and should be implemented together.

Points of Discussion and Agreement: Decoupling

Stakeholders agreed upon many design details and recommendations for the NCUC regarding decoupling. Some of the key points of consensus were that residential customers and all utility functions (generation, transmission, distribution) should be included. The group also agreed that small/medium general service customers should be included but noted that there may be some technical challenges with doing so given the current structure of the net lost revenue mechanism. The group also generally agreed that lighting and large general service customers would not need to be included, but that this design detail would need to be decided upon in the context of implementing PBR at the NCUC. Stakeholders also agreed that there were two methods for adjusting revenue in a decoupling mechanism that ought to be considered but did not come to agreement on a recommendation because there were pros and cons identified for both methods. Stakeholders agreed that annual adjustments to rates should be transparent, and that there should be a cap on the annual size of any adjustment to rates with any additional amount deferred to a future period. Finally, the group agreed that if electric vehicle charging sales are included in a decoupling mechanism, then other approaches (e.g., a PIM) should be used to incentivize the utility to enable EV adoption.

Points of Discussion and Agreement: Multi-Year Rate Plan

Stakeholders generally agreed that the concept of a MYRP could work for North Carolina. MYRPs can encourage cost containment and can remove the current disincentive utilities face in making smaller scale investments needed for the clean energy transition by reducing regulatory lag on those investments. Many of the implementation details were not agreed upon in NERP and would need to be discussed in greater detail through the process of filing and approving a PBR Application at the NCUC. The group believes that MYRP can work well with decoupling and PIMs as part of a broader package of reforms and that the cost containment incentive in a MYRP could motivate the utility to choose the most cost-effective solutions for grid needs, leading to cost control that would benefit customers. At least one stakeholder expressed a concern that a MYRP can reduce NCUC oversight and the ability of all stakeholders to advocate on points important to them on a regular basis, as they are currently able to do in rate cases.

Stakeholders did not agree on a revenue adjustment mechanism to be used to adjust rates between rate cases but did agree that it should be clearly defined at the outset in the initial rate case and closely coordinated with the revenue adjustment mechanism chosen in the decoupling mechanism. The group recommends using a three-year term for an initial MYRP in order to gain experience with the mechanism. The scope of costs to be included within the MYRP was a point of disagreement among the stakeholders. Historically, MYRPs implemented elsewhere have covered most utility base costs in order to create the strongest cost-containment incentive possible. However, a MYRP would not necessarily need to apply to a broad swath of utility costs. Stakeholders within the PBR study group had varying opinions on whether the scope of costs covered by the MYRP should be broad or narrow. Some stakeholders expressed concerns that a MYRP of broader scope could

³ Deeper explanation can be found in the NERP PBR study group document titled *NERP Guidance on Performance-Based Regulation*.

increase risks to ratepayers and favored an approach that limited MYRP to known and measurable capital projects. The PBR study group recommends that an earnings sharing mechanism (ESM) be used in order to protect both customers and shareholders from over- and under-earnings. However, the group did not agree on whether there ought to be a “dead-band” of over- or under-earning in which no adjustment is made, and how sharing tiers within the ESM ought to be designed.

Points of Discussion and Agreement: Performance Incentive Mechanisms

Stakeholders agreed that there ought to be some underlying principles that would guide the design of PIMs and help align around shared objectives. Specifically, PIMs should: advance public policy goals and drive new areas of utility performance; be clearly defined, measurable, and verifiable; comprise a financially meaningful portion of utility earnings opportunities; avoid duplication of other rewards or penalties created by other regulatory mechanisms; not penalize the utility for metrics or outcomes that are not at least somewhat in its control; and reward outcomes rather than inputs. The group agreed that once a PIM is established, it should be revisited on a regular basis to evaluate whether it is helping to achieve the outcome in question. The stakeholders developed an extensive list of possible PIMs and metrics and recommends that the commission require utilities to track as many of the metrics as deemed useful and cost-effective in order to inform future PIM development. The group recommends tracking the performance separately in low-income counties, where feasible. The following outcome areas were discussed: peak demand reduction, integration of utility-scale renewable energy and storage, integration of DER, low-income affordability, energy efficiency, carbon emissions reduction, electrification of transportation, equity in contracting, resilience, reliability, and customer service. Most of these were assigned “preferred” metrics and “alternative” metrics by the group. It should be noted that not all members of the study group agrees with every metric, but general agreement exists that the outcome areas targeted are the right ones.

NERP Recommendations

NERP recommends that the legislature and the utilities commission pursue a comprehensive package of PBR reforms to include a multi-year rate plan, revenue decoupling, and performance incentive mechanisms.

Additional context about these mechanisms and key design decisions that need to be made are discussed below.

Revenue Decoupling

Many states implement decoupling as part of a broader PBR package, and there are synergies between the mechanisms. For example, PIMs can be used to incentivize electric vehicle charging or economic development when decoupling removes these incentives from the current ratemaking structure. Additionally, where decoupling removes a disincentive for the utility to reduce sales through energy efficiency or other means, PIMs can go a step further and create a positive incentive for the utility to reduce sales. Decoupling also works well with multi-year rate plans. The MYRP can provide for small, annual changes in rates, and the decoupling mechanism can true up the sales that the MYRP rates are based on to actual sales realized during each year of the plan. Thus, decoupling and MYRPs together can reduce the need for frequent rate cases and can break the linkage between utility sales and profit margin.

Key design decisions that states must make when implementing decoupling include what rate classes to include within the mechanism, what utility cost functions (e.g., generation, transmission) to include, how to adjust allowed utility revenue over time (if at all), and how to handle surcharges and refunds to customers.

Multi-Year Rate Plan (MYRP)

This approach can create added incentives for the utility to contain costs and can also reduce the regulatory costs from more frequent rate cases. MYRPs can mitigate the regulatory lag associated with certain utility assets, such as grid investments and distributed energy resources, give an incentive for utility cost containment,

by setting a framework for predictable revenue increases into the future. The terms of a MYRP often include the following:

1. Moratoriums on general rate cases for the term of the MYRP.
2. Attrition relief mechanisms (ARMs) in the interim years that automatically adjust rates or revenue requirement to reflect changing conditions, such as inflation and population growth.
3. To maintain or pursue other regulatory and policy goals, MYRPs should be combined with PIMs (sometimes considered “backstop” protections for reliability or other services), an ESM, and other tools.
4. Off-ramp or other course correction tools can be built in to ensure that the commission or other parties have the ability to raise concerns and make adjustments to the plan under certain circumstances.

As discussed above, MYRPs work well with decoupling. Additionally, MYRPs can work well with PIMs by establishing the cost recovery plan for investments that will achieve a goal and then creating a financial incentive or penalty for achieving or failing to achieve that goal. For example, to encourage increases in electric vehicle adoption or distributed energy resources, a multi-year rate plan can include the investments the utility must make to achieve these goals and then a PIM can attach a financial incentive to the goal.

Key design decisions that states must make when implementing multi-year rate plans include: choosing the mechanisms with which to adjust rates between rate cases; the term (or length) of the MYRP which sets the amount of time the utility must “stay out” between rate cases; the scope of the utility costs to be included or covered by the MYRP; whether and how to structure an ESM by which the utility and its customers share the benefits and costs of earnings above and below the allowed return; and how to structure an off-ramp or course correction.

Performance Incentive Mechanisms

Development of PIMs requires setting desired outcomes, identifying metrics that can be used to measure utility performance toward those outcomes, and collecting data to determine how a utility has performed historically. This data can be used simply to track and report utility performance, or to score that performance against a target or benchmark that has been set. It can also be tied to financial rewards or penalties, at which point the mechanism is formally referred to as a PIM. If a utility achieves its performance target, it can receive a financial reward or it can avoid a penalty.

Key design decisions that states must make when developing PIMs include the prioritization of key outcomes to be targeted, identification of potential data sources for tracking utility performance, identification of metrics that will usefully track utility performance toward outcomes, the design of a financial penalty or reward (which can take many different forms), and the time period over which to measure achievement and deliver financial rewards or penalties.

Process Recommendations

The NC General Assembly would need to authorize the NCUC to implement PBR. The NCUC would then need to lead a rulemaking process to set up all of the filing requirements and procedures that a utility would need to follow in a PBR application. The group recommends that the NCUC determine whether and in what form a stakeholder process should take place to gather input prior to a utility filing a PBR application. The group also recommends that the NCUC monitor utility performance and system outcomes and make adjustments to guide utilities to continued improvement and value creation for customers.

PBR Outputs

NERP produced the following documents for dissemination, to inform subsequent policy discussions with various audiences:

1. **Draft PBR legislative language authorizing certain PBR mechanisms in North Carolina:** Legislation that allows the NCUC to use performance-based regulation, specifically revenue decoupling, multi-year rate plans, and performance incentive mechanisms. Directs the NCUC to develop rules related to PBR filings, their reviews, and the decision-making process.
2. **PBR regulatory guidance for the NCUC:** Guidance and recommendations for the NCUC in implementing PBR reforms in ways that reflect the NERP stakeholder discussions
3. **PBR fact sheet:** Three-page fact sheet explaining PBR mechanisms for legislative or similar audiences
4. **Two PBR case studies:** One examining Minnesota's process and experience with PBR; another looking at North Carolina's process and experience with gas decoupling

Wholesale Electricity Markets

Wholesale Electricity Markets in Brief

- Reform of the State wholesale electricity market was a significant focus of NERP stakeholder work, due to its relevance to the CEP broadly, mention in key publications, and recent developments in North Carolina including southeast utilities' proposal for an energy exchange market.
- A study group investigated market reforms and mechanisms specifically where applicable to existing or proposed studies.
- NERP assessed reforms and market designs including the Southeast energy exchange market (SEEM) proposed by utilities in the Southeast U.S., a potential energy imbalance market (EIM), and a regional transmission organization (RTO) for the Carolinas or a larger southeast footprint.
- NERP recommends that the General Assembly direct the NCUC to conduct a study on the benefits and costs of wholesale electricity market reform and implications for the North Carolina electricity system.

Background

Wholesale electricity markets are markets where electricity is bought and sold for resale. Unlike retail transactions – electricity sales to the end user – wholesale transactions consist of power sales from generators to electricity providers. The rates and service standards, as well as reliability and market design of interstate transmission is regulated by the Federal Energy Regulatory Commission (FERC). FERC, established by the Federal Power Act of 1935, oversees all interstate wholesale power sales and markets. State-specific regulators, serving on public utility commissions (PUCs), provide oversight to ensure reasonable rates for end-use customers.

There are seven organized wholesale markets in the U.S. These territories are managed by a Regional Transmission Operator (RTO) or an Independent System Operator (ISO) and regulated by FERC. RTOs & ISOs are balancing authorities; they are responsible for bulk system reliability, transmission system access, and operation of the competitive market mechanisms that allow independent power producers and other non-utility generators to trade and dispatch power. Neither RTOs nor ISOs own generation or transmission but rather control how these assets operate, serving as independent, non-profit, system operators.

The Southeastern and Western U.S. markets are traditionally regulated; a single entity owns and operates the three major grid components - generation, transmission, distribution - within a designated service territory. In a vertically integrated utility market like North Carolina, the regulated utilities own and operate the transmission system, are responsible for bulk system reliability, non-discriminatory transmission system access and are the balancing authority responsible for constant grid operation. In exchange for performing those services, these utilities have prices set by the NC Utilities Commission and are legally obligated to provide reliable electric service to all customers per the regulatory compact.

North Carolina features 3 investor-owned utilities (IOUs), more than 70 municipal utilities, and 26 electric cooperatives. Duke Energy Carolinas and Duke Energy Progress represent the majority of supplied electricity in the state - 96% in 2018. Dominion Energy North Carolina, in the northeast corner of the state, supplied the remaining 4% of utility-supplied electricity. Combined, 23% of IOU sales in 2018 were to the wholesale market where state electric cooperatives, municipalities, or agencies representing those parties, procured electric power

for their retail markets. North Carolina's wholesale market makeup and processes, therefore, have significant relevance to the State population, markets, and industries.

While the NERP was initiated by the CEP: B-1 Recommendation, the CEP listed multiple recommendations related to the state's wholesale market:

- **B-4:** Initiate a study on the potential costs and benefits of different options to increase competition in the electricity sector, including but not limited to joining an existing wholesale market and allowing retail energy choice.
- **C-1:** Establish comprehensive utility system planning process that connects generation, transmission, and distribution planning in a holistic, iterative, and transparent process that involves stakeholder input throughout, starting with a Commission-led investigation into desired elements of utility distribution system plans.
- **C-3:** Implement competitive procurement of resources by investor-owned utilities.
- **D-2:** Use comprehensive utility planning processes to determine the sequence, needed functionality, and costs and benefits of grid modernization investments. Create accountability by requiring transparency, setting targets, timelines and metrics of progress made toward grid modernization goals.
- **H-1:** Identify and advance legislative and/or regulatory actions to foster development of North Carolina's offshore wind energy resources.

Discussions about the potential for wholesale market reform in North Carolina are not new. The North Carolina General Assembly enacted legislation in 1999 to study the use of wholesale and retail electricity markets in the state. The study recommended a more competitive system, but such a system was never implemented due to numerous factors including the California energy crisis in the late 1990's.

Likewise, enacting state wholesale reform has recent precedent. In 2007, North Carolina adopted the Renewable Energy and Energy Efficiency Portfolio Standard (REPS). The REPS, coupled with stable, long term avoided cost contracts, and a state tax credit, enabled NC to diversify its electricity supply and offset over 10% of its electricity demand with renewables and efficiency.

More recently, in 2020, the South Carolina state legislature authorized, via SC HB 4940, a study to evaluate a broad variety of electric wholesale, retail, and operational reforms and a study committee to review resulting options. NERP stakeholders have identified that any resulting reform in South Carolina could impact North Carolina as both states share utilities and electric infrastructure. Key provisions specifically mention creation of broader wholesale markets with states neighboring S.C. and the separation of existing vertically integrated electric utilities into two distinct entities: companies that generate electricity and companies that transmit and distribute electricity.

Key Points of Discussion and Content Development

Many NERP stakeholders are interested in wholesale market reforms because increased competition and transparency to generation economics may lower prices, diversify supply, and aid both system planning, and the integration of renewables. Conversely, N.C. has low prices compared to the national average, and diverse generation with respect to its integration of more solar electric generation than any state except California. Joining or creating an RTO does not ensure perfect competition, nor would it inherently lower emissions. In addition, due to typical RTO governance structures, RTOs may not protect stakeholder interests outside of participating buyers, sellers, and transmission owners. Thus, there is agreement that any proposed or potential wholesale market reform in the state must first be carefully studied as the implications of wholesale reforms affect many parties- retail, wholesale, and otherwise.

Throughout NERP, stakeholders reviewed, proposed, refined, and in some cases rejected, a number of wholesale electricity market reforms based on potential to meet net-zero greenhouse gas emissions by 2050, align regulatory incentives with cost control and policy, and maintain affordability and bill stability.

Points of Discussion: North Carolina Joins PJM Interconnection

Early in the process, stakeholders investigated the potential benefits and costs of joining PJM – the wholesale electricity market bordering North Carolina – as Dominion Energy had previously joined PJM and PJM’s proximity to NC, along with some shared infrastructure, suggested ease of process. In investigating Dominion Energy’s path to PJM, the Wholesale study group found the NCUC decision explicitly stated that such a ruling was not to serve as precedent and further, Dominion Energy did not own any generation in NC (the power it supplies the State is generated outside NC). PJM’s Minimum Offer Price Rule (MOPR), a mechanism which accounts for state policy support of renewables by increasing renewable bid prices into the market, is a concerning factor as well. Given NC’s established success as a utility scale solar state, MOPR is viewed as particularly detrimental to NC’s dispatch into the PJM market and the NC solar industry. It’s impact to state’s ability to carry out its own energy and environmental policies has resulted in certain PJM states taking legal action related to MOPR.

Ultimately, NERP recommends that joining PJM should not be evaluated at this time. The nature of the PJM market could make North Carolina state goals, such as REPS, clean energy standards, greenhouse gas reduction targets, and other state policies more difficult and costly to implement. Further, integration into PJM takes minimally 24 months and any associated integration expenses are billed directly to the transmission owner impacting customer rates. While NERP does not support NC joining PJM at this time, it is acknowledged that changes in Federal policy and a new FERC could warrant reconsideration of this item at a future date.

Points of Discussion: Form a Joint Carolinas RTO

NERP discussed the merits of investigating a North and South Carolina RTO. Duke Energy and Dominion Energy operate in each state. These utilities have critical high-voltage infrastructure in each state, and perhaps just as important, experience with each states’ process and regulatory compliance. Because of these factors, some NERP stakeholders postulated a joint Carolinas RTO could be easier to implement and less costly than joining an existing RTO. NERP stakeholders caution that the further apart the Carolinas’ power market structure become, the more complex the challenges of managing costs, environmental impact/compliance, and broader system operation become.

A Carolinas RTO concept presents a number of considerations worthy of investigation. Conventional understanding holds that geographic footprint of the RTO is a key factor of cost and benefits. NERP questioned whether a Carolinas RTO could achieve significant cost savings when compared to larger RTOs and regardless, what methodology would best represent such a comparison. Further, if the benefits did prove limited, could that difference be mitigated? NERP ultimately decided that due to the above considerations, the RTO in the proposed study could be defined by the geographic barriers of North and South Carolina or a larger area such as the southeastern United States.

Of specific relevance to this process, traditional RTOs do not feature robust, non-stakeholder processes such as NERP by default nor are RTOs regulated by any one state. While most RTO decision making does happen through a participant-driven process, most RTOs restrict voting-member participants to transmission system owners, buyers, and sellers. Similarly, the role of each state's utilities commission could be limited under an RTO as FERC is the regulatory agency with jurisdiction over interstate electricity and wholesale markets. Stakeholders agreed that any proposed reform should protect processes such as NERP, which include broader system, environmental, and social concerns, and also ensure that both states' regulatory agencies have roles in system oversight to the extent FERC jurisdiction and RTO rules allow.

Points of Discussion: EIM & SEEM

NERP identified energy imbalance markets (EIMs) as a less timely and costly alternative compared to the Carolinas or Southeastern RTO concept. An EIM is voluntary market for dispatching real-time energy across utility service territories. Each participating utility retains ownership and control of its transmission assets but opts to bid generation into a centralized dispatch authority. EIMs allow utilities to optimize intersystem imbalances without the added operational or structural requirements of an RTO.

A Carolinas, or Southeastern, EIM could bring benefits to the region via gains in broad system efficiencies, lower operational reserve requirements, generator price transparency, and a governance structure that allows input by non-utility participants such as states or independent power producers. Existing EIMs are extensions of RTOs and operated as such; PJM would likely be the Carolinas RTO operator. Yet this function would not require utility RTO membership and benefit by avoiding transmission operations, compliance, and transmission allocation costs. While not as expensive as creating an RTO, EIMs have required costly, multi-year processes in other regions of the country. Critical to some NERP stakeholder interests, while EIMs may provide better integration of variable renewable production, they do not inherently provide non-balancing authority entities, such as Independent Power Producers (IPPs), a platform for market access.

Publicly announced in mid-2020, SEEM, the Southeastern Energy Exchange Market, is a proposed 15-minute automated energy exchange market between balancing authorities of the Southeastern U.S. While full details of the market construct are not yet known, what is proposed indicates a simpler market than a traditional EIM with a contracted platform administrator that operates the system that follows market transactions and a market auditor tracking market rules. Further, SEEM will not depend on utility RTO membership and thus avoids additional significant infrastructure, compliance costs administrative, and transmission allocation costs.

NERP stakeholders agreed in principle to the lower setup costs of SEEM as compared to an EIM. However, some stakeholders viewed the marginal reforms proposed by SEEM to be unsatisfactory. SEEM, per that perspective, does not appear to expand market opportunities to non-utility participants, nor does it expose incumbent generators to competition, provide operational transparency or public interest governance, nor a framework for additional market expansion. Ultimately, each of the proposed wholesale market reforms feature potential benefits and costs to North Carolina.

NERP Recommendations

NERP recommends the General Assembly of North Carolina direct the NCUC to conduct a study on the benefits and costs of wholesale market reform and implications for the North Carolina electricity system.

A proposed study rationale, elements, authorization, and funding accompanies this report. NERP recommends the following market structures be evaluated:

1. An RTO as defined by a) geographical boundaries of North Carolina and South Carolina or b) a larger region such as the Southeast.
2. An EIM as defined by a) geographical boundaries of North Carolina and South Carolina or b) a larger region such as the Southeast.
3. The energy exchange market proposed by a consortium of over 15 entities in the Southeast U.S. in 2020 and referred to as the Southeastern Energy Market (SEEM).

Additionally, the study should be required to offer recommendations to the General Assembly as to whether any of these market structures should be pursued further. This includes:

1. Recommending whether legislation is to be brought forward to allow reform of the wholesale electricity marketplace,
2. Recommending a model for wholesale competition that should be implemented if applicable, and
3. Recommending a stepwise approach to incorporating municipal and cooperative electricity generators and providers into wholesale market reforms, as needed.

Wholesale Market Outputs

NERP produced the following documents for dissemination, to inform subsequent policy discussions with various audiences:

1. **Legislative language authorizing the NCUC to conduct a wholesale market reform study:** A number of wholesale reforms are relevant to NERP stakeholder organizations, recent academic research, and adjacent state policies. The study authorized by this language considers the costs and benefits of wholesale electricity market reform at the state and regional level.
2. **Wholesale market reform study scope and criteria:** This document reviews the proposed market reforms in greater detail and offers guidance to study process, structure, and funding.
3. **A meta-analysis of proposed market reforms:** As each market reform features a number of similarities and points of comparison, the group provides a high-level review of key market criteria.
4. **Electricity market structure factsheets:** Each construct outlined in the meta-analysis are featured in 2- to 3-page factsheets which provide greater detail on the respective markets.

Securitization for Generation Asset Retirement

Asset Retirement in Brief

- NERP participants' interest in asset retirement was primarily focused on securitization, which is the focus of the content in this report.
- Securitization is a financing mechanism involving the issuance of bonds to raise funds to refinance remaining undepreciated value of existing coal plants.
- If properly designed, securitization used with a coal retirement plan, can lower customer bills, reduce air and water pollution, support coal plant communities in the transition, and allow utilities to reinvest in clean energy to replace lost revenue from legacy coal plant investments.
- NERP's primary recommendation is to expand the use of securitization in North Carolina beyond storm recovery costs to include generation asset retirements.

Background

The declining costs of renewable energy and higher cost of operating coal plants relative to other resources, in addition to the state priority of reducing greenhouse gas emissions, particularly carbon dioxide, has increased interest in retiring coal plants in a low-cost way. However, these coal units remain in the portfolio due to the utilities' need to recover their investment and maintain reliability. As North Carolina has a significant amount of coal capacity that could be financed to provide ratepayer benefits, the large amount of generation needing to be replaced must be planned carefully to ensure costs are minimized, utilities are fairly compensated, system reliability is maintained, cleaner technology solutions are deployed, and pollution levels are reduced.

In order to retire coal plants, the remaining undepreciated value must be addressed. Securitization is a refinancing mechanism involving the issuance of bonds to raise funds to refinance the remaining undepreciated value of existing coal plants. The bonds are paid back over time through a dedicated surcharge on customer bills. Because the surcharge is irrevocable and payment to the lender is basically "guaranteed" through the legislation, the bonds can typically be issued at an interest rate even lower than the usual utility bond interest rate. In addition, most major credit rating agencies do not include securitization debt, up to certain limits, in assessing the utilities debt to equity ratio for credit rating purposes. Therefore, the utility can generally refinance the outstanding undepreciated value with 100% securitization financing instead of using its standard combination of debt and equity financing. Both of these factors combined lead to cost savings for customers.

By itself, securitization would translate to a loss in earnings for the regulated utility by reducing the total amount of capital in which the utility is invested. However, securitization can also be paired with utility reinvestment in replacement capacity to maintain reliability. Because this replacement generation would be financed using a combination of debt and equity, this option has the potential to recoup and even grow utility earnings.

Duke Energy currently operates six coal plants totaling about 10,000 MW of capacity. The low cost of natural gas and renewables, along with additional environmental compliance costs, has shifted electricity generation toward cheaper sources of energy in recent years, and the trend is expected to continue as the economic gap widens. Coal plants in the state, originally built to run 75-80% of the time, are now running, on average, only 35% of the time.

Early economic retirement of North Carolina's coal plants and replacement with zero emitting resources is estimated to achieve the 70% reduction in greenhouse gas emissions goal specified in the Clean Energy Plan by itself, provided the amount of imported electricity and its carbon intensity remain at or below historic levels.

Key Points of Discussion and Content Development

NERP participants discussed several topics related to securitization that fed into the development of the draft legislation. These included the savings for customers, reinvestment by the utility, transition assistance for affected communities, and replacement of coal assets.

Many believed that, at a minimum, securitization should be a tool available in North Carolina, as an option for utilities to retire fossil generating assets. Some participants believed that securitization should at least be neutral on customer cost impact, but would ideally save money for customers. For others, savings to customers should be a mandatory precondition for securitizing undepreciated assets.

There was a strong consensus among participants that the utility needs a clear path to reinvest in something — whether it be capital assets or a portfolio — after the securitization and closure of fossil assets. All supported making utility reinvestment a required element of securitization in order to make the utility whole and reduce the disincentive for utilities to use securitization for undepreciated assets. Related, there were early conversations about limiting utility ownership to a lesser, undetermined percentage (i.e., 50% of new procurements could be utility-owned and 50% of new procurements would be third-party owned). Stakeholders could not agree on an appropriate path forward, and ultimately concluded that the legislation should not prescribe a percentage of allowable utility ownership. However, there was an emphasis on recognizing that competition would be critical to ensuring least cost; thus, the asset should be owned by whoever can provide it or a portfolio at the lowest cost to customers.

As for replacement resources, there was more debate among participants of NERP. One subset of stakeholders believe that coal should be replaced through a competitive, all-source RFP process, another subset of stakeholders believe that replacement resources should be required to be clean energy resources that reduce GHG emissions and support the North Carolina Clean Energy Plan, and another subset of stakeholders believe that the IRP process should continue to dictate replacement resource planning. Another issue was raised that the state does not need a 1:1 replacement for coal capacity because those plants are currently running at low-capacity factors.

Near the end of the process, a majority of the study group aligned around the following points:

- The procurement system of the future should be one that balances carbon reduction with affordability and reliability in order to achieve the goals in the Clean Energy Plan and the prioritized outcomes of NERP.
- Natural gas systems might appear least-cost today in some cases, but may, as a result of declining costs of alternative resources, changes to public policy, or other factors, become stranded assets within 10 years.
- In order to avoid stranded assets, risk should be weighted in analysis of resource selection. There is risk to procuring new gas assets. There is a need to ensure that assets are not just cheaper today, but will be fully functional and cost effective for the entirety of their lifetime.
- Utilities should consider portfolios instead of single, specific assets.

Transition assistance to help communities affected by plant shutdowns was of importance to most participants in NERP. It was of interest to have communities be in control of how funds are used and make decisions appropriately, with some specific interest in supporting schools and local governments that will be affected by reduced tax bases. There was also interest in developing solar in locations that previously had coal to bring some level of tax base back to the community. Two areas of discussion arose around which participants did not reach a conclusion. First, there was discussion about whether transition assistance should come from securitization savings or from the state's general fund, with some believing that "it's a state policy, not a utility policy, so all state taxpayers should pay."

The study group determined that the legislation would outline that the NCUC could approve up to 15% of savings, or less, to be used for transition assistance. The study group decided it would be best not to prescribe how the funds should be allocated, as to preserve that responsibility for those on the ground who have the best sense for what is needed in the community. Therefore, the group aligned around ensuring that local governments are involved in the process.

NERP Recommendation

The asset retirement study group recommends that the North Carolina General Assembly expand securitization to be an available tool for electric utilities to retire undepreciated assets, in addition to the current use around storm recovery costs.

- The recommendation is modeled after best practices from the Colorado statute.
- Legislation would be enabling a tool, not mandating that a utility use it.
- Up to 15% of savings could be used to create a transition fund; the Commission would make this final determination.
- Any replacement capacity needed should be procured through a competitive process and approved by the Commission.
- The recommendation does not include restrictions on utility ownership of replacement resources.

Asset Retirement Outputs

NERP produced the following documents for dissemination, to inform subsequent policy discussions with various audiences:

1. **Legislative language expanding the use of securitization for retirement of uneconomic power plants:** An act to permit financing for certain undepreciated utility plant costs and for transition assistance for affected workers and communities.
2. **Securitization statute comparison:** A comparison of securitization statutes which include recovery of undepreciated plant balances and transition assistance for workers and communities affected by early plant retirements as allowable uses for securitized bonds.
3. **A fact sheet, *Expanding Securitization: Accelerating the Clean Energy Transition & Building the North Carolina Economy*:** Describes what securitization is, what the opportunity is, and highlights national precedent for any audience needing to learn more about securitization, such as the North Carolina General Assembly.
4. **Early asset retirement analysis accompanied by a two-page summary:** Analysis that evaluates accelerated depreciation, regulatory asset treatment, securitization (with and without reinvestment) and compares them to business-as-usual. It examines the tradeoffs between the different scenarios for utility earnings and customer rates on a first-year and levelized basis and can also be used to determine these impacts on an asset-by-asset or a portfolio level. The analysis is described in a two-pager that compares securitization to regulatory asset treatment and showcases the relative impacts on ratepayer savings, utility earnings, and community assistance.

Competitive Procurement

Competitive Procurement in Brief

- Competitive procurement and all-source solicitations are an area of significant interest among many of the NERP stakeholders.
- The study group evaluated issues related to the use of competitive processes for purposes of meeting future resource capacity and generation needs.
- State policy regarding utility competitive procurement should take into account unique characteristics of each utility service territory
- Subject to details provided in the group’s policy paper, NERP identified competitive solicitations as an important tool that should be utilized to meet energy and capacity needs identified in IRPs and as otherwise deemed appropriate by the NCUC.

Background

North Carolina investor-owned utilities are required to submit IRPs to the NCUC to forecast, and address, grid needs at least cost. Federal and state policies, as well as utilities themselves, are increasingly recognizing the opportunity for competition to drive these costs down as more technologies qualify as grid resources. In 2017, NC HB 589 created the competitive procurement of renewable energy program which provided a competitive bidding process for renewable energy projects in Duke Energy’s North Carolina service territory. North Carolina’s Executive Order 80 and DEQ further identified many non-generating resources, such as efficiency and battery storage as grid scale technologies — technology not traditionally in line with the utility capital expenditure and return model.

Due to its relatively small customer base and small geographic service territory in North Carolina compared to Duke Energy, and because Dominion Energy North Carolina serves its customers primarily with energy generated in Virginia and the larger PJM region, Dominion Energy North Carolina was exempt from the competitive procurement provisions of HB 589. Additionally, the Virginia Clean Economy Act (VCEA) enacted by the Virginia legislature in 2020 established comprehensive competitive procurement requirements for Dominion Energy in connection with the renewable portfolio standard (RPS) also enacted as part of the legislation. The VCEA RPS requires Dominion Energy to achieve an RPS of 100% renewable energy by 2045 in its Virginia service territory.

Competitive procurements do not restrict utility self-build or utility ownership by definition. Instead, utility-built resources or utility owned generation, become one of many potential options. Competition by this design has resulted in cost savings generally and should continue to provide lower cost investments and lower customer bills in the future. Further, utilities could potentially benefit via more innovative business structures, expanded generation options, a cleaner grid, and optimization of existing grid investments.

Key Points of Discussion and Content Development

Points of Discussion and Agreement: Defining Competitive Procurement

Given the impact of existing procurement in North Carolina, and the vast number of stakeholders interested in potential procurement reform, the competitive procurement study group began by proposing definitions to the broader NERP group. The majority of participants agree with the following definition:

Competitive procurement is an IRP-driven, all-source procurement to meet all identified needs for new resources in a manner that is consistent with policy directives and at the best available overall price.

While this definition was ultimately selected, stakeholders offered a number of suggestions as to the scope of competitive procurement. Some participants wondered for example if demand side management, energy efficiency, and distributed energy resources qualified as potential resources. Regarding the scale of competition, stakeholders asked whether new resources could compete against existing assets if their prices were advantageous. Finally, stakeholders identified cost as an area to further define as cost could include impact of stranded asset costs to ratepayers and whether carbon or other environmental considerations could be added.

Points of Discussion and Agreement: Participation

The VCEA enacted by the Virginia legislature in 2020 established comprehensive competitive procurement requirements for Dominion Energy in connection with the renewable portfolio standard (RPS) also enacted as part of the legislation. The VCEA RPS requires Dominion Energy to achieve an RPS of 100% renewable energy by 2045 in its Virginia service territory. Dominion Energy holds that any such expanded competitive procurement program in North Carolina should not apply to it as Dominion Energy owns no generation in North Carolina and further, VCEA established a number of relevant and similar processes for the utility to abide by.

While the study group did not discuss this item in detail, the group agreed that any State policy regarding competitive procurement should take into account the unique characteristics of each utility service territory and other relevant features such as, but not limited to, location of generation assets, geographic footprint, and generation portfolio.

Points of Discussion and Agreement: Utility Ownership

One of the primary points of discussion within the Competitive Procurement study group was utility participation or utility ownership of generation assets procured. Historically, utilities' ability to rate-base (i.e., allow recovery of capital costs plus a return on equity) has provided low-cost, reliable generation for NC. However, some stakeholders asserted that this model was best utilized when generation was viewed as part of the natural monopoly.

There are potential benefits to ratepayers and utilities as utility ownership ensures the financial health and growth of the utility and offers more direct operational control of the generation, diversifies life-cycle risk of the assets (due to declining revenue requirement), along with other benefits. On the other hand, rate-basing can create risks to both entities in the form of potentially higher costs, construction delays, and cost overruns.

Stakeholders have considered a myriad of issues, including whether utility ownership models are best for specific types of generation — large, thermal generation for example which are high capital cost investment that traditionally provide baseload, year-round grid support. Additionally, stakeholders discussed if there is an ideal amount of utility purchases of assets from the broader developer community.

Stakeholders have yet to come to a determination and formal recommendation on these questions. The key question that will inform this work is whether there should be a pre-determined allocation between utility, rate-based ownership and third-party ownership

NERP Recommendations

NERP recommends that the North Carolina General Assembly expand existing procurement practices to utilize competitive procurement as a tool for State electric utilities to meet energy and capacity needs defined in their respective IRPs and where otherwise deemed appropriate by the NCUC.

State policy regarding utility competitive procurement should take into account unique characteristics of each utility service territory, e.g. number of customers, geographic size, amount of utility-owned generation in the service territory, and proportion of existing generation from renewable sources located in the service territory and serving utility customers.

Competitive Procurement Outputs

NERP produced the following documents for dissemination, to inform subsequent policy discussions with various audiences:

1. **Competitive procurement policy recommendation for the North Carolina General Assembly:** An overall policy recommendation which, subject to the more detailed recommendations outlined in the document, states that competitive solicitations are an important tool that should be utilized to meet energy and capacity needs identified in an IRP and as otherwise deemed appropriate by the North Carolina Utilities Commission.
2. **A case study into the Public Service Company of Colorado's recent procurement cycle:** The subcommittee evaluated a number of states but focused primarily on a recent procurement cycle in Colorado for the Public Service Company of Colorado (Xcel Energy), which was ultimately determined to be a successful generation procurement framework.
3. **A case study into key generation procurements enacted by the Virginia Clean Economy Act:** The summary outlines the sweeping package of energy reforms established in March, 2020 that set Virginia on a path toward a 100% carbon-free electricity grid by 2050.

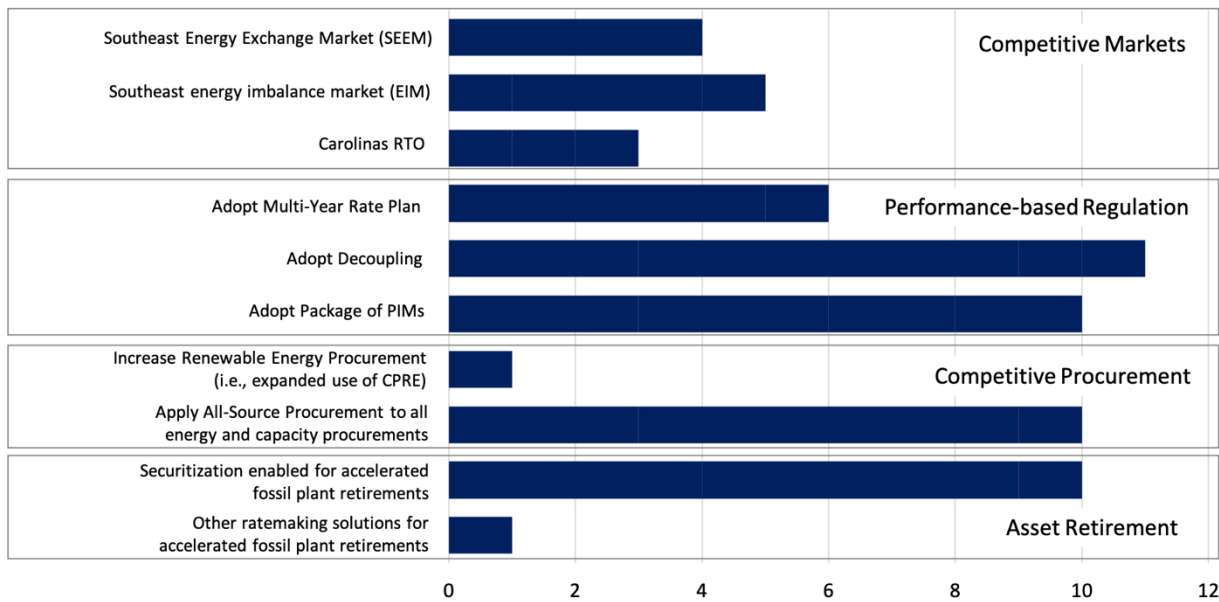
Conclusion

Achieving full consensus on reforms was not an objective of NERP, but NERP participants remain dedicated to continuing the conversation and arriving at a reform package that best meets the needs of North Carolina. Despite strong support for several reforms discussed in this report, no one reform enjoys the full support of every NERP participant, and there are nuances to participants’ views. To achieve priority outcomes, this work will need to move forward through actions of the North Carolina General Assembly, NC Utilities Commission, by the state’s utilities, and through continued input and support from stakeholders.

To aid in those continued conversations, this section explores where interest and alignment emerged through NERP dialogue, as well as how reform options may be combined in upcoming legislative action.

Stakeholder Support for Reforms

Throughout NERP in 2020, participants were asked to express their level of support for various reforms and to prioritize the work that NERP should pursue according to what reforms were (i) most important to those represented and (ii) most likely to lead to priority outcomes (carbon reduction, affordability, and alignment of regulatory incentives with 21st century public policy goals). The facilitators conducted polls and surveys of participants to assist in guiding the work of the group and inform the next steps in North Carolina. Summary results of one of those surveys is provided below, in which participants responded to the question, “Which reforms are priorities for you or your organization to immediately advance at the conclusion of this 2020 NERP process?” Each respondent could select up to three reforms; bars show the number of people who selected each reform.



The results of this informal survey, as well as other similar exercises conducted throughout NERP, demonstrate that all potential reforms discussed during 2020 have some level of support among NERP participants. Several reforms, particularly revenue decoupling, performance incentive mechanisms, all-source competitive procurement, and enabling securitization to accelerate fossil plant retirements, are high priorities for many participants at the conclusion of NERP.

A Possible Package of Reforms

Multiple possible paths forward emerged at the conclusion of the 2020 NERP process. The following describes some of the options for putting forward a package of reforms. Options 1 through 3 describe paths forward for NERP-specific topics and recommendations, whereas Option 4 recognizes the desire among many participants to ensure that a legislative package includes other provisions related to climate and clean energy.

Option 1	Option 2	Option 3	Option 4
One legislative package combines: (1) PBR authorization, (2) wholesale market study direction, (3) direction to NCUC to use competitive procurement, and (4) expansion of securitization for retirement of coal assets	One legislative package combines PBR, new securitization authorization, and direction to NCUC to use competitive procurement Separate legislation creates wholesale market study	One legislative package combines PBR and new securitization authorization Competitive procurement is pursued at the NCUC Standalone legislation creates wholesale market study	Some combination of Options 1-3, with the addition of other policy provisions such as a Clean Energy Standard, carbon reduction policy, economic growth policy, or other enabling actions

NERP briefly discussed these options in the final workshop of 2020. A majority of participants expressed support for some version of Option 4 as the best path forward. That is, there was agreement to combine policy concepts into one piece of legislation, and that such legislation should also include other enabling policies not discussed in NERP.

Agreement was not reached on what that additional enabling policy ought to be. Multiple participants believe a clean energy standard (CES) is a necessary complementary policy to the NERP reforms. Others believe that some policy that enables or requires carbon reductions, as informed by the modeling being conducted in the “A1” process, should be included in the package.

Some participants prefer including additional enabling policies in this package, including revisions to House Bill 589 (2017), inclusion of a “carbon adder” in utility planning, and IRP reform to make competitive procurement more viable. These ideas were not fully explored in the final workshop.

A handful of participants argued that Option 4 was the best path, but that legislation to create a wholesale market study should be considered separately from other reforms.

Some participants were reluctant to state their opinions about these options without having more information, particularly what the recommendations will be from the CEP A1 process on carbon reduction policy designs. Although NERP in 2020 did not negotiate a “final agreement” on a package of reforms, participants acknowledged the need to continue the conversation to further refine the details to be included.

Next Steps

A combination of the reforms discussed in this paper, combined with other energy reforms including those described in the Clean Energy Plan and the parallel “A1 process”, can support the state’s transition to a cleaner energy system. Following the NERP 2020 process, stakeholders will continue to refine details and find areas of alignment in the proposals to advance collectively. Conversations may be supported by RMI and RAP; however, participants will also consult independently with NC policymakers, decision-makers, and other constituents to brief and educate them on potential reforms. The study group outputs produced during NERP (and attached to this report) can aid in briefings and further refinement of policies for advancement through legislative and regulatory processes. Draft legislation produced during NERP will be subject to continued refinement and development through the legislative session; drafts attached to this report represent their status at the conclusion of 2020 NERP discussions.

Appendix

Full List of NERP Participating Organizations

Organization Type
North Carolina Department of Environmental Quality (DEQ)
North Carolina Utilities Commission (NCUC)
NCUC Public Staff
North Carolina Legislature
North Carolina Governor's Office
North Carolina Attorney General's Office
Duke Energy
Dominion North Carolina Power
North Carolina Electric Cooperatives
ElectriCities of North Carolina
City of Charlotte
City of Asheville
Durham County
North Carolina Chamber of Commerce
Smithfield Foods
North Carolina Retail Merchants Association
Appalachian Voices
North Carolina Manufacturers Association
Carolina Utility Customer Association
North Carolina Clean Energy Business Alliance
North Carolina Sustainable Energy Association
DEQ Environmental Justice & Equity Board
North Carolina Justice Center
Environmental Defense Fund
Southern Environmental Law Center
North Carolina Conservation Network
NC WARN
Sierra Club
Duke University Nicholas Institute
North Carolina Clean Tech Center

Contact Information

Contact	Organization	Email
NERP Contact		
Sushma Masemore	NC DEQ	sushma.masemore@ncdenr.gov
PBR Study Group Co-Chairs		
Sally Robertson	NC WARN	sally@ncwarn.org
Laura Bateman	Duke Energy	laura.bateman@duke-energy.com
Wholesale Market Study Group Chair		
Chris Carmody	NCCEBA	director@ncceba.com
Asset Retirement Study Group Co-Chairs		
David Rogers	Sierra Club	david.rogers@sierraclub.org
Tobin Freid	Durham County	tfreid@dconc.gov
Competitive Procurement Study Group Co-Chairs		
Steve Levitas	NCCEBA Board	slevitas@pgrenewables.com
Jack Jirak	Duke Energy	jack.jirak@duke-energy.com

Study Group Outputs

Outputs attached to this report represent their status at the conclusion of 2020 NERP discussions, as of December 18, 2020. If substantive revisions were received too late to allow study group discussion or full NERP feedback, it was not incorporated. Draft legislation produced during NERP will be subject to continued refinement and development through the legislative session.

PERFORMANCE BASED REGULATION STUDY GROUP

WORK PRODUCTS



NERP FACT SHEET

PERFORMANCE BASED REGULATION

ALIGNING UTILITY SYSTEM PERFORMANCE WITH REGULATORY OR PUBLIC POLICY GOALS

The 2020 North Carolina Energy Regulatory Process prioritized energy reforms that would drive affordability, carbon-reduction, and align regulatory incentives with policy goals.

WHAT IS PERFORMANCE BASED REGULATION?

Performance based regulation (PBR) is a regulatory approach that more precisely aligns utilities' profit interests with customer and societal interests through regulatory mechanisms that incentivize utilities to improve operations and management of expenses, increase program effectiveness, and otherwise align system performance with identified regulatory or public policy goals.

WHAT IS THE OPPORTUNITY?

While North Carolina is a leader in clean energy, with the second highest installed solar capacity in the nation, more than 40% of in-state generation being provided by carbon free resources, and over 110,000 clean energy sector jobs,¹ the future success of the state's clean energy transition will require, among other things, substantial greenhouse gas emission reductions; increased electric energy conservation savings over and above current savings of 1%²; continued grid modernization investments in storm hardening, targeted undergrounding of transmission and distribution power lines,

and advanced metering; and increased integration of innovative distributed energy solutions, including customer sited solar and energy storage. Indeed, both Duke Energy and Dominion Energy have established ambitious mid-century clean energy targets. Duke's own Queue Reform Proposal calls for more than "5,390 MW of additional proposed North Carolina-sited utility-scale solar projects."³

Furthermore, existing utility incentives under the current ratemaking system are not always aligned with achieving these outcomes. Under the current system, utilities make more money by increasing their electric sales, which disincentivizes increased energy conservation. In addition, grid modernization investments are often not in a utility's financial best interest, at least in the short to medium term, as considerable time may pass between when (1) a utility first incurs financing costs to fund grid modernization investments and (2) it can stand to potentially recover all of those costs in a rate case.⁴ Furthermore, a utility typically earns no profits on distributed energy, with profits being earned instead from infrastructure the utility owns and uses to provide electric services, in particular generation assets. Therefore, utilities may be incentivized to prioritize investments in utility owned generation over

¹ See <https://www.e2.org/wp-content/uploads/2019/07/E2-Clean-Jobs-North-Carolina-2019.pdf>

² See <https://nicholasinstitute.duke.edu/sites/default/files/publication/North-Carolina-Energy-Efficiency-Roadmap-Final.pdf>

³ See <https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=f83235af-6c15-4a08-ab04-7d03ef047383>

⁴ A rate case is a process through which a utility can adjust the rates it collects from customers by seeking approval from the North Carolina Utilities Commission.

investments that might, over the long term, reduce the amount of utility generation and result in cleaner energy.

