Appendix: Regulatory Challenges With Utility Investment Planning and Cost Recovery for Grid Modernization

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Background and Approach

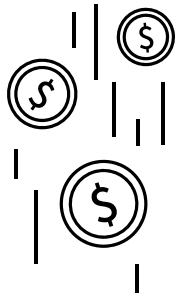
Background

- State policies and regulations, utility business plans and initiatives, and evolving grid technologies and systems are driving large investments in electricity distribution systems.
- U.S. utilities file a variety of electricity system plans, as a result of state requirements or on their own motion, from dedicated grid modernization plans to integrated distribution system plans, as well as other types of plans that include grid modernization investments.
- Cost recovery for grid modernization investments is typically dictated by a different set of state requirements and procedures than grid modernization planning. Prudence determinations are made in general rate cases or, for some states, in separate proceedings that consider expedited cost recovery for grid modernization investments.

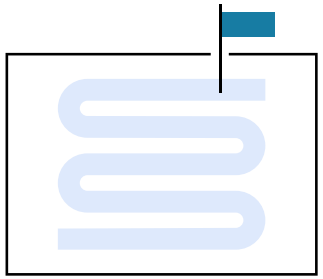
Research questions

This report answers 3 questions

Are cost recovery approvals for grid modernization investments significantly lower than utilities are requesting? If so, why?



How can utilities improve grid modernization-related filings — both plans and cost recovery applications — to provide appropriate justification for cost recovery?



How can state policies, regulations, and procedures improve outcomes for grid modernization investments to help achieve state goals?

Approach

Utility cost recovery proceedings reviewed

Duke Energy
Duke Energy Carolinas (NC)
Duke Energy Progress (NC)
Duke Energy Indiana (IN)
Duke Energy Florida (FL)

Exelon
ComEd (IL)
PECO (PA)
ACE (NJ)
BGE (MD)
Delmarva Power (DE)

Southern Company
Georgia Power (GA)

PG&E
PG&E (CA)

NextEra
FP&L (FL)

ConEd
ConEd (NY)
Orange &
Rockland (NY)

Ameren
Ameren Illinois (IL)

Entergy
Entergy (LA)
Entergy (TX)

AEP
Indiana Michigan (IN)
ApCo (VA)

Xcel
Northern States (MN)
Public Service Colorado (CO)
Northern States Power (WI)

Berkshire Hathaway
NV Energy (NV)
Rocky Mountain Power (UT)
Pacific Power (OR)

DTE
DTE (MI)

First Energy
West Penn Power (PA)
Penelec (PA)
Met-ED (PA)
JCP&L (NJ)

Approach

Utility cost recovery proceedings reviewed

- Berkeley Lab reviewed investor-owned utility filings by holding companies with annual retail sales >$400 million and identified a subset to include in the analysis.
  - Size, geographic diversity and availability of information were the primary criteria used to downselect the utilities for the analysis.
- We reviewed Commission decisions and comments by public utility commission (PUC) staff and consumer advocates.
- We synthesized filing deficiencies identified in Commission decisions and filed comments by PUC staff and utility consumer advocates, as well as successful justifications for grid modernization cost recovery.
- We identified barriers to regulatory approval of cost recovery and example practices for successful cost recovery requests.

Utility filings analyzed (1)

Utility	State	Grid Modernization Proceeding	Cost Recovery Proceeding	Docket/Case Number
Atlantic City Electric (ACE)	NJ	Infrastructure Investment Program	Infrastructure Investment Program	Docket No. ER22100666
Baltimore Gas and Electric (BGE)	MD	Multi Year Rate Plan (MYRP)	MYRP	Docket 9692
Commonwealth Edison (ComEd)	IL	Multi Year Integrated Grid Plan	MYRP	Dockets 23-0055 23-0486
Consolidated Edison (ConEd)	NY	Distribution system implementation plan	General Rate Case (GRC)	Case 22-E-0064
DTE Energy (DTE)	MI	Distribution Grid Plan	GRC	Case No. U-20836
Duke Energy Carolinas (DEC)	NC	Transmission and Distribution Information Filing, in advance of general rate case (GARC)	GRC; utility requested MYRP	E-7 Sub 1276

Utility filings analyzed (2)

Utility	State	Grid Modernization Proceeding	Cost Recovery Proceeding	Docket/Case Number
Duke Energy Indiana (DEI)	IN	Transmission, distribution, and storage system improvement cost (TDSIC)	80% of costs are in TDSIC rider; 20% of costs deferred to next rate case	Cause No. 45647
Duke Energy Progress (DEP)	NC	Transmission and Distribution Information Filing, in advance of GRC	GRC; utility requested MYRP	Docket E-2 Sub 1300
Georgia Power Company (GPC)	GA	Grid Investment Plan included in GRC filing	GRC	Docket No. 44280
Jersey City Power & Light (JCP&L)	NJ	Infrastructure Investment Program	Infrastructure Investment Program	Docket No. ER19091238
Northern States Power Company (Xcel)	MN	Integrated Distribution Plan	Multi Year Rate Case	Docket No. E-002/GT-21-630
Pacific Gas & Electric (PG&E)	CA	GRC	GRC	A.21-06-021

Grid modernization technology examples, by utility

Berkeley Lab selected technologies for the analysis that were discussed in the reviewed proceedings by the Commission, PUC staff, utility consumer advocates, or the attorney general on behalf of another state agency.

Utility	Illustrative grid modernization technology
ACE	Capacitors, reclosers, smart sensors, fiber/radio regulators, and distribution automation (DA)
BGE	Grid communications and connectivity; distribution sensors, advanced distribution management system (ADMS)
ComEd	Renewable Energy Advanced Control and Telemetry Systems (REACTS) and Intelligent Substation & Relay, Protection, and Control Replacement Programs
ConEd	Conservation voltage optimization (CVO)
DEC, DEP	Self-optimizing grid, DA

Utility	Illustrative grid modernization technology
DTE	ADMS, distribution management system (DMS), and outage management system (OMS); conservation voltage reduction (CVR)
DEI	Self-optimizing grid, DA
Georgia Power	Distributed energy resource management system (DERMS)
JCP&L	DA
Northern States (Xcel)	Distributed intelligence
PG&E	ADMS, DERMS

Analysis challenges

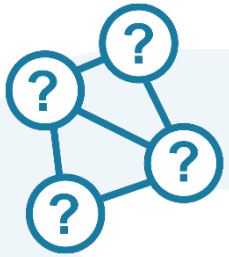
- All utility cost recovery requests studied in this analysis included grid modernization projects and many other expenditures (e.g., operating and maintenance costs). We attempted to separate grid modernization cost recovery requests from other cost recovery requests.
- Some proceedings reviewed were resolved through a settlement agreement, which typically does not provide details on why investments were approved or denied, or a Commission order with limited discussion of why investments were approved or denied.
- The utilities did not use consistent terminology to characterize grid modernization technology investments, making comparison of costs, benefits and approved technologies difficult. In some cases, utilities intertwined grid modernization investments with other distribution system investments, making it difficult to discern grid modernization expenditures from other grid investments.

Findings

Summary of findings

Investment rationale of utilities: Improving reliability, resilience, customer control // Enabling achievement of state energy goals

Objections from reviewers: Insufficient information for technology or project on: investment costs, need, and timing // Most comments by Commissioners, PUC staff and consumer advocates focus on aspects of utility filings they disagree with



Topics of interest for Commissioners, PUC staff and consumer advocates: Timing of investments // Optimization // Transparency // Affordability

Proposals supported by utility regulators included: Clear linkages between grid modernization investment proposals, state policies and electricity planning processes (e.g., distribution system planning) // Robust cost-effectiveness analysis // Strong analysis of alternative investment options // Complete approval or disapproval of cost recovery for all grid modernization expenditures was uncommon.