If the Clean Smokestacks Act, Senate Bill 3, House Bill 589, and other landmark state clean energy legislation are any indication, further state legislative action will be crucial to the future of the state's clean energy transition. In particular, performance based regulation can help catalyze clean energy innovation.

WHAT IS BEING RECOMMENDED?

The North Carolina Energy Regulatory Process (NERP) has identified three mechanisms that should be adopted as a package:

1. Decoupling – a ratemaking mechanism that severs the link between utility sales and revenues by authorizing allowed revenues separate from utility sales and adjusting prices periodically to ensure actual revenues match allowed revenues.
2. Performance incentive mechanisms (PIMs) – a ratemaking mechanism that ties some portion of a utility's revenues or earnings to its performance on measurable customer, utility system, or public policy outcomes.
3. Multi-year rate plan (MYRP) with an earnings sharing mechanism – a ratemaking mechanism through which base rates and revenues are fixed for a multi-year term and a utility is barred from filing a rate case during that term (often referred to as a rate case moratorium). Rates or revenues are then periodically adjusted in non-rate case proceedings according to a predetermined formula or set of variables (e.g. inflation).

An earnings sharing mechanism allocates to customers a portion of utility overearnings that exceed (or under-earnings that fall short of) the earnings approved under a multi-year rate plan.

HOW DOES PERFORMANCE BASED REGULATION WORK? HOW IS IT DIFFERENT FROM THE CURRENT SYSTEM?

For a multi-year rate plan, which NERP recommends should be combined with decoupling and PIMs, a utility would still be required to file an initial base rate case to adjust its authorized electric rates and submit cost of service studies. These studies would in turn serve as the basis through which the North Carolina Utilities Commission would determine (1) the total revenue required for the utility and (2) how the revenue would be allocated and collected from the utility customer classes. The proposed performance based regulations, specifically decoupling, PIMs, and the revenue adjustment mechanisms within a MYRP, would adjust,

through increments or decrements, any base rates approved in the base rate case.

Decoupling

Once the revenue requirement is established, a decoupling mechanism would provide for periodic rate adjustments to ensure that the utility's actual revenues match its allowed revenues. Therefore, in contrast to the current system, where sales increases result in increased utility revenues, if a utility's sales increased under decoupling, rates would instead be adjusted downward to ensure parity between the utility's actual revenues and allowed revenues. If utility sales decreased, rates would be adjusted upwards to ensure the utility's actual revenues equaled its allowed revenues. As a result, changes in utility sales would have no impact on a utility's revenues, and a utility would no longer be dis-incentivized to pursue energy efficiency savings.

NERP recommends that the legislature authorize the Commission to adopt decoupling. Among other things, NERP suggests that the Commission limit the application of an approved decoupling mechanism to base rates and the residential, small and medium general service customer classes. Detailed suggestions for the Commission are contained in the NERP Guidance on Performance-Based Regulation.⁵

Performance Incentive Mechanisms

Performance incentive mechanisms would condition some portion of a utility's earnings on its performance on certain measurable consumer, utility system, or public policy outcomes. For example, if a utility were to meet identified distributed energy integration or energy efficiency performance targets, it could receive a fixed cash reward, a basis point adjustment to its return on equity, a percentage return on any shared savings or net benefits created through its achievement of those targets. Conversely, depending on the design of the performance incentive mechanism, a utility might be penalized for failing to achieve those targets. As a result, a utility would have a direct incentive to pursue these outcomes.

This is a departure from the current system, where a large portion of utility earnings stems from the allowed rate of return on certain capital expenditures. Certain PIMs can help to mitigate this capital expenditure (or "capex") bias by providing the utility the opportunity to profit from meeting agreed-upon performance targets.

NERP recommends that the legislature authorize the Commission to adopt performance incentive mechanisms. Specifically, NERP recommends that the Commission consider PIMs that incentivize affordability, carbon reduction, customer service, distributed energy, electrification of transportation, energy efficiency, equity, peak demand reduction, reliability,

⁵ The Guidance Document is available with all other NERP outputs on the website at the end of this fact sheet.

and resilience. Detailed suggestions for the Commission are contained in the Guidance Document.

Multi-Year Rate Plan and Earnings Sharing Mechanism

A multi-year rate plan usually begins with a rate case that determines a utility's initial revenue requirement and establishes how these allowed revenues should be adjusted each year over the course of the rate plan term, which is typically between three and five years. These adjustments can be based on cost forecasts, external indexes, or a combination of both. In contrast to the current system, where the underlying costs recovered in rates reflect prior costs incurred in some previous twelve-month period (referred to as the historic test year), costs and revenues for a multi-year rate plan are forward-looking.

Accordingly, the utility could prospectively identify grid modernization projects and ensure more timely cost recovery for these projects and other investments. In addition, the rate case moratorium could create significant cost containment pressure. A multi-year rate plan that capped a utility's revenues would also incentivize cost containment by providing the utility the opportunity to keep some or all of its cost savings. Given these cost containment incentives, some experts recommend that states adopt targeted PIMs to prevent potential cost cutting from impacting system reliability and customer service.

Subject to Commission pre-approval, an earnings sharing mechanism could specify a formula for sharing any utility cost savings or losses between customers and utility shareholders when utility earnings exceed or fall short of Commission set levels.

NERP recommends that the legislature authorize the Commission to adopt multi-year rate plans and earnings sharing mechanisms. Detailed suggestions for the Commission are contained in the Guidance Document.

HAS PERFORMANCE BASED REGULATION BEEN DONE BEFORE?

Other states

Several other states and international jurisdictions have pursued performance-based regulation. For example, New York is exploring performance based regulation through the Reforming the Energy Vision proceeding before the New York Public Service Commission. Through this proceeding, the Commission has adopted performance incentive mechanisms for distributed energy and other innovative non-wires solutions. In Minnesota, recent legislation, direction from the Minnesota Public Utilities Commission, and extensive stakeholder involvement have resulted in wide ranging performance-based regulation reforms, including a MYRP and decoupling. For more information on the Minnesota PBR development process and outcomes, see the MN PBR Case Study prepared by NERP.⁶

⁶ See the Minnesota case study, available with all other NERP outputs on the website at the end of this fact sheet.

North Carolina

Natural gas decoupling, which is currently authorized under statute, was implemented in North Carolina in 2005. In addition, the North Carolina Utilities Commission has adopted performance incentive mechanisms pursuant to a separate statute to encourage more utility energy efficiency programs and savings.

This fact sheet represents the work of stakeholders as of 12/18/2020.


About the North Carolina Energy Regulatory Process

Governor Cooper's Executive Order 80 mandated the development of a clean energy plan for the state of North Carolina. The Clean Energy Plan recommended the launch of a stakeholder process to design policies that align regulatory incentives with 21st century public policy goals, customer expectations, utility needs, and technology innovation. The stakeholder process was launched in February 2020 and has led to policy proposals on energy reform.

LEARN MORE

Contact NERP PBR Study Group Leads:
Sally Robertson, NC WARN, sally@ncwarn.org
Laura Bateman, Duke Energy, laura.bateman@duke-energy.com

Access the NERP summary report and other NERP documents at:
<https://deq.nc.gov/CEP-NERP>



PBR REGULATORY GUIDANCE

IMPLEMENTATION SUGGESTIONS FOR THE NCUC FROM THE
NORTH CAROLINA ENERGY REGULATORY PROCESS

AUTHORS & ACKNOWLEDGMENTS

STUDY GROUP MEMBERS

Laura Bateman, Duke Energy, co-lead¹
 Sally Robertson, NC WARN, co-lead²
 Dionne Delli-Gatti, Environmental Defense Fund²
 Paula Hemmer, Dept. of Environmental Quality¹
 Preston Howard, NC Manufacturers Alliance³
 Steve Kalland, NC Clean Energy Technology Center
 Munashe Magarira, NC Attorney General's office²
 Sushma Masemore, Dept. of Environmental Quality¹
 Rory McIlmoil, Appalachian Voices^{1,3}
 Mark McIntire, Duke Energy²
 Jeremy Tarr, Governor's office
 Gudrun Thompson, Southern Environmental Law Center
 Peter Toomey, Duke Energy³

¹ Revenue decoupling subteam

² Performance-incentive mechanisms subteam

³ Multi-year rate plan subteam

CONTACTS

Sally Robertson, sally@ncwarn.org
 Laura Bateman, laura.bateman@duke-energy.com

ACKNOWLEDGMENTS

NERP thanks the following individuals/organizations for offering their insights and perspectives on this work.

Josh Brooks, Rocky Mountain Institute
 Daniel Brookshire, NC Sustainable Energy Association
 Dan Cross-Call, Rocky Mountain Institute
 Matthew Davis, NC Dept. of Environmental Quality
 Tim Duff, Duke Energy
 Jack Floyd, NC Public Staff
 Rachel Gold, American Council for an Energy-Efficient Economy
 Cara Goldenberg, Rocky Mountain Institute
 Heather House, Rocky Mountain Institute
 Lon Huber, Duke Energy
 Matthew McDonnell, Strategen Consulting
 Kevin O'Donnell, Nova Energy Consultants
 Doug Scott, Great Plains Institute
 Richard Sedano, Regulatory Assistance Project
 Jessica Shipley, Regulatory Assistance Project

This work was last updated on 12/18/2020.

Cover image courtesy of GYPSY FROM NOWHERE IMAGES/ALAMY STOCK PHOTO

ABOUT THE NORTH CAROLINA ENERGY REGULATORY PROCESS

Governor Cooper's Executive Order 80 mandated the development of a clean energy plan for the state of North Carolina. The Clean Energy Plan recommended the launch of a stakeholder process to design policies that align regulatory incentives with 21st century public policy goals, customer expectations, utility needs, and technology innovation. The stakeholder process was launched in February 2020 and has led to policy proposals on energy reform.

ABOUT THIS DOCUMENT

This guidance document contains a detailed discussion of performance-based regulation mechanisms with a specific focus on revenue decoupling, multi-year rate plans, and performance incentive mechanisms. It includes recommendations for the NCUC to consider if and when it begins a process to implement performance-based regulation. The document represents the consensus work of the NERP process stakeholders as of the above date. However, individual NERP stakeholders do not necessarily endorse all of the ideas or recommendations herein.

TABLE OF CONTENTS

Authors & Acknowledgments 2

Summary of Recommendations 4

 PBR implementation 4

 Revenue decoupling 4

 Multi-year rate plan 4

 Performance incentive mechanisms 5

INTRODUCTION 5

 Purpose and objectives 5

 Context and history 6

 What problems is PBR solving? 8

 Other ongoing processes and trends impacting PBR 9

 Statutory authority and rationale for legislation 10

NERP RECOMMENDATIONS FOR PBR TOOLS 10

 Revenue Decoupling 10

 Multi-year rate plan & earnings sharing mechanism 14

 Performance incentive mechanisms 19

RECOMMENDED PROCESS FOR PBR DEVELOPMENT 29

CONCLUSION 30

REFERENCES 31

Appendix A 33

Appendix B 35

SUMMARY OF RECOMMENDATIONS

This document contains recommendations for implementation of performance-based regulation (PBR) developed by the North Carolina Energy Regulatory Process (NERP) participants. The primary intended audience is the NC Utilities Commission (NCUC), as it may be authorized by the General Assembly to develop regulations for PBR. The document contains detailed descriptions of each of the PBR mechanisms discussed in NERP: revenue decoupling, multi-year rate plans (MYRPs), and performance incentive mechanisms (PIMs). NERP participants met throughout 2020 and developed the following recommendations regarding the implementation of PBR.

PBR implementation

1. PBR should be designed to provide for just and reasonable rates and be consistent with the public interest, including the goals of the Clean Energy Plan.
2. PBR for NC should include all three of the mechanisms studied in NERP, as they can work well together to accomplish a broad set of outcomes and stakeholder objectives.
3. Effective PBR will require ongoing monitoring and possible course corrections.
4. A PBR process at the NCUC should consider the conclusions reached by NERP and make sure to receive comment from as broad a group of stakeholders as possible, including representatives from underserved communities with limited access to traditional docket proceedings.
5. The NCUC should, subject to guidance and timelines provided in legislation, begin as soon as possible a proceeding to develop rules for filing, and criteria for evaluating, a comprehensive PBR package including revenue decoupling, a multi-year rate plan, and performance incentive mechanisms or tracked metrics, as well as provisions for annual or more frequent decoupling and MYRP true-ups and adjustments of PIM metrics, targets, and incentive levels.

Revenue decoupling

1. Revenue decoupling should apply to residential and small and medium general service classes. Large general service and lighting do not necessarily need to be included. However, attention should be paid to how excluding any customer class would impact the design of a multi-year rate plan.
2. Revenue decoupling should include all utility functions (generation, transmission, and distribution).
3. Revenue decoupling should include base rates only, excluding riders that have separate true-up mechanisms.
4. Revenue decoupling should include EV charging sales, but a PIM should be adopted related to EV adoption and/or smart charging to incentivize vehicle electrification.
5. Revenue decoupling should utilize either the revenue-per-customer or attrition method for adjusting revenue between rate cases. Decoupling adjustments to the allowed revenue would be impacted by the MYRP design as well, so the interplay of these two mechanisms should be noted.
6. The amount of adjustment to customer rates under decoupling should be capped, and the design of refunds and surcharges should consider ways to encourage energy efficiency.
7. Rate adjustments should occur once a year.
8. The NCUC will need to consider the above issues, as well as ways to encourage utilities to pursue beneficial electrification when decoupled.

Multi-year rate plan

1. The mechanism for adjusting rates should be defined at the outset of a MYRP.
2. A maximum of three years should be the term of an initial MYRP.
3. A MYRP should not be used to recover costs for large, discrete investments, such as a conventional power plant. Investment programs that are made up of a series of smaller utility assets placed in service over time are well-suited for a MYRP.
4. A MYRP should be accompanied by a pre-set earnings sharing mechanism to share savings between customers and utility stockholders. The mechanism could include sharing tiers and a “deadband” of over- or underearning in which no adjustment is made.

5. The NERP team did not come to consensus on whether MYRP should cover base rates or be more narrowly constructed to cover only certain projected costs.
6. The NCUC should determine the general conditions under which a MYRP may be revised or revisited.

Performance incentive mechanisms

1. PIMs should adhere to a set of principles to help align stakeholders on shared objectives and guide PIM design.
2. At the outset, utilities should track as many metrics as are deemed useful and cost-effective. This document lays out recommended metrics.
3. The utility should track the overall performance for each adopted PIM or tracked metric, and, where possible, separately track the utility's performance in low-income counties, specifically Tier 1 and 2 counties.
4. The utility should establish a public dashboard for reporting performance on PIMs and tracked metrics.
5. The following outcomes should be targeted for PIM and/or tracked metric development:
 - a. Peak demand reduction
 - b. Integration of utility-scale renewable energy and storage
 - c. Integration of distributed energy resources
 - d. Low-income affordability
 - e. Carbon emission reductions
 - f. Electrification of transportation
 - g. Equity in contracting
 - h. Resilience
 - i. Reliability
 - j. Customer service
6. The NCUC will need to evaluate the appropriateness of any proposed performance incentive assigned to each potential tracked metric.

INTRODUCTION

Purpose and objectives

The purpose of this document is to communicate the findings of the NC Energy Regulatory Process (NERP) with regard to performance-based regulation (PBR) to the NC Utilities Commission (NCUC) as it may be authorized by the General Assembly to develop rules for PBR. It may also be of interest to the NC General Assembly and other parties who want more information on PBR or the NERP process than is provided in the companion fact sheet.¹

Duke Energy's Climate Report² and Dominion Energy's Sustainability and Corporate Responsibility Report³ set ambitious goals for reducing carbon emissions. The NC Clean Energy Plan⁴ calls for the state's electric power sector to reduce greenhouse gas emissions 70% below 2005 levels by 2030 and attain carbon neutrality by 2050, transitioning to cleaner energy resources while growing the state's economy. As detailed below, however,

¹ All NERP PBR companion documents can be found at the following location: <https://deq.nc.gov/CEP-NERP>

² *Achieving a Net Zero Carbon Future: Duke Energy 2020 Climate Report*, <https://www.duke-energy.com/media/pdfs/our-company/climate-report-2020.pdf?la=en>.

³ *Building a Cleaner Future for Our Customers and the World, 2019 Sustainability and Corporate Responsibility Report*, Dominion Energy, https://sustainability.dominionenergy.com/assets/pdf/Dominion-Energy_SCR-Full-Report-FY2019.pdf.

⁴ *North Carolina Clean Energy Plan: Transitioning to a 21st Century Electricity System*, NC Dept. of Environmental Quality, Oct. 2019, https://files.nc.gov/governor/documents/files/NC_Clean_Energy_Plan_OCT_2019_.pdf.

the current cost of service (COS) ratemaking⁵ system for the state’s investor-owned utilities (IOUs) does not provide the proper utility incentives for timely and efficient accomplishment of these goals at reasonable cost.

NERP stakeholders have determined that better alignment of incentives would be created by transitioning the state to a comprehensive PBR framework.

This document communicates NERP’s recommendations for designing a PBR system that would benefit North Carolina.

Improved Utility Regulations for North Carolina’s Energy Transition

PBR offers a suite of reforms that, together, can resolve limitations of COS ratemaking while encouraging utilities to better serve state policy goals and customer interests. In North Carolina, this includes decarbonization of the power system, accelerated adoption of clean energy technologies including new customer service opportunities from distributed energy resources (DER), alleviating low-income energy burden, and reduction of costly administrative burdens and regulatory lag.⁶

Three PBR mechanisms are the focus of this document, and NERP suggests they be jointly considered and designed for NC electric utilities:

- Decoupling to remove the utilities’ incentive to grow energy sales
- Performance incentive mechanisms (PIMs) to create new earnings opportunities (or penalties) for targeted outcomes
- Multi-year rate plans (MYRP) to increase the time between utility rate cases in order to introduce cost containment incentives for the utility and reduce regulatory lag

PBR design and adoption is a significant undertaking. Critical details must be considered and worked through, typically through a regulatory proceeding that includes utility proposals, input and counterproposals of other stakeholders, and eventual decision-making by utility regulators. As outlined below, a probable first step will be enactment of PBR-enabling legislation.

Context and history

On October 29, 2018, Governor Roy Cooper issued *Executive Order 80: North Carolina’s Commitment to Address Climate Change and Transition to a Clean Energy Economy*.⁷ The Order established the North Carolina Climate Change Interagency Council and tasked the Department of Environmental Quality (DEQ) with producing a clean energy plan.

Companion documents

In addition to this guidance document, NERP has produced:

- Draft legislation authorizing the NCUC to pursue PBR
- A fact sheet providing an introduction to PBR, an overview of the draft legislation and a summary of this guidance document
- Case studies discussing:
 - how PBR has been implemented in Minnesota, and
 - how North Carolina has implemented revenue decoupling for natural gas utilities.

⁵ According to NARUC, “In Cost of Service Regulation, the regulator determines the Revenue Requirement—i.e., the ‘cost of service’—that reflects the total amount that must be collected in rates for the utility to recover its costs and earn a reasonable return.” <https://pubs.naruc.org/pub.cfm?id=538E730E-2354-D714-51A6-5B621A9534CB>. Under the proposed PBR system, the utility would still file cost of service studies in a general rate case and those studies would be the basis for establishing the total revenue required and the allocation to the customer classes. The PBR adjustments discussed in this document would be increments or decrements to that base.

⁶ Regulatory lag results when a utility’s costs change, either up or down, in between rate cases. Issues result when regulatory lag creates financial incentives for utilities that are not aligned with public interest. For more detail, see Appendix A.

⁷ Executive Order 80. <https://governor.nc.gov/documents/executive-order-no-80-north-carolinas-commitment-address-climate-change-and-transition>.

DEQ convened a group of stakeholders that met throughout 2019. In October 2019, DEQ released the *North Carolina Clean Energy Plan: Transitioning to a 21st Century Electricity System* (CEP).⁸ Recommendation B-1 of the CEP states: “Launch a NC energy process with representatives from key stakeholder groups to design policies that align regulatory incentives and processes with 21st Century public policy goals, customer expectations, utility needs, and technology innovation.” That process was launched as NERP, which met throughout 2020.

Also relevant to this document is NC Senate Bill 559,⁹ introduced in 2019. SB559 eventually passed and authorized utilities to petition the NCUC to recover certain storm recovery costs through securitization. The initial version of the bill included a separate section that would have authorized the NCUC to accept MYRP proposals from utilities. After concerns were raised by a large number of stakeholders, and no adequate compromise was found, that section of the bill was dropped. NERP has attempted to recognize the advantages of – and resolve the objections to – the MYRP as proposed in SB559.

NERP process

The NERP process, facilitated by Rocky Mountain Institute and the Regulatory Assistance Project, brought together roughly 40 diverse stakeholders to consider four main avenues of utility regulatory reform:

- PBR
- Wholesale market reform
- Competitive procurement of resources
- Accelerated retirement of generation assets

The NERP stakeholder group identified ten desired outcomes of reform in North Carolina, as shown below in Figure 1. Of those, the focus of PBR deliberations were:

- Regulatory incentives aligned with cost control and policy goals
- Carbon neutral by 2050
- Affordability and bill stability

⁸ *North Carolina Clean Energy Plan: Transitioning to a 21st Century Electricity System*, NC Dept. of Environmental Quality, Oct. 2019, https://files.nc.gov/governor/documents/files/NC_Clean_Energy_Plan_OCT_2019_.pdf.

⁹ SB559, Storm Securitization, passed Oct. 2019, <https://www.ncleg.gov/BillLookUp/2019/s559>.




Outcome Category	Outcome
Improve <u>customer value</u>	Affordability and bill stability 
	Reliability
	Customer choice of energy sources and programs
	Customer equity
Improve <u>utility regulation</u>	Regulatory incentives aligned with cost control and policy goals 
	Administrative efficiency
Improve <u>environmental quality</u>	Integration of DERs
	Carbon neutral by 2050 
Conduct a quality <u>stakeholder process</u>	Inclusive
	Results oriented

FIGURE 1: PRIORITY OUTCOMES IDENTIFIED BY NERP STAKEHOLDERS

PBR Study Group

A subset of NERP participants volunteered to serve on a PBR study group and began meeting in May 2020. Three subteams were created to discuss: revenue decoupling, multi-year rate plans (and earnings sharing mechanisms), and performance incentive mechanisms. (See page 2 for a list of PBR study group and subteam members.)

The subteams regularly presented their work to the PBR study group for feedback. The study group presented a straw proposal to the larger NERP group, detailing how a comprehensive PBR package might be designed for NC. Feedback was received from NERP participants and incorporated into the eventual design recommendations detailed below.

What problems is PBR solving?

Performance-based (or outcome-based) regulation is intended to motivate utilities to accomplish outcomes that customers or society deem desirable. In doing so, PBR can help shift utility focus away from certain outcomes that may be inadvertently incentivized by traditional ratemaking.

In the current system, utilities increase their revenues by increasing electricity sales in the short term (known as the throughput incentive) and increase their profits by favoring rate-of-return-based utility capital spending over other options as the method by which to solve identified grid needs (known as the capital expenditure, or capex, bias).

The throughput incentive arises from the fact that, in traditional ratemaking, prices are set primarily on a volumetric basis based on a historic level of costs and sales, normalized and adjusted for known and measurable changes. After volumetric prices are set in the rate case, if utilities sell more electricity than was estimated in the rate case, they increase their revenues and therefore profits (assuming costs do not fluctuate significantly based on sales volume in the short term).

The capex bias originates from the fact that utilities are typically allowed to earn a regulated rate of return (profit percentage) on shareholder capital that they invest in physical assets, such as power plants, transmission wires, distribution grid assets, company trucks, computers, buildings, etc. This results in utility preference for capital expenditures as solutions for grid needs, whereas many cost-saving or emissions-reducing opportunities result from program innovations, such as customer efficiency programs, that fall into the category of operating expenditures (opex), on which no rate of return is earned.

Even as NC's population is growing, the demand for electricity from existing customers continues to remain flat, and in some cases has declined compared to historical years as more customers are investing in their own on-site generation and energy efficiency measures. This changing economic landscape can further drive the throughput incentive and capex bias, the two main limitations of the current framework.

PBR offers a set of tools that can create utility incentives that are more aligned with customer and societal goals. For example, PBR can make it more likely that clean energy, energy efficiency, and carbon reduction goals are achieved. There is no one uniform combination of PBR tools. Some states have implemented one or two reforms; others are examining comprehensive measures. The reforms discussed below were the focus of NERP and have been implemented or are currently being discussed in other states.

See Appendix B for a diagram depicting potential interactions and coordination between the different mechanisms within a PBR framework.

Other ongoing processes and trends impacting PBR

The world in general, and North Carolina in particular, are in an exciting period of transition to a cleaner and more equitable electricity system. As a result, there are emerging technologies, rapidly changing cost dynamics, potential new policies, and revisions of old policies all up in the air at once. NERP has designed recommendations for PBR implementation based on its best estimate of where these balls might land.

In considering any PBR proposal that comes before it, the NCUC will have to evaluate where these processes stand and how the PBR mechanisms interact with them. Some examples of ongoing processes include:

- other proposals emerging from the NERP process (securitization of uneconomic coal assets, all-source competitive procurement, and wholesale market study),
- an analysis of carbon reduction policies under the A-1 recommendation of the CEP including accelerated coal retirements; a Clean Energy Standard or other clean energy policy (e.g., Energy Efficiency Resource Standard or Peak Reduction Standard); an offshore wind requirement; a carbon adder or shadow carbon price for purposes of planning and/or dispatch; and/or a market-based cap and invest program (e.g., joining the Regional Greenhouse Gas Initiative),
- the Southeastern Energy Exchange Market proposal being advanced by Duke Energy and other Southeast utilities,
- the trend toward vehicle electrification and state strategies for accelerating adoption of electric vehicles, including the NC Zero-Emission Vehicle Plan, Duke's EV pilot, distribution of VW Settlement Funds, and NC signing onto the multistate Medium- and Heavy-Duty ZEV MOU,
- the low-income collaborative proposed by Duke Energy in the current NC rate cases,
- the comprehensive rate design study proposed by Duke Energy in the current NC rate cases,
- implementation of changes to the EE/DSM incentive ordered by the NCUC in its October 2020 order, including new incentive levels and use of the Portfolio Performance Incentive and Utility Cost Test,¹⁰
- any changes to net metering policy,
- NCUC orders that will be issued on DEC and DEP rate cases and Duke's Integrated Resource Plan,

¹⁰ Order Approving Revisions to Demand-Side Management and Energy Efficiency Cost Recovery Mechanisms, Oct. 20, 2020, <https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=5aaea5ce-6458-41fe-ab2d-14d86881092d>.

- the NC Transmission Planning Collaborative’s study of onshore transmission investments necessary to integrate up to 5,000 MW of offshore wind (expected completion in early 2021),
- the newly established nonprofit NC Clean Energy Fund that will make funding available for clean energy projects that are traditionally difficult to finance, and
- Duke Energy’s implementation of its Integrated System & Operations Planning (ISOP) process that will allow integration of new technologies and customer programs as technology and policy pertaining to generation, transmission, and distribution continue to evolve.

Some of these factors are flagged in the specific recommendations below.

Statutory authority and rationale for legislation

Legislation has been used in many states to provide explicit authority to utility commissions to implement or approve proposed PBR mechanisms. In the expectation that the NCUC would welcome specific authorizing legislation, NERP has drafted legislation authorizing the NCUC to pursue comprehensive PBR. It specifies deadlines and baseline requirements that any PBR package should meet, but is minimally prescriptive so that the NCUC has leeway to consider the many PBR design parameters in a manner that best meets the needs of the state at the time the mechanisms are established.

NERP RECOMMENDATIONS FOR PBR TOOLS

After studying the PBR mechanisms described below, NERP has come to the conclusion that a comprehensive package of revenue decoupling, multi-year rate plan, and performance incentive mechanisms would best address North Carolina’s changing needs. The three sub-sections below explain how each mechanism works, how the mechanisms interact with each other, what recommendations NERP makes for their design, and key issues that need attention from the NCUC. NERP participants offer the following takeaways and recommendations from our deliberations on PBR to inform the NCUC’s thinking.

Revenue Decoupling

Definition

Decoupling breaks the link between the amount of energy a utility delivers to customers and the revenue it collects, thus minimizing the throughput incentive described above. Allowed revenue is set in a rate case as usual. Rather than setting prices in the rate case and leaving them unchanged until the next rate case, under revenue decoupling prices are set in the rate case but adjusted up or down over the course of the rate effective period to ensure that collected revenues equal allowed revenues (no more and no less). See Figure 2.

Traditional System:

$$\text{Revenue} = \text{Fixed Price} \times \text{Sales}$$

Decoupled System:

$$\text{Price} = \text{Fixed Revenue} \div \text{Sales}$$

Comparison with current system

Currently, for many residential and smaller commercial and industrial rate schedules, there are no demand charges and a majority of fixed costs are recovered through variable energy rates (cents per kWh). When fixed costs are recovered through a variable rate, a utility’s margin is higher when it increases its sales and lower when it decreases its sales. Consequently, the utility has a financial incentive to increase sales and a disincentive to reduce sales. Decoupling seeks to break this linkage.

This incentive and linkage have already been recognized by the NCUC in its approval of net lost revenue mechanisms within utility energy efficiency and demand side management riders.

The net lost revenue (NLR) mechanism addresses this issue by removing the financial disincentive to reduce sales when the utility implements an approved DSM/EE program. Decoupling goes a step further by removing the incentive/disincentive to increase or reduce sales in all situations. This would include reduced sales from DER deployment, reduced sales from customer efficiency and conservation efforts that are not part of a utility program, and reduced sales from certain rate designs or other utility programs that may not qualify as an approved DSM/EE program. It would also break the incentive for increases in sales from electric vehicle charging and economic development. Since some of these sales may align with the public interest, it is important to implement decoupling as part of a comprehensive PBR package to ensure that the utility still has an incentive to beneficially grow sales in areas that are aligned with public interest.

Decoupling is one part of broader PBR plan

Many states implement decoupling as part of a broader PBR package and there are synergies between the mechanisms. For example, PIMs can be used to incentivize electric vehicle charging or economic development when decoupling removes these incentives from the current ratemaking structure. Additionally, where decoupling removes a disincentive for the utility to reduce sales through energy efficiency or other means, PIMs can go a step further and create a positive incentive for the utility to reduce sales. Decoupling also works well with multi-year rate plans. The MYRP can provide for small, annual changes in rates, and the decoupling mechanism can true-up the sales that the MYRP rates are based on to actual sales realized during each year of the plan. Thus, decoupling and MYRPs together can reduce the need for frequent rate cases and can break the linkage between utility sales and profit margin.

Alignment with the goals of the Clean Energy Plan

Decoupling is aligned with the broader CEP goals. First, the CEP supports increased DERs, EE, and DSM, all of which decrease sales per customer. Decoupling removes the sales-related disincentive utilities have to promote and utilize these resources. Decoupling is also an alternative to increasing fixed charges in the rate design structures for residential and smaller commercial and industrial customers. If fixed costs are recovered through fixed charges and variable through variable, this also removes the throughput incentive for utilities. However, increasing fixed charges also decreases variable charges, which reduces the incentive for customers to be energy efficient, conserve energy, and/or invest in DERs. Additionally, higher fixed charges, on average, place a higher energy burden on low-income customers, who tend to have lower usage per customer. Reducing the incentives for EE, conservation, and DERs and placing a higher energy burden on low-income customers are contrary to the goals of the CEP. Decoupling is therefore better aligned with the goals of the CEP than increasing fixed charges as a means of removing the throughput incentive.

Experience in other states and jurisdictions

North Carolina has experience with decoupling in the natural gas distribution sector.¹¹ In addition, electric decoupling has been adopted successfully in 17 states and another 7 states have pending actions. Rate adjustments under decoupling are typically small. According to a 2013 report produced for the American Council for an Energy-Efficient Economy and the Natural Resources Defense Council, almost two-thirds of adjustments made under decoupling were within 2% of the retail rate and 80% within 3%. Such adjustments are modest compared to other utility expenses that influence rates.¹²

Design Details of Decoupling and NERP Recommendations

The utility's proposed decoupling mechanism must be evaluated to ensure that it will produce just and reasonable rates and is consistent with the public interest, including the goals of the CEP. NERP explored several key design components of decoupling mechanisms, and has the following recommendations.

¹¹ Case Study: Natural Gas Decoupling in North Carolina, NERP, December 2020, available here: <https://deq.nc.gov/CEP-NERP>.

¹² <https://www.aceee.org/sites/default/files/publications/researchreports/u133.pdf>

Decide what is covered

Affected Classes: Because the primary rate schedules that recover fixed costs through variable rates are the residential and small to medium general service, we recommend that these classes be included. The rate design for large general service includes demand charges and other provisions to recover more of the fixed costs through fixed charges. Also, lighting rate schedules generally recover fixed costs through fixed charges. When only variable costs are recovered through variable rates, there is no throughput incentive (revenue and costs go up or down proportionally and there is no impact to margin from higher or lower sales levels). Large general service and lighting do not necessarily need to be included for the decoupling mechanism to be effective and the NCUC may determine that it makes more sense to exclude them from the mechanism. However, attention would need to be paid to how excluding these customers from decoupling might impact the design of a utility's MYRP.¹³

Including small to medium general service in the decoupling mechanism would introduce a complexity that NERP did not have time to work through. Decoupling would replace the current net lost revenue mechanism recovered through the DSM/EE rider for classes participating in decoupling. Because there is only one general service rate in the DSM/EE rider for all three general service classes (small, medium, and large), it may not be feasible to include net lost revenues for only one of the three sizes in the rider. Consideration also needs to be given to small and medium general service accounts that can currently opt out of the net lost revenue mechanism and how that will be addressed with decoupling.

Costs to include:

- Recommend including all functions (generation, transmission, and distribution). In order for the mechanism to be effective and completely address the throughput incentive, it should not exclude any function included in the utility's bundled rate.
- Recommend including base rates only and excluding riders that have separate true-up mechanisms. If a rider already has a mechanism to true-up for sales volume (like fuel), then it should be excluded from the decoupling mechanism. If a rider does not have a separate true-up mechanism for sales, it may be included.
- The PBR study group considered recommending excluding EV charging sales in order to maintain the utility incentive to promote vehicle electrification. However, the only state where we have seen this done is Minnesota, and it may overly complicate the mechanism. Therefore, NERP recommends including EV charging sales in the decoupling mechanism and simultaneously adopting a PIM related to EV adoption and/or smart charging.

¹³ Large industrial customers are excluded from decoupling in some states on account of possible rate volatility should a single very large user leave the utility territory or change operations. Different treatment between customer classes is complicated, however, when decoupling is part of a MYRP framework. In many states with comprehensive MYRPs, such as California, Minnesota, Hawaii, and Massachusetts, decoupling is applied to all major customer classes. See Regulatory Assistance Project, Revenue Regulation and Decoupling: A Guide to Theory and Application, November 2016. <http://www.raonline.org/wp-content/uploads/2016/11/rap-revenue-regulation-decoupling-guide-second-printing-2016-november.pdf>; Minnesota Public Utilities Commission, "Order Approving True-Ups and Requiring Xcel to Withdraw its Notice of Changes in Rates and Interim Rate Petition," March 13, 2020.

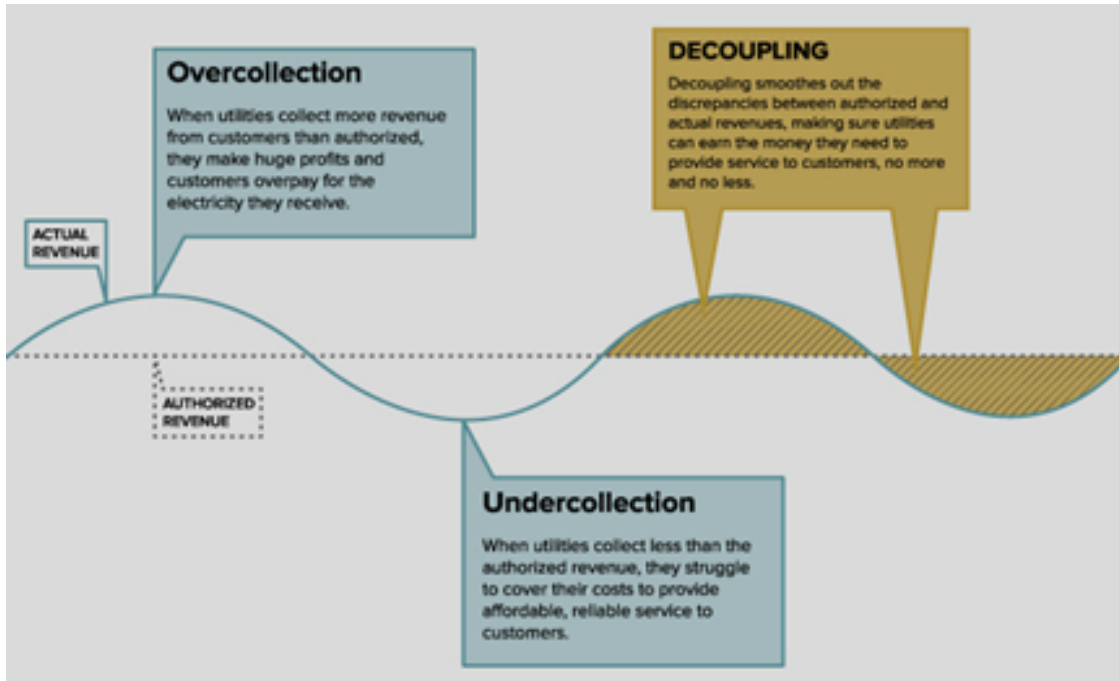


FIGURE 2: HOW DECOUPLING SMOOTHS OUT REVENUE FLUCTUATIONS¹⁴

Choose how to adjust utility revenue

The team explored several methods of adjusting the annual revenues under a decoupling mechanism and recommends consideration of the following two options: Revenue Per Customer (RPC) and Attrition Adjustment.

- RPC – allows for increases in revenue as new customers are added to the system, but mitigates changes in revenue driven by changes in usage per customer. In the initial base rate case, a revenue requirement per customer is set for the affected classes. Periodically, the actual revenue received from a class is compared to the target revenue per customer times the number of customers. Any excess or shortfall is deferred and returned to or collected from customers over the following year through adjustments to the customer class-specific rates. In addition, the tariff rates used going forward may be adjusted to reflect changes in usage per customer. This going-forward adjustment would need to be made in conjunction with any adjustments in the MYRP.

Target revenue = number of customers x revenue requirement per customer

This method is fairly straightforward and consistent with the current mechanism for gas utilities in NC; however, some NERP participants expressed concerns that actual costs per customer may decline over time, especially if generation assets (which depreciate over time) are included in the mechanism. If this is the case, some experts suggest that an attrition adjustment method may be more appropriate.¹⁵

- Attrition - adjusts the fixed level of revenue to be collected based on changes in costs and sales. This method may be appropriate when generation assets are included in decoupling. Just like with RPC, the actual revenue received from a customer class is compared to a target level of revenue, and any excess

¹⁴ Nissen Will, “Strategic electrification and revenue decoupling: different purpose, same goal,” May 2, 2018, Fresh Energy, <https://fresh-energy.org/strategic-electrification-and-revenue-decoupling-different-purpose-same-goal/>.

¹⁵ Migden-Ostrander, J., and Sedano, R. (2016). Decoupling Design: Customizing Revenue Regulation to Your State’s Priorities. Montpelier, VT: Regulatory Assistance Project. Available at: <http://www.raonline.org/knowledge-center/decouplingdesign-customizing-revenue-regulation-state-priorities>

or shortfall is deferred and returned to or collected from customers over the following year through adjustments to the customer class-specific rates. However, the target revenue is based on the actual costs incurred over the same period and may be based on a formula rate template or agreed-upon formula adjustments to the rate case test year cost of service study. These “attrition review” proceedings are sometimes referred to as “mini-rate cases” but are a streamlined alternative to full-blown rate cases.

It should be noted that, under both types of decoupling, the going-forward adjustments would need to be coordinated with adjustments under the multi-year rate plan. This linkage is one way in which decoupling and MYRP work well together. MYRP involves a detailed analysis of how utility revenue should be allowed to adjust over time, while decoupling ensures that the allowed revenue is recovered (but not more or less than the allowed revenue).

If both decoupling and a MYRP with a revenue cap are adopted, the details of the two mechanisms must be determined together. The MYRP will likely inform how allowed revenues adjust each year, while decoupling will adjust customer rates so collected revenues equal allowed revenues. Options to adjust revenues may be based on inflation or other index, multi-year cost forecasts, customer growth, or a hybrid approach.

Select how to handle refunds or surcharges.

The process for the annual adjustment to rates should be efficient and transparent. NERP recommends considering caps on annual impacts to customers, with any additional amounts deferred into a future period. NERP also recommends considering design options for handling refunds and surcharges that encourage greater energy efficiency.

In terms of frequency of adjustments, NERP recommends decoupling price adjustments once a year. Some mechanisms are updated monthly, but that could lead to customer confusion with too-frequent price adjustments. According to a 2012 survey,¹⁶ over two-thirds of electric utility decoupling true-ups were conducted on an annual basis.

Multi-year rate plan & earnings sharing mechanism

Definition

A MYRP begins with a rate case that sets the utility base revenues for the test year, based on the normal ratemaking process.

Under a MYRP, the revenue requirements necessary to offset the costs that are contemplated to occur under a plan approved by the NCUC would be set for multiple years in advance (typically 3–5 years). Utility compensation would be based on forecasted costs that are expected under the NCUC-approved plan, rather than the historical costs of services. Customer rates would be reset annually through NCUC review under the terms set out for the MYRP.

This approach can create added incentives for the utility to contain costs and can also reduce the regulatory costs from more frequent rate cases. The terms of a MYRP often include the following:

- A moratorium on general rate cases for longer periods (the term of the MYRP).
- Attrition relief mechanisms (ARMs) in the interim to automatically adjust rates or revenue requirements to reflect changing conditions, such as inflation and population growth.

¹⁶ Morgan, P. *A Decade of Decoupling for US Energy Utilities: Rate Impacts, Designs, and Observations*. Graceful Systems LLC, rev. February 2013, <https://www.raonline.org/wp-content/uploads/2016/05/gracefulsystems-morgan-decouplingreport-2012-dec.pdf>.

- MYRPs can (1) mitigate the regulatory lag associated with certain utility assets, such as grid investments and DERs, (2) give an incentive for utility cost containment by setting a framework for predictable revenue adjustments into the future.
- To maintain or pursue other regulatory and policy goals, MYRPs should be combined with performance incentive mechanisms (PIMs) (sometimes considered “backstop” protections for reliability or other services), an earnings sharing mechanism, and other tools.

Comparison with current system

The current system in NC is a traditional cost of service (COS) ratemaking system, which uses historical test years for base rate cases. This system has evolved over the years with the additions of selected cost recovery riders/clauses (e.g., fuel, etc.).

The types of assets to be added to the utility system in the future (renewables, energy storage, and grid improvements) will consist of a series of smaller, more frequent projects, and the addition of any large, central station generation assets will become rarer and rarer. The existing base rate case process does not fit this future well – the utility suffers significant regulatory lag, and so must file rate cases frequently, even annually. Utilities do have the incentive to reduce their costs between rate cases, but when rate cases become so frequent that they are almost annual, this cost reduction incentive is reduced. The NCUC still determines in each rate case what a reasonable level of costs is, but there is less incentive for the utility to try to drive costs below this level.

NERP believes that modifying the existing COS regulation to include a combined package of performance-based ratemaking provisions, including establishing MYRPs with an earnings sharing mechanism, revenue decoupling, and PIMs, will facilitate accomplishment of the goals delineated in the CEP.

MYRPs are one part of a broader PBR plan

MYRPs seem to work well with decoupling – many states currently use both at the same time. Additionally, MYRPs can work well with PIMs by establishing the cost recovery plan for investments that will achieve a goal and then creating a financial incentive or penalty for achieving or failing to achieve that goal. For example, to encourage increases in electric vehicle adoption or distributed energy resources, a multi-year rate plan can include the investments the utility must make to achieve these goals and then a PIM can attach a financial incentive to the goal. Neither a PIM without the enabled cost recovery through a MYRP, nor a MYRP without the accountability of a PIM, are as effective as the two mechanisms working in combination.

MYRP alone would not do anything to specifically address other policy goals such as the reduction of household energy burden, however. Addressing these key goals, and others under the CEP, would require the use of specific PIMs, or other requirements being placed on the utility, along with implementing the MYRP. See also the section below on PIMs.

Because of the complementary nature of the mechanisms, NERP recommends that MYRPs, decoupling, and PIMs be implemented in combination as part of a comprehensive PBR package.

Alignment with the goals of the Clean Energy Plan

One of the top three desired outcomes identified by NERP is to create “utility incentives aligned with cost control and policy goals.”

MYRPs may give the utility the incentive to control and reduce its costs by giving it the opportunity to keep some of the cost savings as long as the MYRP is coupled with an earnings sharing mechanism. This cost containment incentive could potentially help address the utility’s capex bias by motivating the utility to choose the most cost-effective solutions for grid needs, regardless whether they are capex or opex.

The effect of MYRPs in reducing regulatory lag on the kinds of new investments needed under the CEP is another key alignment of utility incentives with policy goals.

Also, page 12 of the CEP states:

The following overarching recommendations are critical to the transition and will drive the priorities identified by the stakeholders:

- *Develop carbon reduction policy designs for accelerated retirement of uneconomic coal assets and other market-based and clean energy policy options.*
- *Develop and implement policies and tools such as performance-based mechanisms, multiyear rate planning, and revenue decoupling, that better align utility incentives with public interest, grid needs, and state policy.*
- *Modernize the grid to support clean energy resource adoption, resilience, and other public interest outcomes.*

Significant investments will need to be made to modernize the grid consistent with these recommendations. MYRPs are a way to address the current financial disincentive that utilities have to make significant investments in the grid (see Appendix A) and therefore support the CEP priorities.

Experience in other states and jurisdictions

Fifteen US states have adopted electric utility MYRPs. Examples with a longer experience of MYRPs include Central Maine Power, MidAmerican Energy, and utilities in California and New York (MYRPs are also common in Canada, including Ontario). In our region, Georgia Power has been under MYRPs since the mid-1990s, and FP&L has used these repeatedly in Florida. The PBR study team reviewed a series of reports and studies of the other states to attempt to learn from the experiences of others. That review shows that while MYRPs show significant promise, there are many examples that indicate MYRPs must be enacted carefully. While our review was not exhaustive, the following are some of the key insights:

- Setting up MYRPs is a complicated process. It will require a lot of work from all stakeholders, and is fraught with risk of errors in the initial design that can have large consequences. The initial design can and should be improved over the years to correct any initial difficulties. Nevertheless, the PBR study team feels that the benefits of successfully implementing MYRPs – when coupled with an appropriately-designed earnings sharing mechanism – make this worth the effort, and the attendant risks can and should be mitigated and corrected.
- *The oversight of the NCUC should not be reduced.* Under a MYRP, the NCUC would be able to see the utility’s business plans for a period of years into the future – which does not happen under the current system. This would allow for discussion of the types and amounts of assets to be added to the grid before the fact, instead of after the fact. Additionally, the NCUC would have detailed reviews of utility costs before each increase under a MYRP is authorized.
- There should be monitoring of utility service levels to mitigate the risk that utilities with a stronger incentive to reduce costs under a MYRP do not let existing service levels suffer. The use of a PIM with penalties for degradation of basic reliability and service levels outside of reasonable norms should be considered.

Examples of comments extracted from one report¹⁷ that the team used as a reference:

“...It can be difficult to design MRPs that generate strong utility performance incentives without undue risk, and that share benefits of better performance fairly with customers. MRPs invite strategic behavior and controversies over plan design.”

¹⁷ Deason, J, et al. "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities." 2017, pp. 7-2,7-3. https://eta.lbl.gov/sites/default/files/publications/multiyear_rate_plan_gmlc_1.4.29_final_report071217.pdf.

“...The strengths and weaknesses of MRPs are not fully understood. Plan design continues to evolve to address outstanding challenges. Areas of recommended future research include impacts of MRPs (and reduced rate case frequency more generally) on service quality, operating risk, and levels of bills that customers pay.”
 “...We also found that the [productivity] growth of utilities that operated for many years without rate cases, due to MRPs or other circumstances, was significantly more rapid than the full sample norm. Cumulative cost savings of 3 percent to 10 percent after 10 years appear achievable under MRPs.”

Design Details of MYRPs and NERP Recommendations

The mechanism for adjusting rates between rate cases must be clearly defined at the outset in the initial rate case. It is crucial for the rate adjustments to be defined at the outset to ensure a high degree of certainty of how the adjustments will be subsequently made. The utility is then clear about the extent to which a successful effort to control costs will result in increased earnings. Rider/trackers, true-ups, deferral accounts, and similar mechanisms are often used to address the need for additional expenditures or investments separately from rate cases to reduce the utility’s exposure between rate cases.

The term of the MYRP

NERP recommends using a maximum of three years as the term of an initial MYRP, but this is a key term to be decided. While most MYRPs are 3-5 years, NERP recommends starting on the shorter end of this range until more experience with the mechanism is gained. At the expiration of the MYRP, the utility would have the right, but not the obligation, to come in and seek a base rate increase. The NCUC could also set a period within which the next base rate case must be filed (e.g., within 5 years).

The scope of the MYRP – which utility costs would be included?

The MYRP would not necessarily apply to all utility costs. The selection of which costs should be included in the MYRP is a key term to be decided, and each of the other states studied appears to have made specific decisions that fit their needs best.

MYRPs are not well suited for the ratemaking for large, single discrete investments, such as conventional power plants to be built and rate-based by the utility. These would normally be excluded from the MYRP design and handled separately, through a deferral or separate base rate adjustment.

Costs recovered through existing clauses, such as the fuel clause, would stay in their clause, and not be included in the MYRP.

Investment programs that are made up of a series of smaller utility assets constantly placed in service over time, such as a grid improvement plan, are very well suited to a MYRP.

An earnings sharing mechanism should be implemented

As the MYRP design sets utility revenue adjustments into the future and creates an incentive for the utility to keep its costs lower than those assumed in the MYRP, the possibility of either over- or underearnings during the term of the MYRP should be addressed when the MYRP is designed.

NERP recommends that the MYRP be accompanied by a preset earnings sharing mechanism (ESM). This would set out the details in advance of how the savings will be allocated between the customers and the utility stockholders.

The ESM could be symmetrical, with earnings above and below the allowed return shared between customers and stockholders according to the method set out by the NCUC when the plan is originally approved. The earnings sharing would be calculated on an annual basis.

Key issues requiring further discussion by the NCUC

Some MYRP design decisions that were either controversial or otherwise unresolved during NERP are flagged here as important for continued attention in the course of the PBR design process.

Determination of what costs to include under MYRP

The NCUC will need to determine whether a MYRP should cover base rates or be more narrowly constructed to only cover certain projected costs. This decision will inform the initial utility revenue requirement the NCUC approves at the beginning of a MYRP and how these allowed revenues might adjust in the interim years between rate cases. Commissions have typically allowed MYRPs to cover most utility costs to more comprehensively impact utility spending decisions.

If the scope of the MYRP is too narrow, the utility may not be able to commit to a multiple-year rate case “stay-out” or moratorium, depending on the planned investments over that period.

On the other hand, risks to ratepayers can be minimized by limiting the scope of costs that may be recovered under a MYRP, so some stakeholders favored using the following definition developed during SB559 negotiations:

"Multiyear rate plan" means a rate mechanism under which the Commission sets base rates and revenue requirements for a multiyear plan period based on known and measurable set of capital investments and all the expenses associated with those capital investments and authorizes periodic changes in base rates during the approved plan period without the need for a base rate proceeding during the plan period.

Course correction if MYRP produces undesired outcomes

The longer stay-out period of a MYRP introduces risk that utility earnings could exceed or be below target levels, resulting in excessive over- or underearning by the utility. This may result from unforeseen events (e.g., tax law changes, economic recession) or from unexpected consequences of regulation design in the MYRP. Provisions can be made in the adoption of a MYRP for regulatory review at interim points in the plan, or for “reopeners” or “off ramps” at the determination of the NCUC, should those be necessary. It is useful for adopted regulations to specify that the NCUC may conduct such reviews or reopeners, including under what general conditions a plan may be revised, although the NCUC does not need to be overly specific on conditions under which this can occur.

Revenue adjustment mechanisms

See above under revenue decoupling for a discussion of the need to consider decoupling and MYRP revenue adjustments together.

Earnings sharing mechanism design

NERP recommends adopting a MYRP in conjunction with an ESM, but did not discuss the particulars of ESM design. Some issues to be resolved include whether there should be a deadband of over- or underearning in which no adjustment is made, and how sharing tiers should be designed.

Performance incentive mechanisms

Definition

Performance incentive mechanisms (PIMs) establish performance targets and tie a portion of a utility's revenue to its performance on meeting those targets. Targets are set to achieve outcomes that align with public policy goals.

Comparison with current system

One of the top three goals identified by NERP is to create “utility incentives aligned with cost control and policy goals.” The COS model incentivizes utilities to sell more electricity and to add capital assets to their rate base, but those incentives do not necessarily align with public policy goals such as the need to quickly reduce carbon emissions or alleviate household energy burdens. Introduction of carefully designed PIMs into ratemaking procedures could bring utility incentives more in line with public policy goals, such as meeting the state's targets under the Clean Energy Plan, by linking a portion of utility revenues to utilities' performance in achieving those goals.

If a significant portion of a utility's revenues is tied to performance, PIMs can begin to shift a utility's investment or management focus away from increasing capital assets and toward the accomplishment of the public policy objectives reflected in PIMs, potentially mitigating the utility's capex bias.

North Carolina has already started down the PIMs path, as the shared savings mechanism under the EE/DSM rider is a PIM incentivizing performance in the areas of energy efficiency and demand-side management.

PIMs are one part of broader PBR plan

As described elsewhere in this document, PIMs complement both decoupling and multi-year rate plans. Decoupling removes the utility's disincentive to promote energy efficiency and DERs, and PIMs can be designed to go further and create incentives for utilities to promote these programs. A MYRP creates an incentive for a utility to cut costs, and it can be paired with PIMs designed to make sure the cost-cutting does not occur in a way that negatively impacts essential functions such as customer service and reliability.

Alignment with goals of the Clean Energy Plan

The purpose of PIMs is to align utility incentives with public policy goals, which is one of the main outcomes sought by the CEP. In addition, the PIMs recommended below by NERP address the following CEP goals: carbon reduction, energy efficiency, affordability, and clean energy deployment.

The PIMs recommended below are those that seemed most useful to NERP participants. The NCUC could consider additional PIMs to help meet other goals and ensure successful implementation of PBR, as long as the desired outcomes are ones over which the utility has some level of control.

Experience in other states and jurisdictions

Several other jurisdictions have implemented, or are studying, PIMs. Two resources that relate their experiences are *Utility Performance Incentive Mechanisms: A Handbook for Regulators* (Whited, et al., 2015) and *PIMs for Progress* (Goldenberg, et al., 2020) (see References below).

Design Details of PIMs and NERP Recommendations

Metrics, Targets, and Incentives

The first step in establishing PIMs is to decide on the desired outcomes. For each outcome, it must be determined whether a reward or penalty is necessary. Among other things, this inquiry rests on existing utility

incentives (and disincentives), the existing regulatory environment, and the level of utility control over the desired outcome. The next step is to identify what metrics will be used to measure utility performance. The collection of some amount of baseline data is typically needed in order to determine how a utility’s performance is changing over time and how a reward or penalty ought to be implemented.

Depending upon whether a reward or penalty is appropriate, and depending on the level of confidence in a particular metric, performance on selected metrics can be (1) tracked and reported, (2) scored against a target or benchmark that has been set, or (3) tied to a financial reward or penalty, at which point the mechanism becomes a PIM.

For PIMs, if the utility achieves its performance target, it can then receive a financial reward or it can avoid a penalty. PIMs can be either symmetrical or asymmetrical. If the PIM is symmetrical, the utility receives a financial reward for achieving the target as well as a penalty for falling short of the target. An asymmetrical PIM provides only a reward (“upside only”) or only a penalty (“downside only”).

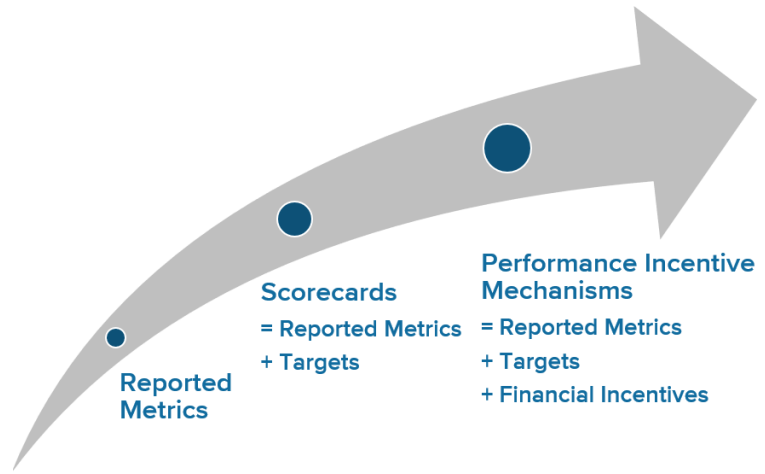


FIGURE 3: STAGES OF PERFORMANCE TRACKING
 MCDONNELL, M., PBR DEEP DIVE WEBINAR: EXAMINING THE HAWAII EXPERIENCE, POWERPOINT, APRIL 2 2020.

PIMs principles

Agreeing on underlying principles to follow in designing PIMs can help align stakeholders on shared objectives. NERP agreed on these key principles to consider:

- PIMs should advance public policy goals, effectively drive new areas of utility performance, and incentivize nontraditional methods of operating.
- PIMs should be clearly defined, measurable, preferably using available data, and easily verified.
- PIMs should collectively comprise a financially meaningful portion of the utility’s earning opportunities.
- No adopted PIM should duplicate a reward or penalty created by another PIM or other legal or regulatory mechanism.
- PIMs should reward outcomes, not inputs. In other words, the NCUC should avoid using expenditures as PIM metrics unless the desired outcome is increased spending.
- PIMs with metrics not controllable or minimally controllable by the utility should be upside only. A utility might prefer program-based PIMs, i.e., where incentives are awarded based on measurable actions, programs, and resources deployed or encouraged by the utility, over outcome-based PIMs given the risk that external factors may influence utility performance on the incentivized outcome (and therefore its compensation). Basing incentives on specific program results, e.g., kilowatt-hours saved through enrollment in an LED program, as opposed to outcomes, e.g., MWh saved system-wide, also makes symmetrical PIMs more of an option. However, a program-based PIM runs the risk of not achieving the desired outcome or decreasing the utility’s flexibility to choose and amend the portfolio of programs and investments that best produces the desired outcomes.¹⁸

Once a PIM is established, it should be revisited on a regular basis to evaluate whether the selected metric, target, and incentive level are appropriate for achieving the outcome in question. If not, those parameters should

¹⁸ For further discussion of activity-, outcome-, and program-based PIMs, see Goldenberg et al., *PIMs for Progress*, <https://rmi.org/insight/pims-for-progress/>.

be adjusted to improve performance. The Minnesota PBR case study that accompanies this document includes a diagram showing this iterative process as it was envisioned in Minnesota.¹⁹

Listed below are a number of performance outcomes discussed by NERP. Under most of the outcomes is listed a preferred metric for achieving that outcome, along with several alternative metrics. NERP recommends:

- At the outset, track as many of the metrics described below as are deemed useful and cost-effective, and any others identified by any stakeholder process or by the NCUC. This data collection will help to determine which metric is actually most useful in measuring performance.
- Track the overall performance for each adopted PIM or tracked metric and, where applicable, separately track the utility’s performance in low-income counties, specifically Tier 1 and 2 counties.
- Establish a public dashboard for reporting performance on PIMs and tracked metrics.

Specific PIM outcomes recommended by NERP for NCUC consideration

<p>Outcome: Peak demand reduction (or “Beneficial load-shaping” or “Aligning generation and load”)</p>
<p><i>Preferred metrics:</i></p> <ul style="list-style-type: none"> • Measurable load reduced/shifted away from peak based on measurement & verification from time-of-use (TOU) and other new rate designs (upside only, likely as shared savings) (program-based PIM) • Load factor for load net of variable renewable generation (upside only) (= average load not met by variable RE divided by peak load not met by variable RE) (Minnesota selected this as the metric for their PIM incentivizing “Cost-effective alignment of generation and load.”)²⁰ • MW reduced from the utility’s NCUC-accepted IRP peak demand forecast (for summer and winter peak) (upside only) (outcome-based PIM)
<p><i>Alternative metrics:</i></p> <ul style="list-style-type: none"> • enrollment (% of load or # of customers) in TOU rates or other advanced rates (symmetrical, likely as ROE adjustment) • MW demand response enrolled with TOU or other advanced rates (upside only, likely as ROE adjustment) • % of peak demand met by renewable energy (RE) or RE-charged storage and non-wires alternatives (upside only or, if symmetrical, set % target low and then progressively increase) • MW demand response utilized during critical peak periods identified for the purpose of utility tariffs using critical peak pricing (downside only with large deadband, i.e., penalty only for falling far short of target)
<p><i>Notes:</i></p> <ul style="list-style-type: none"> • This outcome serves two purposes: system efficiency and reducing need for new fossil fuel generation. • The preferred metrics listed above represent very different ways of looking at the problem. This area is ripe for innovation and requires further study and discussion before settling on an

¹⁹ “Case Study: Minnesota Electricity Performance Based Rates,” NERP, December 2020, page 5. Available here: <https://deq.nc.gov/CEP-NERP>

²⁰ Initial Comments of Fresh Energy, In the Matter of the Commission Investigation to Identify and Develop Performance Metrics and, Potentially, Incentives for Xcel Energy’s Electric Utility Operations, Docket E-002/CI-17-401, pp. 2-6, <https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={D012CC6E-0000-C510-A1A9-501BF633BC7D}&documentTitle=201912-157970-01>.

approach. Even the definition of “peak” must be examined, as increased renewable generation in the future may lead to overall system peaks that are unproblematic because they are met by renewables, whereas the object of this PIM is to reduce demand that requires fossil fuel generation.

- Time-of-use rate design has been facilitated by the widespread installation of smart meters. Duke Energy is currently examining a suite of rate designs and DSM product bundles tailored to various customer segments that the utility believes can save customers money, drive overall system affordability, expand customer bill control, increase options related to clean energy and technology adoption, and create price signals that could offer significant peak demand reduction opportunities with minimal investment costs. Duke Energy believes that the same mechanism currently used for EE and DSM programs would be highly appropriate for measured and verified peak demand reduction and conservation from new rate designs. PIMs could be used to incentivize rate design that achieves desired NERP outcomes.

Outcome: Integration of utility-scale renewable energy (RE) & storage

Preferred metrics:

- Meeting interconnection review deadlines agreed on in queue reform (downside only)
- MW of RE interconnected over and above that required by law or policy (upside only)
- % MWh generation represented by RE

Alternative metrics:

- MW of utility-scale RE interconnected/yr
- MWh RE curtailment (symmetrical around a reasonable number)
- MWh of power from RE-charged utility-scale storage/yr (upside only)
- % RE capacity (MW) (tracked metric only)
- Avg. no. of days to interconnect utility-scale solar, below target(s) set forth in queue reform (upside only)

Outcome: Integration of DERs (RE/storage/non-wires alternatives)

Preferred metrics:

- 3-year rolling average of net metered projects connected (MW and # of projects) (upside only)

Alternative metrics:

- MW/MWh customer-sited storage in utility management programs
- # customers (and MW) participating in utility programs to promote customer-owned or customer-leased DER
- # customers (and MW) participating in utility programs to provide grid services (including RE, storage, smart thermostat, etc.)
- % of rooftop solar systems passing interconnection screens (upside only)

Notes:

- Revenue decoupling eliminates the throughput incentive but does not actively incentivize DER. Pairing this PIM with decoupling creates an incentive to increase DER.

- Consideration should be given to New York’s shared savings program for non-wires alternatives projects, in which the cost of the solution (regardless of ownership) is recoverable in a 10- to 20-year regulatory asset.²¹

Outcome: Low-income affordability

Preferred metric:

- % of low-income households, defined as those falling at or below 200% of the federal poverty level, that experience an annual electricity cost burden of 6% of gross household income or higher (upside only)

Alternative metrics:

- Total disconnections for nonpayment
- Usage per customer vs. historic rolling average, per class
- Average monthly bill
- % customers past due on their accounts
- # customers on fixed-bill programs

Notes:

- Why there is a need: In 2016, Duke Energy Carolinas had around 330,000 residential customers with household incomes ≤ 150% of the federal poverty level. They accounted for around 20% of DEC’s total residential accounts. Those customers spent on average 10.5% of household income on energy (approximately 83% of which was for electricity and the rest for heating), compared to around 3% for DEC customers system-wide.²²
- There is a need to ensure affordability for other customers as well. Municipal utilities would benefit from any outcome that reduces production costs and commercial and industrial (C&I) customers want to keep NC rates competitive with other Southeast states. Metrics may need to be developed for these other classes of customers and for residential customers who do not qualify as low-income. Some of the alternative metrics listed above might be useful for some of these customers.
- If a low-income rate pilot is adopted, it would help to inform the design of this PIM. Participants in the pilot would need to be selected randomly, and results would need to be reported, so that the energy burden of participating and non-participating households could be compared.
- A lower fixed charge could help low-income customers and might be possible with decoupling, which shifts more of the fixed costs into rates.

Outcome: Energy efficiency

Notes:

- Revenue decoupling eliminates the throughput incentive but does not actively incentivize energy efficiency (EE). Pairing this PIM with decoupling creates an incentive to increase EE.
- This was one of the more important outcomes for NERP participants, but no preferred metric was chosen because the NCUC would need to consider any new EE incentives in conjunction with the existing EE/DSM incentive, which is a PIM using a shared savings mechanism. It was

²¹ Trabish, Herman K. "Tackling the perverse incentive: Utilities need new cost recovery mechanisms for new technologies," Utility Dive, March 16, 2018, <https://www.utilitydive.com/news/tackling-the-perverse-incentive-utilities-need-new-cost-recovery-mechanism/518320/>.

²² Direct testimony of Rory McIlmoil in Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina, Docket No. E-7, Sub 1214, February 18, 2020, p. 35, <https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=11d407e8-1a85-487f-8548-ac2fa7cde2a5>.

amended in October 2020 under NCUC Dockets No. E-2, Sub 931 and E-7, Sub 1032, with changes to take effect in 2022.²³

- If North Carolina enacts revenue decoupling for electricity, the lost revenue adjustment mechanism (LRAM) associated with the existing EE/DSM incentive will no longer be needed and will need to be removed by the NCUC for the classes included in decoupling. Particular attention will need to be given to how this is done for the general service class, if small and medium general customers are included in decoupling but large general service customers are not. There also needs to be consideration given to small and medium general service accounts that can currently opt out of the LRAM mechanism and how that will be addressed with decoupling. The recommendations below could be considered at that time.

Possible amendments to existing incentive:

- The current incentive imposes a penalty for incremental annual savings below 0.5% and offers a bonus above 1%. The NCUC order directed the EE/DSM Collaborative to study the impact of switching to a step approach in which the incentive is scaled up or down linearly above a minimum and maximum level (so that there is a possibility of some bonus between 0.5% and 1% and a possibility of additional bonus above 1%). If the study shows this approach to yield greater savings, such a step approach could be adopted. That incentive should likely be capped at a certain percentage of costs (e.g., Minnesota caps incentives at 30% of program costs).²⁴
- Consider advantages/disadvantages of shared savings mechanism vs. using as the core metric either kWh saved, Btu saved (to give credit for electrification) and/or greenhouse gas emissions saved.
- Most states base their goals on savings in a given year (called incremental annual savings, that measure savings from measures installed in that year). Illinois and, more recently, Virginia measure total annual savings (savings persisting from previously installed measures and new measures installed in that year). Incremental annual savings is a simple place to start, but over time total annual savings may be a good framework, because it addresses the persistent effect of short-term measures such as low-flow showerheads or behavioral EE programs.

Additional metrics to track or incentivize:

- Low-income participation in EE programs
- % participation per class
- # of C&I customers participating (upside only, with the utility rewarded for implementing programs that cause fewer C&I customers to opt out, but not penalized for failing to do so, since the outcome is minimally controllable by the utility)

Outcome: Carbon emissions reduction

Preferred metric:

- Tons of CO2 equivalents reduced beyond what is required by law or policy (with cost-effectiveness test, upside only)

Alternative metrics:

- Reduction in carbon intensity (tons carbon/MWh sold) (symmetrical)
- Carbon price used in IRP scenarios (\$/ton, tracked metric only)

Notes:

²³ Order Approving Revisions to Demand-Side Management and Energy Efficiency Cost Recovery Mechanisms, Oct. 20, 2020, <https://starw1.ncuc.net/ncuc/ViewFile.aspx?Id=5aaea5ce-6458-41fe-ab2d-14d86881092d>.

²⁴ “Case Study: Minnesota Electricity Performance Based Rates,” NERP, December 2020, Available here: <https://deq.nc.gov/CEP-NERP>

- Needs to be designed in accordance with any carbon policy resulting from the A-1 process. If no carbon reduction policy is achieved in the A-1 process, a PIM would be essential and could set benchmarks for reduction between now and 2050 that would incentivize meeting CEP carbon reduction goals.
- If this PIM were awarded on a dollar per ton basis, the NCUC could consult with the A-1 stakeholder group, who examined the effects of different carbon prices for future years.
- Consideration should be given to calculating and reporting (but likely not incentivizing) reduction in upstream methane emissions associated with gas burned in North Carolina, as these contribute significantly to climate change yet are not captured by the carbon accounting of the CEP. A PIM could eventually be appropriate if the state wishes to incentivize progress toward Duke Energy’s goal, announced October 2020, of reducing upstream methane emissions in its natural gas distribution and power generation supply chains.²⁵
- Any PIM in this area would need to be either based on North Carolina consumption with any incremental costs direct assigned to North Carolina customers or agreed to by regulators in both North Carolina and South Carolina.

Outcome: Electrification of transportation
<p><i>Preferred metric:</i></p> <ul style="list-style-type: none"> • EV customers on TOU or managed charging (include home, workplace, fleets, and public charging) (upside only) OR • MWh or % of EV charging load at low-cost hours (upside only)
<p><i>Alternative metrics:</i></p> <ul style="list-style-type: none"> • Utilization of utility-owned public charging stations (upside only) • Utility-owned charging in low-income areas (# or % chargers) (symmetrical) • Customers enrolled in programs to encourage private charger installation (upside only) • EV education (avoid rewarding \$ inputs; maybe clicks on a web page; if expenditure metric, then downside only with spending cap) • EV adoption • CO2 avoided in transportation sector by electrification
<p><i>Notes:</i></p> <ul style="list-style-type: none"> • Design in accordance with Duke Energy’s EV pilot as approved November 2020.²⁶ • Design depends on whether utility or others own charging infrastructure, since ROE on assets may be incentive enough. • More research needed on how EVs can help with RE integration and how they can lead to reduced costs for all customers. • Utility could use credits for off-peak charging but not put customers on TOU, or could use subscription pricing with managed charging. PIM should not constrain what method is used to promote off-peak EV charging.

Outcome: Equity in contracting

²⁵ "Duke Energy to reduce methane emissions in its natural gas business to net zero by 2030," https://www.duke-energy.com/_/media/pdfs/our-company/methane-reduction-fact-sheet.pdf?la=en.

²⁶ Order Approving Electric Transportation Pilot, In Part, Nov. 24, 2020, <https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=1c1665d0-d645-4293-82d8-ae9d7e672e3d>.

Preferred metrics:

- % of utility scale RE & storage suppliers that are 51% owned, managed, and controlled by one or more individuals who are socially and economically disadvantaged as defined by 15 U.S.C. § 637 (tracked metric only)
- % of utility scale RE & storage suppliers that are 51% owned, managed, and controlled by one or more individuals who are women (tracked metric only)

Notes:

- There is also a desire to achieve equity in use of utility programs across income levels, but that needs more discussion.

Outcome: Resilience
<p><i>Preferred metrics:</i></p> <ul style="list-style-type: none"> • Number of critical assets (see note below) without power for more than N hours in a given region (# of assets), N may be set as 0 hours or greater than the number of hours backup fuel is available • Critical asset energy demand not served (cumulative kW) • Critical asset time to recovery (average hrs)
<p><i>Alternative metric:</i></p> <ul style="list-style-type: none"> • Cumulative critical customer hours of outages (hrs)
<p><i>Notes:</i></p> <ul style="list-style-type: none"> • Recommended metrics revolve around impacts on critical community assets since that is the framework used in the PARSG (Planning an Affordable, Resilient and Sustainable Grid) project and in the state Resilience Plan. This approach is also being integrated into the NARUC-NASEO comprehensive system action plan that the NC delegation is considering. • Critical assets may include hospitals, fire stations, police stations, evacuation shelters, community food supply distribution centers, production facilities, military sites, etc. • Since resilience study is very much a work in progress in North Carolina, it is recommended that these initially be tracked metrics, with no incentive attached. • Efforts to develop resilience metrics are currently underway across organizations such as the DOE, FERC, EPRI and multiple state public utility commissions. The industry is lacking agreed-upon performance criteria for measuring resilience, as well as a formal industry or government initiative to develop consensus agreement.²⁷ As such, there are currently no standardized metrics to measure resilience efforts or to quantify the extent or likelihood of damage created by a catastrophic event. Resilience is addressed state-by-state, and oftentimes event-by-event. If different metrics, benchmarks, rewards or incentives are identified and developed for reliability and resilience,²⁸ there is a need to properly distinguish each, take into account the benefits for each, and differentiate how to separately determine the benefits, rewards and penalties for each.²⁹ • The metrics identified above are based on community impact driven resilience needs for critical infrastructure. It is based on current North Carolina state and local government led application of energy vulnerability and risk analysis framework that uses the Resilience Analysis Process (RAP) developed by the Sandia National Lab, which includes prioritization of grid-modernization initiatives that could achieve a desired set of resiliency goals for the community.

²⁷ IEEE Standards Association (2018) Grid Resilience and the NESC®.

²⁸ According to DOE, reliability refers to the ability of the system or its components to withstand instability, uncontrolled events, cascading failures, or unanticipated loss of system components. Resilience refers to the ability of a system or its components to adapt to changing conditions and to withstand and rapidly recover from disruptions.

²⁹ DOE (2017). See Key Findings at S-13: "There are no commonly used metrics for measuring grid resilience. Several resilience metrics and measures have been proposed; however, there has been no coordinated industry or government initiative to develop a consensus on or implement standardized resilience metrics."

<https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf>.

PIMs needed in conjunction with a multi-year rate plan

A MYRP provides an incentive to cut costs. Therefore, these two PIMs should accompany a MYRP to guard against detrimental cost-cutting in the areas of reliability and customer service. If there is no MYRP, the metrics could be simply tracked and reported.

Outcome: Reliability
<p><i>Preferred metric:</i></p> <ul style="list-style-type: none"> SAIDI (performance year-over-year, excluding extreme event days, downside only, feeder-by-feeder) (see note below)
<p><i>Alternative metrics:</i></p> <ul style="list-style-type: none"> CEMI4 (customers experiencing more than 4 outages of 1 minute or more per year) SAIFI Miles of vegetation management (tracked metric only; see note below)
<p><i>Notes:</i></p> <ul style="list-style-type: none"> The design should be downside only because the utilities’ performance on reliability is already high. Providing a reward for further improvement might not provide a net benefit to customers (point of diminishing returns). The feeder-by-feeder specification prevents selective maintenance. Central Maine Power experienced a drop in reliability on certain feeders when they had a reliability PIM in conjunction with a MYRP. Tracking miles of vegetation management would give the NCUC a way to ascertain whether the MYRP was resulting in decreased maintenance. But many other factors affect that metric, so a financial penalty could unfairly punish the utility for matters beyond its control, and a financial reward could perversely incentivize unnecessary vegetation work.

Outcome: Customer service
<p><i>Preferred metric:</i></p> <ul style="list-style-type: none"> Third-party customer satisfaction survey (e.g., JD Power score or Net Promoter score) (downside only)

Key issues requiring further discussion by the NCUC

As the NCUC considers PIM implementation, it will have to consider all of the parameters discussed above. The NCUC will need to review a utility’s proposed metrics and PIMs and determine whether they incentivize the right outcomes, whether they employ the best metrics to measure each outcome, whether the targets are at the right level, and whether financial incentives for each metric are at the right level and appropriate to include. NERP hopes that the suggestions made above will help with that process.

Options for designing incentives

NERP did not discuss the form that PIMs should take. The four most common design options are listed here. Each design option has advantages and disadvantages, and some PIMs incorporate aspects of more than one design.

- Shared savings or shared net benefits**
Incentives can be based on shared net benefits or savings that allow a utility to keep a portion of the net benefits or savings that are created by the achievement of a performance target. Net benefits are

calculated using the avoided costs that a utility would have incurred without the program minus the cost of the program itself.

- **Percentage adders based on spending**

PIMs can allow a utility to earn a percentage return on their spending on particular programs, such as energy efficiency or DER initiatives, if they meet performance targets or program goals. This allows utilities to earn a return on expenses that would otherwise be a pass-through.

- **Fixed rewards or penalties**

Utilities can earn or be penalized a fixed amount based on achievement of targets.

- **Adjustment to a utility's regulated ROE**

PIMs can make a basis point adjustment of a utility's regulated ROE, which could more fundamentally impact utility investment decisions.

RECOMMENDED PROCESS FOR PBR DEVELOPMENT

PBR requires careful attention to key design details, especially for a comprehensive PBR approach as described here. NERP participants believe that enabling legislation will be beneficial to direct the next stage of PBR development, followed by a NCUC rulemaking process to adopt necessary rules for filing applications and criteria for evaluating them. Effective incentive regulation will also require ongoing monitoring and possible course corrections during a PBR regime (e.g., at the conclusion of a multi-year term, before advancing to the next term). This foretells the need for devoted attention and care from the NCUC and stakeholders to monitor utility performance and system outcomes, then make adjustments to guide utilities to continued improvement and value creation for customers.

Other states have applied a sequential process to develop and refine PBR, for example:

1. Articulate goals
2. Identify desired outcomes
3. Assess how current regulations meet or do not meet desired outcomes
4. Prioritize outcomes and identify PBR tools for further development
5. Design and iterate on PBR tools
6. Determine steps and requirements for implementation, including opportunity for evaluation

The NERP process has made substantial progress on the first four of these steps. A PBR process at the NCUC should seriously consider the conclusions reached by NERP, then follow the steps above, making sure to receive comment from as broad a group of stakeholders as possible, including any other relevant state agencies. Some specific steps that may be necessary are outlined below.

- First, the NCUC would lead a rulemaking process, to set up all of the filing requirements and procedures that any utility would need to follow to file a PBR application, including the criteria to be used by the NCUC in evaluating PBR applications. The NCUC should determine whether and in what form a stakeholder process should take place to gather input prior to a utility filing a PBR application.
- The utility would submit its PBR application as part of an initial base rate case. The utility would still file cost of service studies and those studies would be the basis for establishing the total revenue required and the allocation to the customer classes. The PBR adjustments discussed in this document would be increments or decrements to that base. The utility's accompanying PBR application would include:
 - a decoupling plan including proposed adjustment and true-up mechanisms
 - a multi-year rate plan including the planned investments that the utility proposes to undertake during the term of a MYRP
 - an earnings sharing mechanism
 - a set of proposed PIMs, scorecard targets or reported metrics
- In addition to all the normal rate case activities, the NCUC would need to:
 - review and rule on the proposed decoupling and MYRP designs and proposed PIMs

- evaluate whether the planned investments are consistent with the goals of the CEP and the public interest and determine which of those planned investments would be allowed and what the allowed revenue increases would be over the term of the MYRP
 - for the customers included in decoupling, amend as needed the lost revenue adjustment mechanism (LRAM) that is part of the existing EE/DSM incentive, since decoupling adjusts revenue in a different manner
 - Annually, the NCUC would review the results of the utility’s operations during the prior year, including:
 - actual capital projects placed in service
 - utility earnings levels
 - utility sales and any adjustments needed due to a decoupling mechanism, including amounts to be refunded to or collected from customers based on the decoupling true-up mechanism and adjustments to rates going forward as a result of the mechanism
 - other utility revenue adjustments required by the adopted MYRP and ESM
 - utility performance against any adopted PIMs or tracked metrics to calculate penalties and incentives.
- After this review, the NCUC would approve the actual rates to be used in the subsequent year.
- NCUC rulemaking should outline what steps will be taken at the end of the initial MYRP period, including opportunities to add, delete, or adjust the approved set of PIMs to ensure they are capturing and driving desired utility performance.

Theoretical timeline

To help visualize how this process might unfold in North Carolina, NERP developed this entirely theoretical timeline:

- Legislation signed into law: June 2021
- NCUC issues rules for utility PBR applications: December 2021
- PBR application and base rate case filed by utility: July 2022
- NCUC proceeding to evaluate application: July 2022-March 2023
- NCUC order establishing PBR: March 2023
- First annual decoupling/MYRP true-up and PIMs review: March 2024

CONCLUSION

To summarize, NERP recommends that NCUC, subject to any guidance and timelines provided by legislation, begin as soon as possible a proceeding to develop rules under which a utility may file a comprehensive PBR application, including:

- Revenue decoupling excluding the large general service class to reduce the throughput incentive
- MYRP with an ESM and off-ramp to eliminate regulatory lag
- PIMs or tracked metrics to transition the utility revenue model toward achievement of regulatory goals, addressing the following outcomes: peak demand reduction, integration of DER and utility-scale RE and storage, low-income affordability, energy efficiency, carbon emissions, electrification of transportation, resilience, equity and – assuming a MYRP is adopted – reliability and customer service
- Provisions for annual or more frequent decoupling and MYRP true-ups and adjustment of PIM metrics, targets and incentive levels

Members of the NERP stakeholder group, in particular the PBR study group, stand willing to help the NCUC in its implementation of PBR, either in a stakeholder process or in any other way the NCUC deems appropriate.

REFERENCES

There are many resources on PBR. Here are some that NERP found most useful.

Cross-Call, Gold, Goldenberg, Guccione, and O'Boyle, *Navigating Utility Business Model Reform*, Rocky Mountain Institute (2018). Available at <https://www.rmi.org/insight/navigating-utility-business-model-reform/>.

Gold, R. et al. *North Carolina Can Boost Economy, Cut Utility Bills and Carbon with Energy Efficiency Efforts*, American Council for an Energy-Efficient Economy, September 23, 2020. <https://www.aceee.org/research-report/u2007>.

Goldenberg, Cara, Dan Cross-Call, Sherri Billimoria, and Oliver Tully, *PIMs for Progress: Using Performance Incentive Mechanisms to Accelerate Progress on Energy Policy Goals*, Rocky Mountain Institute, 2020, <https://rmi.org/insight/pims-for-progress/>.

Hawaii PUC, Proceeding to Investigate Performance-Based Regulation (Docket 2018-0088). Information and filings available at <https://puc.hawaii.gov/energy/pbr/>.

Lazar, Jim, et al. *Revenue Regulation and Decoupling: A Guide to Theory and Application*, Regulatory Assistance Project; 2016. Available at <https://www.raonline.org/knowledge-center/revenue-regulation-and-decoupling-a-guide-to-theory-and-application-incl-case-studies/>.

Littell, et al, *Next Generation Performance Based Regulation: Emphasizing Utility Performance to Unleash Power Sector Innovation*, Regulatory Assistance Project, 2017. Available at <https://www.raonline.org/knowledge-center/next-generation-performance-based-regulation-emphasizing-utility-performance-unleash-power-sector-innovation/>.

Lowry and Makos, *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities*, 2017. Available at https://eta.lbl.gov/sites/default/files/publications/multiyear_rate_plan_gmlc_1.4.29_final_report071217.pdf.

Migden-Ostrander, J., and Sedano, R. (2016). *Decoupling Design: Customizing Revenue Regulation to Your State's Priorities*. Montpelier, VT: Regulatory Assistance Project. Available at: <http://www.raonline.org/knowledge-center/decouplingdesign-customizing-revenue-regulation-state-priorities>.

Whited, M., Woolf, T., Napoleon, A. *Utility Performance Incentive Mechanisms: A Handbook for Regulators*, Synapse Energy Economics; 2015. Available at

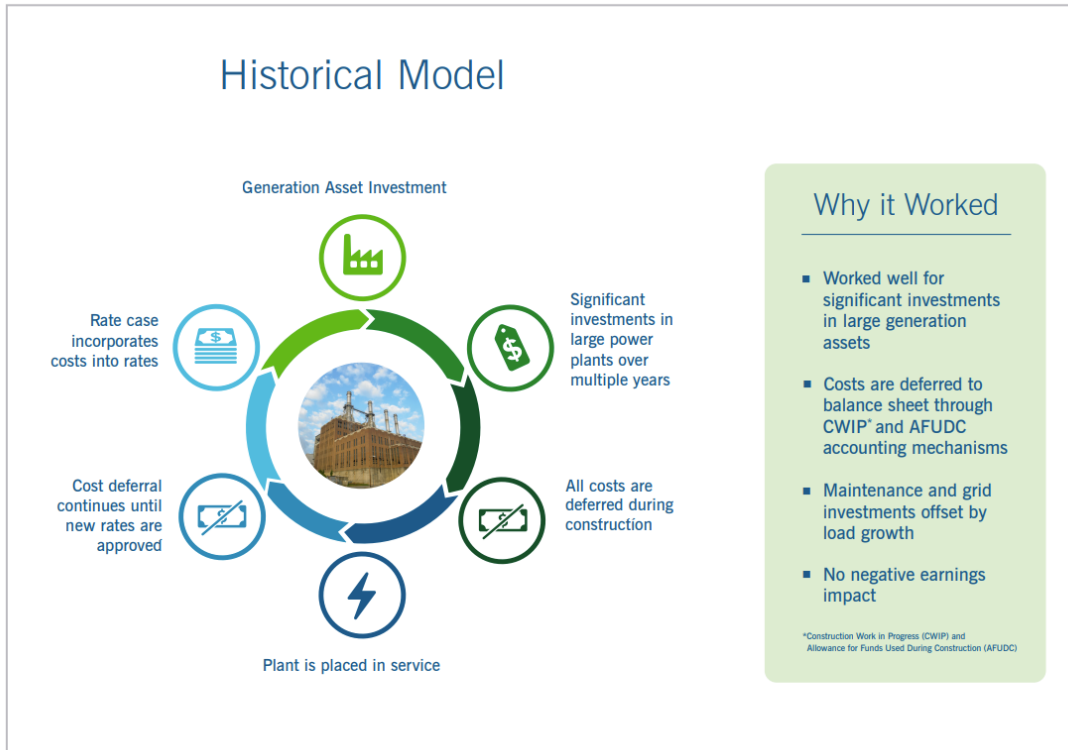
http://www.synapseenergy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf

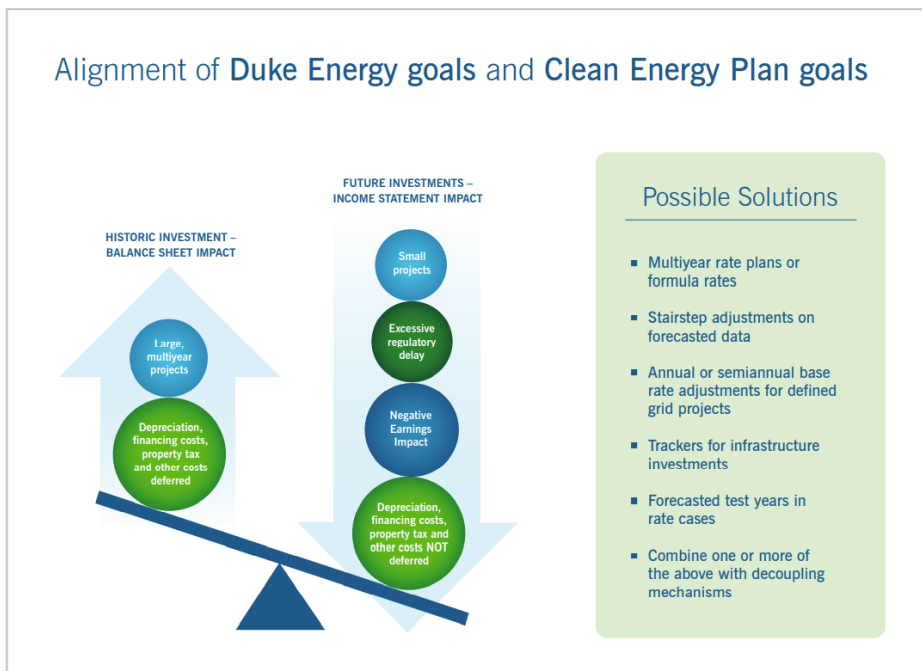
APPENDIX A

Solving for Regulatory Lag (Source: Duke Energy)

North Carolina Ratemaking and Recovery

The current regulatory system has served customers and utilities well for many decades. But today, utilities are shifting away from large-scale power plants toward modernizing the energy grid and adding more distributed energy. Therefore, a new model is needed to align the regulatory framework with investments in a 21st-century energy system.