Utility's rationale for cost recovery for grid modernization investment varies

- Improve reliability, resilience and safety
- Reduce customer restoration time
- Proactively address grid needs
- Facilitate customer choice and control
- Enable integration of distributed energy resources (DERs)
- Support increased electrification
- Improve operational efficiency
- Assist in achieving state energy goals

Example objections to utility cost recovery requests

- Improper, duplicative or outdated cost estimates
- Premature consideration of technology
- Insufficient explanation of need for investment in the planning period
- Inconsistent with planning objectives
- Inadequate or absent benefit-cost analysis
- Inadequate consideration of alternative technologies
- Failure to show the project will be prudently implemented

Examples of commission justifications

Reasons Commissions offered for approving cost recovery for grid modernization investments in reviewed proceedings:

- Alignment with state energy goals
- Robust benefit-cost analysis
- Evaluation of alternative options

Complete approval or disapproval was uncommon

There were no examples in our analysis of a utility's cost recovery request for grid modernization being completely approved or denied.

In most cases, portions of the utility's cost recovery request were approved *and* other aspects were reduced or disallowed. For example:

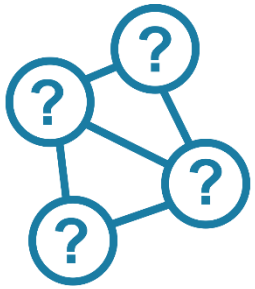
- In Xcel Energy's multi-year rate case, the PUC approved cost recovery for the utility's fault location, isolation and service restoration (FLISR) in full, but rejected Distributed Intelligence project costs. (MN PUC Order, 2023)
- The Georgia Public Service Commission did not approve Georgia Power to move forward with its DERMS project in the rate case, but allowed the utility to begin preliminary steps. That included "system modifications to allow for modeling and visibility of DER, integration of these modifications with the Company's real-time operations platforms such as EMS, DMS and SCADA, and the establishment of DER remote configuration capabilities." (GA PSC Order, 2022)

Commissions support plans that promote state energy goals

- "ADMS [advanced distribution management system] is a **key component of its grid modernization effort** and a reduced [financial] forecast could delay the functionality" which could **impede a high DER future**. (CPUC, approving PG&E investment)
- "[ADMS] is a **fundamental component to enabling the DSP and supporting the achievement of the CLCPA's** goals. All planned advanced applications will enhance the visibility, monitoring, and control that the Company has across the system." (NY PSC, approving Orange & Rockland investment)
- "The Commission recognizes that ComEd's **REACTS program aligns with P.A.102-0662's goal of promoting a flexible, secure, and resilient grid.** The program's hybrid fiberoptic and private wireless network will enhance grid management, facilitate DER integration, and improve overall operational efficiency." (ICC, approving ComEd investment)

Commissions used alignment between proposed utility grid modernization investments and state policy goals as part of their explanation for approving investments.

Commissions are interested in aligning proceedings



- "The Commission directs the company [DTE] to **include as part of its next distribution plan** a detailed description of its plans relating to grid hardening and conversion, including anticipated timelines, and to also include learnings derived from the technical conference…"(MI PSC Order 2022).
- "**[R]eport back to the Georgia Commission in the 2025 Integrated Resource Plan** on development of these systems and the need for any further system modifications to plan for DER integration." (GA PSC Order 2022)
- "**[P]ropose and discuss ways for the IDP process to inform financial and cost recovery issues in rate cases,** including but not limited to: a. The feasibility of conducting cost-benefit analyses for discretionary portions of the distribution budget; b. The decisions needed in the IDP to provide guidance to Xcel to ensure distribution spending that may be approved in forthcoming rate cases is in alignment with policy goals established through the IDP." (MN PUC Order 2023)

Commissions support plans with robust cost-effectiveness analysis

The North Carolina Commission approved grid investments that Duke Energy Carolinas proposed. Project summaries included:

- Project purpose
- Explanation of need for proposed expenditure
- Timeline for construction
- Estimated in-service date
- Program description
- Illustrative figures
- Project costs
- Grid capabilities enabled
- Policy considerations
- Benefit-cost analysis
  - Costs, benefits, net value (absolute $)
  - Benefit-cost ratio
- Benefit category and description of benefits

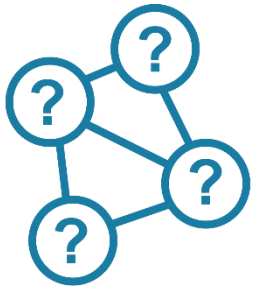
"Xcel's cost-benefit analysis **was reasonable because it relied on sound assumptions and methodologies**. The [Commerce] Department agreed with Xcel's analysis that the proposed FLISR [Fault Location, Isolation, and Service Restoration] program is likely to produce net benefits and therefore recommended that the Commission approve recovery of the requested FLISR expense." (MN PUC approving Xcel's FLISR investment)

Lack of cost-effective analysis is a reason for deferring approval

"ComEd has not provided sufficient justification for the proposed investments, and has **failed to show that the investments are prudent, reasonable, and cost-effective**. The REACTS [Renewable Energy Advanced Control and Telemetry Systems] program is the Company's most expensive proposed MYIGP investment. Without a compliant analysis of the Grid Plan's cost effectiveness, the Commission cannot determine whether the REACTS program is a cost effective Grid Plan investment." (ICC deferring approval of the REACTS program in ComEd's Multi-Year Integrated Grid Plans)

Staff also commented on poor benefit-cost analysis. For example, the OUCC found that "The prices of copper, aluminum, and steel have risen dramatically in the past two years since DEI [Duke Energy Indiana] first began pricing these projects. As such, DEI's Plan estimates are understated and, therefore**, DEI's incremental benefit calculation is almost certainly overstated**." (OUCC comments 2022)

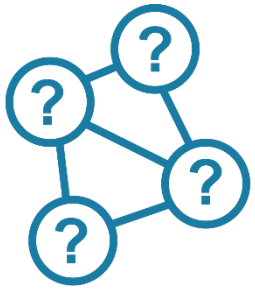
Commissions and staff are interested in robust analysis of alternatives



“ComEd did not meaningfully seek and consider alternatives to a capital-intensive, utility-built communications project… As a result of these flaws, the AG recommends that the Commission defer approval of the REACTS/PERFORM program until a more thorough examination of the plan can take place.” (ICC deferring approval of ComEd’s grid modernization investment)

“BGE is directed to **provide the internal management approval documentation that includes a review of alternatives,** any risks associated with starting Stage 2 while also implementing Stage 1 of the ADMS program, total project cost, project timeline, and discussion of quantitative and qualitative benefits of the project to the Company and ratepayers.” (MD PSC approving BGE’s ADMS investment, with additional documentation)

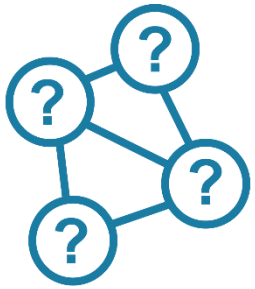
Commissions and staff are interested in improved transparency



"In future MYPs, the Commission encourages utilities to **provide robust project-level detail,** which is a necessary element of allowing stakeholders and the Commission transparency into the utility's planning process." (MD PSC, denying part of BGE's grid modernization request)

> "…the Commission should also direct the Company that in its next rate case it should provide **a full accounting of the OMS/DMS project costs with sufficient detail** for Staff and intervenors to perform a through prudency review of the actual expenditures against the initial project costs." (MI AG comments on DTE's plan)

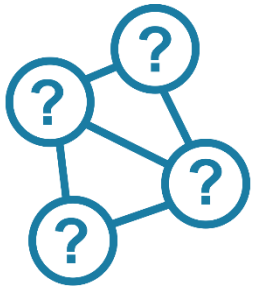
Affordability is a common theme



"**BGE has *also* proposed more work than ratepayers should reasonably pay for**, and … part of the Commission's job is to balance the needs of BGE's distribution system, including reliability, resiliency, safety, and environmental goals, **with the needs of ratepayers that include affordability**…." (MD PSC, denying part of BGE's grid modernization request)