Modern Cost Recovery for Electric Utilities

Many other states have adopted one or more cost recovery mechanisms that enable higher levels of grid improvement investment:

- 24 states have multi-year rate plans or formula rates
- 23 states have trackers for grid/electric infrastructure investments
- 30 states have forward test years (full or partial)
- Only 7 states have none of these mechanisms – including North Carolina

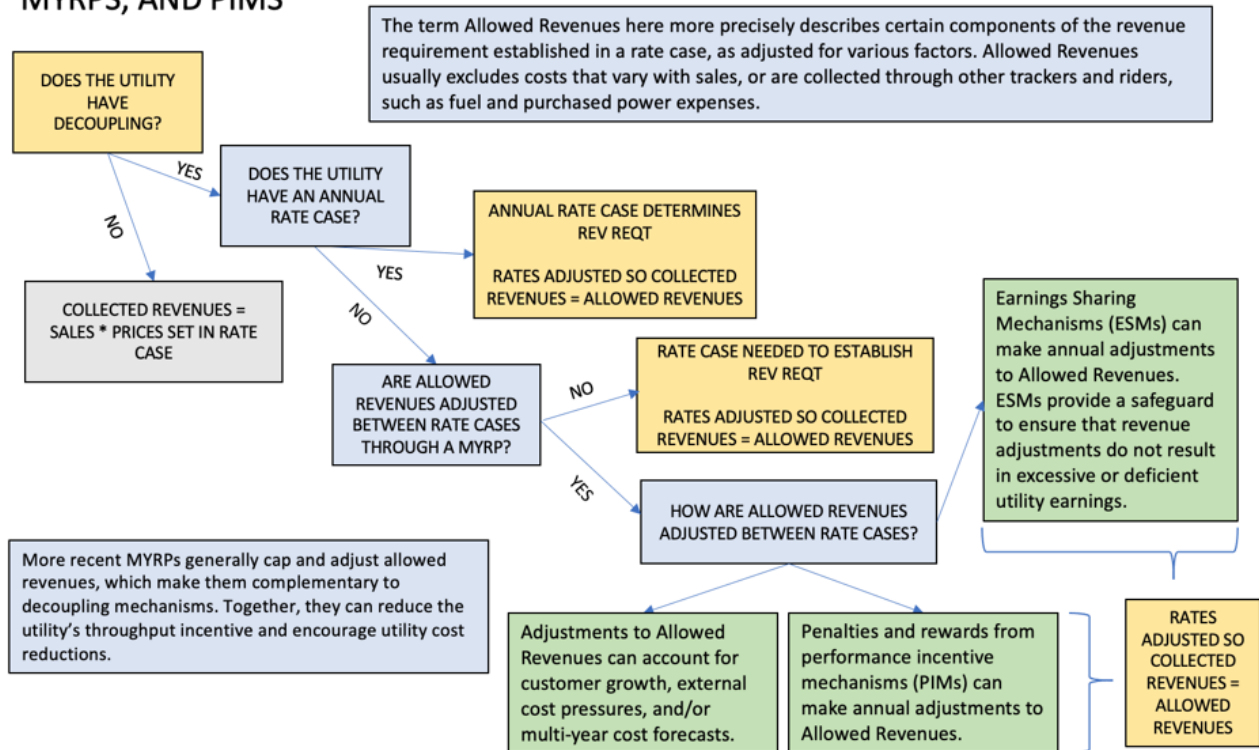
APPENDIX B

Flow Chart Diagram Depicting Potential Interactions and Coordination Between MYRP, Decoupling, and PIMs

Source: Rocky Mountain Institute

The following diagram depicts how several key PBR mechanisms operate together to adjust utility revenues and customer rates. It shows how revenue decoupling could operate with a MYRP that caps and adjusts a utility’s revenues in the years between rate cases. Additional revenue adjustments resulting from performance incentives and an earnings sharing mechanism are also included to show how they might ultimately impact the revenues a utility is allowed to collect and the rates then charged to customers.

HOW ALLOWED REVENUES AND RATES COULD ADJUST WITH DECOUPLING, MYRPS, AND PIMS



PART I. AUTHORIZE RATES USING ALTERNATIVE MECHANISMS

Section 1.(a) Article 7 of Chapter 62 of the General Statutes is amended by adding a new section to read:

"§ 62-133A. Performance-based rate methodology authorized.

(a) Declaration of Policy. - The General Assembly declares that utilities in the state have an important role to play in the transition to cleaner energy, and must be fully empowered, through regulatory tools and incentives, to achieve the goals of this policy. In combination with new technology and emerging opportunities for customers, this policy will spur transformational change in the utility industry. Given these changes, the legislature authorizes that the Utilities Commission's statutory grant of authority for rate making includes consideration and implementation of performance-based regulation (PBR) including: multiyear rate plans with earnings sharing mechanism, decoupling of utility revenues from energy sales, and performance incentive mechanisms to achieve just and reasonable rates and achieve its public interest objectives. The General Assembly also finds that the regulatory cost recovery mechanisms should better align the interests of customers and electric public utilities and that improvements should be made in the current rate making process to decrease the number of rate cases and reduce the regulatory lag that currently hinders certain capital investments, such as investments in the electric grid, storage or small scale renewables, and other technologies, necessary to support the clean energy transition. The PBR approach can be used to encourage: (a) alignment of electric utility incentives with customer and societal interests through regulatory mechanisms that motivate utilities to improve operations, increase program effectiveness, and better manage business expenses, (b) electric utility innovation in how it delivers service to customers; (c) electric utility investments to reduce carbon emissions, make the grid smarter, more resilient to adverse weather and to cyber and physical security threats, and capable of accommodating more renewable and distributed energy resources onto the system; (d) more efficient use of energy by customers; and (e) maintaining affordable and more predictable rates through annual rate adjustments spread over time. As such, the General Assembly declares that it is in the public interest to develop standards for performance-based regulation of electric utilities.

(b) Definitions. - For purposes of this section, the following definitions apply:

(1) "Performance-based regulation (PBR)" means an alternative rate making approach that includes (1) revenue decoupling; (2) multiyear rate plans with earnings sharing mechanism; and (3) performance incentive mechanisms.

(2) "Decoupling" means a ratemaking mechanism intended to break the link between a utility's revenue and the level of consumption of electricity by its customers.

(3) "Multi-year rate plan (MYRP)" means a ratemaking mechanism under which the Commission sets base rates based on a historic test year and revenue requirements necessary to cover new Commission-authorized costs that are expected to be incurred over a multi-year period through a plan which authorizes periodic changes in rates without a general rate application.

(4) "Earnings sharing mechanism" means a ratemaking mechanism that shares surplus or deficit earnings, or both, between utilities and customers.

1 (5) “Performance incentive mechanism (PIM)” means a ratemaking mechanism
2 that links electric utility revenue or earnings to electric utility performance in
3 targeted areas consistent with customer and societal interests and regulatory
4 and public policy goals and includes specific performance metrics and targets
5 against which utility performance is measured.

6 (6) “Distributed Energy Resource (DER)” means a device or measure that
7 produces electricity or reduces electricity consumption, and is connected to
8 the electrical system, either ‘behind the meter’ on the customer’s premises, or
9 on the utility’s primary distribution system. A DER can include, but is not
10 limited to, energy efficiency, distributed generation, demand response,
11 microgrids, energy storage, energy management systems, and electric
12 vehicles.

13 (7) “Tracking metric” means a methodology for tracking and quantitatively
14 measuring and monitoring outcomes or utility performance, meaning that the
15 data reflected by the unit of measurement is tracked and published to
16 illuminate progress toward a particular regulatory outcome.

17 (c) Authorization. - Notwithstanding the methods for fixing rates established under
18 G.S. 62-133, the North Carolina Utilities Commission is authorized to utilize and approve PBR
19 mechanisms proposed by electric public utilities and/or other stakeholders and intervenors,
20 including, but not limited to, revenue decoupling, MYRP with an earnings sharing mechanism,
21 and PIMs.

22 (d) Rulemaking. - Within six months of the effective date of this act, the Commission
23 shall issue an order adopting rules consistent with this act. The Commission may initiate a
24 stakeholder process to inform its rulemaking. The rules should prescribe the specific procedures
25 and requirements that an electric utility must meet when filing a PBR Application, the criteria for
26 evaluating such an Application, and the process for addressing deficiencies through a remedy
27 that may consist of a collaborative process between stakeholders and the utility to cure any
28 identified deficiency in the Utility’s PBR Application in the event the Commission ultimately
29 rejects a utility’s PBR Application.

30 (e) Application. - A PBR Application shall be made in a general rate case proceeding
31 initiated pursuant to G.S. 62-133, and must include details of: (1) a decoupling rate adjustment
32 mechanism; (2) a MYRP if desired by the electric utility (including proposed revenue
33 requirement and rates for each year of the MYRP or method for calculating such); and (3) PIMs
34 (including but not limited to targeted areas of energy efficiency, peak demand reduction, and
35 renewable energy and DERs). It may also include proposed tracking metrics with or without
36 targets or benchmarks to measure utility achievement, and other PBR mechanisms to support the
37 clean energy transition. The following additional requirements apply:

38 (1) MYRP may include annual rate adjustments based on projected investments,
39 formulas, indexes, or a combination thereof. If the MYRP includes rate
40 increases based on forecasted planned investments, the Commission shall
41 require the electric utility to include in its PBR Application major planned
42 investments over the plan period, the schedule for completion of those
43 investments, and an explanation as to why the investments are in the public

1 interest. If projected investments are not included in the MYRP rate
2 adjustments until after the investments are in service, then the utility may
3 request Commission approval to defer to a regulatory asset the incremental
4 costs from the time the investment is placed in service until the costs are
5 reflected in the MYRP rates.

6 (2) PIMs should be clearly defined, measurable with a defined performance
7 metric, and reasonably within the utility’s control. The incremental costs
8 required to achieve a PIM shall, upon approval by the Commission, either be
9 included in rates under a MYRP or deferred to a regulatory asset until such
10 time as the costs can be incorporated into the utility’s rates.

11 (f) When reviewing a PBR application, the Commission may approve PIMs proposed
12 by the electric utility as part of a PBR application including the following:

- 13 (1) Rewards based on the sharing of savings achieved by meeting or exceeding a
14 specific performance target;
15 (2) Rewards or penalties based on differentiated authorized rates of return on
16 common equity to encourage utility investments or operational changes to
17 meet specific performance targets;
18 (3) Fixed financial rewards to encourage achievement of specific performance
19 targets, or fixed financial penalties for failure to achieve such targets; and
20 (4) Any other incentives or financial penalties that the Commission determines to
21 be appropriate.

22 (g) The Commission shall approve the PBR Application by an electric utility only
23 upon a finding by the Commission that such mechanisms are just and reasonable, and are in the
24 public interest pursuant to G.S. 62-2(a). In reviewing any such Application under this section,
25 the Commission may consider whether the Application, as proposed: (i) assures that no customer
26 or class of customers is unreasonably harmed and that the rates are fair both to the electric utility
27 and to the customer, (ii) reasonably assures the continuation of safe and reliable electric service,
28 (iii) will not unreasonably prejudice any class of electric customers and result in sudden
29 substantial rate increases or “rate shock,” to customers, (iv) is otherwise consistent with the
30 public interest, (v) encourages peak load reduction or efficient use of the system, (v) encourages
31 utility-scale renewable energy and storage, (vi) encourages DERs, (vii) reduces low-income
32 energy burdens, (viii) encourages energy efficiency, (ix) encourages carbon reductions, (x)
33 encourages beneficial electrification, including electric vehicles, (xi) supports equity in
34 contracting, (xii) promotes resilience and security, and (ix) maintains adequate levels of
35 reliability and customer service.

36 (h) Decision. - Upon receiving a PBR Application by an electric utility that
37 incorporates PBR mechanisms as listed in (e), the Commission, after notice and an opportunity
38 for interested parties to be heard, is authorized to issue an order within the time frames set forth
39 in G.S. 62-134, approving or rejecting the utility’s PBR Application; in addition to its order
40 ruling on the electric utility’s request to adjust base rates under G.S. 62-133. If the Commission
41 rejects the PBR Application, it must provide an explanation of the deficiency and an opportunity
42 for the utility to refile or for the utility and the stakeholders to collaborate to cure the identified
43 deficiency and refile.

1 (i) Plan Period. - Any PBR Application approved pursuant to this section shall
2 remain in effect for a plan period of not more than 60 months. Prior to the end of the PBR plan
3 period, if the utility has not filed a petition for a subsequent PBR plan, the Commission shall
4 initiate a proceeding to examine options for renewing or revising the PBR mechanisms.

5 (j) Review. - At any time prior to conclusion of a PBR plan period, the Commission,
6 with good cause and upon its own motion, has the discretion to examine the reasonableness of
7 the electric utility’s rates under the plan, conduct periodic reviews with opportunities for public
8 hearings and comments from interested parties, and initiate a proceeding to adjust rates or PIMs
9 as necessary. In addition, nothing in a PBR proposal shall inhibit or take away from the
10 Commission’s authority to grant deferrals for extraordinary costs in between rate cases.

11 (k) Utility Reporting. - For purposes of measuring an electric utility’s earnings under
12 a PBR Application approved under this section, the electric utility shall make an annual filing
13 that sets forth the electric utility’s earned return on equity, the electric utility’s revenue
14 requirement trued up with the actual electric utility revenue, the amount of revenue adjustment in
15 terms of customer refund or surcharge, and the adjustments reflecting rewards or penalties
16 provided for in performance-based plans approved by the Commission.

17 (l) Nothing in this section shall be construed to (i) limit or abrogate the existing rate-
18 making authority of the Commission or (ii) invalidate or void any rates approved by the
19 Commission prior to the effective date of this section. In all respects, the alternative ratemaking
20 mechanisms, designs, plans or settlements shall operate independently, and be considered
21 separately, from riders or other cost recovery mechanisms otherwise allowed by law, unless
22 otherwise incorporated into such plan.

23 (m) Commission Report. - No later than April 1 of each year, the Commission shall
24 submit a report on the activities taken by the Commission to implement, and by electric power
25 suppliers to comply with, the requirements of this section to the Governor, the Environmental
26 Review Commission, and the Joint Legislative Oversight Committee on Agriculture and Natural
27 and Economic Resources, the chairs of the Senate Appropriations Committee on Agriculture,
28 Natural, and Economic Resources, and the chairs of the House of Representatives Appropriations
29 Committee on Agriculture and Natural and Economic Resources. The report shall include any
30 public comments received regarding environmental impacts (including but not limited to air,
31 water and waste emission levels) of the implementation of the requirements of this section. In
32 developing the report, the Commission shall consult with the Department of Environmental
33 Quality.

34 **SECTION 2.(b)** The Commission shall adopt rules as required by G.S. 62-133A(g), as
35 enacted by Section 2(b) of this act.

36 **PART II. EFFECTIVE DATE**

37 **SECTION 1.** Part I of this act is effective when it becomes law and applies to any rate-
38 making mechanisms filed by an electric utility on or after the date that rules adopted pursuant to
39 G.S. 62-133A(g), as enacted by Section 2(a) of this act, become effective.



NERP CASE STUDY

NATURAL GAS DECOUPLING IN NORTH CAROLINA

The 2020 North Carolina Energy Regulatory Process (NERP) prioritized energy reforms that would drive affordability, carbon-reduction, and align regulatory incentives with policy goals.

BACKGROUND AND JUSTIFICATION FOR NATURAL GAS DECOUPLING IN NORTH CAROLINA

Historically, there have been large fluctuations in the cost of natural gas. During a rate case in 2002, natural gas had a benchmark cost¹ of \$2.75 per dekatherm. When the natural gas distribution companies (Piedmont Natural Gas Company, Inc., North Carolina Natural Gas, and Eastern North Carolina Natural Gas Company, [“Company”]), filed their joint rate case² in 2005, their benchmark cost was \$7.00 per dekatherm. Subsequently, the benchmark increased to \$11.00 per dekatherm by the time that the Notice of Decision from the North Carolina Utilities Commission (NCUC) was made. The higher prices caused customers to decrease use, insulate homes, and purchase efficient appliances. Both the increase in gas cost and decreases in customer use resulted in the natural gas companies not recovering their approved cost margin. All these practices adversely impacted the Company’s recovery of its approved margin.

The Company’s weather-normalized usage per residential customer declined an average of 2% per year and was expected to continue in future years. Usage was declining due to customer adoption of more efficient appliances to lower natural gas bills.

The Company’s volumetric rate structure created a disincentive for the Company to implement energy efficiency and conservation initiatives for its customers (i.e. was not environmentally or economically sustainable).

The historical ratemaking process did not ensure that the Company fully recovered the cost of gas delivered to its customers. Gas costs (meeting the definition of North Carolina General Statute (NCGS) 62-133.4) were trued-up based on the amount billed to customers, instead of the amount “actually” collected. Therefore, the cost of the gas delivered to customers’ who did *not* pay their bills (referred to as the uncollectables³ expense) could not be recovered by the Company.

IMPLEMENTATION TIMELINE AND HISTORY

- On February 28, 2005, the Company gave notice of their intent to file a rate case.

¹ The benchmark reflects the price that market participants use to write contracts and achieve full transparency around transactions. The benchmark is the variable cost in rate design.

² See dockets [G-9, Sub 499](#); [G-21, Sub 461](#); and [G-44, Sub 15](#)

³ Accounts that have virtually no chance of being paid.

- On April 1, 2005, the Company filed a petition for: 1) consolidation of their revenues, rate bases, schedules and expenses; 2) a general increase in their rates and charges; and 3) approval of depreciation rates. This facilitated the transition from a three-company operation into a single integrated Company.
- On August 31, 2005, the Company, the NCUC Public Staff, Carolina Utilities Customers Association (CUCA), and the federal Department of Defense (DOD) filed a Stipulation to further request the merger. In addition, the Stipulation requested the implementation of a test program for decoupling termed the “Customer Utilization Tracker” (CUT) in conjunction with an energy conservation program.
- On September 2, 2005, the Office of the Attorney General filed its Statement of Position regarding the Stipulation objecting to the implementation of: (1) the CUT; and (2) the recovery mechanism for the gas cost portion of uncollectable expenses. The Attorney General recommended the CUT be implemented for only a trial period.
- On September 28, 2005, the NCUC approved the Joint Proposed Order of Stipulating Parties. This document contained the proposed program details and rate design (which is described in more detail later in this case study).
- On November 3, 2005, the NCUC issued the final order to approve a pilot decoupling mechanism (the CUT) for a period of no more than three years.
- The NCUC specified that there was statutory authority to authorize true-up mechanisms for:
 - natural gas ([NCGS 62-133.4](#)); and
 - electricity ([NCGS 62-133.2](#)).⁴
- Despite their determination that statutory authority existed to authorize decoupling mechanisms, the NCUC asked the legislature to enact a law that allowed NCUC to adopt a natural gas decoupling rate mechanism to avoid future lawsuits associated with rate cases.
- On July 18, 2007, Session Law 2007-227 House Bill 1086 authorized customer usage tracking rate adjustment mechanisms for natural gas local distribution company rates.⁵ This bill formally codified the CUT rate adjustment mechanism for natural gas local distribution company rates in NCGS 62-133.7.⁶
- On March 31, 2008, the Company filed for approval to permanently extend the decoupling mechanism in its general rate case⁷. The decoupling mechanism’s name was proposed to be changed from the CUT to the Margin Decoupling Tracker (MDT). In this general rate case, the Company also asked for a rate increase for a fair rate of return on invested capital. This was due to: 1) significant new investments to grow and maintain the gas distribution systems to benefit current and future customers; 2) significant changes in the Company’s costs and capital structure; and 3) significant declines in average per-customer usage from the assumed usage levels in existing base rates.
- On August 25, 2008, the Company, Public Staff, CUCA, DOD, and Texican filed a Stipulation of agreement.⁸ The Stipulation contained the proposed rate changes and request for permanently extending the decoupling mechanism’s pilot program into the MDT.
- On October 24, 2008, NCUC issued an order that allowed the Company to permanently incorporate the MDT and increase rates by a total of \$15.7 million (1.5% of the Company’s total operating revenues). The NCUC specified that increases to the Company’s revenues during the pilot program did not indicate any flaw in the decoupling mechanism. However, it indicated that the Company was continuing to experience system growth (53,000 new customers since 2005) which produced additional revenues. One advantage of the MDT is that any growth that adds revenues at a rate higher than that approved by the NCUC actually lowers rates for existing customers.
- The NCUC relied on NCGS 62-133.7 for authority to permanently implement the MDT in 2008. The MDT’s foundational design elements remained consistent with the CUT. A couple notable revisions in 2008 were: (1) an increase in the rates (1.5% of the Company’s total operating revenues) so the Company could earn a fair rate of return; and (2) an increased annual expenditure of \$1.275 million on conservation and energy efficiency programs.

⁴ North Carolina case law for historical precedents included the following:

State ex rel. Utilities Comm. v. CF Industries, Inc., 299 NC 504 (1980);

○ CF Industries, 299 NC at 505-6 and 508;

○ CF Industries, 299 NC at 507-9; and

State ex rel. Utilities Comm. v. Public Service Company, 35 NCApp 156 (1978);

○ Public Service Company, 35 NCApp at 156-7;

State ex rel. Utilities Comm. v. Edmisten, 291 NC 327 (1976); and

State ex rel. Utilities Comm. v. N.C. Natural Gas Corp., 323 NC 630, 631 (1989)

⁵ House Bill 1086 (Session Law 2007-227): <https://www.ncleg.gov/EnactedLegislation/SessionLaws/PDF/2007-2008/SL2007-227.pdf>

⁶ The Session Law’s text states: § 62-133.7. *Customer usage tracking rate adjustment mechanisms for natural gas local distribution company rates. In setting rates for a natural gas local distribution company in a general rate case proceeding under G.S. 62-133, the Commission may adopt, implement, modify, or eliminate a rate adjustment mechanism for one or more of the company’s rate schedules, excluding industrial rate schedules, to track and true-up variations in average per customer usage from levels approved in the general rate case proceeding. The Commission may adopt a rate adjustment mechanism only upon a finding by the Commission that the mechanism is appropriate to track and true-up variations in average per customer usage by rate schedule from levels adopted in the general rate case proceeding and that the mechanism is in the public interest.*

⁷ See [Docket G-9, Sub 550](#) for material related to adopting a permanent extension of the decoupling mechanism.

⁸ See the [Stipulation](#) for details on the rate design for the MDT, including Net operating income, Rate Base and Overall Return “Exhibit A”; Rate design “Exhibit B”; Fixed gas cost allocations “Exhibit C”; Margin decoupling mechanism factors “Exhibit D”; Tariffs “Exhibit E”; Service regulations “Exhibit F”; Cost of gas “Exhibit G”; Impact of stipulated rate increase by customer class “Exhibit H”

DESIGN ELEMENTS OF THE 2005 DECOUPLING PILOT

The mechanism decouples recovery of the approved margin from customer usage. The piloted decoupling mechanism ensured that the Company collects 100% of its gas costs, prospectively. The residential and commercial sectors were included in the mechanism. The industrial sector was not included since its usage patterns and tariffs are vastly different than the residential and commercial sectors.⁹

The CUT rate adjustments were made semi-annually. These adjustments were not made in dollar amounts (like the Weather Normalization Adjustment that had been in effect prior to the adoption of the decoupling pilot). Rather, the CUT adjustments were to rates (prices) paid by customers.

The decoupling mechanism promoted conservation efforts by the Company and customers. In addition, it allowed customers to realize savings in their total gas bill associated with lower gas consumption. In the order authorizing the CUT mechanism, the NCUC ordered the Company to contribute \$500,000 per year toward conservation programs and work with the Attorney General and Public Staff to develop appropriate and effective conservation programs. Such programs were to be submitted for approval by the NCUC within 45 days of the final order's issuance and were subject to an annual effectiveness review.

The decoupling mechanism used a straight fixed variable rate structure where the fixed costs would be recovered through a fixed monthly charge to customers.

Multiple compliance reports were required, including:

- annual conservation reports;
- conservation effectiveness reports;
- semi-annual true ups; and
- monthly account adjustment reports.

SOME ARGUMENTS FOR AND AGAINST THE 2005 DECOUPLING PILOT

Opponents argued that decoupling expanded the definition of “gas cost” beyond what was allowed by NCGS 62-133.4. Specifically, that the Company’s write offs for nonpayment of bills were not “*occasioned by changes in the cost of natural gas supply and transportation*” in accordance with NCGS 62-133.4(a). They also stated that the affected portion of uncollectible accounts expense was not a cost “*related to the purchase and transportation of natural gas to the Company’s system*” consistent with NCGS 62-133.4(e) or Rule R1-17(k).

The counterargument, which was ultimately persuasive to the Commission, is that the Company must pay suppliers for all the gas sold to customers, regardless of the number of customers who fail to pay their bills. The gas cost portion of uncollectables represents “*costs related to the purchase and transportation of natural gas*” which are under NCGS 62-133.4. Prior to decoupling, customers were at risk that the pro forma¹⁰ uncollectible accounts expense could be higher than the actual expense of the Company. The CUT mechanism eliminates this risk and ensures that the Company will collect 100 percent of gas costs compared to a “proxy amount.”

Opponents argued that rate adjustment mechanisms or “true up procedures” such as the CUT were traditionally prohibited in the State since it constitutes a retroactive ratemaking.¹¹ The Commission disagreed, stating that the prohibition is based upon the theory of ratemaking contained in G.S. 62-133, and it therefore does not apply to true up mechanisms specifically authorized by statute. The Commission stated that the prohibition on retroactive ratemaking applies to “fixed general” rates but not “formula rates” such as the CUT.

⁹ See the [Stipulation of the Parties](#) for details on the pilot program’s rate design, including: Net operating income, Rate Base and Overall Return “Exhibit A”; Depreciation rates “Exhibit B”; Rate design “Exhibit C”; Fixed gas cost allocations “Exhibit D”; Customer utilization tracker factors “Exhibit E”; Tariffs “Exhibit F”; Service regulations “Exhibit G”; Cost of gas “Exhibit H”; Temporary rate increments/decrements “Exhibit I”

¹⁰ A report of the company's earnings that excludes unusual or nonrecurring transactions.

¹¹ The Attorney General cited case law. But the NCUC did not agree that the case law and stated, “*The prohibition against retroactive ratemaking was discussed in State ex rel. Utilities Comm. v. Edmisten, 291 NC 451, at 468-470 (1977). The prohibition is based upon the theory of ratemaking contained in G.S. 62-133, and it therefore does not apply to true up mechanisms specifically authorized by statute such as G.S. 62-133.2 or G.S. 62-133.4. The prohibition applies to “fixed general” rates and is not violated when a formula that has been approved as part of a utility’s rate structure is used to true-up an estimated rate. 156 (1978). The Commission believed that the CUT is not a “fixed general” rate but rather should be approved as a formula rate*”

Opponents argued that decoupling shifts the risk of fluctuations in gas costs from the Company to the ratepayer,¹² and that decoupling penalizes customer conservation by eventually causing rate increases to allow the companies to recover costs.¹³ The Commission strongly disagreed with both of these arguments.

This fact sheet represents the work of stakeholders as of 12/18/2020.

About the North Carolina Energy Regulatory Process

Governor Cooper's Executive Order 80 mandated the development of a clean energy plan for the state of North Carolina. The Clean Energy Plan recommended the launch of a stakeholder process to design policies that align regulatory incentives with 21st century public policy goals, customer expectations, utility needs, and technology innovation. The stakeholder process was launched in February 2020 and has led to policy proposals on energy reform.

LEARN MORE

Contact NERP PBR Study Group Leads:

Sally Robertson, NC WARN, sally@ncwarn.org

Laura Bateman, Duke Energy, laura.bateman@duke-energy.com

Access the NERP summary report and other NERP documents at:

<https://deq.nc.gov/CEP-NERP>

¹² NCUC Order Granting Partial Rate Increase and Requiring Conservation Initiative (p. 17). <https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=0ab8a646-9837-4c85-b650-77638a534073>

¹³ NCUC Order Granting Partial Rate Increase and Requiring Conservation Initiative (p. 21 and 23). <https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=0ab8a646-9837-4c85-b650-77638a534073>



NERP CASE STUDY

MINNESOTA ELECTRICITY PERFORMANCE BASED RATES

The 2020 North Carolina Energy Regulatory Process (NERP) prioritized energy reforms that would drive affordability, carbon-reduction, and align regulatory incentives with policy goals.

INTRODUCTION

Due to the complexity of Minnesota's lengthy performance-based regulation (PBR) process, this case study summarizes the basic aspects of PBR in the state. It then focuses on data that may indicate some of the outcomes from the implementation of these efforts over the last few years.

BACKGROUND

In 2007, Minnesota passed the Next Generation Energy Act (NGEA).¹ This law requires investor-owned utilities (IOUs) to do the following;

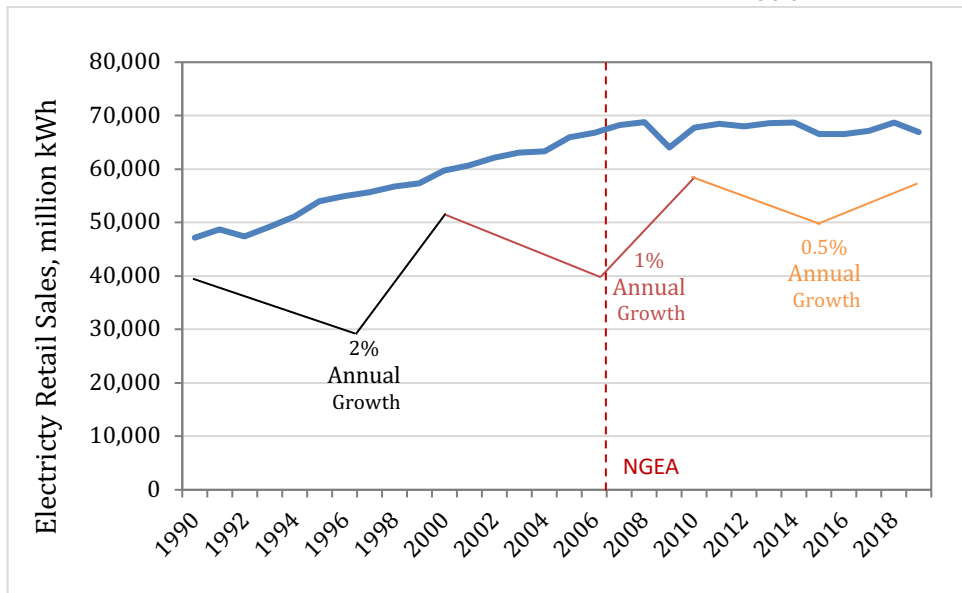
1. Reduce energy sales,
2. Spend a minimum percentage of annual operating revenues on energy efficiency, demand-side management and renewable energy starting in 2010, and
3. Incorporate a **shared savings financial incentive** model for energy efficiency.

It also required the Minnesota Public Utilities Commission (MPUC) to establish criteria and standards for **decoupling energy sales from revenues** to mitigate the impact of these energy savings goals on public utilities.

There were other factors driving electricity rate reform in the state including declining sales growth, minimal increases in customer base, and the need for infrastructure investments. The decline in sales growth, from 2% annual growth rate in the 1990s to the current annual growth rate of 0.5%, is shown in Figure 1.

¹ Minnesota Statutes, Section 216B.2412, Next Generation Energy Act, 2007.

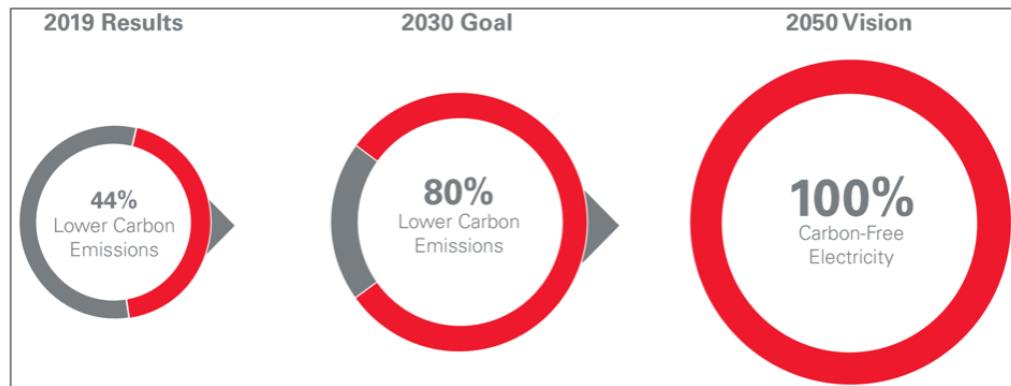
FIGURE 1: MINNESOTA RETAIL SALES OF ELECTRICITY SINCE 1990



SOURCE: ENERGY INFORMATION ADMINISTRATION (EIA) AND NC DEPARTMENT OF ENVIRONMENTAL QUALITY (NC DEQ)

Another factor in Minnesota’s PBR history is Xcel Energy initiating an enterprise-wide carbon reduction plan in December of 2018.² Xcel was one of the first utilities in the country to develop such a plan, with a goal of 80% reduction by 2030 and 100% carbon free by 2050. As of 2019, Xcel Energy reduced its enterprise-wide carbon by 44% from 2005 levels. During 2019, Xcel Energy generated 35% of all electricity in Minnesota with fossil fuel, with 21% of that generation coming from coal and the remainder coming from natural gas.

FIGURE 2: XCEL ENERGY’S 2018 CARBON REDUCTION GOAL



SOURCE: XCEL ENERGY

While Minnesota began its path toward performance-based rates through the NGEA in 2007, it is still being developed and implemented today. This ongoing effort consists of the following components;

- Multiyear rate plan (MRP),
- Revenue decoupling mechanism (“decoupling”),
- Performance incentive mechanisms, including metrics and incentives, and
- Shared savings mechanism (“shared savings”).

AUTHORITY AND ENABLING STRUCTURES FOR PBR IN MINNESOTA

Multiyear Rate Plans

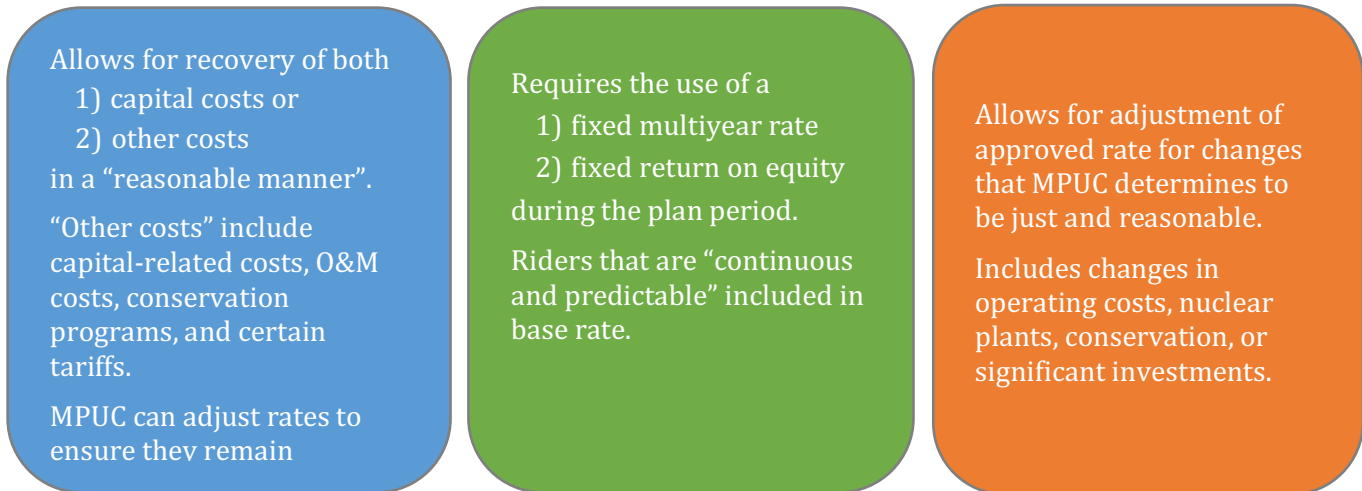
² Xcel Energy Clean Energy Transition, https://www.xcelenergy.com/environment/carbon_reduction_plan
Case Study: Minnesota PBR

In 2011, the Minnesota Legislature enacted Minn. Stat. § 216B.16, subd. 19 Multiyear Rate Plan, authorizing the MPUC to approve **multiyear rate plans** (MRP) up to 3 years in length for regulated utilities and to establish the terms, conditions, and procedures for plans.³ On June 17, 2013, the MPUC issued a final order on the terms and conditions for MRPs.⁴ This order specified that rates charged under any MRP should be based on the utility's reasonable and prudent costs of service. It also specified that a MRP could be designed to recover costs for “specific, clearly identified capital projects and, as appropriate, non-capital costs”. It also declined the use of formula rates and required a fixed rate for the plan period; however, rate adjustments pertaining to the cost of energy, emissions controls, conservation improvement, and specific tariffs were allowed. Lastly, the PUC decided that the authorized rate for return on equity would be fixed during the plan period based on the rate used in the general rate case. While the MPUC did not include an “off ramp” for the MRP, it did specify that the MPUC could adjust rates while a plan was in effect to ensure that the rates remain reasonable.

In June 13, 2015, the Minnesota Legislature modified the statute to allow a MRP to extend up to 5 years. The legislation also gave the MPUC the authority to require utilities proposing MRPs “to provide a set of reasonable performance measures and incentives that are quantifiable, verifiable, and consistent with state energy policies.”

The components of the MRP, as established in the MPUC’s 2013 decision, are presented in Figure 3.

FIGURE 3: COMPONENTS OF MINNESOTA MULTIYEAR RATE PLANS BASED ON MPUC 2013 ORDER



Decoupling Rate Mechanisms

In 2007, the Minnesota Legislature enacted Minn. Stat. § 216B.2412 as part of the NEGA requiring the MPUC to establish criteria and standards for decoupling of energy sales from revenues. The legislation specified that decoupling include the following;

- Ensure the criteria and standards do not adversely affect utility ratepayers,
- Consider energy efficiency, weather, cost of capital, and other factors,
- Assess the merits of decoupling to promote energy efficiency and conservation, and
- Implement a voluntary pilot program to determine if decoupling achieves energy savings.

On June 19, 2009, the Commission issued its Order Establishing Criteria and Standards to be Utilized in Pilot Proposals for Revenue Decoupling in Docket E, G-999/CI-08-132. The details of the decoupling mechanism not included in this case study in lieu of the detailed discussion of decoupling as implemented by Xcel Energy in Section 3 below.

Performance Incentive Mechanisms

³ Minnesota Statutes, Section 216B.16, subd. 19 Multiyear rate plan

⁴ Order Establishing Terms, Conditions, and Procedures for Multiyear Rate Plans, Issued June 17, 2013, Docket No. E,G-999/M-12-587
Case Study: Minnesota PBR

As discussed above, performance incentive mechanisms (PIMs) were authorized by the MRP Legislation in 2015. This legislation gives the MPUC authority to require IOUs to submit PIMs with MRP and to establish the PIMs. The statute also authorized the Commission “to initiate a proceeding to determine a set of performance measures that can be used to assess a utility operating under a multiyear rate plan.”

An important first step in the development of PIMs began with a multi-year stakeholder process called the “e21 Initiative”. This process began in 2014 and was facilitated by Great Plains Institute and Center for Energy and Environment. The goal was to advance a decarbonized, customer-centric, and technologically modern electric system in Minnesota. The reports issued by the e21 Initiative documents the stakeholder findings and results.⁵

The e21 Initiative developed the foundation for PIMs. Over 100 performance metric topics were discussed by stakeholders. Key aspects included:

- Specifying goals for PIMs,
- Determining data points to measure in order to evaluate utility performance,
- Limiting the specific number of metrics and prioritizing implementation of certain metrics,
- Developing concrete procedures for calculating, verifying, and reporting metrics, and
- Specifying metrics should measure outcomes, not deployment of technologies or programs.

The MPUC opened a docket to identify and develop performance metrics and, potentially, incentives in 2017 in response to Xcel Energy submitting a set of performance metrics in their general rate case filed in 2015. On January 8, 2019, the MPUC issued the Order Establishing Performance-Incentive Mechanism Process.⁶ The order initiated a PIM development process, which included discussions and workshops with stakeholders over a 9-month period. The order established a “goals-outcomes-metrics process” as an effective method to gather stakeholder input and develop performance metrics. Figure 4, presented on the following page, summarizes the 7-step process laid out by the MPU. The MPUC completed Steps 1 and 2 via the January 8, 2019 order.

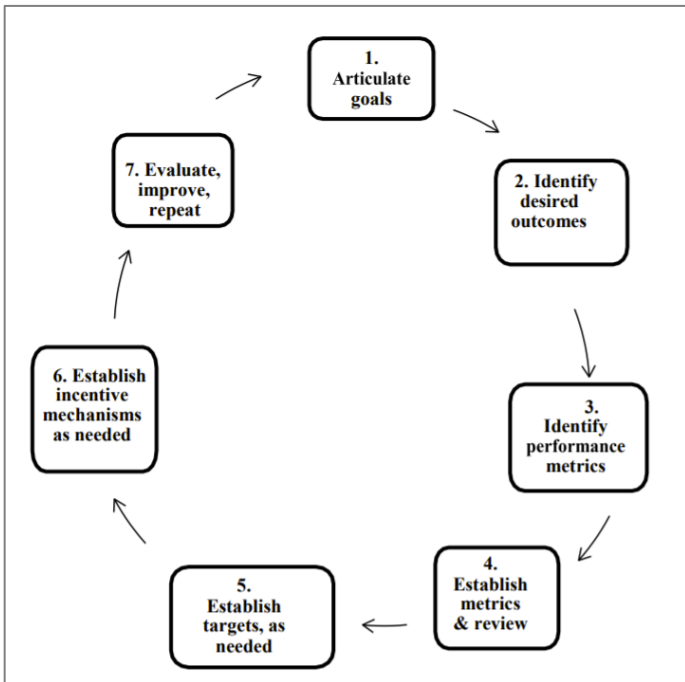
On September 18, 2019, the MPUC issued an order establishing performance metrics.⁷ In this order, Xcel Energy was directed to work with stakeholders to develop 1) methods to calculate, verify, and report metrics, and 2) a reporting schedule, which are Steps 3 and Step 4 of the PIMs process.

⁵ See <https://e21initiative.org/> for a full description of the e21 Initiative including its work products and reports.

⁶ MPUC Order Establishing Performance-Incentive Mechanism Process, Issued January 8, 2019, Docket No. E-002/Ci-17-401.

⁷ MPUC Order Establishing Performance Metrics, Issued September 18, 2019, Docket No. E-002/Ci-17-401.

FIGURE 4: MINNESOTA PUBLIC UTILITIES COMMISSION PROCESS TO ESTABLISH PIMS

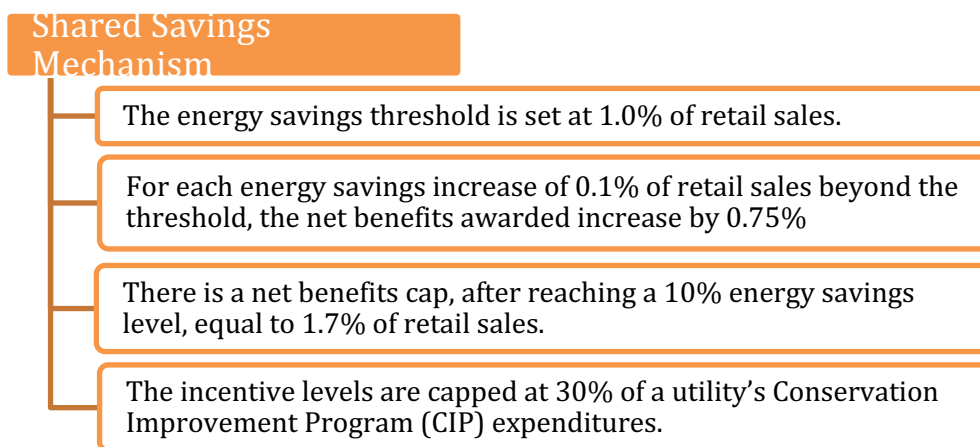


SOURCE: MPUC

Shared Savings Mechanism

Minnesota has had a shared benefit incentive for energy efficiency in place since 1999 called Conservation Improvement Program (CIP). For gas and electric utilities, the percent of net benefits awarded increases as a utility achieves a higher level of energy savings measured as a percentage of retail sales. The current Shared Savings goals for the electricity sector are listed in Figure 5.⁸

FIGURE 5: SHARED SAVINGS MECHANISM FOR ELECTRICITY SECTOR INVESTOR OWNED UTILITIES

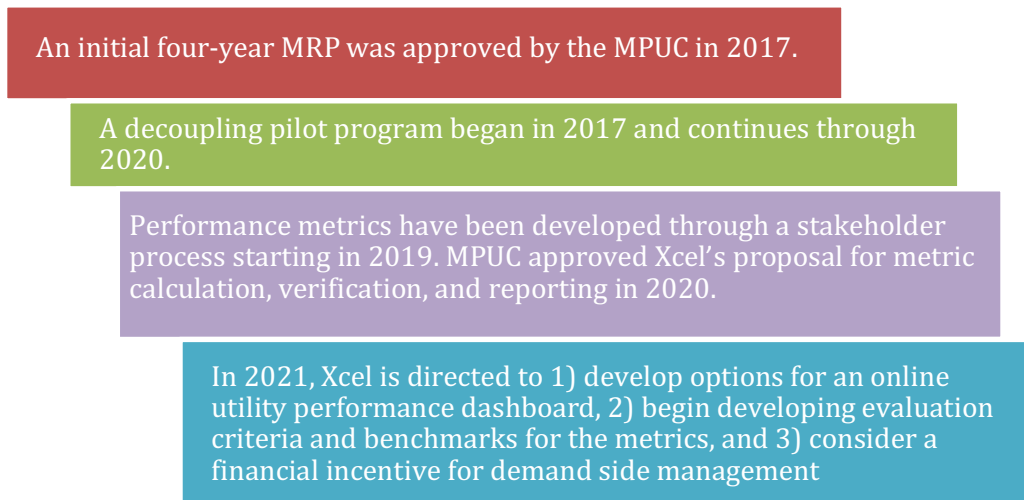


XCEL ENERGY IMPLEMENTATION OF PBR

The only electric utility currently pursuing PBR in Minnesota is Xcel Energy. For Xcel Energy, this process started with filing for a MRP in a general rate case in March of 2015. This filing set off a series of events for Xcel Energy to implement the PBR framework laid out by both legislation and MPUC orders. The events are summarized in Figure 6.

⁸ See Minn. Stat. § 216B.241, subd. 1 (c) and MPUC Docket No. E,G-999/CI-08-133
Case Study: Minnesota PBR

FIGURE 6. SUMMARY OF XCEL ENERGY'S PBR PROCESS



Xcel Energy MRP

Xcel Energy filed a petition on November 2, 2015 requesting a 3-year MRP that allowed revenue increases supporting the utility's proposed cost of service.⁹ The parties could not come to an agreement and the matter was referred to the Office of Administrative Hearings for contested case proceedings. On August 16, 2016, the majority of the parties to the rate case submitted a "Stipulation of Settlement" regarding the utility's MRP. The settlement set out the following design details for the MRP:¹⁰

- The revenue requirement, which entailed annual revenue increases over four years with a cumulative increase of 6.1%.
- The use of weather normalized sales data to set the base rates, and
- A one-year extension of the MRP to 2019.

Not all parties agreed to the settlement, therefore interim rates were set while additional proceedings were conducted to resolve the remaining issues. One of the issues was the return on equity (ROE) of 9.2%, which the Office of the Attorney General argued should be lower, on the order of 7% to 8%. On June 12, 2017, the MPUC issued an order documenting the decisions on Xcel's 2017 MRP based on both the settlement and the additional proceedings.¹¹ The MPUC kept the ROE from the settlement, adjusted Xcel's annual revenue requirements downward substantially, which resulted in rate increases that were less than inflation and significantly less than what Xcel proposed. Additional requirements on Xcel included;

- Prohibiting the filing of another rate case or seeking new riders during the MRP,
- Adopting a **one-way, aggregate, capital-spending true-up** where Xcel can refund money if its spending is under the budget but cannot increase rates if over the budget, and
- Requiring an annual capital projects true-up compliance report providing **granular project data and spending** for approximately 1,800 projects.

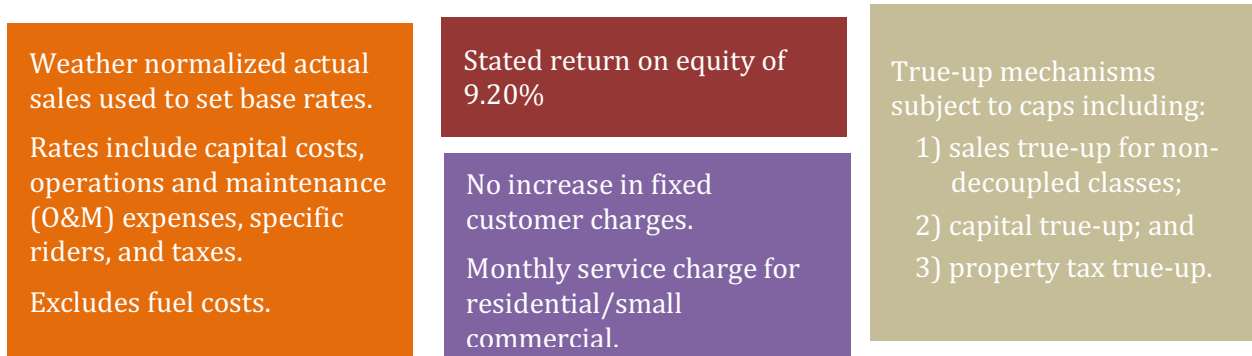
The MPUC found that a capital-projects true-up would provide ratepayers with significant protection against over budgeting of capital-spending. In addition, it would be beneficial for regulatory-review purposes to have Xcel Energy file project-level information on capital spending rather than overall spending in a given year. Figure 7 presents the basic structure of Xcel Energy's MRP for 2017 through 2019 stipulated in the MPUC Order.

⁹ Xcel Energy, Application for Authority to Increase Electric Rates, Filed November 2, 2015, Docket No. E002/GR-15-826.

¹⁰ Xcel Energy Filing, Stipulation of Settlement Authority to Increase Electric Rates Northern States Power Company, Filed August 16, 2016, OAH Docket No. 19-2500-33074 and MPUC Docket No. E002/GR-15-826.

¹¹ MPUC, Findings of Fact, Conclusions, and Order, June 12, 2017, Docket No. E-002/GR-15-826

FIGURE 7: STRUCTURE OF XCEL'S MRP



Adjustments are also allowed for customer classes under full decoupling. See below.

With the ending of the initial MRP in 2019, Xcel Energy filed a new MRP rate case with a request for a 3-year rate increase totaling 15.2% with the MPUC on November 1, 2019. This rate increase included an interim rate increase of 4% for all customer classes, \$466 million in new revenue, and an increase in return on equity to 10.3%. Given the decoupling pilot was expected to end in 2019, the rate plan also proposed a new decoupling mechanism that would apply to all customer classes.

On the same date, Xcel Energy filed a petition to extend the current MRP plan through 2020 using three true-up mechanisms for sales revenues, capital costs, and property taxes, explaining that if the MPUC approved the petition they would withdraw its rate case filing and not file another one until November 2020.

On Dec. 12, 2019 the MPUC approved Xcel Energy's Petition for Approval of True-Up Mechanism and Xcel withdrew its 2020 rate proposal.¹² As a result, electric base rates remained unchanged in 2020. In addition, the sales true-up mechanism (which was functionally equivalent to decoupling for customer classes not included in the 2017 pilot) was extended to all customer classes at that time.

Similar to 2019, Xcel Energy has recently requested Commission approval for 2021 true-ups that would allow the utility to leave base rates for 2021 unchanged.¹³ In the event this petition is not approved, Xcel also has filed a three-year MRP starting in 2021 that would increase revenues a total of 19.7%.¹⁴ Xcel has justified this rate increase on increased investments in renewable energy resources, investments in other core and supporting infrastructure, and declining sales. The utility also has proposed interim rate increases for 2021 and 2022 as the MPUC considers the MRP request.

Xcel Energy Decoupling Pilot

Xcel Energy filed its proposal for a decoupling pilot project in 2015 with its MRP discussed above. On May 8, 2015, the MPUC issued its Findings of Fact, Conclusions of Law, and Order authorizing the pilot.¹⁵ However, the "Stipulation of Settlement" submitted on August 16, 2016 modified the decoupling pilot program by 1) extending the program by one year and 2) requiring the use of partial decoupling (i.e., sales true-up based on weather-normalized data) for commercial and industrial customers. Xcel Energy began the four-year decoupling pilot program starting in 2017.

Xcel Energy's revenue adjustment mechanism is revenue per customer. This means that as the revenue requirement is adjusted according to the pre-agreed schedule in the multi-year rate plan, the decoupling mechanism also adjusts required revenue to reflect the increase or decrease in the number of customers within Xcel's service territory. The decoupling mechanism also has incentives for energy conservation.

Figure 8 presents the decoupling design elements of Xcel Energy's decoupling pilot. It focuses on the customer classes, for which the largest share of fixed costs is recovered through volumetric rates – residential (space heating and non-space heating), and small commercial and industrial (non-demand). It also includes partial decoupling that was added via the Stipulation of

¹² MPUC Order Approving Xcel Energy's Petition for Approval of True-Up Mechanism, Issued March. 13, 2020, Docket E002/M-19-688.

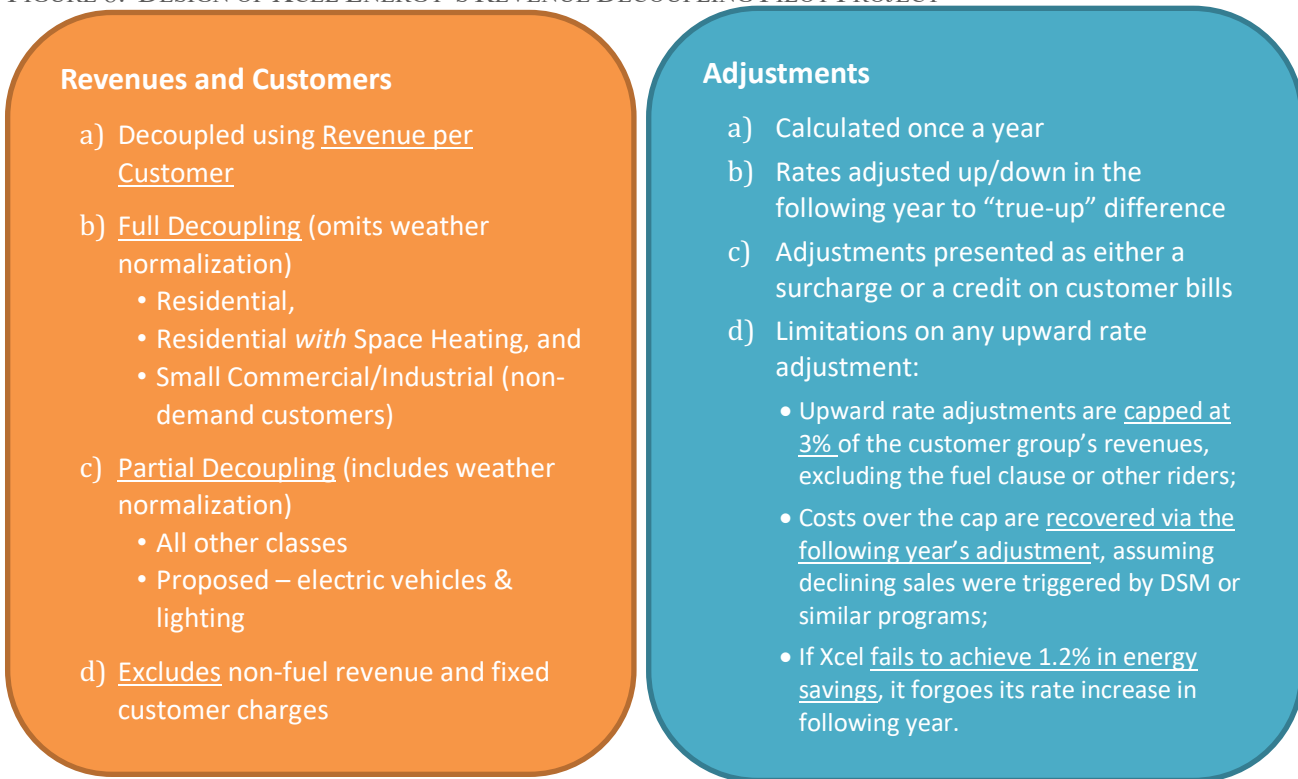
¹³ MPUC Docket No. E-002/M-20-743

¹⁴ MPUC, Application for a Proposed Increase in Electric Rates, November 2, 2020, Docket No.E-002/GR-20-723

¹⁵ MPUC Order Findings of Fact, Conclusions, And Order, Issued May 8, 2015, Docket E-002/GR-13-868.

Settlement in 2016 order discussed above that began in 2019. Xcel Energy filed decoupling annual reports to the MPUC, which will be discussed in the Outcomes section of this study.

FIGURE 8: DESIGN OF XCEL ENERGY’S REVENUE DECOUPLING PILOT PROJECT



Xcel Energy Performance Mechanisms

When the Commission approved Xcel’s MRP in 2017, a docket was opened to focus on PIM development. On September 18, 2019, the MPUC issued an order establishing performance metrics.¹⁶ The order also directed Xcel to work with stakeholders to develop methods to calculate, verify, and report metrics, and a reporting schedule by October 31, 2019.

On October 31, 2019, Xcel Energy submitted its report on performance metrics and proposed both outcomes and metrics to track starting in 2020, with reporting starting in 2021.¹⁷ Over 30 performance metrics were proposed measuring the outcomes listed below. The specific metrics are listed in Appendix A of this report.

- affordability
- reliability
- customer service quality
- environmental performance
- cost effective alignment of generation and load
- workforce and community development impact

The MPUC took comments on the proposal and on April 16, 2020 issued an order accepting Xcel’s proposed methodology and reporting schedules, with several modifications.¹⁸ Annual reporting of performance metrics is required and Xcel was directed to “explore and develop” an online utility performance dashboard.¹⁹ Xcel Energy was directed to continue to work on Steps 3 and 4 of the PIMs process—metric identification and review—and begin work on Steps 4 through 6, which includes the following processes;

- developing a demand response financial incentive via a stakeholder process,

¹⁶ MPUC Order Establishing Performance Metrics, Issued September 18, 2019, Docket No. E-002/CI-17-401

¹⁷ Xcel Energy Filing, Proposed Metric Methodology and Process Schedule on Performance Metrics and Incentives, Docket No. E002/CI-17-401

¹⁸ MPUC Order Establishing Methodologies and Reporting Schedules, Issued April 16, 2020, Docket No. E-002/CI-17-401

¹⁹ Annual reporting is required by April 30 of each year.

- developing evaluation criteria and benchmarks, and
- using a standardized method to ensure consistency with other utility reporting.

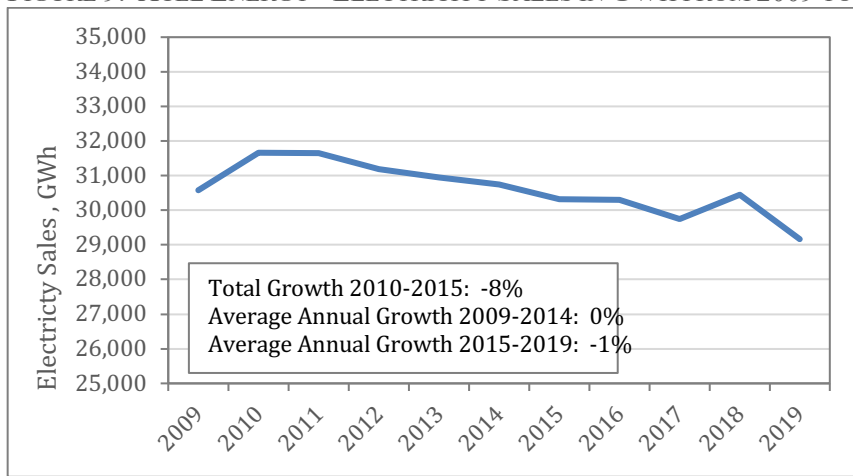
OUTCOMES FROM PBR FOR MINNESOTA AND XCEL ENERGY

Minnesota is still in the early stages of implementing PBR. Xcel Energy’s MRP and the revenue decoupling mechanism pilot program have run over the last 4 years are ending in 2020. Xcel will begin measuring and reporting on performance metrics in 2021.

The following three graphs show how some key data for Xcel Energy has changed in the last 10 years.²⁰ The graphs have imbedded tables with the data broken down to show the 1) total growth over the 10-year period from 2009 to 2019 and 2) and the average annual growth broken into two 5-year periods to show the potential impact of Xcel Energy’s implementation of PBR.

Figure 9 presents electricity sales data in GWh. This graph indicates Xcel Energy’s sales have dropped by 8% over the last 10 years. Note there was an increase in 2018 due to more extreme weather in that year. The average annual growth rate in the first half was 0% while it was -1% in the second period, indicating that sales are decreasing slightly more rapidly in the second half of the period. This could be influenced by a number of things, including decoupling and the ongoing Shared Savings program for energy efficiency. Nonetheless, it indicates that these programs appear to be effective in Minnesota.

FIGURE 9: XCEL ENERGY - ELECTRICITY SALES IN GWh FROM 2009 TO 2019



Despite the decrease in sales, Xcel Energy’s customer base is growing by 7% over the same 10-year period as shown in Figure 10. This amounts to a 1% average annual growth rate over both 5-years periods. Declining load growth creates a problem for traditional ratemaking approaches where increasing sales lead to increasing revenues. Xcel Energy needed to break that relationship to allow the company to recover sufficient revenues to meet its costs associated with additional customers while promoting higher levels of energy efficiency.

²⁰ Energy Information Administration, Form EIA-861M Monthly Electric Power Industry Report, 2019 Final Data, <https://www.eia.gov/electricity/data/eia861m/>

FIGURE 10: XCEL ENERGY – NUMBER OF CUSTOMERS IN THOUSANDS FROM 2009 TO 2019

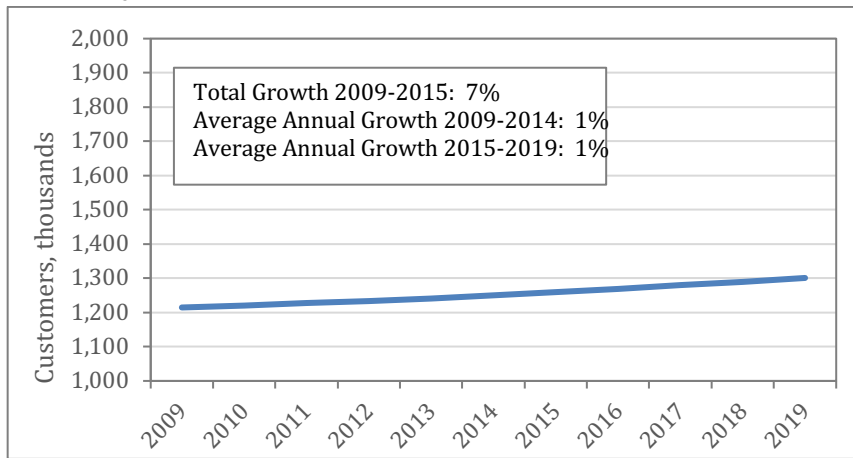
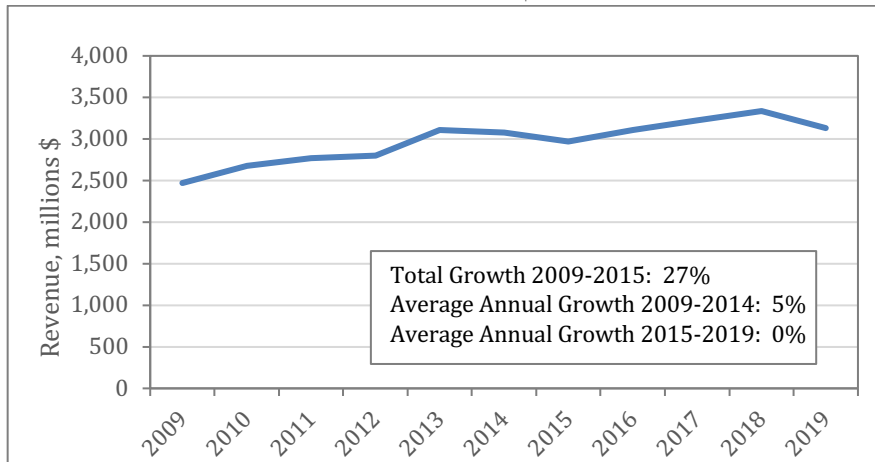


Figure 11 presents Xcel Energy’s revenues over the past 10 years. Revenues have increased by 27% since 2009. However, the average annual growth in the first 5-year period was 5% while the average annual growth was 0% in the last five years. This indicates revenues are stable and increasing at a slower rate under the multiyear rate plan.

FIGURE 11: XCEL ENERGY – REVENUES IN \$ MILLION FROM 2009 TO 2019



One of the benefits of a MRP is improvements in the utility’s credit rating due to more stable revenues. Xcel Energy’s Minnesota utility earned an “A” for its **Long-Term Issuer Default Rating (IDR)** by Fitch Ratings in October of 2020.²¹ Fitch Ratings cited stable revenues for the utility due to the following:

- a constructive regulatory environment in Minnesota,
- its operation under a four-year rate plan, and
- the use of various cost-recovery riders.

This is in contrast to Xcel Energy’s Southwestern Public Service Company (SPS) located in a more “challenging” regulatory environment, which earned it a rating of “BBB”.

Metrics show that Xcel Energy has been financially stable over the last few years, even during the time of the pandemic. In a recent presentation to investors, Xcel showed that it has a return on equity (ROE) of 10.97% at the holding-company level and

²¹ Source: Fitch Affirms Ratings on Xcel Energy & Subs; Outlook Stable, Issued October 1, 2020, accessed at <https://www.fitchratings.com/research/corporate-finance/fitch-affirms-ratings-on-xcel-energy-subs-outlook-table-01-10-2020>.

9.53% for its Minnesota operating company. Xcel Energy also reported that earnings per share for their Minnesota operating company were up 10% in the first nine months of 2020 compared to the same period in 2019.²²

As stated previously, Xcel Energy submitted a report to the MPUC on its decoupling pilot program starting in 2017 for the 2016 calendar year. A summary of the calculations and the data contained in the reports for 2016 through 2019 is presented below and in Table 1.^{23, 24, 25, 26}

For Xcel's Minnesota customers, a cooler than normal summer results in less electricity sales and a warmer summer results in higher sales. Therefore, over-collection of revenues is associated with summers that are warmer the baseline year and generally results in a refund to customers under decoupling. Under-collection of revenues is associated with cooler summers and generally results in a surcharge to customers.

During 2016, a warmer than normal winter resulted in an over collection of revenues for residential and small commercial and industrial customers, however, it also resulted in an under-collection of revenue for the residential space heating class as a result of the higher electricity intensity of this class, causing a surcharge. In total, the amount refunded to customers was \$1.80 million.

The years 2017 and 2019 had cooler than normal summers compared to the baseline year, resulting in total revenue shortfalls and surcharges of \$27.50 million and \$31.20 million. In both years, the revenue surcharge was capped at 3%, thereby reducing the surcharge by \$0.4 million in 2017 and \$4.20 million in 2019. These amounts are carried over into the next year. This leaves a surcharge of \$27.10 million for 2017 and \$27.00 million for 2019 that was added to customer bills. For 2019, Xcel Energy attributes its large decrease in sales in part to energy efficiency realized from the Conservation Improvement Program (CIP).

The year 2018 was cooler than normal and resulted in an under-collection of revenue and a total refund of \$13.80 million. It is noted that surcharges for 2017 and 2019 were significantly higher (+65% difference) than the refund in 2018.

²² Comments of the Office of Attorney General, In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota, filed November 12, 2020, Docket No. E-002/GR-20-723.

²³ Decoupling and Decoupling Pilot Programs: Report to the Legislature, Minnesota Public Utilities Commission February 2, 2018, <https://www.leg.mn.gov/docs/2018/mandated/180155.pdf>

²⁴ Decoupling and Decoupling Pilot Programs: Report to the Legislature, Minnesota Public Utilities Commission February 2019, <https://www.leg.mn.gov/docs/2019/mandated/190367.pdf>

²⁵ Decoupling and Decoupling Pilot Programs: Report to the Legislature, Minnesota Public Utilities Commission January 15, 2020, <https://www.leg.mn.gov/docs/2020/mandated/200074.pdf>

²⁶ Xcel Energy, 2019 Annual Report: Electric Revenue Decoupling Pilot Program, filed January 31, 2020, Docket No. E002/M-20-

TABLE 1: XCEL ESTIMATED REVENUE DECOUPLING ADJUSTMENT, BY CLASS

	Class	Total Decoupling Surcharge/(Refund) \$ millions	Carry Over Balance ²	Estimated Surcharge Cap \$ millions	Class Impact, ³ in \$ millions	Average Monthly Customer Surcharge/(Refund)	Decoupling Rate (\$/kWh) April-March	Year
2016 ¹	Residential Residential w/Space Heat	(\$2.60)		\$0.00	(\$2.60)			Credit
	Small C&I (Non-Demand)	\$1.10		\$0.90	\$0.90			Surcharge
		(\$0.10)		\$0.00	(\$0.10)			Credit
	Total	(\$1.60)		\$0.90	(\$1.80)			
2017	Residential Residential w/Space Heat	\$25.00		\$26.20	\$25.00	\$1.87	\$0.0031	Surcharge
	Small C&I (Non-Demand)	\$1.30		\$0.90	\$0.90	\$2.19	\$0.0024	Surcharge
		\$1.10		\$2.50	\$1.10	\$1.06	\$0.0012	Surcharge
	Total	\$27.50			\$27.10			
2018	Residential Residential w/Space Heat	(\$12.50)	(\$0.70)	\$26.20	(\$13.20)	(\$0.98)	(\$0.0016)	Credit
	Small C&I (Non-Demand)	(\$0.30)	(\$0.10)	\$0.90	(\$0.40)	(\$0.99)	(\$0.0011)	Credit
		(\$0.20)	0	\$2.50	(\$0.20)	(\$0.18)	(\$0.0002)	Credit
	Total	(\$13.00)			(\$13.80)			
2019	Residential Residential w/Space Heat	\$28.20	(\$1.20)	\$25.60	\$24.40	\$1.79	\$0.0031	Surcharge
	Small C&I (Non-Demand)	\$0.30	(\$0.10)	\$0.90	\$0.20	\$0.45	\$0.0005	Surcharge
		\$2.80	(\$0.10)	\$2.50	\$2.40	\$2.31	\$0.0028	Surcharge
	Total	\$31.20			\$27.00			

1 In 2016, adjustments were not applied to monthly bills

2 Carry-over (over/under-collection) balance from decoupling deferrals.

3 Includes the total decoupling credit and carry-over balance.

The main purpose of the decoupling pilot program was to determine if decoupling created incentives for higher energy conservation and energy efficiency than the traditional system. Table 2 presents Xcel Energy’s savings due to Minnesota’s Conservation Improvement Program (CIP) both before and after decoupling.²⁷ Based on the table, the average first-year energy savings under decoupling was 113 GWh, or 23% higher than without decoupling. This indicates that Xcel Energy’s decoupling pilot program was largely successful at significantly reducing electricity sales beyond what CIP required while earning revenue.

TABLE 2. XCEL ENERGY CIP ELECTRIC SAVINGS (2013-2019)

	Year	First-year Energy Savings (GWh)	Retail Sales (GWh) ²⁸	Energy Savings Percent of Retail Sales (GWh)
Without Decoupling	2013	495	28,987	1.71%
	2014	481	28,987	1.66%
	2015	497	28,987	1.72%
	Average	491	28,987	1.69%
With Decoupling	2016	547	28,987	1.89%
	2017	658	28,948	2.27%
	2018	680	28,948	2.35%
	2019	530	28,948	1.83%
	Average	604	28,957	2.09%

²⁷ Xcel Energy, 2019 Annual Report: Electric Revenue Decoupling Pilot Program, filed January 31, 2020, Docket No. E002/M-20-

APPENDIX A

List of PIMs Proposed in 2020 by Xcel Energy for Tracking

Outcome	Metric
Affordability	Rates based on total revenue y customer class and aggregate
	Average monthly bills
	Total residential disconnets for non-payment
Reliability	System Average Interruption Duration Index (SAIDI)
	System Average Interruption Frequency Index (SAIFI)
	Customer Average Interruption Duration Index (CAIDI)
	Customers Experiencing Long Interruption Duration (CELID)
	Customers Experiencing Multiple Interruptions (CEMI)
	Average Service Availability Index (ASAI)
	Momentary Average Interruption Frequency Index (MAIFI)
	Momentary Average Interruption Frequency Index (MAIFI)
	Power Quality
	Equity – Reliability by geography, income, or other benchmarks
Customer Service Quality	Initial customer satisfaction metrics
	Commission-approved utility-specific survey
	Subscription to third-party customer satisfaction metrics
	Call center response time
	Billing invoice accuracy
	Number of customer complaints
	Equity metric – customer service quality by geography, income or other relevant benchmarks
Environmental Performance	Total carbon emissions by utility-owned facilities/PPAs and all sources
	Carbon intensity (ton/MWh) by utility-owned facilities/PPAs and all sources
	Total criteria pollutant emissions
	Criteria pollutant emission intensity
	CO2 emissions avoided by electrification of transportation
	CO2 emissions avoided by electrification of buildings, agriculture, and other sectors
Cost Effective Alignment of Generation and Load	Demand response, including capacity available and amount called
	Amount of demand response that SHAPES customer load profiles through price response, time varying rates, or behavior campaigns
	Amount of demand response that SHIFTS energy consumptions from times of high demand to times when there is a surplus of renewable generation
	Amount of demand response that SHEDS loads that can be curtailed to provide peak capacity and supports the system in contingency events
	Metrics that measure the effectiveness and success of above items individually and in aggregate

SOURCE: XCEL ENERGY FILING, PROPOSED METRIC METHODOLOGY AND PROCESS SCHEDULE ON PERFORMANCE METRICS AND INCENTIVES, DOCKET NO. E002/CI-17-401

This fact sheet represents the work of stakeholders as of 12/18/2020.

About the North Carolina Energy Regulatory Process

Governor Cooper's Executive Order 80 mandated the development of a clean energy plan for the state of North Carolina. The Clean Energy Plan recommended the launch of a stakeholder process to design policies that align regulatory incentives with 21st century public policy goals, customer expectations, utility needs, and technology innovation. The stakeholder process was launched in February 2020 and has led to policy proposals on energy reform.

LEARN MORE

Contact NERP PBR Study Group Leads:
Sally Robertson, NC WARN, sally@ncwarn.org
Laura Bateman, Duke Energy, laura.bateman@duke-energy.com

Access the NERP summary report and other NERP documents at:
<https://deq.nc.gov/CEP-NERP>

WHOLESALE ELECTRICITY MARKETS STUDY GROUP

WORK PRODUCTS



WHOLESALE ELECTRICITY MARKETS STUDY GUIDANCE

SUGGESTED STUDY FRAMEWORK AND SCOPE FOR THE NCGA & NCUC FROM
THE NORTH CAROLINA ENERGY REGULATORY PROCESS

AUTHORS & ACKNOWLEDGMENTS

STUDY GROUP MEMBERS

Chris Carmody, NCCEBA, group chair
 Charles Bayless, NC Electric Cooperatives
 Drew Elliot, Electricities of North Carolina
 Paula Hemmer, Dept. of Environmental Quality
 Stephen Kalland, NC Clean Energy Technology Center
 Kate Konschnik, Duke University Nicholas Institute
 Peter Ledford, NCSEA
 Stewart Leeth, Smithfield Foods
 Kevin Martin, Carolina Utility Customer Association
 Sushma Masemore, Dept. of Environmental Quality
 David Rogers, Sierra Club
 Peter Toomey, Duke Energy

CONTACTS

Chris Carmody, director@nceba.com

ACKNOWLEDGMENTS

The authors thank the following individuals/organizations for offering their insights and perspectives on this work.

Josh Brooks, Rocky Mountain Institute
 Kendal Bowman, Duke Energy
 Dan Cross-Call, Rocky Mountain Institute
 Jennifer Chen, Duke University Nicholas Institute
 Matthew Davis, NC Dept. of Environmental Quality
 Max Dupey, Regulatory Assistance Project
 Heather House, Rocky Mountain Institute
 Jack Jirak, Duke Energy
 Carl Linvill, Regulatory Assistance Project
 Joshua Rhodes, Webber Energy Group
 Ben Serrurier, Rocky Mountain Institute
 Jessica Shipley, Regulatory Assistance Project

This work was last updated on 12/21/2020.

Cover image courtesy of GYPSY FROM NOWHERE IMAGES/ALAMY STOCK PHOTO

ABOUT THE NORTH CAROLINA ENERGY REGULATORY PROCESS

Governor Cooper's Executive Order 80 mandated the development of a clean energy plan for the state of North Carolina. The Clean Energy Plan recommended the launch of a stakeholder process to design policies that align regulatory incentives with 21st century public policy goals, customer expectations, utility needs, and technology innovation. The stakeholder process was launched in February 2020 and has led to policy proposals on energy reform.

About this document

This guidance document contains a detailed discussion of wholesale electricity market mechanisms with a specific focus on regional transmission operators, energy imbalance markets, and the southeast energy exchange market. It includes recommendations for the NCGA and the NCUC to consider if and when the NCGA authorizes the NCUC to conduct a study of wholesale electricity market reform. The document represents the consensus work of the NERP process stakeholders, however, NERP stakeholders do not necessarily endorse all of the ideas or recommendations herein.

TABLE OF CONTENTS

Authors & Acknowledgments 2

Summary of recommendations 4

 Study scope 4

 NERP recommendations 4

Introduction 5

 Purpose 5

 Context and history 5

 NERP 6

 NERP companion documents 7

Study Scope and framework 8

 Rationale 8

 Study authorization 9

 NERP recommendations 9

 Relevant context and potential study criteria 9

Study Scope and framework 11

 Electricity generation and capacity adequacy and diversity 11

 Transmission systems 12

 Customer service and rates 12

 Environmental quality 12

 Economic opportunity 13

 Impact on State regulatory authority of electric systems 13

 Comparison of market approaches 14

Conclusion 14

Appendix 15

SUMMARY OF RECOMMENDATIONS

This document contains the recommended framework, authorization, context, and key elements of a study into wholesale electricity market reform for North Carolina developed by the North Carolina Energy Regulatory Process (NERP) participants. The primary intended audience is the NC General Assembly (NCGA) and the NC Utilities Commission (NCUC), as the NCGA may authorize the NCUC to conduct such a study. The document contains detailed descriptions of each wholesale mechanism reviewed by NERP: regional transmission operator (RTO), energy imbalance market (EIM), and the southeast energy exchange market (SEEM) defined below. NERP participants met throughout 2020 and developed the following guidance document to assist any study into wholesale electricity market reform for North Carolina.

Study scope

1. The study, and any resulting reform proposed or enacted, should be designed to provide for just and reasonable rates and be consistent with the public interest, including the goals of the Clean Energy Plan.
2. The study must be required to offer recommendations to the General Assembly as to whether any of the market structures should be pursued further.
3. The study must recommend whether legislation is to be brought forward to allow reform of the wholesale electricity marketplace.
4. The study must recommend a model for wholesale competition that should be implemented if applicable.
5. The study must recommend a stepwise approach to incorporating municipal and cooperative electricity generators and providers into wholesale market reforms, as needed.

NERP recommendations

NERP recommends the General Assembly of North Carolina direct the NCUC to conduct a study on the benefits and costs of the following wholesale electricity market reforms and implications for the North Carolina electricity system.

1. A regional transmission organization (RTO) with the geographical boundaries of North Carolina and South Carolina or a larger area such as the southeast U.S.,
2. An energy imbalance market (EIM) with the geographical boundaries of North Carolina and South Carolina or a larger area such as the southeast U.S.,
3. The Southeastern Energy Exchange Market (SEEM), defined below, and
4. Any other structures that the NCUC determines worth investigating, such as,
 - a. Joining an existing RTO,
 - b. Developing joint dispatch agreements (JDA) beyond the current Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) agreement to include additional utilities in neighboring states and/or regionally, and
 - c. Developing a customer choice program that allows large customers, either at a single site or as an aggregate of multiple sites, to choose an independent electricity provider over the existing provider.

INTRODUCTION

Purpose

The purpose of this document is to communicate the findings of the NC Energy Regulatory Process (NERP) to the NC General Assembly (NCGA) and the NC Utilities Commission (NCUC), as the NCGA may authorize the NCUC to conduct a study into the potential costs and benefits of wholesale electricity market reform and implications for the North Carolina electricity system. It may also be of interest to other parties who want more information on wholesale electricity market mechanisms or the NERP process that is provided in the companion fact sheet.ⁱ

Context and history

On October 29, 2018, Governor Roy Cooper issued *Executive Order 80: North Carolina's Commitment to Address Climate Change and Transition to a Clean Energy Economy*.ⁱⁱ The Order established the North Carolina Climate Change Interagency Council and tasked the Department of Environmental Quality (DEQ) with producing a clean energy plan.

DEQ convened a group of stakeholders that met throughout 2019. In October 2019, DEQ released the *North Carolina Clean Energy Plan: Transitioning to a 21 Century Electricity System* (CEP).ⁱⁱⁱ Recommendation B-1 of the CEP states: “Launch a NC energy process with representatives from key stakeholder groups to design policies that align regulatory incentives and processes with 21st Century public policy goals, customer expectations, utility needs, and technology innovation.” That process was launched as NERP, which met throughout 2020.

Although initiated by CEP: B-1, the CEP listed multiple recommendations related to the state’s wholesale market:

- B-4: Initiate a study on the potential costs and benefits of different options to increase competition in the electricity sector, including but not limited to joining an existing wholesale market and allowing retail energy choice.
- C-1: Establish comprehensive utility system planning process that connects generation, transmission, and distribution planning in a holistic, iterative, and transparent process that involves stakeholder input throughout, starting with a Commission-led investigation into desired elements of utility distribution system plans.
- C-3: Implement competitive procurement of resources by investor-owned utilities.
- D-2: Use comprehensive utility planning processes to determine the sequence, needed functionality, and costs and benefits of grid modernization investments. Create accountability by requiring transparency, setting targets, timelines and metrics of progress made toward grid modernization goals.
- H-1: Identify and advance legislative and/or regulatory actions to foster development of North Carolina's offshore wind energy resources.

ⁱ <https://deq.nc.gov/CEP-NERP>

ⁱⁱ Executive Order 80. <https://governor.nc.gov/documents/executive-order-no-80-north-carolinas-commitment-address->

ⁱⁱⁱ NC Dept. of Environmental Quality. “North Carolina Clean Energy Plan” https://files.nc.gov/governor/documents/files/NC_Clean_Energy_Plan_OCT_2019_.pdf

NERP

The NERP, facilitated by Rocky Mountain Institute and the Regulatory Assistance Project, brought together roughly 40 diverse stakeholders to consider four main avenues of utility regulatory reform:

- PBR
- Wholesale market reform
- Competitive procurement of resources
- Accelerated retirement of generation assets

These stakeholders identified ten desired outcomes of reform in North Carolina, as shown below in Figure 1. Of those, the wholesale committee focused on:

1. Reducing emissions to net-zero by 2050,
2. Maintaining affordability and bill stability,
3. Developing regulatory incentives that are aligned with cost control and policy goals, and
4. Improving integration of distributed energy resources (DERs) onto distribution and transmission systems.

Outcome Category	Outcome
Improve <u>customer value</u>	Affordability and bill stability
	Reliability
	Customer choice of energy sources and programs
	Customer equity
Improve <u>utility regulation</u>	Regulatory incentives aligned with cost control and policy goals
	Administrative efficiency
Improve <u>environmental quality</u>	Integration of DERs
	Carbon neutral by 2050
Conduct a quality <u>stakeholder process</u>	Inclusive
	Results oriented

Figure 1: PRIORITY OUTCOMES IDENTIFIED BY NERP

Wholesale Electricity Markets Study Group

A subset of NERP participants volunteered to serve on a wholesale market study group and began meeting in late May 2020 (see page 2 for a list of groups members). The group met regularly to advance research into wholesale electricity market mechanisms deemed relevant to North Carolina due to physical proximity or because said mechanisms were either proposed or technically possible in NC.

The study group presented a series of mechanism studies to the broader NERP group, detailing the potential implications of each market reform, and why further investigation into each reform is warranted. Feedback was received from NERP participants and incorporated into a proposed wholesale electricity markets reform study outlined detailed below.

NERP companion documents

NERP produced the following documents for dissemination, to inform subsequent policy discussions with various audiences:

Legislative Language Authorizing the NCUC to conduct a wholesale market reform study: A number of wholesale reforms are relevant to NERP stakeholder organizations, recent academic research, and adjacent state policies. The study authorized by this language considers the costs and benefits of wholesale electricity market reform at the state and regional level.

A Meta-Analysis of proposed market reforms. As each market reform features a number of similarities and points of comparison, the group provides a high-level review of key market criteria.

Market Structure Factsheets:

Each construct outlined in the meta-analysis are featured in 2-to-3-page factsheets which provide greater detail on the respective markets.

Definitions

The following terms are used throughout the document:

- Regional transmission organization (RTO) - (also known as an Independent System Operator (ISO)) - a nonprofit entity that independently manages the transmission system of participating utilities. RTOs/ISOs run energy markets and centrally dispatch energy subject to economic and reliability constraints. (Less flexible generation may also self-schedule to continuously run.) RTOs/ISOs sometimes also run capacity and other grid services markets. FERC has encouraged the creation of RTOs/ISOs but has not required them.
- Energy imbalance market (EIM) - a voluntary market for dispatching real-time energy across utility service territories. Each participating utility retains ownership and control of its transmission assets but opts to bid generation into a centralized dispatch authority.
- Energy exchange market (EEM) - a voluntary market for facilitating bilateral sales of real-time energy across utility service territories. Each participating utility retains ownership and control of its transmission assets but may buy or sell excess power from/to neighboring utilities.
- Southeastern Energy Market (SEEM) - A proposed 15-minute automated energy exchange market between balancing authorities of the southeastern U.S. involving over fifteen entities.
- Wholesale electricity market – a market where electric energy is bought and sold for resale. Under the Federal Power Act, wholesale electricity transactions including those conducted through organized markets are regulated by the Federal Energy Regulatory Commission.
- Retail electricity market – a market where electric energy is sold to end users/consumers. Under the Federal Power Act, retail electricity transactions are regulated by state public utility commissions.
- Distributed energy resources (DERs) - small electricity generators that are connected to the local distribution system or installed behind the meter of an electricity consumer. These resources may include rooftop solar, EV charging stations, smart appliances, and on-site fuel cells.
- Joint dispatch agreements (JDA) - a type of power pool arrangements where utilities agree to jointly dispatch generation resources to meet load requirements across their footprints. Here, one of the utilities will conduct the dispatch; by contrast, for an energy imbalance market or an RTO, an independent nonprofit entity is in charge of dispatch. Each participating utility retains ownership and control of its transmission assets.
- Greenhouse gases – air pollutants that trap and emit radiant heat, warming the earth's atmosphere.

STUDY SCOPE AND FRAMEWORK

Rationale

The large majority of the electric service in North Carolina is currently provided by vertically integrated utilities that provide electric generation, transmission and distribution services to customers in the state, including approximately 85% of the state's electricity generation.

The adoption of North Carolina's Renewable Energy and Energy Efficiency Portfolio Standard (REPS) in 2007, enabled the state to:

1. Diversify its electricity resources with solar, wind and biofuels,
2. Offset over 10% of its electricity demand with renewable resources and energy efficiency measures,
3. Create over \$2 billion worth of new businesses and 4,307 jobs in renewable energy and energy efficiency, and^{iv}
4. Reduce emissions of carbon dioxide by 9%.

North Carolina seeks to

1. Expand its development of new, low-cost electricity resources in the state,
2. Encourage additional private investment in these resources as well as ancillary businesses,
3. Create new tax bases and economic opportunities, and
4. Accelerate the deployment of zero emitting resources.^v

The North Carolina Energy Regulatory Process (NERP) has identified that reforming the structure of the existing wholesale electricity market and electricity transmission services could potentially promote the development of, and access to, low-cost electricity resources for the benefit of North Carolina consumers.

The NERP also identified several key goals for North Carolina's electricity system, in addition to developing low-cost electricity resources, that could potentially be promoted with restructuring wholesale electricity markets and transmission systems including:

1. Reducing greenhouse gas emissions to net-zero by 2050,
2. Maintaining affordability and bill stability,
3. Developing regulatory incentives that are aligned with cost control and policy goals, and
4. Improving integration of distributed energy resources (DERs) onto distribution and transmission systems.

Discussions about a more competitive electricity market are not new. The North Carolina General Assembly enacted legislation in 1999 to study the use of wholesale and retail electricity markets in the state, which recommended a more competitive system but was never implemented. More recently, the South Carolina legislature authorized a study (SC HB 4940) to be completed on November 1, 2021 that examines the benefits of various restructuring options for electricity markets associated with electricity generators, transmitters and distributors in South Carolina including the following:

1. Creating a regional transmission organization (RTO) or an energy imbalance market (EIM) with energy providers in neighboring states to enable a competitive wholesale market for electricity, and
2. Separating the existing vertically integrated electric utilities into two distinct entities: companies that generate electricity and companies that transmit and distribute electricity, and
3. Giving customers in the state the ability to choose their electricity provider.

In a similar fashion, NERP participants have identified that a study of competitive markets in North Carolina be also conducted. Changes to the electricity sector regulatory framework, such as restructuring the existing wholesale electricity markets and transmission services may require changes to state law as well as federal authorization. The

^{iv} *The Solar Economy Widespread Benefits for North Carolina*, Center on Globalization, Governance & Competitiveness (CGGC), Social Science Research Institute at Duke University, February 2015, https://www.seia.org/sites/default/files/resources/Duke_CGGC_NCSolarEnergyReport.pdf

^v *North Carolina Clean Energy Plan*, North Carolina Department of Environmental Quality, October 2019, <https://deq.nc.gov/energy-climate/climate-change/nc-climate-change-interagency-council/climate-change-clean-energy-16>

purpose of this document is to define the study scope and describe elements to be examined that equips policy makers on the pros and cons of future decision making.

Study authorization

The General Assembly of the State of North Carolina would need to authorize the North Carolina Utilities Commission (NCUC) to conduct a study of wholesale competitive market structures, the respective transmission services, and their potential impact on achieving the NERP goals set out above for the state's electricity system, consumers, environment, and economy in a cost-effective manner while also providing low-cost electricity and other ancillary benefits to North Carolina electricity customers.

NERP recommendations

NERP recommends the General Assembly of North Carolina direct the NCUC to conduct a study on the benefits and costs of the following wholesale electricity market reforms and implications for the North Carolina electricity system.

1. A regional transmission organization (RTO) with the geographical boundaries of North Carolina and South Carolina or a larger area such as the southeast U.S.,
2. An energy imbalance market (EIM) with the geographical boundaries of North Carolina and South Carolina or a larger area such as the southeast U.S.,
3. The Southeastern Energy Exchange Market (SEEM),
4. Any other structures that the NCUC determines worth investigating, such as,
 - a. Joining an existing RTO,
 - b. Developing joint dispatch agreements (JDA) beyond the current Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) agreement to include additional utilities in neighboring states and/or regionally, and
 - c. Developing a customer choice program that allows large customers, either at a single site or as an aggregate of multiple sites, to choose an independent electricity provider over the existing provider.

Study Outputs

A study should determine the overall impacts due to changing wholesale electricity regulation in North Carolina to a more competitive market structure.

The study must be required to offer recommendations to the General Assembly as to whether any of these market structures should be pursued further. This includes:

1. Recommending whether legislation is to be brought forward to allow reform of the wholesale electricity marketplace,
2. Recommending a model for wholesale competition that should be implemented if applicable, and
3. Recommending a stepwise approach to incorporating municipal and cooperative electricity generators and providers into wholesale market reforms, as needed

Relevant context and potential study criteria

While not agreed to by all of the involved stakeholders, some stakeholders recommend that the following options should also be studied:

1. Join an existing regional transmission organization (particularly if this is an option studied in South Carolina),
2. Develop joint dispatch agreements (JDA) beyond the agreement that currently exists between Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) to include additional utilities in neighboring states and/or regionally, and
3. Develop a customer choice program that allows large customers, either at a single site or as an aggregate of multiple sites, to choose an independent electricity provider over the existing provider.

North Carolina recognizes the value of its existing nuclear resources to provide zero-greenhouse gas (GHG) emitting, reliable, base load electricity to North Carolina. Given this, the study should consider the impacts new wholesale market

structures would have on the ability of these resources to continue to provide electricity generation and remain financially secure.

North Carolina recognizes the value of ongoing efforts to modernize North Carolina's electricity transmission and distributions system and the study should address whether or not any of the market structures would impact that any improvements resulting from these efforts.

The North Carolina Clean Energy Plan recommended GHG emissions reduction targets of 70% by 2030 and net-zero GHG emissions by 2050 and Duke Energy's stated corporate-wide carbon dioxide (CO₂) emissions reduction targets of 50% by 2030 and net-zero by 2050. The NCUC should consider achievability of these emissions targets for each market structures studied. North Carolina is potentially pursuing other aspects of utility regulatory reform and environmental policy related to the electricity sector, including a policy to reduce GHG emissions from the electricity sector, and the study should consider these reforms and policies where possible, given the level of detail on the polices and reforms available when this study is conducted.

North Carolina values a) stakeholder input into electricity regulatory and policy development processes and b) social equity in providing utilities to all communities and customer classes. The NCUC should consider how to maintain these values when performing the study.