"State policy is to **protect the affordability of utility services**…. The DEI Plan proposes nearly $2 billion in 1) **redundant infrastructure** that does not decrease CI [customer interruptions] and CMI [customer minutes interrupted] and is not for purposes of safety, reliability or modernization; and 2) unnecessary DER projects. There are no identified customers seeking DER connectivity, which falls outside the scope of modernization." (OUCC comments on DEI TDSIC plan)

Timing and optimization matters



- “First, DEI has not demonstrated customer demand for DER exists. Second, any new system improvement would need to be completed according to customers’ DER specifications. **It would be prudent to wait until a customer has a specific project need**, and DEI can build its system specific to meet its customers’ DER needs. DEI’s request amounts to speculation that, perhaps, sometime in the future, such upgrades will help make an easier build for distributed or renewable generation.” (OUCC staff commenting on DEI TDSIC plan)

- Given the Company’s responses regarding MYRP transmission and distribution projects as well as non-MYRP related work, **I do not believe that the Company can execute and complete its entire proposal within the three-year time frame requested** or within its estimated budget.” (NCUC staff commenting on DEP’s multi-year rate plan)

- “A review of the full MYRP also reveals that **the Company did not “globally” optimize project** spend across all of the business groups. While there was project optimization within each business group (e.g., transmission, distribution, nuclear, fossil, renewables, etc.), the Company did not compare projects from one business group to projects from another in an effort to truly maximize the benefits of the total spend requested in this case.” (NCUC staff commenting on DEP and DEC multi-year rate plans)

Commissions rejected costs based on lack of prioritization and consideration of timing

- "Utilities should also provide a **weighing of the importance of proposed capital projects, rather than a simple wish list untethered from ratepayer impact**. The Commission accepts Staff's proposal to disallow a portion of Priority 3 projects as reasonable." (MD PSC, denying part of BGE's grid modernization request)
- "The level of distributed energy resources needed to justify such a system is high, **and will not be reached by the time the proposed DERMS** [DER management system] **is fully depreciated in 2030**, let alone by the end of the upcoming rate planning period in 2025." (GA PSC, denying 40% of GPC DERMS costs)

Ongoing approval of cost recovery for grid modernization technology is not guaranteed

- “The Company bears the burden of supporting **each iteration of its grid plan as appropriate and compliant with state law** and further, adopted the spending protections recommended by Staff...” (ICC approving ComEd’s refiled MYIGP)

- “In approving expenditures for any particular work plan or project for the MYP 2 period, **the Commission is not making an advanced determination of prudency**. To the contrary, prudency issues such as whether particular projects will ultimately benefit ratepayers, whether actual project costs were excessive, and whether the programs were executed effectively and efficiently will become ripe for prudency review during the reconciliation process.” (MD PSC approving a portion of BGE’s MYRP)

Utility Filings

Information included in utility filing summaries

- The slides for each utility filing summarize:
  - Regulatory background
  - Grid modernization technology examples
  - Total cost recovery request and cost recovery request for grid modernization technology
  - Staff, consumer advocate, and attorney general comments on example grid modernization technology, if available
  - Commission comments on example grid modernization technology, if available
  - Commission decision on overall cost recovery request

Atlantic City Electric and Jersey City Power and Light

Regulatory context

- The New Jersey Board of Public Utilities (BPU) adopted rules enabling utilities to accelerate safety, reliability and resiliency investments, including grid modernization investments. Utilities submit an Infrastructure Investment Program to the BPU to obtain accelerated recovery of qualified investments. (NJAC 14:3-2A.1)

- ACE filed their Infrastructure Investment Program petition for approval in October 2022.
  - The petition included five technology categories. The grid modernization technology example used in our analysis of ACE's filing is the Smart Technology Upgrade. It includes six subprojects (see slide 37). Investments were approved through a stipulation.
  - The BPU approved $33.1 M of the $65.8M requested for the Smart Technology Upgrade (see slide 37).
  - In total, the BPU approved $93.1M of the requested $379M for ACE's Infrastructure Investment Program (see slide 37).

- In July 2018, JCP&L filed a petition for approval of its Infrastructure Investment Program.
  - The petition included four program categories. The grid modernization technology example used in our analysis of JCP&L's filing is the Distribution Automation program. It includes four subprograms (see slide 38). Investments were approved through a stipulation.
  - The BPU approved $25.6M of the $48.6M requested for the Distribution Automation program (see slide 38).
  - In total, the BPU approved $93.1 of the $190.8M requested for JCP&L's Infrastructure Investment Program (see slide 38).

Grid modernization cost recovery request examples – utility justifications

ACE

- The benefit-cost ratio of the proposed Smart Technology Upgrade is 4.7 (ACE Direct Testimony Witness Tsuschida Table 3), and the investment will "further further enhance the communications network and supporting devices that are used to reduce the frequency and duration of power outages." (ACE Witness Humphrey 2022 p8)
- The Smart Technology Upgrade are intended to "strengthen ACE's distribution system by further modernizing the grid and strategically targeting where more reliability improvements can be accomplished." (ACE Witness Brubaker 2022 p4)
- "DA improvements, included in the Smart Technology Upgrades, also serve to improve public safety throughout the distribution system by quickly identifying faults, isolating the impacted area, and restoring service to those areas that are not impacted." (ACE Witness Brubaker 2022 p4)

JCPL

"Distribution Automation projects will provide intelligent control over the system and allow for rapid fault location, isolation and service restoration. These projects will reduce the number of customers affected by outages and shorten the duration of outages. They will also provide the platform for future smart grid investments, like Volt/VAR control, and support the integration of power flows from distributed energy resources ("DER") into the distribution system." (JCP&L 2018 p9)

- "This project will have many benefits for the distribution system and customers. State-of-the-art reclosers and controls enable real-time monitoring of the recloser status and system conditions (voltage, current, etc.). They also allow for remote control, which increases safety and reliability and decreases operations cost." (JCP&L Direct Testimony Dennis Pavahadhi 2018 p22)

ACE – Commission order

- The BPU approved $93.1M of ACE's requested $379M Infrastructure Investment Program through a settlement (see table).
- The settlement did not include rationale as to why only a portion of the requested infrastructure investment was approved.

Technology Category	Technology Descriptions	Requested	Approved
Targeted Reliability Improvements	Long Radial Remediation, New Feeders, Rear Lot Conversions, Underground Residential Development (URD), Unfused Laterals, and Priority Feeders	$92.8M	$4.9M
Smart Technologies Upgrades	Capacitors, Reclosers, Smart Sensors, Fiber/Radio Regulators, and Distribution Automation	$68.5M	$33.1M
Infrastructure Renewal	Abandoned Line, Cable URD, Network Renewal, Open Wire Secondaries, Cutout Replacement, and Recloser Replacement	$87.5M	N/A
Solar/DER Enablement	Substation Reverse Power Protection (Capital), Substation Reverse Power Protection (O&M), and Solar/DER Distribution Line Improvements	$34.9M	$33.1M
Substation Improvements	New Substation, Substation Additions, Substation Reliability, Substation Renewal	$96.8M	$22.1M
Total		$379.0M	$93.1M

ACE Proposed and Approved Infrastructure Investment Program (NJ BPU Order 2023 p5; ACE Petition 2022 p5)

JCP&L – Commission order

- The BPU approved $97.0M of JCP&L's requested $386.8M Infrastructure Investment Program through a settlement (Table X).
- The BPU only approved two years of proposed expenditures; JCP&L proposed four years.
- The settlement did not include rationale as to why only a portion of the requested cost recovery was approved.