While developing the study criteria, the NCUC should consider: a) the "Study Commission on the Future of Electric Service in North Carolina dated May 16, 2000 b) the proposed legislation regarding Grid South developed in the late 1990's through 2002, and c) the current study authorized by South Carolina House Bill 4940.^{vi}

^{vi} South Carolina House Bill 4940 accessed at https://www.scstatehouse.gov/sess123_2019-2020/bills/4940.htm

STUDY SCOPE AND FRAMEWORK

The study should examine impacts, including quantifying costs and benefits where possible, to the following aspects of the electricity system:

- I. Electricity generation and capacity adequacy and diversity
- II. Transmission systems
- III. Customer service and rates
- IV. Environmental quality
- V. Economic opportunity
- VI. Affect on State regulatory authority of electricity systems.
- VII. A comparison of the costs, benefits and impacts between the current system and the various market structures.

Electricity generation and capacity adequacy and diversity

Competitive wholesale electricity markets create more competition primarily on the power generation side, where market participants are plentiful as opposed to transmission, which has very few providers due to its highly regulated nature and obligations to serve. Over time, wholesale market reform could have a major influence on the selection of which new energy resources get added to the electricity grid to serve North Carolina. Competitive markets create advantages for lower cost power plants that can be located inside or outside the former power company's territory. Some stakeholders believe that third party ownership lowers risk for ratepayers and creates opportunities for newer technologies. Other stakeholders are concerned that wholesale market reform structures would remove some of North Carolina's control over its sources of electricity.

There are different levels of wholesale markets reform. More modest levels of reform such as the proposed SEEM and an EIM maintain the current generation and transmission ownership structure and allow companies to participate in a limited wholesale power market to trade energy – an energy market. Others such as an RTO could create a level of separation between companies that generate power from those that transmit. If the size and type of the competitive market is expanded beyond the existing structure sufficiently, competition among base load power suppliers can also be created - a capacity market.

A larger, more competitive electricity grid system may also change how clean, intermittent energy is deployed. Lastly, it may impact the growth of electricity demand based on new or existing programs that create incentives to either increase or decrease electricity use.

The current wholesale electricity market structure must be evaluated against the three options discussed above, SEEM, EIM and RTO to develop the relative advantages and disadvantages for North Carolina electricity generators and electric customers. Areas to examine include:

1. Impacts to resource adequacy, or ensuring there are sufficient electricity generation resources to supply power to meet demand at any given time with adequate reserve margin,
2. Impacts to the existing power plants on the system and their parent companies, especially in regard to plant economics, financial security and depreciation,
3. Impacts from the new power plants which are built and their parent companies, especially in regard to clean generation such as solar, wind and storage systems,
4. Financial impacts and efficiencies from sharing generation resources outside of the current system, especially in regard to clean energy,
5. Impacts to wholesale prices in the existing region due to more competitive procurement, and
6. Impacts to energy efficiency and demand side management including both existing programs and any future goals, and
7. Impacts to future changes in electricity demand, especially in regard to “beneficial electrification”, which is a shift to the use of clean electricity over existing fossil fuel energy.

Transmission systems

Some wholesale market forms would functionally unbundle power generation from transmission services. Others market forms merely create opportunities to purchase and transmit generation from other systems. Regardless of the market type, there will be changes to how the electricity grid system currently operates including its physical, operational and financial aspects. Some market structure options will create new entities that are involved in generating and transmitting electricity. The impacts from this increased complexity of the electricity system must be examined including the following:

1. Cost and complexity versus economic benefit of managing of a larger regional transmission system with increased flexibility in generation procurement on a sub-hourly timeframe,
2. Impacts to the reliability of the power supply at all times, especially during peak demand times, extreme weather events, and physical/cyber-attacks
3. Impacts to the resilience of the whole power system to recover quickly from extreme events,
4. Impacts to technical aspects of procuring and managing generation for the grid and grid support services, including interconnection to new grid regions, integration of new generation resources, grid congestion, and system balancing and operation,
5. Impacts to financial aspects of procuring generation, including regional system operational efficiencies, wholesale power prices, financial security of transmission and distribution entities, shifting from bilateral electricity contracts to near real-time energy markets, regional tariffs, and
6. Impacts to planning and developing grid infrastructure, including efforts to modernize the electricity grid to integrate clean energy and distributed energy and to provide new customer-oriented data and services.

Customer service and rates

The primary reason for studying potential moving to regional competitive wholesale electricity markets is to examine the impacts and benefits to electricity consumers, including financial and environmental. This would occur as a result of allowing competitive bidding among electricity generators from a larger region. The largest cost benefit comes from reducing the need to build more power plants in North Carolina by functionally sharing power plants in other grid regions. While numerous studies point to the financial benefits for electricity consumers, North Carolina consumers have goals for the electricity sector beyond low electricity rates that must be examined. Therefore, this study should examine both the financial impacts as well as other customer-oriented requirements and goals for the electricity sector including:

1. Quantifying the rate impacts to all customer classes and areas of North Carolina,
2. Impacts to fairness and equity in both electricity pricing and access among all customer classes and all areas of North Carolina,
3. Impacts to consumer protections,
4. Impacts of increased access to data and other new services desired by consumers, and
5. Impacts of transparency in wholesale pricing for customers.

Environmental quality

Most environmental issues associated with electricity generation and procurement are not directly impacted by switching to competitive wholesale markets. One direct impact may be increased transmission infrastructure. Other environmental issues could be indirectly impacted. For instance, air emissions are decreasing in some RTO and EIM regions due to building lower cost, cleaner power plants. However, some of these market structures pose greater challenges in implementing state level environmental policy, specifically RTOs. Recently, the federal government has considered changes to existing RTOs regulations that would resolve some of the issues faced by states pursuing environmental goals within the RTO framework.

Economic incentives for lower cost electricity generation could influence a) the type of power plants constructed in the future and b) the type of power that is purchased to meet electricity demand in North Carolina. These economic decisions would impact environmental and public health outcomes not just inside North Carolina's borders, but outside our borders as well. Such impacts include the following:

1. Greenhouse gas emissions per megawatt-hour of electricity generated and/or consumed from the electricity system supplying power to North Carolina (i.e., both in-state and imported generation),
2. Impacts to air quality from the electricity system supplying power to North Carolina,
3. Impacts to land and water resources due to both building new power plants and transmission systems and decommissioning existing plants in North Carolina,
4. Public health outcomes from the increased/decreased operation of power plants supplying power to North Carolina, and
5. Impacts to the current or future use of clean energy resources to supply power to North Carolina, where these resources may be located either inside or outside the state,
6. Environmental justice and equity concerns where specific community impacts are identified, and
7. Just transition concerns to communities affected by retiring assets.

Economic opportunity

Competitive wholesale electricity markets could create economic opportunities in North Carolina due to independent power producers being able to more readily access North Carolina electricity markets as well as the potential impacts of lower electricity rates. However, there may be some negative economic impacts as well. Therefore, the study should quantify the economic impacts from the proposed wholesale market structures options including:

1. Impacts to the economy from changes to electricity technological and infrastructure investments,
2. Responses to changes in wholesale pricing of electricity for North Carolina businesses,
3. Impacts to the creation and/or retention of jobs in the state,
4. Impacts to rural and disadvantaged communities, and
5. Impact of competition on tax revenues and/or subsidies in various areas of North Carolina.

Impact on State regulatory authority of electric systems

Competitive markets, depending on their structure, would potentially create additional administrative entities within the electricity system. Combined, these entities would be responsible for overseeing the newly created market and electricity procurement and transmission to consumers across a wider grid region and at sub-hourly timeframes. At a minimum, it could require increased coordination among existing electricity generation and transmission entities. Therefore, there are administrative issues which must be studied that may result in impacts to the critical areas discussed above, as well as potential changes to the role of the NCUC. Administrative concerns that should be evaluated for the wholesale market structures include:

1. Electricity system governance structure and administrative costs versus benefits,
2. Delegation of authority,
3. Reciprocity between states,
4. Clarification of state and federal jurisdiction, including reliance on other states joining North Carolina to implement wholesale market reform options,
5. Impacts to energy regulatory and policy innovation, including stakeholder involvement in its development,
6. Responsibilities of owners and operators of electricity grid generation and transmission, and
7. Impacts to state government regulation of electricity supply, transmission and distribution.

Comparison of market approaches

Lastly, the study should clearly layout the fundamental differences between the current market structure and the three proposed competitive markets systems being studied. A key element in this comparison is determining the a) size of the region and b) level of competition that is necessary for benefits to outweigh the costs of the proposed reforms. Such differences should include the following:

1. Overall effectiveness of each mechanism in meeting NERP goals,
2. Comparison of costs, benefits, and risks for each mechanism,
3. Level of competition resulting from each mechanism,
4. Impacts to system adequacy and reliability,
5. Level of administrative impacts from each mechanism,
6. Level of transparency in procurement of electricity, wholesale pricing, and customer data for each mechanism, and
7. Implementation timelines for each mechanism.

CONCLUSION

To summarize, NERP recommends the General Assembly of North Carolina direct the NCUC to conduct a study on the benefits and costs of the following wholesale electricity market reform options and the related implications for the North Carolina electricity system:

1. A regional transmission organization (RTO) with the geographical boundaries of North Carolina and South Carolina or a larger area such as the southeast U.S.,
2. An energy imbalance market (EIM) with the geographical boundaries of North Carolina and South Carolina or a larger area such as the southeast U.S.,
3. The Southeastern Energy Exchange Market (SEEM), defined above,
4. Any other structures that the NCUC determines worth investigating, such as,
 - a. Joining an existing RTO,
 - b. Developing joint dispatch agreements (JDA) beyond the current Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) agreement to include additional utilities in neighboring states and/or regionally, and
 - c. Developing a customer choice program that allows large customers, either at a single site or as an aggregate of multiple sites, to choose an independent electricity provider over the existing provider.

Members of this NERP stakeholder group will continue to collaborate in early 2021 to assist the State and parties interested in the work conducted by this group.

APPENDIX

The following documents were prepared by the wholesale electricity markets study committee to supplement this guidance document and the proposed legislative language.

- RTO fact sheet
- EIM fact sheet
- SEEM fact sheet - produced by utilities sponsoring SEEM; included here to provide additional detail on this proposal
- Meta-analysis of market structures
- Wholesale electricity market reform study bill

NERP FACT SHEET

REGIONAL TRANSMISSION ORGANIZATION

A FACTSHEET PRODUCED BY THE WHOLESALE ELECTRICITY MARKETS STUDY GROUP

The 2020 North Carolina Energy Regulatory Process identified wholesale electricity market reforms that could potentially benefit North Carolina consumers.

WHAT IS REGIONAL TRANSMISSION ORGANIZATION?

A Regional Transmission Organization (RTO) is a type of electricity market over a large region that uses an independent operator to manage the transmission system of the utilities participating in the market. Some characteristics of RTOs include the following:

- Administers and operates the transmission system through an independent entity,
- Fosters competition among generators with an open-access approach to transmission,
- Provides centralized, automated, real-time balancing of supply and demand,
- Dispatches all electricity across the system using a least-cost approach, and

- Requires mandatory participation by utilities and independent power producers in the market.

A similar market system to an RTO is an Independent System Operator (ISO).¹ About two-thirds of U.S. customer electricity demand is served by RTOs or ISOs as shown in Figure 1.

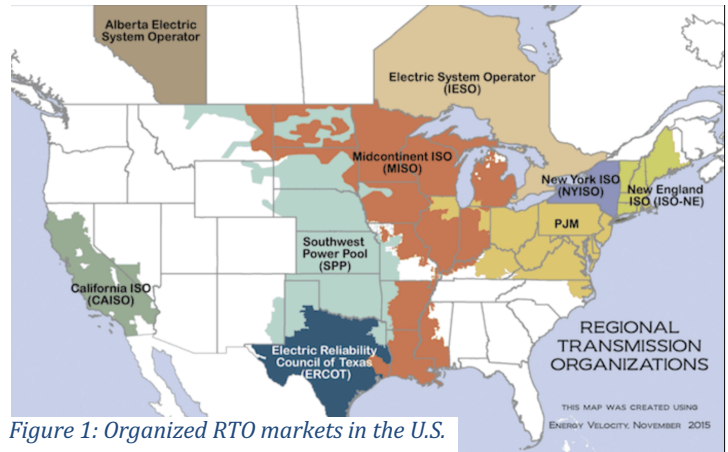


Figure 1: Organized RTO markets in the U.S.

¹ See <https://www.ferc.gov/industries-data/electric/power-sales-and-markets/rto-and-isos> for more information on RTOs and ISOs.

There are additional markets and services provided by RTOs. These include the following:

- Voluntary or mandatory capacity markets where generators commit to provide electricity in the future (also called the day-ahead market), and
- Voluntary ancillary markets related to grid operation such as voltage regulation.

HOW DOES THE ENERGY MARKET WORK?

RTOs create competitive wholesale electricity markets. A simplified overview of the market is outlined below.

1. RTO grid operators balance supply and demand for all electricity used in the market over 5-minute intervals in real-time using an automated system.
2. Each generator is required to supply a bid to the grid operator for a specific amount and price of electricity.
3. The grid operator puts together a set of bids, starting with the least-cost bids, until the demand for that interval is met. All other bids remain unfilled.
4. Less flexible nuclear and coal generation may still self-schedule to run continuously.
5. The grid operator must ensure a reliable supply of energy at all times and deal with any outages.

Recent FERC orders have directed RTOs to change their rules in a way that accommodates demand response programs (Order 745), energy storage (Order 841) and aggregations of distributed energy resources (Order 2222). Therefore, new market participants could develop to offer these products and services into the RTO's energy, capacity, and ancillary services markets.

HOW IS THE MARKET MANAGED?

RTOs and ISOs have an independent, non-profit entity with complete authority over the following aspects of the system:

- Transmission facilities and their operation,
- Transmission planning, expansion, administration and management,
- Non-discriminatory transmission service,
- Short-term reliability of the grid, and
- Fair, competitive energy market supplying least-cost generation.

RTOs and ISOs are regulated by Federal Energy Regulatory Commission (FERC) with specific rules and requirements for administering and operating these markets. Any changes to the market operation must be approved by FERC. Changes also require multi-state and multi-utility engagement in this process as well.

WHAT ARE THE BENEFITS OF AN RTO?

The primary benefit of an RTO is lowering wholesale energy costs and transferring these cost-savings to rate payers. Specific examples of these cost-savings are given below.

- PJM Interconnection estimates its services produce annual savings of \$3.2–\$4 billion.²
- Midcontinent Independent System Operator (MISO) estimates that its services produced savings in 2019 of \$3.2–\$4 billion compared to standard industry practice.³
- Southwest Power Pool (SPP) estimates that for 2018, its services provided \$2.2 billion in annual net benefits with a benefit-to-cost ratio of 14:1.⁴

Utilities have achieved cost savings from joining an RTO. For example, Dominion's economy energy purchases from PJM's day-ahead market saved about \$75 million in 2013 alone, compared to if Dominion had self-generated the same energy.⁵ Entergy, joined MISO in December 2013. Entergy has estimated the five-year savings realized by its customers from joining MISO to be about \$1.3 billion, an average of \$261 million annually.⁶

While there are cost-savings from joining an RTO, there may be costs associated with the transition into an RTO, and

² See, e.g., FERC Docket No. ER20-2100-000, Motion to Lodge of PJM Interconnection, LLC (Oct. 19, 2020), <https://www.pjm.com/-/media/documents/ferc/filings/2020/20201019-er20-2100-000-er20-1068-000.ashx>.

³ MISO Value Proposition 2019: Detailed Calculation Description, <https://cdn.misoenergy.org/2019%20MISO%20Value%20Proposition%20Calculation%20Details425713.pdf>.

⁴ Southwest Power Pool, 14 to 1: The Value of Trust (2019), <https://spp.org/documents/58916/14-to-1%20value%20of%20trust%2020190524%20web.pdf>.

⁵ "Potential Benefits of a Regional Wholesale Power Market to North Carolina's Electricity Customers", Prepared by Judy Chang, Johannes Pfeifenberger, John Tsoukalis, for the Brattle Group, April 2019, accessed at https://brattlefiles.blob.core.windows.net/files/16092_nc_wholesale_power_market_whitepaper_april_2019_final.pdf

⁶ Entergy Newsroom, "Entergy Utility Customers Realize Significant Benefits After 5 Years as MISO Member" (Dec. 16, 2019), <https://www.entergynewsroom.com/news/entergy-utility-customers-realize-significant-benefits-after-5-years-as-miso-member/>.

administering the RTO, which should be accounted for in any cost-benefit analysis conducted for North Carolina.

Another benefit of the RTO is creating economic incentives for new independent power producers. More equitable access to transmission allows these producers to enter the energy, capacity and ancillary services markets if they can provide a lower-cost power supply.

Lastly, an RTO can improve power system efficiency, reliability and flexibility. Fluctuations in supply and demand in the smaller balancing areas can be mitigated by pooling electricity resources from a larger area. Outages can be better supported as well.

RTOs do not create specific benefits to lower greenhouse gas (GHG) emissions. However, an RTO may decrease the use of fossil-fuel based resources and decrease GHG emissions by creating a more favorable market for low-cost, non-emitting energy resources.

WHAT IS THE GOVERNANCE STRUCTURE FOR THE MARKET?

RTO governance structures are not dictated by FEC, therefore, each of the RTOs/ISOs have the different governance structures. However, there are some commonalities presented below.

- A Board of Directors that is independent from the RTO/ISO management with 5 to 9 members who are nominated to serve by a committee, the governance board, stakeholders, or elected officials.
- Set of Standing Committees under the Board that oversee development of policies and performance of functional activities. Examples of committees include finance, audit, human resources, and legal.
- An Advisory Committee that receives, reviews, and adjudicates recommendations and concerns from stakeholder sectors.
- A Stakeholder Committee, which is a collection of members that advocate for various aspects of the electricity sector and public good while also respecting members' common interests within the broad diversity of RTO/ISO stakeholders. Members include representatives from transmission owners, generators, transmission users, other suppliers, state regulators and consumer organizations.

HOW ARE EXISTING UTILITIES IMPACTED BY THE MARKET?

Vertically integrated utilities (VIUs), those that own and operate generation, transmission and distribution systems, are most impacted by joining an RTO due to the independence of the transmission system. Utilities such as municipal and rural electric cooperatives can actually compete more fairly with VIUs in an RTO by both supplying and purchasing low-cost wholesale electricity. The impacts for utilities are discussed below.

- VIUs maintain ownership of the transmission system but cede control over its operation and planning to the independent RTO. Utilities continue to own, operate and expand their distribution systems and customers.
- Utilities might, or might not continue to own, operate and expand their generation resources. In some RTOs, but not all, utilities were required to sell their generation assets. Some RTOs have optional or mandated generation capacity markets that determine which generation resources enter and exit the market.
- Utilities' generating resources must compete with each other and independent power producers.
- Utilities can decrease their capacity reserves.
- Utilities with state-mandated environmental or clean energy goals can continue to meet these goals, however, least-cost dispatch may impact how these goals are met.

This fact sheet represents the work of stakeholders as of 12/18/2020.

About the North Carolina Energy Regulatory Process

Governor Cooper's Executive Order 80 mandated the development of a clean energy plan for the state of North Carolina. The Clean Energy Plan recommended the launch of a stakeholder process to design policies that align regulatory incentives with 21st century public policy goals, customer expectations, utility needs, and technology innovation. The stakeholder process was launched in February 2020 and has led to policy proposals on energy reform.

LEARN MORE

Contact Wholesale Market Reform Study Group Lead:
Chris Carmody, NCCEBA, director@ncceba.com
Access the NERP summary report and other NERP documents at:
<https://deq.nc.gov/CEP-NERP>

NERP FACT SHEET

ENERGY IMBALANCE MARKET

A FACTSHEET PRODUCED BY THE WHOLESALE ELECTRICITY MARKETS STUDY GROUP

The 2020 North Carolina Energy Regulatory Process identified wholesale electricity market reforms that could potentially benefit North Carolina consumers.

WHAT IS AN ENERGY IMBALANCE MARKET?

An energy imbalance market is a type of electricity market that uses an independent entity to manage the energy imbalances between supply and demand within multiple balancing authority areas (BAAs). Some characteristics of an EIM include the following:

- Administers and operates the market through an independent entity,
- Provides centralized, automated, and region-wide generation dispatch for imbalances,
- Fosters competition among generators using a least-cost approach to supply energy,
- Allows voluntary participation in the market by utilities and independent power producers.

There is currently only one EIM in the U.S., the Western Energy Imbalance Market operated by the California Independent System Operator (ISO). In 2021, the Southwest Power Pool (SPP) plans to launch a new energy imbalance service market

over a broader geographic area. Figure 1 presents the Western EIM and its active and pending participants.¹

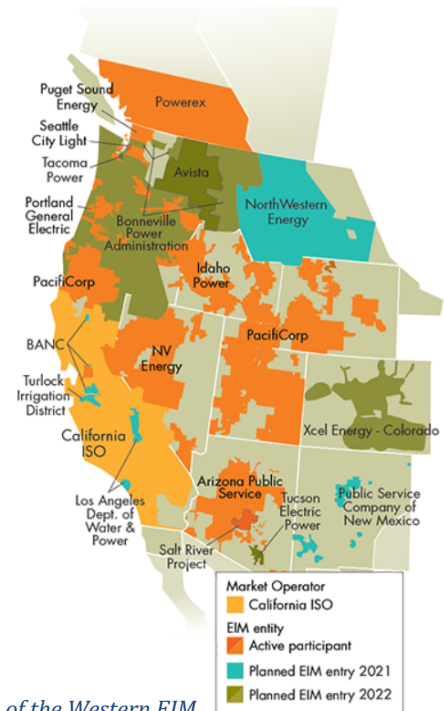


Figure 1: Map of the Western EIM

¹ Active and pending participants in the Western Energy Imbalance Market, accessed at <https://www.westerneim.com/Pages/About/default.aspx>.

An EIM does not provide day-ahead capacity markets. It may provide voluntary ancillary markets related to grid operation such as voltage regulation.

HOW DOES THE ENERGY MARKET WORK?

An EIM is a platform for balancing fluctuations in electricity supply and demand across multiple BAAs to meet real-time demand. A simplified overview of the market is outlined below.

1. The EIM platform balances supply and demand in the market over sub-hourly intervals in real-time using an automated system.
2. Each BAA voluntarily participates by issuing requests for energy to the EIM platform.
3. Generators volunteer to supply energy outside their balancing area via a bid in the market platform for a specific amount and price of electricity.
4. The platform matches least-cost energy bids with demand in each BAA until the demand for that interval is met.
5. Utilities/balancing authorities continue to control and schedule their generation resources as before.
6. The market is security-constrained, meaning transmission and reliability constraints must be honored.

Recent FERC orders have directed wholesale markets to change their rules in a way that accommodates demand response programs (Order 745), energy storage (Order 841) and aggregations of distributed energy resources (Order 2222). These orders could potentially extend to the voluntary participants in EIMs as well, and facilitate participants offering these products and services to the EIM's energy market.

If the Clean Smokestacks Act, Senate Bill 3, House Bill 589, and other landmark state clean energy legislation are any indication, further state legislative action will be crucial to the future of the state's clean energy transition. In particular, performance-based regulation can help catalyze clean energy innovation.

HOW IS THE MARKET MANAGED?

EIMs have an independent, non-profit entity with complete authority over the following aspects of the system:

- Non-discriminatory transmission balancing service,
- Short-term reliability of the grid, and

- Fair, competitive energy market supplying least-cost generation.

EIMs are regulated by Federal Energy Regulatory Commission (FERC) with specific rules and requirements for administering and operating these markets. Any changes to the market operation must be approved by FERC. Changes also require multi-state and multi-utility engagement in this process as well.

WHAT ARE THE BENEFITS OF AN EIM?

- Lowers wholesale energy costs by ensuring least-cost dispatch to meet energy imbalances in the market.
- Reduces costs for participants by lowering the amount of capacity reserves utilities need to carry, and more efficient use of the regional transmission system.
- The Western EIM has quantified the gross and annual cost-savings.²
 - Gross benefits for the entire EIM are \$1.11 billion between Nov 2014 through October 2020,
 - Annual benefits for 2019 were \$297 million,
 - Annual benefits for 2018 were 276 million, and
 - Annual benefits for 2017 were \$145 million
- Enhances reliability by increasing operational visibility across electricity grids and improves management of transmission line congestion.
- Creates a market where there is more efficient use and integration of renewable energy across a larger region.
- EIMs do not create specific benefits to lower greenhouse gases (GHGs). However, an EIM may decrease the use of fossil-fuel based resources and decrease GHG emissions by creating a more favorable market for low-cost, non-emitting energy resources.

WHAT IS THE GOVERNANCE STRUCTURE FOR THE MARKET?

Governing Body

The Western EIM has a five-member board nominated by participating members. Board members come from a variety of backgrounds, and include utility executives, regulators, and energy economists.

² See Western Energy Imbalance Market: Benefits at <https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx>

Regulatory Committee

The Western EIM has a regulatory committee made up of a utility commissioner from every participating state. Members are regularly briefed on EIM developments, plans, and results, and have input into decisions.

Transparency & Public Involvement

The Western EIM has a Regional Issues Forum held three times a year, which is a “public meeting for stakeholders to discuss broad issues about the Western EIM. The Forum encourages collaboration and helps shape policy and find solutions to challenges in the energy industry.”³

HOW ARE EXISTING UTILITIES IMPACTED BY THE MARKET?

Vertically integrated utilities (VIUs), those that own and operate generation, transmission and distribution systems, are not significantly impacted by joining an EIM. Utilities such as municipal and rural electric cooperatives can actually compete more fairly with VIUs in an EIM by both supplying and purchasing low-cost wholesale electricity to meet energy imbalances. The impacts for utilities are discussed below.

- Utilities continue to own, operate and expand their transmissions and distribution systems.
- Utilities continue to own, operate and expand their generation resources.
- Utilities’ generating resources must compete with each other and independent power producers.
- Utilities can decrease their capacity reserves.
- Utilities with state-mandated environmental or clean energy goals can continue to meet these goals, however, least-cost dispatch may impact how these goals are met.

WHAT IS BEING RECOMMENDED?

The North Carolina Energy Regulatory Process (NERP) has proposed a study, conducted by the NCUC, into the benefits and costs of wholesale market reform and implications for the NC electricity system.

A proposed study rationale, elements, authorization, and funding, titled North Carolina Wholesale Market Reform Study Scope and Criteria, accompanies this report. NERP recommends the following market structures be evaluated:

1. A regional transmission organization (RTO) with the geographical boundaries of North Carolina and South Carolina or a larger area such as the southeast U.S.,
2. An energy imbalance market (EIM) with the geographical boundaries of North Carolina and South Carolina or a larger area such as the southeast U.S.,
3. The Southeastern Energy Exchange Market (SEEM), and,
4. Any other structures that the NCUC determines worth investigating,

This fact sheet represents the work of stakeholders as of 12/18/2020.

About the North Carolina Energy Regulatory Process

Governor Cooper’s Executive Order 80 mandated the development of a clean energy plan for the state of North Carolina. The Clean Energy Plan recommended the launch of a stakeholder process to design policies that align regulatory incentives with 21st century public policy goals, customer expectations, utility needs, and technology innovation. The stakeholder process was launched in February 2020 and has led to policy proposals on energy reform.

LEARN MORE

Contact Wholesale Market Reform Study Group Lead:
Chris Carmody, NCCEBA, director@nceeba.com

Access the NERP summary report and other NERP documents at:
<https://deq.nc.gov/CEP-NERP>

Southeastern Energy Exchange Market (SEEM)

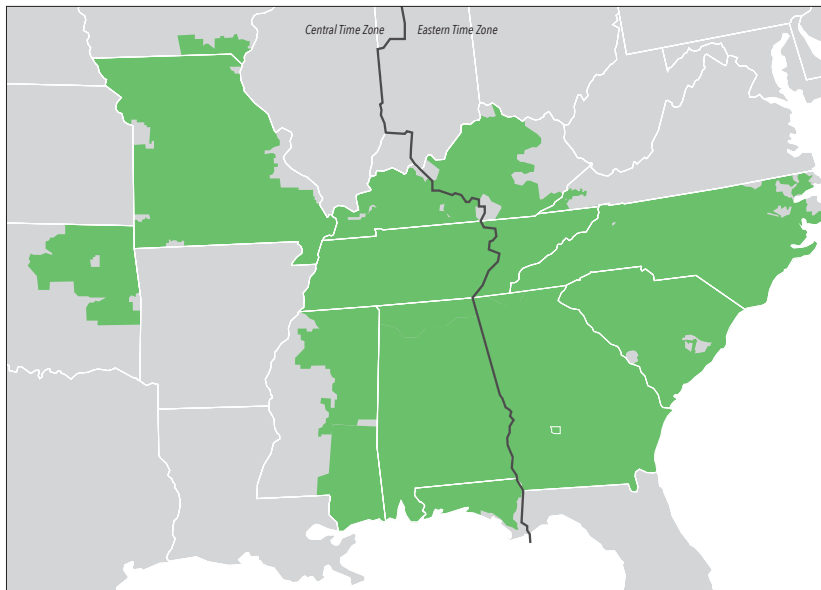


Fact Sheet

What is SEEM?

A group of energy companies serving electricity customers across a wide geographic region in the southeastern U.S. is exploring an integrated, automated intra-hour energy exchange with goals of lowering costs to customers, optimizing renewable energy resources and helping maintain the reliable service we provide today.

Companies exploring the energy exchange market include Associated Electric Cooperative Inc., Dalton Utilities, Dominion Energy South Carolina, Duke Energy Carolinas, Duke Energy Progress, Electricities of North Carolina, Inc., Georgia System Operations Corporation, Georgia Transmission Corporation, LG&E and KU Energy, MEAG Power, NCEMC, Oglethorpe Power Corp., PowerSouth, Santee Cooper, Southern Company, and TVA.



Members

- The members represent 16 entities in parts of 11 states with more than 160,000 MWs (summer capacity; winter capacity is nearly 180,000 MWs) across two time zones. These companies serve the energy needs of more than 32 million retail customers (roughly more than 50 million people).
- SEEM members would maintain existing control of generation and transmission assets, and membership is voluntary.

Benefits

- This is the first of its kind in our region and is a low-cost, low-risk way to provide immediate customer benefits through a shared market structure.
- SEEM would be a 15-minute energy exchange market that would use technology and advanced market systems to find low-cost, clean and safe energy to serve customers across a wide geographic area.
- Potential benefits include cost savings for customers and better integration of diverse generation resources, including rapidly growing renewables and fewer solar curtailments. An independent third-party consultant estimated that total benefits to grid operators and customers range from \$40 million to \$50 million annually in the near-term, to \$100 million to \$150 million annually in later years as more solar and other variable energy resources are added. (This is dependent, of course, on the number of member companies.)
- We expect customer savings to be realized through lower fuel costs as we're able to select lower-cost and more efficient generation resources to serve customer demand. As sellers identify a use for their excess energy, those profits also benefit customers.

Is SEEM an energy imbalance market?

No, while this market would share some of the same principles as an energy imbalance market (to assist with imbalances and reduce energy costs), it's less complex, less costly and less time intensive compared with setting up an EIM. It also does not rely on centralized unit dispatch.

How is SEEM similar or different from the Western Energy Imbalance Market?

	Western EIM	Southeast EEM
Resource Dispatch	5-minute nodal SCED market platform sends individual resource dispatch signals to participating resources every 5 minutes	15-minute block schedule via electronic interchange tags – BA/BA interface transactions – the Market Platform tool matches bids and offers to maximize benefit savings, while adhering to transmission capability (ATC) constraints
Complexity	Moderately complex due to establishing marketing system that also assesses security constraints	Simple due to leveraging existing bilateral trading processes
Costs	Significant startup costs	Low startup and ongoing costs
Transmission Service Charge	\$0/MWh	\$0/MWh
Ancillary Services	Limited	Limited
Manual/Automated	Automated	Automated
Day Ahead Market	No	No
Resource Offer into Market	Voluntary	Voluntary
Manages Imbalance	Directly	Indirectly

Regulatory approvals

FERC approval will be required to implement the SEEM. The FERC filing and approval process will provide an opportunity for the members of the SEEM to demonstrate the benefits of the proposed market design and for interested parties to provide feedback and comments for FERC to consider. State jurisdiction is limited to the affiliate component, if triggered, while FERC governs the structure and wholesale nature of the transactions.

What does this potential market mean for state utilities commissions and governing boards?

A primary objective is to maintain the same level of jurisdictional control and oversight as currently exists, where applicable, while facilitating more interchange transactions that support the cost-effective use of a diverse resource mix. FERC will have oversight authority as they do today to ensure those transactions occur with just and reasonable rates, terms and conditions.



Wholesale Electricity Markets Meta-Analysis: High-level comparison of market structures relevant to North Carolina

	Current State	SEEM	EIM	RTO
Scope	Business	Current state, plus the addition of Proposed SEEM	An EIM operating along the lines of the Western EIM	An RTO that meets the FERC definition
Examples	None exists in US, one being developed	One EIM exists in US, one being developed	Seven RTOs exist in US, none developed after 2008	
Customer Benefit <i>(For entire footprint – see notes)</i>	N/A – Baseline	<ul style="list-style-type: none"> Forecasted net savings range from \$40 to \$50 million in early years, not net of costs¹ 	<ul style="list-style-type: none"> Western EIM self-reported energy savings in a recent year were \$296 million, not net of costs² 	<ul style="list-style-type: none"> 6-7+ years Benchmarks point to one-time costs of \$500-750M+ Battle group estimate of \$59M annual operating costs for Duke's NC system
Time and Costs to Implement		<ul style="list-style-type: none"> 18-24 months, depending on regulatory approval One-time costs: estimated around \$5M 	<ul style="list-style-type: none"> 2-5 years (e.g., Western EIM took ~ 2 years, SPP WEIS > 2 years) One-time costs – SPP WEIS early estimate was \$65-75M 	<ul style="list-style-type: none"> Generation Offers: mandatory Real-time dispatch: day-ahead and sub-hourly market (varies: 15-minute to 1-minute)
Energy Market	<ul style="list-style-type: none"> Generation Offers: N/A Bilateral: day-ahead, hourly 	<ul style="list-style-type: none"> Generation Offers: voluntary Bi-lateral: day-ahead, hourly 15-minute bilateral transaction market 	<ul style="list-style-type: none"> Generation Offers: voluntary Bi-lateral: day-ahead, hourly 15-minute to 5-minute energy imbalance market 	<ul style="list-style-type: none"> RTO Design Dependent: <ul style="list-style-type: none"> If no capacity market, then Utility IRPs: States If in capacity market, then RTO: FERC
Capacity Planning		Utility IRPs: States		
Support of Carbon Policies / Renewables	<ul style="list-style-type: none"> Carbon policy: Utilities aligned with state efforts RE Integration: Utilities aligned with state efforts 	<ul style="list-style-type: none"> Carbon policy: Utilities aligned with state efforts Renewables Integration: Utilities aligned with state efforts More robust energy trading reduces needed curtailments of renewable resources 	<ul style="list-style-type: none"> Carbon policy: voluntary Bi-lateral: day-ahead, hourly 15-minute to 5-minute energy imbalance market 	<ul style="list-style-type: none"> If in capacity market, then resource additions subject to market pricing, RTO rules and FERC regulations; recent conflict re: FERC MOPR⁴
Regional Allocation of Costs / Exit fees	N/A – Baseline	<ul style="list-style-type: none"> Operation: minimal Allocations for operations only Exit Charges: None 	<ul style="list-style-type: none"> Board with some independent members State regulators committee Stakeholders meetings 3X per year⁷ 	<ul style="list-style-type: none"> Operation: substantial Substantial regional cost allocations, exit charges can be material⁵
Governance / Stakeholder Processes		<ul style="list-style-type: none"> No independent Board Platform Auditor Annual public stakeholder meeting⁸ 	<ul style="list-style-type: none"> Board with some independent members State regulators committee Stakeholders meetings 3X per year⁷ 	<ul style="list-style-type: none"> Independent Board State regulators committee Stakeholder approaches vary⁸
Pricing Info/ transparency	FERC Electric Quarterly Reports (EQR)	<ul style="list-style-type: none"> FERC EQR SEEM aggregated data provided daily, monthly, quarterly 	<ul style="list-style-type: none"> FERC EQR Current pricing data provided by EIM 	<ul style="list-style-type: none"> Current pricing data provided by RTO

¹ Note: See accompanying fact sheets on SEEM, EIM, and RTO's for further details and explanation.

² SEEM and EIM are not comparable. The proposed SEEM and EIM are based on the most recent annual published statements of benefits from the existing markets. RTOs reported net savings. SEEM and EIM reflect energy savings, not net of costs. None of the benefit figures were "scaled" to try to match just the NC or NC/S/C market. Final market size and footprint is not determined yet and benefits will depend on the scale and diversity of region, resource mix, entries' profiles, and EIM / RTO rules.

³ From "Potential Benefits of a Regional Wholesale Power Market to North Carolina's Electricity Customers," The Brattle Group, Table 3.

⁴ In recent years, public conflict between FERC MOPR and states' climate and energy policies; subject to potential policy changes at FERC going forward.

⁵ Allocation for operations, transmission system expansion, compliance, enforcement of rules/policies; exit charges can be substantial, particularly for Transmission Owners, based on design to keep the RTO financially whole on open commitments.

⁶ SEEM governance described more fully in the recently filed Southeast Energy Exchange Market Agreement.

⁷ EIM governance info shown here was taken from Western EIM; actual gov enhance in new EIM would be determined when created.

⁸ RTO Governance info shown here was taken from existing RTOs, which all differ somewhat; actual governance in new RTO would be determined when created.

**GENERAL ASSEMBLY OF NORTH CAROLINA
SESSION 2021**

Short Title:

Sponsors:

Referred to:

A BILL TO BE ENTITLED

AN ACT TO (I) DIRECT THE NORTH CAROLINA UTILITIES COMMISSION TO CONDUCT A STUDY OF NORTH CAROLINA WHOLESALE ELECTRICITY MARKET REFORMS AND (II) ISSUE A REPORT TO THE NORTH CAROLINA GENERAL ASSEMBLY REGARDING PUBLIC BENEFITS AND ANY PROPOSED REFORMS

Whereas, much of the electric service provided in North Carolina is currently provided by vertically integrated providers of electric distribution and transmission services; and

Whereas, the State has adopted legislation including Session Law 2007-397 and Session Law 2017-192 to diversify the resources used to reliably meet the energy needs of consumers and provide economic benefits in the State; and

Whereas, North Carolina seeks to 1) expand its development of new, low-cost electricity resources in the state, 2) encourage additional private investment in these resources as well as ancillary businesses, 3) create new tax bases and economic opportunities, and 4) accelerate the deployment of zero emitting resources; and

Whereas, stakeholders that participated in the North Carolina Energy Regulatory Process (“NERP”) identified common outcomes to reduce greenhouse gas emissions, improve integration of distributed energy resources (“DERs”), improve customer choice of energy sources, provide energy affordability and bill stability, and align regulatory incentives with cost control and policy goals; and

Whereas, electricity sector regulatory framework changes to the wholesale electricity market may require changes to state law as well as federal authorization; and

Whereas, South Carolina legislature authorized a study (SC HB 4940) to be completed on November 1, 2021 that examines the benefits of various restructuring options for electricity markets associated with electricity generators, transmitters and distributors in South Carolina; and

Whereas, regional and interstate arrangements may require changes to laws in states other than North Carolina; Now, therefore,

The General Assembly of North Carolina directs:

SECTION 1. The North Carolina Utilities Commission (NCUC) to conduct a study and issue a final report to the General Assembly evaluating reform of the regulatory wholesale electricity market in North Carolina.

- (a) The proposed market structures to be evaluated by the NCUC in the study include:
- (1) A regional transmission organization (RTO) with the geographical boundaries of North Carolina and South Carolina or a larger area such as the southeast U.S.,
 - (2) An energy imbalance market (EIM) with the geographical boundaries of North Carolina and South Carolina or a larger area such as the southeast U.S.,
 - (3) The Southeastern Energy Exchange Market (SEEM) as defined in Section 4, and
 - (4) Any other structures that the NCUC determines worth investigating, such as,

- (i) Joining an existing RTO,
 - (ii) Developing joint dispatch agreements (JDA) beyond the current Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) agreement to include additional utilities in neighboring states and/or regionally, and
 - (iii) Developing a customer choice program that allows large customers, either at a single site or as an aggregate of multiple sites, to choose an independent electricity provider over the existing provider;
- (b) The NCUC is authorized to hire an independent consulting firm with experience and expertise in wholesale electricity markets to assist the NCUC with the study for \$500,000.
- (c) The study shall begin within one month of the legislation being enacted and the final report shall be delivered to the General Assembly within a reasonable timeline considering both SC HB 4940 and other ongoing activities occurring in North Carolina related to energy, environment, affordability, and other related policy goals.
- (d) The study shall address:
 - (1) The cost, benefits and risks to state and local government, utilities, independent power producers, businesses, and customers of all classes regarding the following aspects of the electricity system:
 - (i) Electricity generation and capacity adequacy and diversity;
 - (ii) Transmission systems;
 - (iii) Customer service and rates;
 - (iv) Environmental quality;
 - (v) Economic opportunity;
 - (vi) Affect on State regulatory authority of electricity systems.
 - (2) The legal and procedural requirements in North Carolina, at FERC, or in other states associated with adoption of any recommended electricity market reform measures, including identification of existing laws, regulations, and policies that may need to be amended in order to implement the electricity market reform measures;
 - (3) The impact to existing interstate and interregional arrangements from electricity market reform measures.
 - (4) Existing nuclear power plant units, in operation and located in this State or in the balancing authority of electrical utilities or public power agencies operating in this State, provide an emissions-free source of power while also providing significant employment and economic benefits, and this study is not intended to force divestiture of ownership or cessation of the operation of these nuclear power plants.
 - (5) The potential impacts, including costs and benefits, of electricity market reform measures on disadvantaged or vulnerable populations and/or communities.
 - (6) The NCUC should consider how to maintain the following values under the proposed wholesale market reform structures;
 - (i) Stakeholder input into electricity regulatory and policy development processes, and
 - (ii) Social equity in providing affordable electricity to all communities and customer classes.

SECTION 2. The NCUC shall develop recommendations for North Carolina's wholesale electricity market based on the study outcome. The recommendations shall be included in the final report submitted to the legislature.

- (a) The recommendations shall include the following information:
 - (1) Whether legislation is to be brought forward to allow reform of North Carolina's wholesale electricity marketplace; and
 - (2) What type of model of wholesale reform should be implemented.
- (b) If the NCUC recommends that the State take action, the report shall include draft legislation and identify applicable requirements and schedule that should be established such that the recommended wholesale market reform will result in net benefits without undue risk for the State, utilities, businesses, and residents.

SECTION 3. The NCUC shall appoint an advisory board to ensure the broad concerns of North Carolina are considered; at minimum the advisory board must be comprised of:

- (a) The Executive Director of the North Carolina Public Staff, or designee;
- (b) The North Carolina President of Duke Energy, or designee;
- (c) The North Carolina President of Dominion Energy, or designee;
- (d) Executive Leadership from municipal and cooperative utilities, or designees;
- (e) The North Carolina State Energy Director, or designee;
- (f) The North Carolina Attorney General, or designee;
- (g) Executive Directors of NCCEBA and NCSEA or their designees
- (h) A representative set of stakeholders from NERP selected by the NCUC, including but not limited to:
 - (1) Two representatives of residential consumers of electricity;
 - (2) Two representatives of commercial consumers of electricity;
 - (3) Two representatives of industrial consumers of electricity;
 - (4) Two representatives of power producers;
 - (5) Two representatives with subject matter expertise from the academic community;
 - (6) Two representatives of the environmental advocacy community; and
 - (7) Two representative of the social equity and justice community.

SECTION 4. For purposes of this Bill, the following definitions apply:

- (a) "RTO" means regional transmission organization or other entity established for the purpose of promoting the efficiency and reliability in the operation and planning of the electric transmission grid and ensuring nondiscrimination in the provision of electric transmission services meeting the minimum criteria established by the Federal Energy Regulatory Commission under 18 C.F.R. Section 35.34.
- (b) "EIM" means energy imbalance market, a voluntary market for dispatching real-time energy across utility service territories. Each participating utility retains ownership and control of its transmission assets but opts to bid generation into a centralized dispatch authority.
- (c) "SEEM" means southeastern energy exchange market, a proposed 15-minute automated energy exchange market between balancing authorities of the southeastern U.S. involving over fifteen entities.
- (d) "JDA" means joint dispatch agreement, a type of arrangement where utilities agree to jointly dispatch generation resources to meet load requirements across their footprints. Here, one of the utilities will conduct the dispatch; by contrast, for an energy imbalance market or an RTO, an independent nonprofit entity is in charge of dispatch. Each participating utility retains ownership and control of its transmission assets.

SECURITIZATION STUDY GROUP

WORK PRODUCTS



NERP FACT SHEET

EXPANDING SECURITIZATION:

ACCELERATING THE CLEAN ENERGY TRANSITION AND BUILDING THE NC ECONOMY

The 2020 North Carolina Energy Regulatory Process prioritized energy reforms that would drive affordability, carbon-reduction, and align regulatory incentives with policy goals.

WHAT IS THE OPPORTUNITY?

The declining costs of renewable energy and higher cost of operating coal plants relative to other resources has increased interest in retiring coal plants in a low-cost way. However, these coal units remain in the portfolio due to the utilities' need to recover their investment and maintain reliability.

In order to retire coal plants, the remaining undepreciated value must be addressed. Securitization, an innovative financing mechanism, has the potential to create a win-win-win for customers, utilities, and communities. If properly designed, it can be a tool to help facilitate a system-wide transformation - lowering customers' bills, reducing air and water pollution, supporting coal plant communities in the transition, and allowing utilities to reinvest in clean energy to replace lost revenue from legacy coal plant investments. This tool is already available to North Carolina utilities to recover storm costs. Expanding securitization to retire coal plants requires enabling legislation and subsequent implementation to provide creditors with assurances that sufficient funds will be collected to cover the costs of the bonds over its lifetime.