Program Category	Program Descriptions	Requested (2019 -2022)	Requested (2019 -2020)	Approved (2019 -2020)
Overhead Circuit Reliability and Resiliency	Lateral Fuse Replacement with Circuit Mounted Reclosers, Enhanced Vegetation Management, Install Generations at District Line Shops	$132.9M	$71M	$55.1M
Substation Reliability Enhancement	Flood Mitigation, Substation Equipment Replacement, Mobile Substations, Modernize Protective Equipment, Substation Fencing Enhancement	$85.9M	$39.9M	$16.1M
Distribution Automation	Circuit Protection and Sectionalization, Install SCADA – Line Devices, Distribution Automation, ADMS and Remote Terminal Unit Upgrades in Substations	$108.4M	$48.6M	$25.6M
Underground System Improvements	Underground Cable Replacement, Submersible Transformer Replacement, Conventional and Network Rehabilitation	$59.7M	$31.2M	$0M
Total		$386.8M	$190.8M	$97M

Table X. JCP&L Proposed and Approved Infrastructure Investment Program (NJ BPU Order 2019 p2,4; JCP&L Direct Testimony Dennis Pavahadhi 2018 p18-30)

Baltimore Gas & Electric

Regulatory context

- Maryland PSC approved the use of multi-year rate plans in 2020. BGE submitted their second Multi-Year Rate Plan in February 2023, for years 2023-2026, seeking approval of $602.4 million distribution rate increase (incremental) for the term of the plan. (MD PSC Order 2023 p1)
- The plan included “capital investments and ongoing costs [that] are necessary to maintain and modernize the electric and gas distribution systems.” (BGE Witness Vahos 2022 p4)
- The grid modernization technology examples used in our analysis of BGE’s filing are Grid Communications and Connectivity, Distribution Sensors, and ADMS.
- The Commission disallowed Priority 3 projects, including BGE’s Grid Communication and Connectivity (project 77112), and Distribution Sensors (project 67883) for which BGE requested $84.6M. (Direct testimony Smith 2022 p45)
- The Commission approved all of BGE’s proposed $16.6M for their ADMS projects. (MD PSC Order 2023 p166)
- In total, the Commission approved $408 million increase (incremental) for the term of the plan. (MD PSC Order 2023 p1)

Grid modernization cost recovery – Utility justification
Grid Communication and Connectivity; Distribution Sensors

Grid Communications and Connectivity

- "The proposed Grid Communications and Connectivity, Project 77112, which represents the incremental capital to improve and expand BGE's fiber network. This project improves the grid connectivity and includes the budget for underground fiber project." (Vahos testimony p52).
- The project will "Improve and expand fiber optic network to create a robust communications backbone, improving reliability, resiliency, safety, and enabling distributed energy resources (DERs) and renewables. Project 77112 includes the budget for BGE's portion of the underground fiber project for which BGE submitted a grant application in September 2022 to the National Telecommunications and Information Administration under the Infrastructure and Investment Jobs Act." (BGE 2024-2026 Plan Documentation 2022 p40)

Distribution Sensors

"Increasing grid risks driven by changes in load profiles, workmanship challenges, coupled with an ever increasing electric customer reliability expectation has driven technology verticals to implement distribution sensor devices capable of predictive analytics to address issues proactively and quickly. Deploying proven sensors that can evaluate system and equipment conditions that provides accurate fault prevention, detection, and identification of emergent issues. This product is expected to positively impact Tier 1 reliability metrics. Predictive analytics will drive more planned work and reduce reactive work, adding more stability to Work Load Management. O&M Savings with thermal inspections and time savings with trouble shooting and locating faults. More intelligent asset management model. Reduction in outages and outage times." (Apte Testimony p99).

Grid modernization cost recovery – Staff comments
Grid Communication and Connectivity; Distribution Sensors

Grid Communications and Connectivity

- "While I appreciate the Company's efforts to leverage IIJA funding to improve its communication network I believe further implementation of grid fiber upgrades, excluding IIJA grants, should only continue after demonstration of operational feasibility and viability of pilot projects, review of expected benefits to customers, and internal management approval of the program. I recommend that the Commission only allow the Company to implement and recover, subject to prudency review, costs associated with the two demonstration projects the Company proposed and discussed in the management presentation document.

- I recommend that the Commission disallow additional expenditure, beyond the $13.136M proposed for the pilot programs for 2022 and 2023, as well as expenditures proposed for the 2024-2026 period. The Commission may allow additional grid fiber upgrade investments in the future subject to demonstration of viability and feasibility of the pilot as well customer benefits." (Direct Testimony Dererie 2023 p31).

Distribution Sensors

"I have also recommended that the Commission should take the following actions on the following proposals: (1) Designate the Company's Distribution Sensors program a pilot program and disallow further expansion and spending on this program after 2024 until the Company is able to demonstrate that there are not risks to full scale deployment and that program benefits are being obtained as projected." (Direct Testimony Austin 2023 p4).

Commission order
Grid Communications and Connectivity; Distribution Sensors

"BGE witness Vahos testified that "BGE always has more work than it can perform so that priority is often a matter of timing." The Commission notes that BGE has *also* proposed more work than ratepayers should reasonably pay for, and that part of the Commission's job is to balance the needs of BGE's distribution system, including reliability, resiliency, safety, and environmental goals, with the needs of ratepayers that include. In order to balance these competing interests, the Commission required in Order No. 89678 that BGE provide a weighing of its proposed capital budgets." (MD PSC Order 2023, p155-156)

"In future MYPs, the Commission encourages utilities to provide robust project-level detail, which is a necessary element of allowing stakeholders and the Commission transparency into the utility's planning process. Utilities should also provide a weighing of the importance of proposed capital projects, rather than a simple wish list untethered from ratepayer impact. The Commission accepts Staff's proposal to disallow a portion of Priority 3 projects as reasonable. As Mr. Smith testified, BGE's proposed capital budgets demonstrate a significant increase year-to-year through 2025, and also as measured against BGE's MYP 1 budget." (MD PSC Order 2023, p155-156)

Grid modernization cost recovery – utility justification and staff comments
ADMS

Utility Justification

"The implementation of an ADMS platform enables the distribution system to adapt and transform in support of changing customer needs and the market shifts anticipated by grid modernization. The ADMS program drives standardization of business processes and the convergence of multiple, utility-specific systems onto a common platform for distribution operations. The benefits of this integration include improved reliability, resiliency, and efficiencies. The project will also improve communications during storm events, and leverage analytics to improve IT system performance during high-volume transaction events such as storms." (BGE 2024-2026 Plan Documentation 2022, p21)

Staff Comments

"Regarding Project 84816 [ADMS], Ms. Dererie [PSC Staff witness] asserted that BGE has not provided evidence of alternatives considered. In responses to Staff data requests, BGE stated that the project is still in the planning phase and is expected to be completed by 2029, and that the management approval documentation will not be available until the planning phase is complete. Ms. Dererie did not raise concerns with BGE's other three projects under ADMS. Accordingly, Ms. Dererie recommended that the Commission approve Project 78280, Project 78282, Project 85295, and Project 84816, subject to prudence review at reconciliation." (MD PSC Order 2023 p165)

Commission order
ADMS

"The Commission accepts Staff's recommendation to approve funding during the MYP 2 period of the four new ADMS related projects: Project 78280, Project 78282, Project 85295, and Project 84816, subject to prudence review at reconciliation. Regarding Project 84816, the Commission requires that BGE provide the information requested by Staff. In particular, BGE is directed to provide the internal management approval documentation that includes a review of alternatives, any risks associated with starting Stage 2 while also implementing Stage 1 of the ADMS program, total project cost, project timeline, and discussion of quantitative and qualitative benefits of the project to the Company and ratepayers. BGE should provide this information when it becomes available. (MD PSC Order 2023 p166)

Commonwealth Edison

Regulatory context

- ComEd filed their Multi-Year Integrated Grid Plan in January 2023 and included information on their planned investments, expenses, initiatives and activities during the five year planning period (2024-2027), and sought approval of a $672 million rate increase.
- The Illinois Commerce Commission (ICC) required utilities to include distribution investments, policies, and plans designed to ensure coordination with the state's renewable energy and climate and environmental goals over a 5-year planning horizon.
- The ICC rejected ComEd's Multi-Year Integrated Grid Plan, and adopted an alternative methodology to establish the rate base and revenue requirement for the test year. (ICC Order 2023 p518)
- ComEd filed a revised Multi-Year Integrated Grid Plan in 2024, and the ICC approved it with modifications and approved a $606 million rate increase. (ICC)
- The grid modernization technology examples for ComEd are the Renewable Energy Advanced Control and Telemetry Systems (REACTS) and Intelligent Substation & Relay, Protection, and Control Replacement Programs.
- The ICC approved a reduced budget, as proposed by ComEd, for the REACTS program of $248M. (ICC Order 2024 p108)

Grid modernization cost recovery – Utility justification
REACTS; Intelligent Substation & Relay, Protection, and Control Replacement Programs

- "ComEd notes that its distribution grid already relies on communication systems to optimally function, utilizing a variety of technologies including wireless mesh networks, microwave, radio, fiber, and cellular technologies. However, ComEd recognizes that some of these technologies are becoming obsolete and more expensive to maintain, providing fewer capabilities and offering less flexibility to manage current and future grid monitoring and control needs. ComEd states that the REACTS program integrates next generation communication technology to replace this obsolete telecommunication infrastructure to improve telemetry and redundancy between its major substations, enhance its SCADA system, and unify disparate wireless network." (ICC Order 2023, p179).

- "ComEd explains that REACTS and PERFORM [Platform Enablement Reinforcement Measures] have been ongoing since 2019 and these investments have been reviewed and approved by the Commission during annual reconciliation proceedings for reasonableness and prudence." (ICC Order 2023 p180).

"ComEd further explains that its intelligent substations allow automated fault locating, which provides precise locations of disturbances on the distribution system for faster response time and enables advanced pre-failure detection (e.g., advanced transformer monitoring, slow breaker clearing times) and analysis, which helps predict a variety of failure modes such as transformer degradation or pending breaker failure. ComEd contends that investments in intelligent substations have resulted in fewer circuit breaker failures and bus lockouts, and thus fewer customer interruptions." (ICC Order2023 p169).

Grid modernization cost recovery – Staff comments
REACTS; Intelligent Substation & Relay, Protection, and Control Replacement Programs

- The AG demonstrates that there are several flaws in the Company's proposed Intelligent Substations project… Given these increasing costs, as well as historical data which could be analyzed to determine the cost-effectiveness of such investments, the AG argues that ComEd should have been able to provide a robust business case to support the program…
- The AG explains that when asked for a benefit-cost analysis, or the underlying customer and reliability data for the substations in question that would allow stakeholders to conduct their own benefit-cost analysis, the Company refused to provide such data on the grounds that "the Intelligent Substation program is not primarily or directly prioritized to respond to outages in the context of short term reliability impacts, but rather to advance resiliency in prevention of, and impact reduction of, future events and outages. (ICC Order 2023 p171)

Commission order
REACTS; Intelligent Substation & Relay, Protection, and Control Replacement Programs

REACTS

"The Commission finds that ComEd has not provided sufficient justification for the proposed investments, and has failed to show that the investments are prudent, reasonable, and cost-effective. The REACTS program is the Company's most expensive proposed MYIGP investment. Without a compliant analysis of the Grid Plan's cost effectiveness, the Commission cannot determine whether the REACTS program is a cost effective Grid Plan investment." (ICC Order 2023 p203)

Intelligent Substation & Relay, Protection, and Control Replacement Programs

"The Commission agrees with the AG that ComEd has not completed a specific benefit-cost analysis of the Intelligent Substation program. The AG further contends there are likely other less expensive alternatives that the Company could employ to reduce costs … the Commission finds that, without the cost-effectiveness analysis required by 220 ILCS 5/16-105.17 (d)(1), (2), and (7), it is unable to determine if these system performance investments are prudent, reasonable, in compliance with the goals and objectives of P.A. 102-0662" (ICC Order 2023 p183)

Commission order (revised grid plan)
REACTS

- “ComEd reduced its proposed REACTS investment from $909 million to $602.45 million in the MYIGP. ComEd now proposes a $406.34 million investment, $248.32 million for REACTS and $158.01 million for PERFORM. The Commission recognizes that ComEd’s REACTS program aligns with P.A. 102- 0662’s goal of promoting a flexible, secure, and resilient grid. The program’s hybrid fiber optic and private wireless network will enhance grid management, facilitate DER integration, and improve overall operational efficiency.” (ICC Order 2024 p108)

- The AG’s suggestion to defer the investment in favor of public telecommunications networks overlooks the need for a utility-specific communications platform that ensures the level of control, security, and reliability necessary for critical grid operations…The Commission agrees with ComEd’s assessment that public networks would not adequately meet these needs, particularly as DER penetration increases and grid operations become more complex.” (ICC Order 2024 p108)

- “The AG and the Company both state the cost to complete PERFORM and REACTS is much more than the amount approved in this RGP and the project will likely continue into 2041. The Commission notes that P.A. 102-0662 envisions an iterative and holistic grid and rate planning structure. The Commission agrees with the AG that it must consider cumulative impacts of a project in this planning structure. The Commission emphasizes that approval of the program for this RGP does not necessarily imply approval for these programs in a future grid plan. The Company bears the burden of supporting each iteration of its grid plan as appropriate and compliant with P.A. 102-0662. The spending protections recommended by Staff, including the stipulation that unspent funds cannot be reallocated without Commission approval, are essential safeguards to ensure that ratepayer funds are used appropriately and that the program stays on track. Staff’s recommendation is adopted.” (ICC Order 2024 p108)

Consolidated Edison

Regulatory context

- In New York, the utilities distribution system implementation plans (DSIP) consider proposed grid modernization investments, informed by the Community Leadership and Climate Protection Act. (ConEd 2020 p1)
- Grid modernization projects included in the DSIP are included in the revenue requirement request in the general rate case, and includes the project cost, work description, and the specific relationship to the broader company plans and initiatives. (ConEd Joint Proposal 2023 p5)
- ConEd's 2022 requested revenue requirement in their electric general rate case was $1.2 billion (2023 only). (ConEd)
- The New York Public Service Commission approved $457 million/year for three years. (ConEd Joint Proposal 2023 p4; approved NY PSC 2023)
- The grid modernization technology example for Consolidated Edison (Con Ed) is conservation voltage reduction (CVO), which was requested and approved for $45 million ($15 million/year for three years). (ConEd Joint Proposal Appendix 12 p3)

Grid modernization cost recovery – Utility justification
CVO

- “To increase CVO energy savings during the upcoming period, we will make the following two investments. First, to address secondary system areas where there may be low voltage, we need to reinforce the secondary system. That is, we will upgrade and reconductor our secondary system to allow the Company to adjust the voltage, while meeting voltage range requirements. Second, we will adjust transformers in area substations to allow settings to be changed for voltage optimization, an O&M cost. This work requires the transformer to be removed from service to work on the internal equipment.” (ConEd Customer Energy Solutions 2022 p72)

- “These efforts are expected to produce net energy savings that will reduce the supply-side costs of the customer bill, while further reducing GHG emissions.” (ConEd Customer Energy Solutions Testimony 2022 p72)