WHAT IS SECURITIZATION?

Securitization is a refinancing mechanism involving the issuance of bonds to raise funds to refinance the remaining undepreciated value of existing coal plants. The bonds are paid back over time through a dedicated surcharge on customer bills. Because the surcharge is irrevocable and payment to the lender is basically "guaranteed" through the legislation, the bonds can typically be issued at an interest rate even lower than the usual utility bond interest rate. In addition, most major credit rating agencies do not include securitization debt, up to certain limits, in assessing the utilities debt to equity ratio for credit rating purposes. Therefore, the utility can generally refinance the

outstanding undepreciated value with 100% securitization financing instead of using its standard combination of debt and equity financing. Both of these factors combined lead to cost savings for customers.

By itself, securitization would translate to a loss in earnings for the regulated utility by reducing the total amount of capital in which the utility is invested. However, securitization can also be paired with utility reinvestment in replacement capacity to maintain reliability. Because this replacement generation would be financed using a combination of debt and equity, this option has the potential to recoup and even grow utility earnings.

HOW BIG IS THE OPPORTUNITY IN NC?

Duke Energy currently operates six coal plants totaling more than 10,000 MW of capacity. The low cost of natural gas and renewables, along with additional environmental compliance costs, has shifted electricity generation toward cheaper sources of energy in recent years, and the trend is expected to continue as the economic gap widens. Coal plants in the state, originally built to run 75-80% of the time, are now running, on average, only 35% of the time.

Recognizing the significant potential in ratepayer savings, the North Carolina Utilities Commission ordered Duke Energy to evaluate the merits of continuing to operate the coal units by examining the most economic and the earliest practicable dates of retirements. In its 2020 IRP, for the most economic case, Duke Energy recommended the retirement of 11 of 18 units by 2030, even without securitization. For the earliest practicable retirement case, Duke Energy identified that all coal units could be retired by 2030, with one unit converted to natural gas. Securitization should be a tool made available to North Carolina

regulators and utilities for cases where it would provide a benefit in customer rates to retire and replace the coal plant.

HOW DOES SECURITIZATION SOLVE THE PROBLEM?

Through the refinancing of the plant using low-cost debt, securitization has the potential to:

- Create customer savings on day-one and for the remainder of the plant's life due to lower costs of financing
- Create funds for transition assistance to workers and communities affected by plant closures
- Keep the utility whole through reinvestment in replacement renewable generation and/or storage

Early economic retirement of North Carolina's coal plants and replacement with zero emitting resources is estimated to achieve the 70% reduction in greenhouse gas emissions goal specified in the Clean Energy Plan by itself, provided the amount of imported electricity and its carbon intensity remain at or below historical levels.

As North Carolina has a significant amount of coal capacity that could be financed to provide ratepayer benefits, the large amount of generation needing to be replaced must be planned carefully to ensure costs are minimized, utilities are fairly compensated, system reliability is maintained, cleaner technology solutions are deployed, and pollution levels are reduced.

HOW IS SECURITIZATION DIFFERENT FROM CURRENT OPTIONS TO FINANCE COAL PLANT RETIREMENTS?

The three options currently available to utilities and regulators all have drawbacks and benefits, especially for customers.

Accelerate the retirement of these plants through a rapid return of unrecovered investment (e.g., through accelerated schedule of undepreciated assets than normally allowed over the project life). This helps get the uneconomic plant offline more quickly and likely saves ratepayers money long term. But accelerated depreciation could cause short-term rate spikes, which would impact businesses and low-to-moderate income customers acutely.

Retire a plant and create a regulatory asset. This allows the utility to continue to earn a return on a plant that is no longer in service, until the plant is fully depreciated. The downside of this path is that customers are paying for an asset that provides no benefits. For the utility there is also the risk of future disallowance, as there is no guarantee that the public utilities commission will continue to let the regulatory asset be charged to ratepayers.

Disallow the utility from recovering any remaining plant balance. The public utilities commission could decide that the uneconomic plant is no longer "used and useful" and prohibit the utility from recovering any remaining plant balance. This

has obvious downsides for the utility, possibly impacting their credit rating, impacting customers over the long run, and potentially chilling interest in future investments.

HAS SECURITIZATION BEEN USED BEFORE?

In 2019, following the significant disaster recovery and response expenses incurred from hurricanes Matthew and Florence, the North Carolina General Assembly passed SB559 (SL 2019-244) to permit financing for certain storm recovery costs.

Though securitization's proposed use for early coal retirement is recent, it has been used extensively in the past for a variety of reasons – ranging from recovering costs from a damaged plant¹ to financing pollution control upgrades² to enabling electricity market restructuring³. It is a financial mechanism that Wall Street is both familiar and comfortable with.

Securitization for early plant retirement is already enabled in four states, three of which passed legislation in 2019. PNM Resources in New Mexico is in the process of securitizing its San Juan coal plant⁴ and replacing it with a portfolio of renewable energy and storage. Duke Energy Florida securitized \$1.3 billion of the remaining plant balance of the Crystal River nuclear plant, resulting in more than \$700 million in customer savings. Many other states are expected to introduce supporting legislation in the 2021 session.

This fact sheet represents the work of stakeholders as of 12/18/2020.

About the North Carolina Energy Regulatory Process

Governor Cooper's Executive Order 80 mandated the development of a clean energy plan for the state of North Carolina. The Clean Energy Plan recommended the launch of a stakeholder process to design policies that align regulatory incentives with 21st century public policy goals, customer expectations, utility needs, and technology innovation. The stakeholder process was launched in February 2020 and has led to policy proposals on energy reform.

LEARN MORE

Contact NERP Securitization Study Group Leads:
David Rogers, Sierra Club, david.rogers@sierraclub.org
Tobin Freid, Durham County, tfreid@dconnc.gov

Access the NERP summary report and other NERP documents at:
<https://deq.nc.gov/CEP-NERP>

¹See <https://www.tampabay.com/news/business/energy/duke-energy-florida-customers-will-see-a-new-charge-on-their-bill-starting/2282006/>

² See <https://saberpartners.com/press/allegheeny-closes-pollution-control-issue/>

³ See <http://nescoe.com/resource-center/restructuring-dec2015/>

⁴ See <https://www.abqjournal.com/1439120/prc-approves-san-juan-abandonment.html>



NERP STATUTE COMPARISON

SECURITIZATION STATUTE COMPARISON

The 2020 North Carolina Energy Regulatory Process (NERP) prioritized energy reforms that would drive affordability, carbon-reduction, and align regulatory incentives with policy goals.

INTRODUCTION

Securitization is a financial mechanism allowing bonds to be used to recover undepreciated capital costs of assets and, in some cases, replace other losses of revenue. Securitized bonds, also called ratepayer backed bonds, must be authorized by state legislation. A comparison of securitization statutes that include recovery of undepreciated plant balances and transition assistance for workers and communities affected by early plant retirements can be useful as North Carolina decision makers consider this issue.

Key provisions in legislation typically include:

- Creation of the property right which underlies the bonds
- Definition of allowable uses for the bonds
- Key protections for bond purchasers
- Process for defining bond issuance amount and procedures
- Role of the Public Utilities Commission
- Role of the Public Utility

The North Carolina securitization legislation passed in 2019 contains the basic legal and financial components for creating securitized bonds in statute. However, the only allowable use for the bonds was recovery of costs incurred from storm damage.

Statutes in other states provide for different or additional uses for the bonds. Specifically, use of bonds for utility capital recovery in the event of early plant retirement and for transition assistance for communities and workers affected by early plant retirements. Statutes permitting these uses also define acceptable capital reinvestment opportunities for the utility retiring an uneconomic plant. Inclusion of a reinvestment or “capital recycling” pathway is a key to securing utility support for securitization legislation with the plant retirement bond use.

Securitization statutes specify the role of the public utilities commission in issuing the financing order for the bonds and its oversight in the bond issuance process. Commission oversight is key to protecting ratepayer interests. Comparisons between the commission’s role as defined in the North Carolina Statute, and statutes in Colorado, Montana, New Mexico and Michigan are provided.

COMPARISON OF SECURITIZATION STATUES

State	Specified Bond Uses				Utility	Regulator
	<i>Storm Costs</i>	<i>Plant Retirement</i>	Retire Debt/Equity	<i>Transition Assistance</i>	Reinvestment Options	<i>Strength of PUC Role</i>
North Carolina	X					medium
Colorado		X		X	X	strong
Montana		X			X	strong
New Mexico		X		X	X	weak
Michigan		X	X			weak

BEYOND STORM COSTS: BOND USES AUTHORIZED IN CO, MT, NM, MI STATUTES

1. PLANT RETIREMENT

Using low-interest securitized bonds to replace higher cost utility capital remaining in a retired plant saves ratepayers money. Utility concerns about maintaining rate base often require the legislation include a pathway for reinvestment or “recycling” the returned utility capital into other approved uses. Securitization statutes in Colorado, Montana and Michigan allow securitized bonds to be used for recovering the remaining utility capital invested in a retired power generating station. The New Mexico statute allows bond use for the retirement of a specific power generating station defined in the statute.

Colorado

CO SB19-236, Article 41 – The Colorado Energy Impact Bond Act, part of the Public Utility Commission Sunset/Reauthorization Act

Allowable Use: The allowable uses for the bonds extend to the “pretax costs”, including unrecovered capitalized cost of a retired electric generating facility that will be retired, and also the “pretax costs” incurred previously related to a commission-approved closure of an electric generating facility retired before the statute was in effect. (CO SB19-236 - page 52, lines 15-24; line 27; page 53, lines 1-3)

Montana

2019 MT HB 467, placed securitization in Statute.

Allowable Use: The two allowable bond uses are the “pretax costs” incurred when the utility retires or replaces electric generating infrastructure or facilities located in Montana, and the “pretax costs” previously incurred related to the closure or replacement or electric generating infrastructure or facilities. (2019 MT HB 467 – page 4, (13)(a))

New Mexico

NM 2019 Energy Transition Act. Securitization is a centerpiece of this act which also included a renewable portfolio standard and climate goals.

Allowable Use: The act allows bond use for the abandonment costs of a “qualifying generating facility”, and specifies cap on the amount of money which may be securitized. Other specific dollar amounts for decommissioning and mine reclamation costs, and job retraining are listed as allowable uses. The specificity of the dollar amounts and retirement date for the generating station are tied to a specific plant owned by Public Service of New Mexico (PNM), one of the primary advocates for the bill. The qualifying generating facility language does have some flexibility for application to other plants in New Mexico. (2019 NM SB 489 – page 4, lines 9-24; page 9, lines 6-19)

Michigan

MI 2000, Act 142, Customer Choice and Electricity Reliability Act included securitization. It was used in 2016 by Consumers Energy for the early retirement of a 950MW coal-fired electric generating station. The bond issue amount was \$389.6M. Recently, Consumers Energy filed for a \$702.8M financing order related to the early retirement of Units 1 & 2 at the Karn coal-fired generating station.

Allowable Use: Refinancing or retirement of debt or equity. (MI 1939 PA 3, Sec. 10h (g); Sec. 10j (1)(a))

2. TRANSITION ASSISTANCE: AUTHORIZED IN CO AND NM STATUES

When securitization is used for the early retirement of an electric generating facility, some statutes passed in 2019 added a new use for securitized bonds, providing transition assistance to workers and communities affected by the closure.

Colorado

The introduced 2019 bill, HB19-1037, included a formula for sharing the savings realized by refinancing the remaining capital in a retired plant between ratepayers (85% of the savings) and the affected workers and communities (15% of the savings). The savings would be calculated as the net present value of the savings over the tenor (life) of the bonds, compared to the amount ratepayers would have paid to retire the plant without the lower-cost bonds. However, this formula did not survive the legislative process. Instead, the bill includes a simple phase allowing bonds to be used for transition assistance. The decision on the amount of funds for transition assistance will be made by the Commission as part of the financing order.

Allowable Use: The statute allows the bonds to be used for “amounts for assistance to affected workers and communities, if approved by the Commission”. (CO SB19-236 - page 52, lines 25-26)

New Mexico

The Energy Transition act contains very detailed guidelines, establishing three different funds for state agencies to administer transition funding for affected Indian communities, affected communities and workers.

Allowable Use: 0.5% of amount bonded is earmarked for the energy transition Indian affairs fund; 1.65% of the bonded amount goes to the energy transition economic development fund; and 3.35% of the bonded amount goes to the energy transition displaced worker assistance fund. (2019 NM SB 489 – page 4, lines 24-25; page 5, lines 1-3; 20-21; SECTION 16, page 40-47)

UTILITY REINVESTMENT: INCLUDED IN CO, MT, NM STATUTES

Colorado

Reinvestment/Capital Recycling: Specific opportunities for the utility to reinvest capital recovered from securitizing a retired plant are not listed in Article 41. Instead, reinvestment opportunities for the utility are defined earlier in the statute in the section describing the Clean Energy Plan the utility is required to submit to the Commission. This plan requires the utility to adopt carbon reduction goals, strategies for achieving the goals, projected costs and proposed new clean energy acquisitions required to meet the goals. The utility is awarded up to 50% ownership of the new clean energy acquisitions. (CO SB19-236 - page 17, lines 1-17)

Montana

Reinvestment/Capital Recycling: The statute provides guidance on how the utility shall expend or invest the funds received from a bond issue. It will first reduce the balance owed on the retired electric generating facility. Following that, the utility may invest or expend funds to own least-cost generation resources, electric storage, network modernization, or to replace any damaged or destroyed electric transmission facilities. (2019 MT HB 467 – page 18-19, Section 18)

New Mexico

Reinvestment/Capital Recycling: The statute provides a detailed process for how PNM must replace the power from the abandoned generating facility. The specificity is partially a means to replace property tax base for the affect school district and community. (2019 NM SB 489 – page 10, lines 2-25; page 11, lines 1-23)

ROLE OF THE PUBLIC UTILITIES COMMISSION: STATUES IN CO, MT, NM, MI

Securitization statutes should describe the role of the public utilities commission in issuing a financing order that 1) allows the issuance of bonds; 2) establishes oversight of the bond issuance process; and 3) protects ratepayer interests throughout both processes. The stronger the commission’s role, and the more oversight it exercises, the better the outcome for ratepayers.

During the legislative process, the utility has an interest in limiting the commission's role and oversight authority; ratepayer advocates typically push for the opposite outcome, with compromises occurring to achieve bill passage. Among the state statutes we review in this memo, the Colorado statute creates the strongest commission oversight role, followed by Montana, Michigan, and then New Mexico. A key component for empowering a commission to conduct effective oversight is the authority to hire outside financial advisors to assist the commission. Funds for outside advisors or additional staff to manage the bond issuance process may not be covered in a commission's normal staff budget. Statutes typically allow commission expenses related to a bond issue to be covered as a part of the bond issue expenses. If a utility receives a financing order, but decides not to issue the bonds, commission expenses incurred in producing the financing order would have to be paid by the utility, which can recover those expenses in a future rate case.

The existing North Carolina securitization statute provides reasonable oversight authority for the commission. The Commission can hire outside financial advisors, with their costs paid as part of the bond issue. The North Carolina statute, however, does not address the situation of recovery of commission expenses when the utility does not follow through and issue bonds.

Colorado

Public Utility Commission Role: The Statute gives the Commission the authority to:

- Require the bonds provide maximum net present value savings for ratepayers (CO SB19-236 - page 59, lines 14-27)
- Conduct oversight of how the bond issue will be structured, priced and marketed to achieve maximum savings for ratepayers (CO SB19-236 - page 60, lines 14-22)
- Attach conditions to the financing order to maximize benefits and minimize risks for all parties (CO SB19-236 - page 66, lines 4-8)
- Hire outside financial advisors to assist the Commission in its oversight work (CO SB19-236 - page 67, lines 9-20)
- Require the utility to simultaneously add a negative cost rider to ratepayer bills to reflect the decreased cost of service and counterbalance the bond repayment charge (CO SB19-236 - page 62, lines 19-24)
- Conduct a rule making for how to manage the securitization financing order process. (CO SB19-236 - page 65, line 27)

Montana

Public Utility Commission Role: The Statute gives the Commission the authority to:

- Require the bonds to provide substantial quantifiable savings for ratepayers (2019 MT HB 467, Section 5 (iv)(c) (I)(ii))
- Include findings determined by the commission to be in the best interests of consumers. (2019 MT HB 467, Section 5 (vii))
- Require the utility to reduce rates simultaneously with the addition of the bond repayment charge on ratepayer bills (2019 MT HB 467, Section 5 (B))
- Hire outside financial advisors to assist the Commission in its oversight work. (2019 MT HB 467, Section 5 (B)(3)(f))
- Conduct a rule making for how to manage the securitization financing order process (2019 MT HB 467, Section 19)

Michigan

Public Utility Commission Role: The Statute gives the Commission limited authority:

- Oversight to ensure customer savings is weak – savings must be “tangible and quantifiable”, but no reference is made to maximize savings or how savings should be calculated. ((MI 1939 PA 3, Sec.10i (2)(b)(c))
- The authority to hire outside financial advisors to assist the Commission in its oversight work is included. ((MI 1939 PA 3, Sec.10i (10))

New Mexico

Public Commission Utility Role: The Statute gives the Commission very limited authority:

- No oversight to ensure customer savings. Savings are calculated by applicant utility as it deems appropriate, and submitted to the Commission as part of the financing order. (2019 NM SB 489 – page 10, lines 2-25; page 13, lines 17-25)
- Commission has no authority to determine the amount to be securitized for plant retirement or transition assistance. These amounts were determined by the legislature and are in Statute. (2019 NM SB 489 – page 4, lines 9-25; page 40-47, Section 16)
- Commission is required to approve a financing order from qualified applicant utility, if financing order application meets Statute requirements. (2019 NM SB 489 – page 17, lines 7-17)
- Commission does have the power to review and approve replacement generation options. (2019 NM SB 489 – page 10, lines 2-25; page 11, lines 1-23)

RECOMMENDATIONS

- The North Carolina Storm Recovery Costs securitization statute could be amended to include additional permitted uses for the bonds. Additional uses could include plant retirement costs and transition assistance for affected communities and workers.
- If plant retirement becomes an allowable use for the bonds, the bill should also include guidance on re-investment opportunities for the utility.
- The existing statute permits the Commission to hire outside financial advisors with the costs paid as part of the bond issue. Adding a provision for Commission cost recovery in the event that bonds are not issued by the utility, similar to the language in the Colorado statute, may be helpful.
- The North Carolina statute provides reasonable oversight authority for the commission. Attempting to strengthen commission authority might trigger utility resistance to the bill.

This fact sheet represents the work of stakeholders as of 12/18/2020.

About the North Carolina Energy Regulatory Process

Governor Cooper's Executive Order 80 mandated the development of a clean energy plan for the state of North Carolina. The Clean Energy Plan recommended the launch of a stakeholder process to design policies that align regulatory incentives with 21st century public policy goals, customer expectations, utility needs, and technology innovation. The stakeholder process was launched in February 2020 and has led to policy proposals on energy reform.

LEARN MORE

Contact NERP Securitization Study Group Leads:
David Rogers, Sierra Club, david.rogers@sierraclub.org
Tobin Freid, Durham County, tfreid@dconnc.gov

Access the NERP summary report and other NERP documents at: <https://deq.nc.gov/CEP-NERP>

NERP ANALYSIS SUMMARY

GENERATION ASSET RETIREMENT FINANCIAL ANALYSIS

COMPARISON OF SECURITIZATION AND REGULATORY ASSET TREATMENT: RELATIVE IMPACTS ON RATEPAYER SAVINGS, UTILITY EARNINGS, AND COMMUNITY ASSISTANCE

The 2020 North Carolina Energy Regulatory Process prioritized energy reforms that would drive affordability, carbon-reduction, and align regulatory incentives with policy goals.

SUMMARY OF FINDINGS

Based on financial analysis performed for a select group of Duke Energy Progress (DEP) coal plants, Rocky Mountain Institute (RMI) finds that securitization (with reinvestment) leads to greater ratepayer savings (in the short and long term) than using regulatory asset treatment as a method for early retirement. Furthermore, securitization with reinvestment provides the utility opportunity for earnings through additions to rate base and could fund transition assistance for impacted communities.

For example, securitizing Mayo (with utility reinvestment) could save ratepayers between \$13-19/MWh (or \$18-29MM) in the first year and between \$3-5/MWh (or \$46-96MM) on a levelized basis, compared to a regulatory asset treatment. The utility has a significant earnings opportunity with securitization, though less than through the regulatory asset treatment – up to \$600-800MM with the former vs. up to \$800-1100MM (on a levelized basis and including tax credits) with the latter. Finally, securitization could result in between \$8-15MM in community assistance.

While RMI's analysis shows securitization generating ratepayer savings compared to a regulatory asset treatment, the magnitude of that difference varies. In Roxboro 3, for example, securitization with reinvestment could save ratepayers between \$4-6/MWh (or \$9-13MM) in the first year and between \$17-21MM on a levelized basis, compared to regulatory asset treatment. The earnings opportunity for the utility in retiring and replacing Roxboro 3 is similar for both

securitization & regulatory assets – up to \$700-800MM. Finally, between \$2-4MM in community assistance could be made available for this plant.

The ratepayer savings, utility earnings and community assistance opportunity for Roxboro 4 is similar to that of Roxboro 3, for both securitization and regulatory asset treatment.

IMPORTANT CAVEATS AND ASSUMPTIONS

RMI's financial model was used to provide *relative* and *illustrative* modeling results – in their current form, the results are not meant to estimate the absolute size of ratepayer savings or utility earnings from any retirement method.

Rather, the results aim to show the tradeoffs (for the utility, customer and community) between two different methods of early plant retirement, and the relative magnitude of the differences in the two approaches.

If a decision is made to investigate the actual implementation of securitization, the analysis would have to be revisited to more accurately account for (among other items):

- The expected 'ramp down' of existing coal plants, prior to retirement
- The sequencing of replacement generation and storage, relative to early retirement
- Implications of early retirement at the fleet level (vs. the individual plant level)

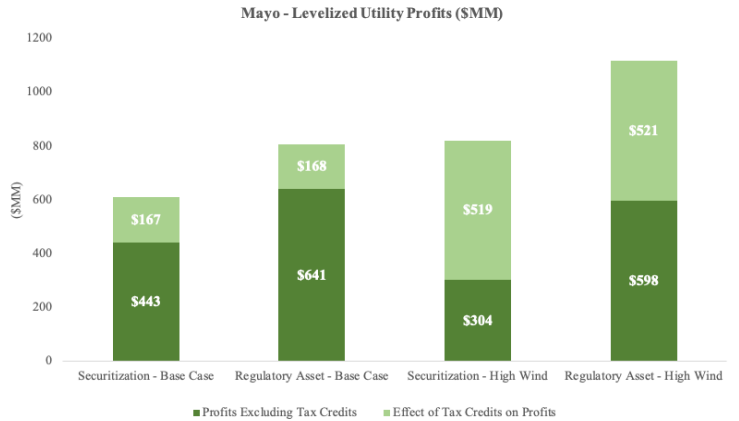
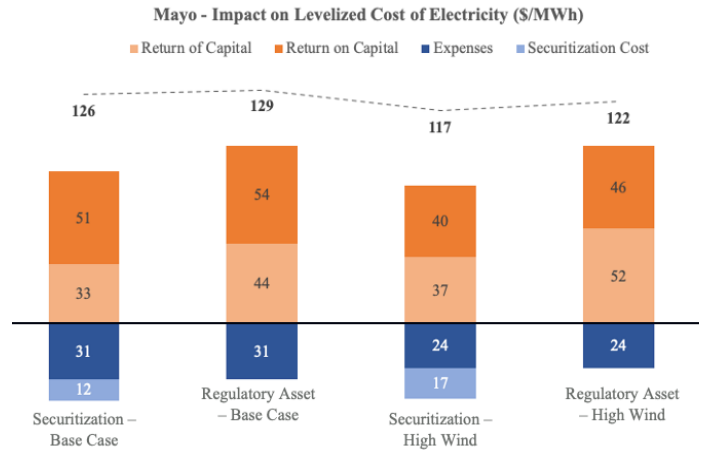
RMI believes that, while the above considerations are critical to implementation, they do not significantly alter the potential opportunity presented by securitization for customers, the utility and the community, relative to a regulatory asset treatment.

ILLUSTRATIVE MODELING RESULTS

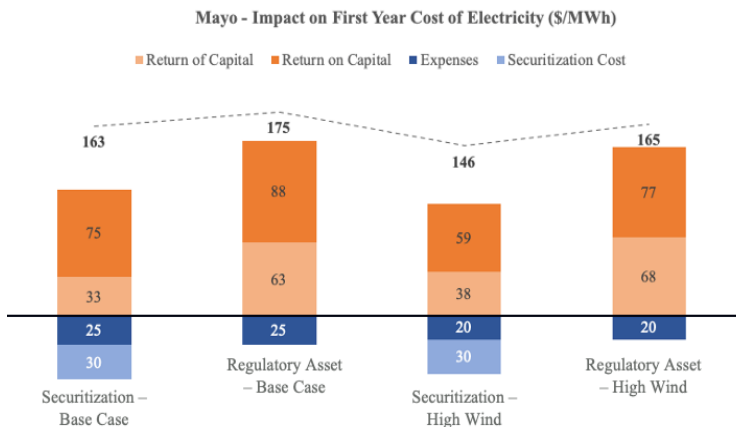
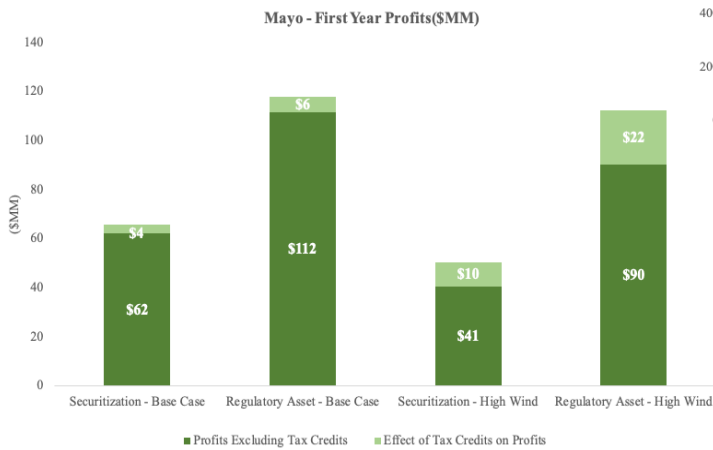
RMI modeled three DEP plants – Mayo 1, Roxboro 3 and Roxboro 4. For each of the plants, two methods of retirement were considered: i) securitization with reinvestment and, ii) regulatory asset treatment.

Furthermore, to determine the retirement year and subsequent replacement portfolio for each plant, Scenario A (Base Case without Carbon Policy) and Scenario D (High Wind) from the DEP 2020 Integrated Resource Plan were used.

The results for Mayo 1 are shown below as an illustrative example:



This fact sheet represents the work of stakeholders as of 12/18/2020.



About the North Carolina Energy Regulatory Process

Governor Cooper’s Executive Order 80 mandated the development of a clean energy plan for the state of North Carolina. The Clean Energy Plan recommended the launch of a stakeholder process to design policies that align regulatory incentives with 21st century public policy goals, customer expectations, utility needs, and technology innovation. The stakeholder process was launched in February 2020 and has led to policy proposals on energy reform.

LEARN MORE

Contact NERP Securitization Study Group Leads:
 David Rogers, Sierra Club, david.rogers@sierraclub.org
 Tobin Freid, Durham County, tfreid@dconnc.gov

Access the NERP summary report and other NERP documents at:
<https://deq.nc.gov/CEP-NERP>

**GENERAL ASSEMBLY OF NORTH
CAROLINA SESSION 2021**

SENATE/HOUSE BILL XXX

A BILL TO BE ENTITLED

“AN ACT TO PERMIT FINANCING FOR CERTAIN UNDEPRECIATED UTILITY PLANT COSTS AND FOR TRANSITION ASSISTANCE FOR AFFECTED WORKERS AND COMMUNITIES”

The General Assembly of North Carolina enacts:

SECTION 1. Article 8 of Chapter 62 of the General Statutes is amended by adding a new section to read:

“§ 62-173. Financing for certain energy transition costs.

- (a) Definitions. – The following definitions apply in this section:
- (1) Ancillary agreement. – A bond, insurance policy, letter of credit, reserve account, surety bond, interest rate lock or swap arrangement, hedging arrangement, liquidity or credit support arrangement, or other financial arrangement entered into in connection with energy transition bonds.
 - (2) Assignee. – A legally recognized entity to which a public utility assigns, sells, or transfers, other than as security, all or a portion of its interest in or right to energy transition property. The term includes a corporation, limited liability company, general partnership or limited partnership, public authority, trust, financing entity, or any entity to which an assignee assigns, sells, or transfers, other than as security, its interest in or right to energy transition property.
 - (3) Bondholder. – A person who holds an energy transition bond.
 - (4) Code. – The Uniform Commercial Code, Chapter 25 of the General Statutes.
 - (5) Commission. – The North Carolina Utilities Commission.
 - (6) Customer securitization savings – The arithmetic difference between the net present value of the costs to customers that are estimated to result from the issuance of energy transition bonds and the net present value of the costs that would result from the application of the traditional method of financing and recovering energy transition costs from customers.
 - (7) Energy transition bonds. – Bonds, debentures, notes, certificates of participation, certificates of beneficial interest, certificates of ownership, or other evidences of indebtedness or ownership that are issued by a public utility or an assignee pursuant to a financing order, the proceeds of which are used directly or indirectly to recover, finance, or refinance Commission-approved energy transition costs and financing costs, and that are secured by or payable from energy transition property. If certificates of participation or ownership are issued, references in this section to principal, interest, or premium shall be construed to refer to comparable amounts under those certificates.
 - (8) Energy transition charge. – The amounts authorized by the Commission to repay, finance, or refinance energy transition costs and financing costs and

that are nonbypassable charges (i) imposed on and part of all retail customer bills, (ii) collected by a public utility or its successors or assignees, or a collection agent, in full, separate and apart from the public utility's base rates, and (iii) paid by all existing or future retail customers receiving transmission or distribution service, or both, from the public utility or its successors or assignees under Commission-approved rate schedules or under special contracts, even if a customer elects to purchase electricity from an alternative electricity supplier following a fundamental change in regulation of public utilities in this State.

(9) Energy transition costs. – All of the following:

(a) (i) at the option of and upon petition by an public utility, and as approved by the commission, any of the pretax costs that the electric utility has incurred or will incur that are caused by, associated with, or remain as a result of the retirement of an electric generating facility located in the state.

(ii) as used in this subsection, "pretax costs," include, but are not limited to, the unrecovered capitalized cost of a retired electric generating facility, costs of decommissioning and restoring the site of the electric generating facility, and other applicable capital and operating costs, accrued carrying charges, deferred expenses, reductions for applicable insurance and salvage proceeds and the costs of retiring any existing indebtedness, fees, costs, and expenses to modify existing debt agreements or for waivers or consents related to existing debt agreements.

(b) amounts for transition assistance to affected workers and communities if approved by the commission;

(c) pretax costs that an electric utility has previously incurred related to the commission-approved closure of an electric generating facility occurring before the effective date of this section.

(d) energy transition costs do not include any monetary penalty, fine, or forfeiture assessed against an electric utility by a government agency or court under a federal or state environmental statute, rule, or regulation.

(10) Energy transition property. – All of the following:

a. All rights and interests of a public utility or successor or assignee of the public utility under a financing order, including the right to impose, bill, charge, collect, and receive energy transition charges authorized under the financing order and to obtain periodic adjustments to such charges as provided in the financing order.

b. All revenues, collections, claims, rights to payments, payments, money, or proceeds arising from the rights and interests specified in the financing order, regardless of whether such revenues, collections, claims, rights to payment, payments, money, or proceeds are imposed, billed, received, collected, or maintained together with or commingled with other revenues, collections, rights to payment, payments, money, or proceeds.

- (11) Financing costs. – The term includes all of the following:
- a. Interest and acquisition, defeasance, or redemption premiums payable on energy transition bonds.
 - b. Any payment required under an ancillary agreement and any amount required to fund or replenish a reserve account or other accounts established under the terms of any indenture, ancillary agreement, or other financing documents pertaining to energy transition bonds.
 - c. Any other cost related to issuing, supporting, repaying, refunding, and servicing energy transition bonds, including, servicing fees, accounting and auditing fees, trustee fees, legal fees, consulting fees, structuring adviser fees, administrative fees, placement and underwriting fees, independent director and manager fees, capitalized interest, rating agency fees, stock exchange listing and compliance fees, security registration fees, filing fees, information technology programming costs, and any other costs necessary to otherwise ensure the timely payment of energy transition bonds or other amounts or charges payable in connection with the bonds, including costs related to obtaining the financing order.
 - d. Any taxes and license fees or other fees imposed on the revenues generated from the collection of the energy transition charge or otherwise resulting from the collection of energy transition charges, in any such case whether paid, payable, or accrued.
 - e. Any State and local taxes, franchise, gross receipts, and other taxes or similar charges, including regulatory assessment fees, whether paid, payable, or accrued.
 - f. Any costs incurred by the Commission or public staff for any outside consultants or counsel retained in connection with the securitization of energy transition costs, except as provided in subparagraph (d)(1)c.
- (12) Financing order. – An order that authorizes the issuance of energy transition bonds; the imposition, collection, and periodic adjustments of an energy transition charge; the creation of energy transition property; and the sale, assignment, or transfer of energy transition property to an assignee.
- (13) Financing party. – Bondholders and trustees, collateral agents, any party under an ancillary agreement, or any other person acting for the benefit of bondholders.
- (14) Financing statement. – Defined in Article 9 of the Code.
- (15) Pledgee. – A financing party to which a public utility or its successors or assignees mortgages, negotiates, pledges, or creates a security interest or lien on all or any portion of its interest in or right to energy transition property.
- (16) Public utility. – A public utility, as defined in G.S. 62-3, that sells electric power to retail electric customers in the State.

(b) Financing Orders. –

- (1) A public utility may petition the Commission for a financing order. The petition shall include all of the following:
 - a. The energy transition costs incurred by the utility and an estimate of the costs that are being undertaken but are not completed.

- b. A statement of whether the public utility proposes to finance all or a portion of the energy transition costs using energy transition bonds. If the public utility proposes to finance a portion of the costs, the public utility must identify the specific portion in the petition. By electing not to finance a portion of such energy transition costs using energy transition bonds, a public utility shall not be deemed to waive its right to recover such costs pursuant to a separate proceeding with the Commission.
 - c. A proposed amount, for Commission consideration, to be included in energy transition costs for use as transition assistance for workers and local governments negatively affected by the retirement of an electric generating facility.
 - d. An estimate of the financing costs related to the energy transition bonds.
 - e. An estimate of the energy transition charges necessary to recover the energy transition costs and financing costs and the proposed period for recovery of such costs.
 - f. An estimate of the quantifiable customer securitization savings resulting from the use of energy transition bonds instead of traditional cost recovery methods.
 - g. Direct testimony and exhibits supporting the petition.
- (2) If a public utility is subject to a settlement agreement that governs the type and amount of costs that could be included in energy transition costs and the public utility proposes to finance all or a portion of the costs using energy transition bonds, then the public utility must file a petition with the Commission for review and approval of those costs no later than 90 days before filing a petition for a financing order pursuant to this section.
- (3) Petition and order. –
- a. Proceedings on a petition submitted pursuant to this subdivision begin with the petition by a public utility, filed subject to the time frame specified in subdivision (2) of this subsection, if applicable, and shall be disposed of in accordance with the requirements of this Chapter and the rules of the Commission, except as follows:
 - 1. Within 14 days after the date the petition is filed, the Commission shall establish a procedural schedule that permits a Commission decision no later than 210 days after the date the petition is filed.
 - 2. No later than 210 days after the date the petition is filed, the Commission shall issue a financing order or an order rejecting the petition. A party to the Commission proceeding may petition the Commission for reconsideration of the financing order within five days after the date of its issuance.
 - b. A financing order issued by the Commission to a public utility shall include all of the following elements:
 - 1. Except for changes made pursuant to the formula-based mechanism authorized under this section, the amount of energy transition costs to be financed using energy transition

- bonds. The Commission shall describe and estimate the amount of financing costs that may be recovered through energy transition charges and specify the period over which energy transition costs and financing costs may be recovered.
2. A finding that the proposed issuance of energy transition bonds and the imposition and collection of an energy transition charge are expected to provide quantifiable benefits to customers as compared to the costs that would have been incurred absent the issuance of energy transition bonds and a statement of the net present value of those benefits to customers.
 3. A finding that the structuring and pricing of the energy transition bonds are reasonably expected to result in the lowest energy transition charges consistent with market conditions at the time the energy transition bonds are priced, and with the terms set forth in such financing order.
 4. A determination of the portion, up to 15%, of the customer securitization savings that shall be included in transition bond costs and used to provide transition assistance to workers and local governments negatively affected by the retirement of the electric generating facility.
 5. A requirement that, for so long as the energy transition bonds are outstanding and until all financing costs have been paid in full, the imposition and collection of energy transition charges authorized under a financing order shall be nonbypassable and paid by all existing and future retail customers receiving transmission or distribution service, or both, from the public utility or its successors or assignees under Commission-approved rate schedules or under special contracts, even if a customer elects to purchase electricity from an alternative electric supplier following a fundamental change in regulation of public utilities in this State.
 6. A formula-based true-up mechanism for making, at least annually, expeditious periodic adjustments in the energy transition charges that customers are required to pay pursuant to the financing order and for making any adjustments that are necessary to correct for any overcollection or undercollection of the charges or to otherwise ensure the timely payment of energy transition bonds and financing costs and other required amounts and charges payable in connection with the energy transition bonds.
 7. The energy transition property that is, or shall be, created in favor of a public utility or its successors or assignees and that shall be used to pay or secure energy transition bonds and all financing costs.
 8. The degree of flexibility to be afforded to the public utility in

establishing the terms and conditions of the energy transition bonds, including, but not limited to, repayment schedules, expected interest rates, and other financing costs.

9. How energy transition charges will be allocated among customer classes.
 10. A requirement that, after the final terms of an issuance of energy transition bonds have been established and before the issuance of energy transition bonds, the public utility determines the resulting initial energy transition charge in accordance with the financing order and that such initial energy transition charge be final and effective upon the issuance of such energy transition bonds without further Commission action so long as the energy transition charge is consistent with the financing order.
 11. A requirement that the applicant public utility, simultaneously with the inception of the collection of energy transition charges, reduce its rates through a reduction in base rates or by a negative rider on customer bills in an amount equal to the revenue requirement associated with the utility assets being financed by energy transition bonds
 12. A method of tracing funds collected as energy transition charges, or other proceeds of energy transition property, and determine that such method shall be deemed the method of tracing such funds and determining the identifiable cash proceeds of any energy transition property subject to a financing order under applicable law.
 13. Any other conditions not otherwise inconsistent with this section that the Commission determines are appropriate.
- c. A financing order issued to a public utility may provide that creation of the public utility's energy transition property is conditioned upon, and simultaneous with, the sale or other transfer of the energy transition property to an assignee and the pledge of the energy transition property to secure energy transition bonds.
- d. If the Commission issues a financing order, the public utility shall file with the Commission at least annually a petition or a letter applying the formula-based mechanism and, based on estimates of consumption for each rate class and other mathematical factors, requesting administrative approval to make the applicable adjustments. The review of the filing shall be limited to determining whether there are any mathematical or clerical errors in the application of the formula-based mechanism relating to the appropriate amount of any overcollection or undercollection of energy transition charges and the amount of an adjustment. The adjustments shall ensure the recovery of revenues sufficient to provide for the payment of principal, interest, acquisition, defeasance, financing costs, or redemption premium and other fees, costs, and charges in respect of energy transition bonds

- approved under the financing order. Within 30 days after receiving a public utility's request pursuant to this paragraph, the Commission shall either approve the request or inform the public utility of any mathematical or clerical errors in its calculation. If the Commission informs the utility of mathematical or clerical errors in its calculation, the utility may correct its error and refile its request. The time frames previously described in this paragraph shall apply to a refiled request.
- e. Subsequent to the transfer of energy transition property to an assignee or the issuance of energy transition bonds authorized thereby, whichever is earlier, a financing order is irrevocable and, except for changes made pursuant to the formula-based mechanism authorized in this section, the Commission may not amend, modify, or terminate the financing order by any subsequent action or reduce, impair, postpone, terminate, or otherwise adjust energy transition charges approved in the financing order. After the issuance of a financing order, the public utility retains sole discretion regarding whether to assign, sell, or otherwise transfer energy transition property or to cause energy transition bonds to be issued, including the right to defer or postpone such assignment, sale, transfer, or issuance.
 - f. Transition assistance funds, if included in the bond issue, may be transferred to a third-party entity designated by the commission to administer transition assistance on behalf of displaced workers and affected communities.
- (4) At the request of a public utility, the Commission may commence a proceeding and issue a subsequent financing order that provides for refinancing, retiring, or refunding the energy transition bonds issued pursuant to the original financing order if the Commission finds that the subsequent financing order satisfies all of the criteria specified in this section for a financing order. Effective upon retirement of the refunded energy transition bonds and the issuance of new energy transition bonds, the Commission shall adjust the related energy transition charges accordingly.
- (5) Within 60 days after the Commission issues a financing order or a decision denying a request for reconsideration or, if the request for reconsideration is granted, within 30 days after the Commission issues its decision on reconsideration, an adversely affected party may petition for judicial review in the Supreme Court of North Carolina. Review on appeal shall be based solely on the record before the Commission and briefs to the court and is limited to determining whether the financing order, or the order on reconsideration, conforms to the State Constitution and State and federal law and is within the authority of the Commission under this section.
- (6) Duration of financing order. –
- a. A financing order remains in effect and energy transition property under the financing order continues to exist until energy transition bonds issued pursuant to the financing order have been paid in full or defeased and, in each case, all Commission-approved financing costs of such energy transition bonds have been recovered in full.
 - b. A financing order issued to a public utility remains in effect and

unabated notwithstanding the reorganization, bankruptcy or other insolvency proceedings, merger, or sale of the public utility or its successors or assignees.

(c) Exceptions to Commission Jurisdiction. –

(1) The Commission may not, in exercising its powers and carrying out its duties regarding any matter within its authority pursuant to this Chapter, consider the energy transition bonds issued pursuant to a financing order to be the debt of the public utility other than for federal income tax purposes, consider the energy transition charges paid under the financing order to be the revenue of the public utility for any purpose, or consider the energy transition costs or financing costs specified in the financing order to be the costs of the public utility, nor may the Commission determine any action taken by a public utility which is consistent with the financing order to be unjust or unreasonable.

(2) The Commission may not order or otherwise directly or indirectly require a public utility to use energy transition bonds to finance any project, addition, plant, facility, extension, capital improvement, equipment, or any other expenditure. After the issuance of a financing order, the public utility retains sole discretion regarding whether to cause the energy transition bonds to be issued, including the right to defer or postpone such sale, assignment, transfer, or issuance. Nothing shall prevent the public utility from abandoning the issuance of energy transition bonds under the financing order by filing with the Commission a statement of abandonment and the reasons therefor. The Commission may not refuse to allow a public utility to recover energy transition costs in an otherwise permissible fashion, or refuse or condition authorization or approval of the issuance and sale by a public utility of securities or the assumption by the public utility of liabilities or obligations, solely because of the potential availability of energy transition bond financing.

(d) Public Utility Duties. –

(1) The electric bills of a public utility that has obtained a financing order and caused energy transition bonds to be issued must comply with the provisions of this subsection; however, the failure of a public utility to comply with this subsection does not invalidate, impair, or affect any financing order, energy transition property, energy transition charge, or energy transition bonds. The public utility must do the following:

a. Explicitly reflect that a portion of the charges on such bill represents energy transition charges approved in a financing order issued to the public utility and, if the energy transition property has been transferred to an assignee, must include a statement to the effect that the assignee is the owner of the rights to energy transition charges and that the public utility or other entity, if applicable, is acting as a collection agent or servicer for the assignee. The tariff applicable to customers must indicate the energy transition charge and the ownership of the charge.

b. Include the energy transition charge on each customer's bill as a

separate line item and include both the rate and the amount of the charge on each bill.

- c. If a public utility's petition for a financing order is denied or withdrawn or for any reason no energy transition bonds are issued, any costs of retaining expert consultants and counsel on behalf of the commission or the public staff, as authorized by Section and approved by the commission, shall be paid by the applicant public utility and shall be eligible for recovery by the public utility, including carrying costs, in the electric utility's future rates.

(e) Energy transition Property. –

(1) Provisions applicable to energy transition property. –

- a. All energy transition property that is specified in a financing order constitutes an existing, present intangible property right or interest therein, notwithstanding that the imposition and collection of energy transition charges depends on the public utility, to which the financing order is issued, performing its servicing functions relating to the collection of energy transition charges and on future electricity consumption. The property exists (i) regardless of whether or not the revenues or proceeds arising from the property have been billed, have accrued, or have been collected and (ii) notwithstanding the fact that the value or amount of the property is dependent on the future provision of service to customers by the public utility or its successors or assignees and the future consumption of electricity by customers.
- b. Energy transition property specified in a financing order exists until energy transition bonds issued pursuant to the financing order are paid in full and all financing costs and other costs of such energy transition bonds have been recovered in full.
- c. All or any portion of energy transition property specified in a financing order issued to a public utility may be transferred, sold, conveyed, or assigned to a successor or assignee that is wholly owned, directly or indirectly, by the public utility and created for the limited purpose of acquiring, owning, or administering energy transition property or issuing energy transition bonds under the financing order. All or any portion of energy transition property may be pledged to secure energy transition bonds issued pursuant to the financing order, amounts payable to financing parties and to counterparties under any ancillary agreements, and other financing costs. Any transfer, sale, conveyance, assignment, grant of a security interest in or pledge of energy transition property by a public utility, or an affiliate of the public utility, to an assignee, to the extent previously authorized in a financing order, does not require the prior consent and approval of the Commission.
- d. If a public utility defaults on any required payment of charges arising from energy transition property specified in a financing order, a court, upon application by an interested party, and without limiting any other

remedies available to the applying party, shall order the sequestration and payment of the revenues arising from the energy transition property to the financing parties or their assignees. Any such financing order remains in full force and effect notwithstanding any reorganization, bankruptcy, or other insolvency proceedings with respect to the public utility or its successors or assignees.

e. The interest of a transferee, purchaser, acquirer, assignee, or pledgee in energy transition property specified in a financing order issued to a public utility, and in the revenue and collections arising from that property, is not subject to setoff, counterclaim, surcharge, or defense by the public utility or any other person or in connection with the reorganization, bankruptcy, or other insolvency of the public utility or any other entity.

f. Any successor to a public utility, whether pursuant to any reorganization, bankruptcy, or other insolvency proceeding or whether pursuant to any merger or acquisition, sale, or other business combination, or transfer by operation of law, as a result of public utility restructuring or otherwise, must perform and satisfy all obligations of, and have the same rights under a financing order as, the public utility under the financing order in the same manner and to the same extent as the public utility, including collecting and paying to the person entitled to receive the revenues, collections, payments, or proceeds of the energy transition property. Nothing in this subdivision is intended to limit or impair any authority of the Commission concerning the transfer or succession of interests of public utilities.

g. Energy transition bonds shall be nonrecourse to the credit or any assets of the public utility other than the energy transition property as specified in the financing order and any rights under any ancillary agreement.