Grid modernization cost recovery – Staff comments
CVO

- "DPS [Department of Public Service] Staff states that the CVO provisions of the JP are reasonable and provide fair and clear instructions to the Company to improve communication and data sharing with high tension customers." (DPS Statement in Support 2023 p95)

- "The Joint Proposal establishes steps Con Edison must take in order to improve communications regarding the implementation of CVO and emergency voltage reduction with high-tension customers, and steps to take if a potential voltage issue arises from a high-tension customer." (DPS Statement in Support 2023 p99)

Commission order
CVO

- “For the Company, the JP [joint proposal] provides sufficient revenues to support necessary infrastructure projects and operate the systems in a safe and reliable manner while maintaining or enhancing the Company’s credit ratings and making meaningful progress in addressing State climate goals. We recognize that rates are increasing. However, increases are needed to fund programs and capital investments necessary to ensure the provision of safe, adequate, and reliable electric and gas service, an express obligation of the Companies and the Commission’s rate-setting authority in PSL §65 and §66, while promoting Commission and State clean energy and other policy objectives. Accordingly, we approve the terms of the JP as in the public interest. (NY PSC Order 2023 p58)
- “The Conservation Voltage Optimization (CVO) program in the JP will reduce total energy consumption and associated power generation emissions while reducing ratepayer energy costs by optimizing the operation of voltage regulation equipment.” (NY PSC Order 2023 p100)

Duke Energy Carolinas and Duke Energy Progress

Regulatory context

- The North Carolina Utilities Commission (NCUC) requires utilities to initiate a technical conference on transmission and distribution projects that they plan to include in a rate case. Prior to the technical conference, the utility must make a Transmission and Distribution Information filing. (NCUC Rule R1-17B(c))
- DEC and DEP filed information on proposed grid modernization projects including program purpose, timeline for construction, estimated in-service date, program description, projected costs, grid capabilities enabled, customer benefits of the project and how the proposed project addresses the state's carbon dioxide emissions reduction goal in their Transmission and Distribution (T&D) Information Filing. (DEC T&D Information Filing 2022; DEP T&D Information Filing 2022)
- In addition to their T&D Information Filing, the utilities also their Grid Improvement Plan (GIP) in the rate case. The GIP is required to include the benefits, cost, scope and schedule compared to plans described in the prior rate case (DEC Guyton Exhibit 1 2023; DEP Guyton Exhibit 1 2022)
- Both utilities included an appendix to their application that listed all of the filing requirements performance-based ratemaking and the exhibit name or location of the file demonstrating how the utility met each requirement. (DEC Application Appendix 2 2023; DEP Application Appendix 2 2022)

Regulatory context (2)

- DEC requested $883 million rate increase (incremental) NCUC approved $778 million (incremental). (NCUC Order p11 2023; NCUC Order Appendix A p2 2024)
- DEP requested $692 million rate increase (incremental); NCUC approved $504 million (incremental). (NCUC Order p18 2023; NCUC Order Appendix A p2 2023)
- The grid modernization technology example for DEC and DEP is the self optimizing grid project, which was included in the multi-year rate plan (MYRP) distribution system projects.
- DEC and DEP requested and were approved for $274.6 million and $205.4 million, respectively for the self optimizing grid project. (DEC Guyton Exhibit 6 p42 2023 and NCUC Order p 270 2023; DEP Guyton Exhibit 6 p11 2022 and NCUC Order p238 2023)

Grid modernization cost recovery – Utilities' justification
Self optimizing grid

"SOG [self optimizing grid] uses self-healing technology to improve grid reliability and resiliency. To detect potential faults in real time, the system uses sensors, switches, and controls. The self-healing system can automatically detect power outages, quickly isolate the problem, and reroute power to restore service to customers as quickly as possible. This smart, self-healing technology can reduce the number of customers issues before a customer reports a power outage. The SOG work executed during the three-year MYRP is expected to save annually, 127,000 customer interruptions (CI) and over 25 million customer minutes interrupted (CMI)." (DEC Guyton Exhibit 6 p38 2023; DEP Guyton Exhibit 6 p8 2022)

Examples of SOG project information included in Duke Energy filings

Self-Optimizing Grid

Program purpose
The Self-Optimizing Grid (SOG) program, also known as the smart-thinking grid, redesigns key portions of the distribution system and transforms it into a dynamic self-healing network to improve system reliability and resiliency, restore outages faster, and manage the dynamic two-way power flows that expansion of distributed energy resources (DER) will bring.

Timeline for construction
Refer to the MYRP Project List for project-specific timelines. At the program level, construction is planned from December 2020 – September 2026

Estimated in-service date
Refer to the MYRP Project List for project-specific dates. At the program level, individual location in-service dates range from October 2023 to September 2026

Program description
SOG uses self-healing technology to improve grid reliability and resiliency. To detect potential faults in real time, the system uses sensors, switches, and controls. The self-healing system can automatically detect power outages, quickly isolate the problem, and reroute power to restore service to customers as quickly as possible. This smart, self-healing technology can reduce the number of customers affected by an outage by up to 75% and can often restore power in less than a minute. This system can even detect issues before a customer reports a power outage. The SOG work executed during the 3 yr. MYRP is expected to save annually, 81,000 customer interruptions (CI) and over 15 million customer minutes interrupted (CMI).

Examples of SOG project information included in Duke Energy filings

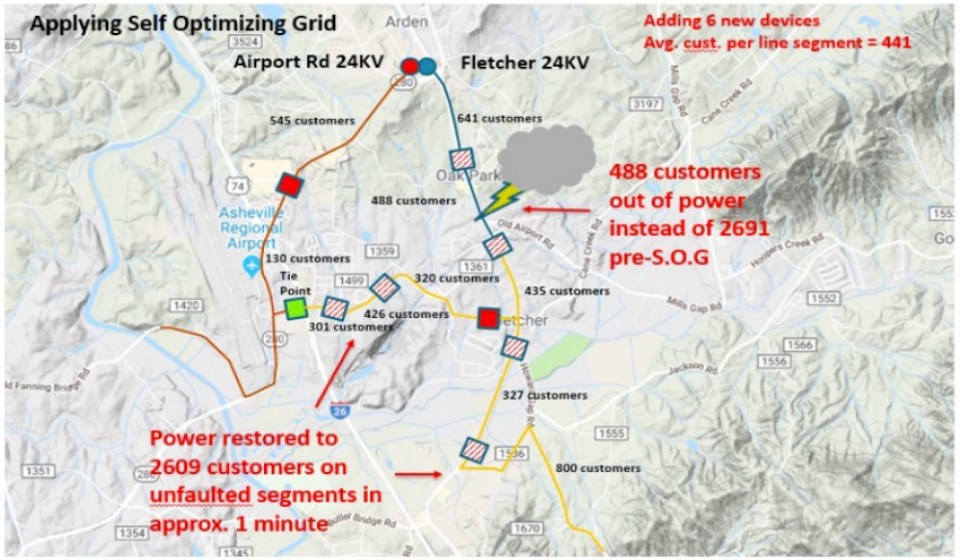
Projected costs (including capital and O&M expenditure) *Note: Timing for costs based on in-service dates for associated projects; capital includes contingency and AFUDC*				
DEP NC	**Oct '23-Sept '24**	**Oct '24-Sept '25**	**Oct '25-Sept '26**	**Total**
Capital costs	$91.5	$57.2M	$83.2M	**$231.9M**
O&M costs (installation only)	$1.3M	$0.8M	$1.1M	**$3.2M**

Grid capabilities enabled	**HB951 Policy Considerations addressed**
Reliability • Improve resiliency to increase grid strength and ability to rapidly restore power	• Encourages DERs • Encourages beneficial electrification, including electric vehicles

Financial cost-benefit analysis	
Total NPV Costs	**$205.4M**
Total NPV Benefits	**$1,231.5M**
Net value of program	**$1,026.1M**
Benefit to Cost Ratio (BCR)	**6.0**

Description of benefits	
Benefit Category	**Description**
Improve reliability and resiliency	SOG creates a network of interconnected circuits that are split into smaller automatically switchable segments that can isolate faults and reconfigure to greatly reduce the number of customers affected by sustained outages. The program also reduces the number of outages, decreases the duration of outages up to 75% when they do occur, and helps restore power in a matter of minutes

Figure 3 demonstrates the future state under the SOG program in which a circuit with additional segmentation devices and interconnectivity to adjacent circuits allows the system to isolate faults to a small portion of the circuit while all other customers do not experience an outage.



Grid modernization cost recovery – Staff comments
DEP MYRP projects

"DEP's proposal has several broad issues that could impede successful implementation of the MYRP to the detriment of ratepayers, including inadequate staffing, lack of Company-wide project optimization, inability to adapt to changing conditions given the timing of the MYRP projects, and the likelihood of costs attributable to projects not currently in the plan." (NCUC Metz p49 2023)

"If the Company has proposed to complete a portfolio of programs on an unrealistic timeline without acquiring and maintaining adequate staffing levels or material procurement over the three-year planning period, there could be a significant risk that ratepayers will pay for projects that will not be completed or will have to pay even more to complete planned projects due to higher labor costs and project management inefficiencies. Mitigating this risk is not as simple as asserting that if the Company spends less than forecasted, the earnings mechanism will result in refunds." (NCUC Metz p49 2023)

Given the Company's responses regarding MYRP transmission and distribution projects as well as non-MYRP related work, I do not believe that the Company can execute and complete its entire proposal within the three-year time frame requested or within its estimated budget. Thus, approval of the Company's proposed MYRP would place a considerable amount of risk on ratepayers. NCUC Metz p71 2023

Grid modernization cost recovery – Staff comments
DEC and DEP MYRP

"A review of the full MYRP also reveals that the Company did not "globally" optimize project spend across all of the business groups. While there was project optimization within each business group (e.g., transmission, distribution, nuclear, fossil, renewables, etc.), the Company did not compare projects from one business group to projects from another in an effort to truly maximize the benefits of the total spend requested in this case." (NCUC Metz p49 2023; NCUC Metz p120 2023)

"Based on my review of the MYRP, discovery, and substitution of projects, it appears that each business unit was assigned a narrow range of total capital spend and maximized their individual portfolios without immediate coordination and re-optimization with other business groups." (NCUC Metz p73 2023; NCUC Metz p129 2023)

Commission order
MYRP projects

"After having carefully reviewed all the evidence in the record on DEP's distribution MYRP proposal in this docket, and based on that evidence, the Commission finds that DEP's distribution MYRP projects satisfy the requirements set forth in N.C.G.S. § 62-133.16(c)(1)(a). The Commission further concludes that the evidence supports approval of the Revenue Requirement Stipulation's provision regarding these distribution MYRP projects." (NCUC Order p103 2023; NCUC Order p77 2023)

Duke Energy Indiana

Regulatory context

- A utility in Indiana may file an application requesting approval of its six year transmission, distribution and storage system improvements and for a rate adjustment and deferral for eligible transmission and distribution infrastructure improvement costs (TDSIC) (Indiana Code Section 8-1-39-1 through -11).
- State law permits the utilities to recover 80% of approved costs in a TDSIC rider and defer 20% of the deferred to the next rate case (Indiana Code Section 8-1-39-9).
- DEI proposed four grid modernization projects in their application: self-optimizing grid (SOG), condition based monitoring (CBM), Supervisory Control and Data Acquisition (SCADA) and Integrated Volt VAR Controls Systems (IVVC).
- The grid technology example for DEI is the SOG.
- DEI's entire requested TDSIC was approved (which included all SOG costs). (IURC Order p27 2022)

Grid modernization cost recovery – Utility justification (1)
Self optimizing grid

"The Self Optimizing Grid and Automated Lateral Device investments are key programs contributing to the Distribution system resiliency through improvements to restoration times." (DEI Pinegar p13 2021)

"These programs include Self Optimizing Grid ("SOG") that will isolate faults on the backbones of circuits from approximately 1,000 customers per segment to 400 customers per segment, allowing service to be restored to other portions of the circuit…"(DEI Lewis p11 2021)

"The Self-Optimizing Grid redesigns key portions of the distribution system and transforms it into a dynamic self-healing network that ensures issues on the grid can be isolated and customer impacts are limited. Self-healing technologies can reduce outage impacts on a circuit by as much as 75 percent. These grid capabilities are enabled by: (1) increasing system "connectivity" by building more circuit ties that allow for more flexibility in restoration options; (2) increasing "capacity" by installing larger wires, transformers, and system banks to be able to handle dynamic switching and expanding two-way power flow from adjacent circuits and renewable generation; and (3) increasing "control" through additional system automation and intelligence. SOG includes upgrades to the Advanced Distribution Management System head end systems and devices such as line sensors, which are used to measure voltage and/or current levels at targeted locations on the Duke Energy Indiana distribution system and transmit those measurements to the Distribution Control Center ("DCC")." (DEI Lewis p21 2021)

SOG allows reconfiguring of circuits to match load to production, and it supports two-way power flow that is associated with significant penetration of distributed energy resources on a circuit. In particular, during shoulder seasons which have more temperate weather and light load demand, high adoption circuits can produce more power than is locally needed. SOG automation and rerouting capability will allow the company to match load to that production. This has several benefits, one of which is locally produced power can be quickly rerouted to local neighborhoods on adjacent circuits, which reduces line losses." (DEI Lewis p31 2021)

Grid modernization cost recovery – Utility justification (2)
Self optimizing grid

- Duke Energy Indiana estimated the overall benefit and cost for its projects and highlighted the potential economic impact of the projects.
- “Again, excluding the targeted economic impact projects, the level of expenditures anticipated in TDSIC 2.0 is estimated to create or support about 1,270 jobs per year, in the state of Indiana, for each of the six years.” (DEI Pinegar p19 2021)

Grid modernization cost recovery – Utility justification (2)
Self optimizing grid

Duke Energy Indiana Mapping Benefits to Sub-programs

Sub-Programs	Reduce or avoid costs							
	Capital	O&M	Generation Capacity	Energy	Ancillary Services	T&D Losses	Customer Fuel	Restoration
Self-Optimizing Grid (SOG)			X	X				
Circuit Visibility & Control								X
Inaccessible ROW								X
Declared Circuits								X
IVVC		X	X	X	X	X	X	X
Capacitor Automation		X						X
Circuit Segmentation								X
Ltd Access Road Crossing								
Circuit Sectionalization								
Deteriorated Conductor								X
Automated Lateral Device								X
Targeted Undergrounding	X	X						X
UG Cable Rehabilitaion								
4Kv Conversion	X	X	X			X		
GLT Pole Inspection & Replacement								

Grid modernization cost recovery – Utility justification (2)
Self optimizing grid

Duke Energy Indiana Mapping Benefits to Sub-programs

	Risk			Benefits	
Sub-Programs	Compliance	Public Property	Safety	Reduced Customer Outage	Increased Customer Satisfaction
Self-Optimizing Grid (SOG)				X	X
Circuit Visibility & Control				X	
Inaccessible ROW				X	X
Declared Circuits				X	X
IVVC					
Capacitor Automation					X
Circuit Segmentation				X	X
Ltd Access Road Crossing	X				
Circuit Sectionalization				X	X
Deterioriated Conductor				X	X
Automated Lateral Device				X	X
Targeted Undergrounding				X	X
UG Cable Rehabilitation				X	
4Kv Conversion				X	X
GLT Pole Inspection & Replacement		X	X	X	X