(2) Provisions applicable to security interests. –

a. The creation, perfection, and enforcement of any security interest in energy transition property to secure the repayment of the principal and interest and other amounts payable in respect of energy transition bonds; amounts payable under any ancillary agreement and other financing costs are governed by this subsection and not by the provisions of the Code.

b. A security interest in energy transition property is created, valid, and binding and perfected at the later of the time: (i) the financing order is issued, (ii) a security agreement is executed and delivered by the debtor granting such security interest, (iii) the debtor has rights in such energy transition property or the power to transfer rights in such energy transition property, or (iv) value is received for the energy transition property. The description of energy transition property in a security agreement is sufficient if the description refers to this section and the financing order creating the energy transition property.

- c. A security interest shall attach without any physical delivery of collateral or other act, and, upon the filing of a financing statement with the office of the Secretary of State, the lien of the security interest

shall be valid, binding, and perfected against all parties having claims of any kind in tort, contract, or otherwise against the person granting the security interest, regardless of whether the parties have notice of the lien. Also upon this filing, a transfer of an interest in the energy transition property shall be perfected against all parties having claims of any kind, including any judicial lien or other lien creditors or any claims of the seller or creditors of the seller, and shall have priority over all competing claims other than any prior security interest, ownership interest, or assignment in the property previously perfected in accordance with this section.

d. The Secretary of State shall maintain any financing statement filed to perfect any security interest under this section in the same manner that the Secretary maintains financing statements filed by transmitting utilities under the Code. The filing of a financing statement under this section shall be governed by the provisions regarding the filing of financing statements in the Code.

e. The priority of a security interest in energy transition property is not affected by the commingling of energy transition charges with other amounts. Any pledgee or secured party shall have a perfected security interest in the amount of all energy transition charges that are deposited in any cash or deposit account of the qualifying utility in which energy transition charges have been commingled with other funds and any other security interest that may apply to those funds shall be terminated when they are transferred to a segregated account for the assignee or a financing party.

f. No application of the formula-based adjustment mechanism as provided in this section will affect the validity, perfection, or priority of a security interest in or transfer of energy transition property.

g. If a default or termination occurs under the energy transition bonds, the financing parties or their representatives may foreclose on or otherwise enforce their lien and security interest in any energy transition property as if they were secured parties with a perfected and prior lien under the Code, and the Commission may order amounts arising from energy transition charges be transferred to a separate account for the financing parties' benefit, to which their lien and security interest shall apply. On application by or on behalf of the financing parties, the Superior Court of Wake County shall order the sequestration and payment to them of revenues arising from the energy transition charges.

(3) Provisions applicable to the sale, assignment, or transfer of energy transition property. –

a. Any sale, assignment, or other transfer of energy transition property shall be an absolute transfer and true sale of, and not a pledge of or secured transaction relating to, the seller's right, title, and interest in, to, and under the energy transition property if the documents governing the transaction expressly state that the transaction is a sale or other absolute transfer other than for federal and State income tax purposes. For all purposes other than federal and State income tax purposes, the parties' characterization of a transaction as a sale of an interest in energy transition property shall be conclusive that the transaction is a true sale and that ownership has passed to the party

characterized as the purchaser, regardless of whether the purchaser has possession of any documents evidencing or pertaining to the interest. A transfer of an interest in energy transition property may be created only when all of the following have occurred: (i) the financing order creating the energy transition property has become effective, (ii) the documents evidencing the transfer of energy transition property have been executed by the assignor and delivered to the assignee, and (iii) value is received for the energy transition property. After such a transaction, the energy transition property is not subject to any claims of the transferor or the transferor's creditors, other than creditors holding a prior security interest in the energy transition property perfected in accordance with subdivision (2) of subsection (e) of this section.

- b. The characterization of the sale, assignment, or other transfer as an absolute transfer and true sale and the corresponding characterization of the property interest of the purchaser, shall not be affected or impaired by the occurrence of any of the following factors:
1. Commingling of energy transition charges with other amounts.
 2. The retention by the seller of (i) a partial or residual interest, including an equity interest, in the energy transition property, whether direct or indirect, or whether subordinate or otherwise, or (ii) the right to recover costs associated with taxes, franchise fees, or license fees imposed on the collection of energy transition charges.
 3. Any recourse that the purchaser may have against the seller.
 4. Any indemnification rights, obligations, or repurchase rights made or provided by the seller.
 5. The obligation of the seller to collect energy transition charges on behalf of an assignee.
 6. The transferor acting as the servicer of the energy transition charges or the existence of any contract that authorizes or requires the public utility, to the extent that any interest in energy transition property is sold or assigned, to contract with the assignee or any financing party that it will continue to operate its system to provide service to its customers, will collect amounts in respect of the energy transition charges for the benefit and account of such assignee or financing party, and will account for and remit such amounts to or for the account of such assignee or financing party.
 7. The treatment of the sale, conveyance, assignment, or other transfer for tax, financial reporting, or other purposes.
 8. The granting or providing to bondholders a preferred right to the energy transition property or credit enhancement by the public utility or its affiliates with respect to such energy transition bonds.
 9. Any application of the formula-based adjustment mechanism as provided in this section.
- c. Any right that a public utility has in the energy transition property before its pledge, sale, or transfer or any other right created under this section or created in the financing order and assignable under this section or assignable pursuant to a financing order is property in the form of a contract right or a chose in action. Transfer of an interest in energy transition property to an assignee is enforceable only upon the later of

- (i) the issuance of a financing order, (ii) the assignor having rights in such energy transition property or the power to transfer rights in such energy transition property to an assignee, (iii) the execution and delivery by the assignor of transfer documents in connection with the issuance of energy transition bonds, and (iv) the receipt of value for the energy transition property. An enforceable transfer of an interest in energy transition property to an assignee is perfected against all third parties, including subsequent judicial or other lien creditors, when a notice of that transfer has been given by the filing of a financing statement in accordance with sub-subdivision c. of subdivision (2) of this subsection. The transfer is perfected against third parties as of the date of filing.
- d. The Secretary of State shall maintain any financing statement filed to perfect any sale, assignment, or transfer of energy transition property under this section in the same manner that the Secretary maintains financing statements filed by transmitting utilities under the Code. The filing of any financing statement under this section shall be governed by the provisions regarding the filing of financing statements in the Code. The filing of such a financing statement is the only method of perfecting a transfer of energy transition property.
- e. The priority of a transfer perfected under this section is not impaired by any later modification of the financing order or energy transition property or by the commingling of funds arising from energy transition property with other funds. Any other security interest that may apply to those funds, other than a security interest perfected under subdivision (2) of this subsection, is terminated when they are transferred to a segregated account for the assignee or a financing party. If energy transition property has been transferred to an assignee or financing party, any proceeds of that property must be held in trust for the assignee or financing party.
- f. The priority of the conflicting interests of assignees in the same interest or rights in any energy transition property is determined as follows:
1. Conflicting perfected interests or rights of assignees rank according to priority in time of perfection. Priority dates from the time a filing covering the transfer is made in accordance with sub-subdivision c. of subdivision (2) of this subsection.
 2. A perfected interest or right of an assignee has priority over a conflicting unperfected interest or right of an assignee.
 3. A perfected interest or right of an assignee has priority over a person who becomes a lien creditor after the perfection of such assignee's interest or right.
- (f) Description or Indication of Property. – The description of energy transition property being transferred to an assignee in any sale agreement, purchase agreement, or other transfer agreement, granted or pledged to a pledgee in any security agreement, pledge agreement, or other security document, or indicated in any financing statement is only sufficient if such description or indication refers to the financing order that created the energy transition property and states that the agreement or financing statement covers

- all or part of the property described in the financing order. This section applies to all purported transfers of, and all purported grants or liens or security interests in, energy transition property, regardless of whether the related sale agreement, purchase agreement, other transfer agreement, security agreement, pledge agreement, or other security document was entered into, or any financing statement was filed.
- (g) Financing Statements. – All financing statements referenced in this section are subject to Part 5 of Article 9 of the Code, except that the requirement as to continuation statements does not apply.
- (h) Choice of Law. – The law governing the validity, enforceability, attachment, perfection, priority, and exercise of remedies with respect to the transfer of an interest or right or the pledge or creation of a security interest in any energy transition property shall be the laws of this State.
- (i) Energy transition Bonds Not Public Debt. – Neither the State nor its political subdivisions are liable on any energy transition bonds, and the bonds are not a debt or a general obligation of the State or any of its political subdivisions, agencies, or instrumentalities, nor are they special obligations or indebtedness of the State or any agency or political subdivision. An issue of energy transition bonds does not, directly, indirectly, or contingently, obligate the State or any agency, political subdivision, or instrumentality of the State to levy any tax or make any appropriation for payment of the energy transition bonds, other than in their capacity as consumers of electricity. All energy transition bonds must contain on the face thereof a statement to the following effect: "Neither the full faith and credit nor the taxing power of the State of North Carolina is pledged to the payment of the principal of, or interest on, this bond."
- (j) Legal Investment. – All of the following entities may legally invest any sinking funds, moneys, or other funds in energy transition bonds:
- (1) Subject to applicable statutory restrictions on State or local investment authority, the State, units of local government, political subdivisions, public bodies, and public officers, except for members of the Commission.
 - (2) Banks and bankers, savings and loan associations, credit unions, trust companies, savings banks and institutions, investment companies, insurance companies, insurance associations, and other persons carrying on a banking or insurance business.
 - (3) Personal representatives, guardians, trustees, and other fiduciaries.
 - (4) All other persons authorized to invest in bonds or other obligations of a similar nature.
- (k) Obligation of Nonimpairment. –
- (1) The State and its agencies, including the Commission, pledge and agree with bondholders, the owners of the energy transition property, and other financing parties that the State and its agencies will not take any action listed in this subdivision. This paragraph does not preclude limitation or alteration if full compensation is made by law for the full protection of the energy transition charges collected pursuant to a financing order and of the bondholders and any assignee or financing party entering into a contract with the public utility. The prohibited actions are as follows:
 - a. Alter the provisions of this section, which authorize the Commission to create an irrevocable contract right or chose in action by the issuance of a financing order, to create energy transition property, and make the energy transition charges imposed by a financing order irrevocable, binding, or nonbypassable charges.

- b. Take or permit any action that impairs or would impair the value of energy transition property or the security for the energy transition bonds or revises the energy transition costs for which recovery is authorized.
- c. In any way impair the rights and remedies of the bondholders, assignees, and other financing parties.

- d. Except for changes made pursuant to the formula-based adjustment mechanism authorized under this section, reduce, alter, or impair energy transition charges that are to be imposed, billed, charged, collected, and remitted for the benefit of the bondholders, any assignee, and any other financing parties until any and all principal, interest, premium, financing costs and other fees, expenses, or charges incurred, and any contracts to be performed, in connection with the related energy transition bonds have been paid and performed in full.
- (2) Any person or entity that issues energy transition bonds may include the language specified in this subsection in the energy transition bonds and related documentation.
- (l) Not a Public Utility. – An assignee or financing party is not a public utility or person providing electric service by virtue of engaging in the transactions described in this section.
- (m) Conflicts. – If there is a conflict between this section and any other law regarding the attachment, assignment, or perfection, or the effect of perfection, or priority of, assignment or transfer of, or security interest in energy transition property, this section shall govern.
- (n) Consultation. – In making determinations under this section, the Commission or public staff or both may engage an outside consultant and counsel.
- (o) Effect of Invalidity. – If any provision of this section is held invalid or is invalidated, superseded, replaced, repealed, or expires for any reason, that occurrence does not affect the validity of any action allowed under this section which is taken by a public utility, an assignee, a financing party, a collection agent, or a party to an ancillary agreement; and any such action remains in full force and effect with respect to all energy transition bonds issued or authorized in a financing order issued under this section before the date that such provision is held invalid or is invalidated, superseded, replaced, or repealed, or expires for any reason."
- (p) **Conditions for selecting replacement capacity and energy [DISCLAIMER: This section received support by the majority, but not by all NERP participants.]**
- (1) the public utility shall employ a competitive bidding process, approved by the commission as to its structure, to procure energy resources required to fill the resource need resulting from the closure of generating facilities under this Section.
- (2) The Commission may permit the utility or its affiliates to compete in the bidding process and own a portion of the replacement resources, including associated infrastructure, if the Commission finds –
- a. The utility bids were evaluated in the same manner as other bids;
 - b. the cost of utility or affiliate ownership of the replacement resources is reasonable and is the least cost choice, with an acceptable rate impact; and
 - c. that utility ownership of replacement resources is necessary to assure the utility's financial health.
- (3) Utility ownership may consist of utility or affiliate self-builds, build-transfers from independent power producers, or sales of existing assets from independent power producers or similar commercial arrangements.
- (4) In determining whether to approve proposed replacement resources, the Commission shall consider –

- a. the risk that future federal environmental regulations could increase the life-cycle cost of the resource and create future stranded assets; and
- b. whether the proposed replacement resources support the state’s energy goals, as expressed by the governor and the legislature.

SECTION 2. G.S. 25-9-109(d) reads as rewritten:

"(d) Inapplicability of Article. – This Article does not apply to:

...

- (13) An assignment of a deposit account in a consumer transaction, but G.S. 25-9-315 and G.S. 25-9-322 apply with respect to proceeds and priorities in proceeds;~~or~~
- (14) The creation, perfection, priority, or enforcement of any lien on, assignment of, pledge of, or security in, any revenues, rights, funds, or other tangible or intangible assets created, made, or granted by this State or a governmental unit in this State, including the assignment of rights as secured party in security interests granted by any party subject to the provisions of this Article to this State or a governmental unit in this State, to secure, directly or indirectly, any bond, note, other evidence of indebtedness, or other payment obligations for borrowed money issued by, or in connection with, installment or lease purchase financings by, this State or a governmental unit in this State. However, notwithstanding this subdivision, this Article does apply to the creation, perfection, priority, and enforcement of security interests created by this State or a governmental unit in this State in equipment or fixtures;
~~or~~
- (15) The creation, perfection, priority, or enforcement of any sale, assignment of, pledge of, security interest in, or other transfer of, any interest or right or portion of any interest or right in any storm recovery property as defined G.S. 62-172;
“or
- (16) The creation, perfection, priority, or enforcement of any sale, assignment of, pledge of, security interest in, or other transfer of, any interest or right or portion of any interest or right in any energy transition property as defined G.S. 62-173.”

SECTION 3. This act is effective when it becomes law.

COMPETITIVE PROCUREMENT STUDY GROUP

WORK PRODUCTS



COMPETITIVE PROCUREMENT GUIDANCE DOCUMENT

COMPETITIVE PROCUREMENT POLICY GUIDANCE ADDRESSED TO THE NCUC
FROM THE NORTH CAROLINA ENERGY REGULATORY PROCESS

AUTHORS & ACKNOWLEDGMENTS

STUDY GROUP MEMBERS

Jack Jirak, Duke Energy, co-chair
 Steve Levitas, NCCEBA, co-chair
 Charles Bayless, NC Electric Cooperatives
 Chris Carmody, NCCEBA, group chair
 Marshall Conrad, NC General Assembly
 Peter Daniel, NC Chamber of Commerce
 Drew Elliot, ElectriCities of North Carolina
 Paula Hemmer, Dept. of Environmental Quality
 Preston Howard, NC Manufacturers Alliance
 Stephen Kalland, NC Clean Energy Technology Center
 Peter Ledford, NCSEA
 Kevin Martin, Carolina Utility Customer Association
 Sushma Masemore, Dept. of Environmental Quality
 Rory McIlmoil, Appalachian Voices
 Sally Robertson, NC Warn
 David Rogers, Sierra Club
 Will Scott, NC Conservation Network
 Jeff Thomas, NCUC Public Staff
 Peter Toomey, Duke Energy

CONTACTS

Jack Jirak, Duke Energy, co-chair
 Steve Levitas, NCCEBA, co-chair

ACKNOWLEDGMENTS

The authors thank the following individuals/organizations for offering their insights and perspectives on this work.

Laura Bateman, Duke Energy
 Josh Brooks, Rocky Mountain Institute
 Kendal Bowman, Duke Energy
 Dan Cross-Call, Rocky Mountain Institute
 Matthew Davis, NC Dept. of Environmental Quality
 Max Dupey, Regulatory Assistance Project
 Heather House, Rocky Mountain Institute
 Jessica Shipley, Regulatory Assistance Project
 Lauren Shwisberg, Rocky Mountain Institute
 Kim Smith, Duke Energy
 Matt Wasson, Appalachian Voices

This work was last updated on 12/21/2020.

Cover image courtesy of GYPSY FROM NOWHERE IMAGES/ALAMY STOCK PHOTO

ABOUT THE NORTH CAROLINA ENERGY REGULATORY PROCESS

Governor Cooper's Executive Order 80 mandated the development of a clean energy plan for the state of North Carolina. The Clean Energy Plan recommended the launch of a stakeholder process to design policies that align regulatory incentives with 21st century public policy goals, customer expectations, utility needs, and technology innovation. The stakeholder process was launched in February 2020 and has led to policy proposals on energy reform.

About this document

The Competitive Procurement Subcommittee has evaluated a number of competitive procurement models across the country. Ultimately, the recent procurement cycle in Colorado for the Public Service Company of Colorado (Xcel Energy), offered a good example of a successful generation procurement framework. Based on such review, the Subcommittee supports the following policy recommendations details.

TABLE OF CONTENTS

Authors & Acknowledgments 2

Introduction 4

 Purpose 4

 NERP Recommendations 4

 Context and history 4

 NERP 5

 NERP companion documents 6

Detailed policy recommendations 6

 General principles 6

 NERP recommendations 8

Conclusion 9

Appendix 10

INTRODUCTION

Purpose

The purpose of this document is to communicate the findings of the NC Energy Regulatory Process (NERP) to the NC General Assembly and the NC Utilities Commission (NCUC), as the NCUC may determine it appropriate to consider competitive solicitations as an important tool to meet energy and capacity needs identified in an IRP.

The Competitive Procurement Subcommittee evaluated issues related to the use of competitive processes to meet demands of the recent procurement cycle in Colorado for the Public Service Company of Colorado (Xcel Energy). The Subcommittee determined the PSCo offered a good example of a successful generation procurement framework. Based on such review, the Subcommittee supports the following policy recommendations.

NERP Recommendations

Subject to the more detailed policy recommendations below, NERP has identified competitive solicitations as an important tool that should be utilized to meet energy and capacity needs identified in an IRP and as otherwise deemed appropriate by the North Carolina Utilities Commission (“Commission”).

NERP also holds that State policy regarding utility competitive procurement should take into account unique characteristics of each utility service territory, e.g., number of customers, geographic size, amount of utility-owned generation in the service territory, and proportion of existing generation from renewable sources located in the service territory and serving utility customers.

Context and history

On October 29, 2018, Governor Roy Cooper issued *Executive Order 80: North Carolina's Commitment to Address Climate Change and Transition to a Clean Energy Economy*.ⁱ The Order established the North Carolina Climate Change Interagency Council and tasked the Department of Environmental Quality (DEQ) with producing a clean energy plan.

DEQ convened a group of stakeholders that met throughout 2019. In October 2019, DEQ released the *North Carolina Clean Energy Plan: Transitioning to a 21 Century Electricity System* (CEP).ⁱⁱ Recommendation B-1 of the CEP states: “Launch a NC energy process with representatives from key stakeholder groups to design policies that align regulatory incentives and processes with 21st Century public policy goals, customer expectations, utility needs, and technology innovation.” That process was launched as NERP, which met throughout 2020.

ⁱ Executive Order 80. <https://governor.nc.gov/documents/executive-order-no-80-north-carolinas-commitment-address->

ⁱⁱ NC Dept. of Environmental Quality. “North Carolina Clean Energy Plan”
https://files.nc.gov/governor/documents/files/NC_Clean_Energy_Plan_OCT_2019_.pdf

NERP

The NERP, facilitated by Rocky Mountain Institute and the Regulatory Assistance Project, brought together roughly 40 diverse stakeholders to consider four main avenues of utility regulatory reform:

- PBR
- Wholesale market reform
- Competitive procurement of resources
- Accelerated retirement of generation assets

These stakeholders identified ten desired outcomes of reform in North Carolina, as shown below in Figure 1.

Outcome Category	Outcome
Improve <u>customer value</u>	Affordability and bill stability
	Reliability
	Customer choice of energy sources and programs
	Customer equity
Improve <u>utility regulation</u>	Regulatory incentives aligned with cost control and policy goals
	Administrative efficiency
Improve <u>environmental quality</u>	Integration of DERs
	Carbon neutral by 2050
Conduct a quality <u>stakeholder process</u>	Inclusive
	Results oriented

Figure 1: PRIORITY OUTCOMES IDENTIFIED BY NERP

Competitive Procurement Study Group

A subset of NERP participants volunteered to serve on a competitive procurement subcommittee. This group (see page 2 for a list of groups members) first met in the summer of 2020. The group met regularly to advance research into competitive markets mechanisms relevant to NC.

The study group presented a series of case studies and recommendations to the broader NERP group, detailing the potential implications of each market reform, and why further investigation into each reform is warranted. Feedback from NERP participants shaped the proposed markets outlined below.

NERP companion documents

NERP produced the following documents for dissemination, to inform subsequent policy discussions with various audiences:

1. ***Competitive Procurement Policy Recommendation*** for the North Carolina General Assembly:
 - An overall policy recommendation which, subject to the more detailed recommendations outlined in the document, states that competitive solicitations are an important tool that should be utilized to meet energy and capacity needs identified in an IRP and as otherwise deemed appropriate by the North Carolina Utilities Commission.
2. ***A Case Study into The Public Service Company of Colorado's Recent Procurement Cycle:***
 - The subcommittee evaluated a number of other states but focused primarily on a recent procurement cycle in Colorado for the Public Service Company of Colorado (Xcel Energy), which was ultimately determined to be a successful generation procurement framework.
3. ***A Case Study into Key Generation Procurements Enacted by the Virginia Clean Economy Act:***
 - The summary outlines the sweeping package of energy reforms established in March 2020 that set Virginia on a path toward a 100% carbon-free electricity grid by 2050.

DETAILED POLICY RECOMMENDATIONS

General principles

1. Competitive solicitations benefit customers by ensuring the most cost-effective generation resources are selected.
 - a. Except where other policy considerations give rise to the need for resource-specific solicitations (as discussed further below), competitive generation solicitations should permit participation from all resources that satisfy the operational, reliability and other requirements sought in the RFP.
 - b. Except where otherwise directed by statute, the Utility that is responsible for maintaining reliability should be also be responsible for defining the necessary operational, reliability and other requirements. It may be appropriate to require Commission oversight or approval of such parameters.
2. Independent oversight or administration should be utilized for all competitive generation procurement.
 - a. The exact parameters of the independent oversight or administration may vary depending on the nature of the procurement.
3. In all competitive generation procurements, communications and separation protocols similar to CPRE should be implemented.
4. Consistent with the policy direction of numerous other states, there is value in diversity of generation ownership. A mixture of third-party ownership and utility rate-based ownership diversifies risk for customers and provides a variety of benefits.
 - a. The appropriate allocation between utility and third-party ownership should be determined based on the particular context of the procurement and/or the type of generation resource.

- b. It may be appropriate to determine the allocation between utility and third-party ownership on a technology-specific basis (*i.e.*, percentage allocations differ between solar, wind, storage, and gas).
 - c. Utility-owned, rate-based assets should be procured through competitive processes to ensure the most cost-effective resources are selected.
 - Maximum flexibility should be provided for such RFP and should allow for bids involving (A) sale of constructed assets, (B) Build Own Transfer (“BOT”), and (C) sale of development assets plus EPC.
 - d. Where a particular utility ownership target is established, it is generally preferable to procure utility-owned and rate-based assets through separate “silos.”
 - e. No clear quantifiable basis for the allocation has been identified to date but parties should continue to work to identify quantitatively and qualitative factors that may inform the allocation, including (1) the potential loss of investment opportunity that might occur as a result of early retirement of coal assets and the potential need for replacement generation (depending on the nature of the cost recovery for any remaining NBV), (2) the examples of other states, or (3) impacts of any alternative ratemaking constructs.ⁱⁱⁱ
 - f. Where the utility receives a significant ownership allocation, it may be reasonable and appropriate not to allow it and its affiliates to participate in the PPA procurement silo. In addition to creating equity between the utility and independent power producers, this would simplify oversight of the PPA procurement process.
5. A formal RFP should not be required in the case of uniquely advantageous opportunities, unexpected emergencies, pilot projects, or other circumstances identified by the Commission.
 6. The appropriateness of utilizing an avoided price cost cap or other cost effectiveness parameters in the RFP evaluation process should be evaluated on a case-by-case basis to determine whether necessary in light of the nature or context of the RFP.
 7. It may be appropriate to consider financial incentives to the utility in connection with third party PPAs in order to foster diversity of generation ownership.
 8. Any state policy regarding utility competitive procurement should take into account unique characteristics of each utility service territory, e.g., number of customers, geographic size, amount of utility-owned generation in the service territory, and proportion of existing generation from renewable sources located in the service territory and serving utility customers.

Competitive Generation Procurement in Specific Scenarios

1. **Competitive Solicitation: Connection between IRP – RFP**

- a. In the event that a specific capacity or energy need is identified in any IRP, such need should be filled through an all-source RFP that clearly defines the operational and other characteristics of the needed resource absent any unique circumstance as discussed above.

ⁱⁱⁱ Examples:

- Colorado (Xcel) 2017 RFP: 50/50 split for renewable resources and 75/25 (utility/third party) split for dispatchable and semi-dispatchable resources to be added. Utility-owned assets are rate-based.
- Virginia (Dominion) Clean Energy Act: CEA provides for utility ownership of up to 75% utility ownership for solar and 65% for storage (and potentially up to 100%) by 2035. CEA enables Dominion to own 100% offshore wind (5.2GW by 2035) by demonstrating LCOE<1.4x that of gas. Utility-owned assets are rate-based.
- New Mexico (PNM) 2017 RFP: PNM owned 46% nameplate capacity of preferred portfolio from 2017 RFP. Utility-owned assets are rate-based.
- Michigan (CMS) 2019 RFP: Procurement split 50/50 between PPA and BTA utility-ownership. Utility-owned assets are rate-based.

- b. The inputs and assumptions for any such RFP should be generally consistent with the most recent IRP but with updates as appropriate to reflect changing conditions.
- c. It may be appropriate for the Commission to pre-approve inputs and other modeling assumption to be used in the evaluations.

2. Competitive Solicitation: Potential Coal Retirements

- a. If determined to be reasonable as part of an IRP, the Commission should direct the utility to conduct one or more all source RFPs to assess whether particular coal units can be retired in a cost-effective manner (after accounting for recovery of the remaining NBV of such units in a manner deemed appropriate) through the procurement of replacement generation.

3. Competitive Solicitation: Future Clean Energy Standard or Renewable Energy Target

- b. If future legislation or regulatory changes requires the procurement of additional renewable or low-carbon resources in order to comply with particular policy mandates or directives, resource-specific or otherwise more tailored competitive procurements may be needed.

NERP recommendations

NERP recommends that the North Carolina General Assembly expand existing procurement practices to utilize competitive procurement as a tool for State electric utilities to meet energy and capacity needs defined in their respective IRPs and where otherwise deemed appropriate by the NCUC.

NERP recommends that state policy regarding utility competitive procurement should take into account unique characteristics of each utility service territory, e.g., number of customers, geographic size, amount of utility-owned generation in the service territory, and proportion of existing generation from renewable sources located in the service territory and serving utility customers.

Competitive Procurement Outputs

NERP recommends that the North Carolina General Assembly expand existing procurement practices to utilize competitive procurement as a tool for State electric utilities to meet energy and capacity needs defined in their respective IRPs and where otherwise deemed appropriate by the NCUC.

- a. Competitive procurement policy recommendation for the North Carolina General Assembly: An overall policy recommendation which, subject to the more detailed recommendations outlined in the document, states that competitive solicitations are an important tool that should be utilized to meet energy and capacity needs identified in an IRP and as otherwise deemed appropriate by the North Carolina Utilities Commission.
- b. A case study into the Public Service Company of Colorado's recent procurement cycle:
- c. A case study into key generation procurements enacted by the Virginia Clean Economy Act: The summary outlines the sweeping package of energy reforms established in March 2020 that set Virginia on a path toward a 100% carbon-free electricity grid by 2050.

CONCLUSION

To summarize, NERP recommends that the North Carolina General Assembly expand existing procurement practices to utilize competitive procurement as a tool for State electric utilities to meet energy and capacity needs defined in their respective IRPs and where otherwise deemed appropriate by the NCUC. the General Assembly of North Carolina direct the NCUC.

NERP produced the following documents for dissemination, to inform subsequent policy discussions with various audiences:

1. Competitive procurement policy recommendation for the North Carolina General Assembly: An overall policy recommendation which, subject to the more detailed recommendations outlined in the document, states that competitive solicitations are an important tool that should be utilized to meet energy and capacity needs identified in an IRP and as otherwise deemed appropriate by the North Carolina Utilities Commission.
2. A case study into the Public Service Company of Colorado's recent procurement cycle,
3. The subcommittee evaluated a number of other states but focused primarily on a recent procurement cycle in Colorado for the Public Service Company of Colorado (Xcel Energy), which was ultimately determined to be a successful generation procurement framework.
4. A case study into key generation procurements enacted by the Virginia Clean Economy Act: The summary outlines the sweeping package of energy reforms established in March 2020 that set Virginia on a path toward a 100% carbon-free electricity grid by 2050.

Members of this NERP stakeholder group will continue to collaborate in early 2021 to assist the State and parties interested in the work conducted by this group.

APPENDIX

The following documents were prepared by the competitive procurement study committee to supplement this guidance document.

- Colorado electric resource plan case study
- Virginia clean economy act generation procurement case study



NERP CASE STUDY

COLORADO ELECTRIC RESOURCE PLAN

A CASE STUDY PRODUCED BY THE COMPETITIVE PROCUREMENT
STUDY GROUP

The 2020 North Carolina Energy Regulatory Process identified competitive solicitations as an important tool that should be utilized to meet energy and capacity needs

WHAT ARE COMPETITIVE SOLICITATIONS?

NERP has defined competitive procurement as an Integrated Resource Plan (IRP) -driven, all-source procurement to meet all identified needs for new resources in a manner that is consistent with policy directives and at the best available overall price.

WHAT IS THE COLORADO ELECTRIC RESOURCE PLAN?

- Similar to the IRP process in NC, the electric resource plan (ERP) is how the Public Service Company of Colorado (Xcel Energy, or, referred to as PSCo) forecast and plan to meet customer needs.¹
- Key provisions include ensuring power reliability, cost effective power delivery, increasing clean energy generation, planning for a grid flexibility, and supporting Colorado's energy and economic needs.

OVERVIEW

The Public Service Company of Colorado's (PSCo) request for proposals process (RFP) is inextricably linked to PSCo's (ERP). Therefore, the RFP process must be understood within the context of the overall ERP. This includes broader policy issues and consensus stipulation informing both the design of the RFP and the selection of generation resources.

The Subcommittee evaluated a number of states but focused primarily on the recent procurement cycle in Colorado for the Public Service Company of Colorado (Xcel Energy), as the Subcommittee viewed it as a good example of a successful generation procurement framework. The timeline and process of the 2017 ERP/RFP process is outlined below:

- 1. Phase 1 Decision**
- 2. Stipulation**
- 3. Phase 2 Decision**

Following the process details, the subcommittee outlines a list of key items of relevance to NERP stakeholders and the NC community.

¹ <https://www.xcelenergy.com/staticfiles/xe/PDF/Electric%20Resource%20Plan%20Fact%20Sheet.pdf>

PROCESS TIMELINE AND KEY DETAILS

1. Phase 1 Decision – April 28, 2017

- a. Approved two resource scenarios (0 MW resource need and second scenario showing approximately 400 MW of need based on updated load forecast)
 - i. These two resource scenarios drove the structure of the RFP
- b. Approved evaluation methodology, including the inputs and assumptions to bid evaluation models (e.g., natural gas prices, coal prices, carbon costs, discount rates, and integration costs for intermittent resources).
 - i. Importantly, Colorado commission approved use of carbon price for modeling purposes.
- c. Confirmed IE’s role which was primarily:
 - i. Provide a report to the Commission, containing an analysis of whether Public Service conducted a fair bid solicitation and bid evaluation process, with any deficiencies specified in the report.
 - ii. Review the inputs and outputs from the bid evaluation modeling, including in the report an assessment as to whether the resulting outputs are feasible, and alerting the Commission and parties through the report where there may be deficiencies in the outputs.

2. Stipulation – August 29, 2017

- a. Stipulation reached between PSCo and diverse set of stakeholders.
- b. Specified that PS would model a third resource scenario—the CEP Portfolio, which involves retirement of two coal units (Comanche 1 and 2).
 - i. The Company would compare the costs of the CEP Portfolio against a baseline portfolio, where Comanche 1 and 2 are not retired early, to determine the cost-effectiveness of the CEP Portfolio.
 - o. If the CEP Portfolio keeps customers “neutral” or results in savings for customers on a present value basis, the Stipulation proposed that Public Service would present the CEP Portfolio(s) in its ERP Phase II 120-Day Report.
- c. Stipulation specified utility ownership of a portion of resources.
 - i. 50% of the renewable resources to be added, and 75% of the dispatchable and semi-dispatchable resources to be added.
 - ii. PS Co also agreed not to bid into the CEP any new self-build projects other than for gas-fired projects.

WHY ISSUE AN RFP?

1. Identified Capacity/Energy

- a. Colorado had a potential identified capacity/energy need based solely on project load growth and an alternative capacity/energy need based on potential coal retirement (CEP Portfolio from Stipulation)

Discussion Item:

Should future RFPs be designed to test the market to see whether new generation could be procured to cost-effectively replace particular coal generation?

- b. Comparison to IRP/CPRE:
 - i. Duke IRP does not lead directly into RFP where resource need is identified.
 - ii. CPRE procurements were not tied to IRP.

2. Targeted Renewable Amounts - CPRE / REPs approach.

Discussion Item:

What is the regulatory/policy basis for any targeted amounts apart from identified need?

3. Is there flexibility for the utility in unique situations?

- a. Colorado ERP rules provide flexibility to the utility if competitive solicitation process is perhaps not needed in unique situations. (See 4 CCR 723-3(g)(II)(A)-(B)).

STRUCTURE OF RFP MECHANICS

1. What is the role of the IE?

- a. Comparison to CPRE:
 - i. Role of IE in Colorado RFP was substantially different than role of IA in CPRE
 - o. Utility was primarily responsible for defining technical needs, structuring evaluation methodology (subject to Commission approval) and performing evaluation of bids
 - o. The IE provided oversight, vetted evaluation models and tested results.
- b. Communication restrictions:
 - i. Comparison to CPRE: Separation Protocols were consistent with CPRE with the exception of evaluation issues.

STRUCTURE OF RFP MODELING

1. Avoided Cost Caps

Discussion Item:

In what types of RFPs does it make sense to utilize avoided cost cap?

- a. Comparison to CPRE:
 - i. No avoided cost cap used because resources were being procured to replace existing generation.
- b. Does the analysis assume a carbon cost?
 - i. Colorado ERP regulations permitted inclusion of carbon cost in analysis (4 CCR 723-3(g)(III)(C)(i)).

Discussion Item:

Is NCUC or General Assembly authorization required for future RFP to assume carbon price during selection?

- c. In the case of consideration of early retirement, what assumptions are made about future revenue requirements?

UTILITY OWNERSHIP

1. Colorado stipulation, agreed to by diverse set of stakeholders, contemplated 50% utility, rate-based ownership of renewable resources and 75% utility, rate-based ownership of dispatchable resources (gas/storage).
2. Colorado Commission expressly recognized benefits of balance of utility-ownership and third-party ownership (consistent with past precedent).
3. Allowed for rate-base recovery of utility-owned assets.

WHAT IS BEING RECOMMENDED?

The North Carolina Energy Regulatory Process recommends that the North Carolina General Assembly expand existing procurement practices to utilize competitive procurement as a tool for State electric utilities to meet energy and capacity needs defined in their respective IRPs and where otherwise deemed appropriate by the NCUC.

NERP recommends that state policy regarding utility competitive procurement should take into account unique characteristics of each utility service territory, e.g., number of customers, geographic size, amount of utility-owned generation in the service territory, and proportion of existing generation from renewable sources located in the service territory and serving utility customers.

NERP produced the following documents for dissemination, to inform subsequent policy discussions with various audiences:

1. Competitive procurement policy recommendation for the North Carolina General Assembly.
2. A case study into key generation procurements enacted by the Virginia Clean Economy Act.
3. This case study into the PSCo recent procurement cycle

This fact sheet represents the work of stakeholders as of 12/18/2020.

About the North Carolina Energy Regulatory Process

Governor Cooper's Executive Order 80 mandated the development of a clean energy plan for the state of North Carolina. The Clean Energy Plan recommended the launch of a stakeholder process to design policies that align regulatory incentives with 21st century public policy goals, customer expectations, utility needs, and technology innovation. The stakeholder process was launched in February 2020 and has led to policy proposals on energy reform.

LEARN MORE

Contact Competitive Procurement Committee Leads:
Jack Jirak, Duke Energy, Jack.Jirak@duke-energy.com
Steve Levitas, NCCEBA, slevitas@pgrenewables.com

Access the NERP summary report and other NERP documents at:
<https://deq.nc.gov/CEP-NERP>

NERP CASE STUDY

VIRGINIA CLEAN ECONOMY ACT GENERATION PROCUREMENT

A CASE STUDY PRODUCED BY THE COMPETITIVE PROCUREMENT STUDY GROUP

The 2020 North Carolina Energy Regulatory Process identified competitive solicitations as an important tool that should be utilized to meet energy and capacity needs

WHAT ARE COMPETITIVE SOLICITATIONS?

NERP has defined competitive procurement as an Integrated Resource Plan (IRP) -driven, all-source procurement to meet all identified needs for new resources in a manner that is consistent with policy directives and at the best available overall price.

WHAT IS THE VIRGINIA CLEAN ECONOMY ACT?

- On March 5, 2020, the Virginia legislature passed the Virginia Clean Economy Act (“VCEA”), a sweeping package of energy legislation that sets Virginia on a path toward a 100% carbon-free electricity grid by 2050.¹
- The following is a summary of the key generation procurement elements of the VCEA.

OVERVIEW

1. Renewable Portfolio Standard (“RPS”) mandating 100% renewable energy by 2045 for Dominion Energy with, annual increases of 3%-4% per year according to a defined schedule, including the following (Va. Code § 56-585.5(C)):
 - 14% by 2021
 - 41% by 2030
 - 59% by 2035
 - 79% by 2040
 - 100% by 2045
2. Beginning 2025 and thereafter, at least 75% of all RECs used by Dominion Energy in a compliance period shall come from RPS eligible resources located in Virginia. (Va. Code § 56-585.5(C)).
3. Not primarily cost-based. Mandatory RPS paired with obligation for Dominion Energy to retire nearly all coal units by 2024 and all carbon-emitting power plants by 2045 (Va. Code § 56-585.5(B)(1) and (3)).

¹<https://lis.virginia.gov/cgi-bin/legp604.exe?201+sum+HB1526>

PROCUREMENT DIRECTIVES

Layered on top of the RPS are the following specific statutory generation procurement directives:

1. Overview

- a. Appalachian Power Company must procure 600 MW of solar or onshore wind located in Virginia by Dec. 31, 2030. (*Va. Code § 56-585.5(D)(1)*)
- b. Dominion Energy must procure 16,100 MW of solar or onshore wind located in Virginia by Dec. 31, 2035 (*Va. Code § 56-585.5(D)(2)*):
 - i. Must include 1,100 megawatts of solar generation of a small projects (less than 3 MW).
- c. Construction or purchase by a public utility of one or more offshore wind facilities with an aggregate capacity of up to 5,200 MW off Virginia's Atlantic shorelines of in federal waters and interconnected into Virginia is predetermined to be in the public interest (*Va. Code § 56-585.1:11(B)*).
- d. Construction by Dominion Energy of one or more new utility-owned and utility operated offshore wind facilities located off Virginia's Atlantic shoreline of between 2,500 – 3,000 MW predetermined to be in the public interest. (*Va. Code § 56-585.1:11(C)(1)*).
 - i. Cost cannot exceed 1.4 times the comparable cost, on an unweighted average basis, of a conventional simple cycle combustion turbine generating facility as estimated by the U.S. Energy Information Administration in its Annual Energy Outlook 2019; and must either commence construction prior to 2024 or have a plan to be placed in service prior to January 1, 2028. (*Va. Code § 56-585.1:11(C)(1)*).
- e. Appalachian Power Company must construct or acquire energy storage projects up to 400 MW by 2035 (*Va. Code § 56-585.5(E)(1)*).
- f. Dominion Energy must construct or acquire energy storage projects up to 2,700 MW by 2035. (*Va. Code § 56-585.5(E)(2)*).
 - i. Public interest finding for up to 2,700 MW of energy storage facilities located in Virginia. (*Va. Code § 56-585.1:4*)

2. Ownership Allocation

- a. **Solar or Onshore Wind:** 35% third party ownership and 65% utility ownership (*Va. Code §56-585.5(D)(2)*).
- b. **Storage:** 35% third-party ownership and 65% - 100% utility ownership (*Va. Code §56-585.5(E)(5)*).
- c. **Offshore Wind:** 100% utility ownership. (*Va. Code § 56-585.1:11(B) and § 56-585.5(D)(2)*).

3. RFP Administration

- a. All resources required to be procured through competitive process. (*see e.g., Va. Code § 56-585.1:4(D)* (solar), *Va. Code § 56-585.1:11(E)* (offshore wind), *Va. Code § 56-585.1:4 (G)* (storage)).
 - i. Primarily price-based, but up to 25% of solar may be selected on non-price criteria where it would materially advance non-price criteria, including favoring geographic distribution of generating capacity, areas of higher employment, or regional economic development.
- b. RFP requirements include the following (*Va. Code § 56-585.5(D)(3)*):
 - i. Annual RFP for new solar and wind resources that quantifies and describes the utility's need for energy, capacity, or renewable energy certificates.
 - ii. RFP must provide certain minimum information including major assumptions to be used by the utility in the bid evaluation process, including environmental emission standards; detailed instructions for preparing bids so that bids can be evaluated on a consistent basis; the preferred general location of additional capacity; and specific information concerning the factors involved in determining the price and non-price criteria used for selecting winning bids.
 - iii. Energy storage requirements are also be competitively procured with regulations relating to competitive solicitations to be established through a Commission rulemaking. (*Va. Code § 56-585.5(E)(5)*).

- c. Utility is responsible for evaluation and may evaluate responses to requests for proposals based on any criteria that it deems reasonable but must consider (*Va. Code § 56-585.5(D)(3)*):
 - i. the status of a particular project's development,
 - ii. the age of existing generation facilities,
 - iii. the demonstrated financial viability of a project and the developer,
 - iv. a developer's prior experience in the field,
 - v. the location and effect on the transmission grid of a generation facility,
 - vi. benefits to the Commonwealth that are associated with particular projects, including regional economic development and the use of goods and services from Virginia businesses; and
 - vii. the environmental impacts of particular resources, including impacts on air quality within the Commonwealth and the carbon intensity of the utility's generation portfolio.

- d. Selected portfolio of resources to be reviewed by the Virginia Commission.

WHAT IS BEING RECOMMENDED?

The North Carolina Energy Regulatory Process recommends that the North Carolina General Assembly expand existing procurement practices to utilize competitive procurement as a tool for State electric utilities to meet energy and capacity needs defined in their respective IRPs and where otherwise deemed appropriate by the NCUC.

NERP recommends that state policy regarding utility competitive procurement should take into account unique characteristics of each utility service territory, e.g., number of customers, geographic size, amount of utility-owned generation in the service territory, and proportion of existing generation from renewable sources located in the service territory and serving utility customers.

NERP produced the following documents for dissemination, to inform subsequent policy discussions with various audiences:

1. Competitive procurement policy recommendation for the North Carolina General Assembly.
2. A case study into Colorado's recent procurement cycle.
3. This case study into key generation procurements enacted by the Virginia Clean Economy Act.

This fact sheet represents the work of stakeholders as of 12/18/2020.

About the North Carolina Energy Regulatory Process

Governor Cooper's Executive Order 80 mandated the development of a clean energy plan for the state of North Carolina. The Clean Energy Plan recommended the launch of a stakeholder process to design policies that align regulatory incentives with 21st century public policy goals, customer expectations, utility needs, and technology innovation. The stakeholder process was launched in February 2020 and has led to policy proposals on energy reform.

LEARN MORE

Contact Competitive Procurement Committee Leads:
 Jack Jirak, Duke Energy, Jack.Jirak@duke-energy.com
 Steve Levitas, NCCEBA, slevitas@pgrenewables.com

Access the NERP summary report and other NERP documents at:
<https://deq.nc.gov/CEP-NERP>