Grid modernization cost recovery – Staff comments
SOG

"..discusses DEI's Distributed Energy Resource ("DER") projects, which DEI fails to demonstrate that the public convenience and necessity requires these upgrades to allow for future distributed generation or future renewable projects not yet identified by DEI; 4) Discusses how DEI's project costs do not provide the "best estimate of the cost" as required by Indiana Code 8-1-39 ("TDSIC Statute"); and 5) Discusses how DEI does not show eligible improvements estimates it included in the Plan are justified by incremental benefits attributable to the Plan, as required by Ind. Code § 8-1-39-10(b)(3). I recommend the Indiana Utility Regulatory Commission ("Commission") deny DEI's application." (Office of Utility Cconsumer Counsel (OUCC) Shull Testimony p2 2022)

"First, DEI has not demonstrated customer demand for DER exists. Second, any new system improvement would need to be completed according to customers' DER specifications. It would be prudent to wait until a customer has a specific project need, and DEI can build its system specific to meet its customers' DER needs. DEI's request amounts to, speculation that, perhaps, sometime in the future, such upgrades will help make an easier build for distributed or renewable generation." (OUCC Shull Testimony p8 2022)

"The prices of copper, aluminum, and steel have risen dramatically in the past two years since DEI first began pricing these projects. As such, DEI's Plan estimates are understated and, therefore, DEI's incremental benefit calculation is almost certainly overstated." (OUCC Shull Testimony p8 2022)

"State policy is to protect the affordability of utility services. Mr. Lantrip discusses affordability concerns in greater detail. The DEI Plan proposes nearly $2 billion in 1) redundant infrastructure that does not decrease CI and CMI and is not for purposes of safety, reliability or modernization; and 2) unnecessary DER projects. There are no identified customers seeking DER connectivity, which falls outside the scope of modernization." (OUCC Shull Testimony p10 2022)

Commission order

- “Based on the evidence presented, the Commission finds the total estimated cost of Duke Energy Indiana’s TDSIC 2.0 Plan of $2,140,185,171 rests on a sound factual and analytical foundation. Petitioner’s methodology was robust, sound, and reasonable in yielding the best estimate of the cost of TDSIC 2.0. Accordingly, the Commission further finds the best estimate of the cost of the eligible improvements included in TDSIC 2.0 is the estimate Duke Energy Indiana provided, as its witnesses testified.” (IURC Order p27 2022)

DTE Energy

Regulatory Context

- DTE Electric filed their rate case in January 2022 with the Michigan Public Service Commission. It included requests for grid modernization investments filed in DTE's Distributed Grid Plan (MI PSC Order p73 2022)
- The grid modernization technology example for DTE is ADMS DMS/OMS.
- The Michigan PSC disallowed $13.7 million of DTE's ADMS DMS/OMS cost recovery request.

Grid modernization cost recovery – Utility justification
ADMS OMS/DMS

"There are a number of the additional [ADMS] benefits that were originally detailed in Witness Bruzzano's testimony in MPSC Case No. U-20561, and were also discussed in detail in the Distribution Grid Plan (DGP) section 12.1.

- First, the existing technology the Company had/has in operation was reaching end-of-life and needed to be replaced regardless of implementing a full ADMS (includes GMS, EMS, and OMS).
- Second, implementing a common platform for the GMS, EMS, OMS, and DMS allows the components to seamlessly share data from across the electrical system grid to provide real-time visibility of current conditions and provide operational control of the distribution circuits.
- Third, the DMS applications will allow the Company to improve many of the current manual processes in place to monitor and operate the electrical grid, such as the paper SOM process.
- Fourth, improved data quality allows employees to have a better understanding of the current system configuration in the field, allowing for improved communications between the control room and field employees; this improved communication will also materially improve safety by allowing the field employees visibility into the current configuration of the equipment while in the field so they can see a visual representation of the information being discussed with the control room and collaborate to create the safest restoration plan.
- Fifth, the ADMS allows the Company to fully leverage investments made in the field while modernizing the electrical grid, improving the ability to integrate Distributed Energy Resources (DER) and providing a centralized tool for managing VVC and CVR. Please refer to section 12.1 of the Distribution Grid Plan for more details of benefits of ADMS platform in different scenarios." (DTE Elliot Andahazy p9 2022)

Grid modernization cost recovery – Staff comments
ADMS OMS/DMS

"Most of problems with the project delays and cost overruns for the [ADMS] OMS/DMS project are 3 the result of the Company's decision to proceed with implementation of this system 4 knowing that the OSI's OMS products were still relatively new and their Compass mobile solution was still under development…In summary, the cost overruns have not been adequately justified and at least a major portion of those incremental cost may have been imprudently incurred…. In any case, the Commission should also direct the Company that in its next rate case it should provide a full accounting of the OMS/DMS project costs with sufficient detail for Staff and intervenors to perform a through prudency review of the actual expenditures against the initial project costs, as approved by the Commission in Case No. U-20162." (MI AG Coppola p38 2022)

"Staff asserted that DTE Electric spent only 69.3% of the amount projected [for the ADMS OMS/DMS] in Case No. U-20561…As a result, the Staff revised its recommended disallowances: $11 million for the 22-month bridge period and $2.7 million for the projected test year." (MI PSC Order p121 2022)

Commission order
ADMS DMS/OMS

- The Commission finds that DTE Electric did not explain why, earlier in the ADMS planning process, the company did not hire a system integrator whose expertise and experience likely could have alleviated some of the software missteps, project delays, and cost overruns. Further, as noted by the ALJ, the company provided no testimony or evidence that DTE Electric is pursuing any possible contract remedies to reduce or eliminate the cost overruns associated with software compatibility issues. Therefore, the Commission finds the Staff's recommendation reasonable and prudent to limit DTE Electric's expenditures to the percentage spent of the projected ADMS amount in Case No. U-20561. Accordingly, the Commission approves **disallowances of $11 million for the 22-month bridge period and $2.7 million for the projected test year**." (MI PSC Order p125 2022).

Georgia Power

Regulatory Context

- Georgia Power filed their 2022 rate case, seeking approval for a three-year Alternate Rate Plan (ARP) with proposed rate increases of $852 million in 2023, and additional increases of $107 million and $45 million in 2024 and 2025. The Georgia PSC approved $192 million in 2023, $273 million in 2024 and $314 million in 2025. (GA PSC Order p5 and p13 2022)

- Their Alternate Rate Plan included a Grid Investment Plan (GIP), which supported the utility's request for transmission and distribution investments (inclusive of grid modernization investments).

- The grid modernization technology example for Georgia Power is DERMS.

- The company requested $100 million for their DERMS in the Alternate Rate Plan. The Commission approved forty percent of the Company's DERMS investment. (GA PSC Order Attachment 1 p36 2022, GA PSC Staff Exhibit A 2022)

Grid modernization cost recovery – Utility justification –
DERMS

- “Also, with the increasing levels of distributed energy resources being installed on our system, the Company will begin investing in a Distributed Energy Resource Management System (“DERMS”) that will enable enhanced monitoring and operational capabilities of a more complex power delivery system.” (GPC Testimony Abramovitz, Adams, Houston and Robinson p17 2022)

Grid modernization cost recovery – Staff comments –
DERMS

- “Very few utilities have installed DERMS, due largely to the low penetration of DER on most utilities’ grids. Georgia Power is requesting $100 million to install DERMS in this rate case. Given that the cost to install DER capacity is likely around $1.8 million per MW, the cost to implement DERMS is roughly equivalent to a minimum 6.7% cost premium on top of the costs the Company or its customers incur to install DERs. This represents a high level of overhead for very little benefit. The Commission should reject the Company’s capital request to install DERMS in its entirety due to the small incremental benefits and relatively low DER penetration the Company expects on its grids by the end of the rate case period.” (PIA Staff p17 2022)

- “The level of distributed energy resources needed to justify such a system is high, and will not be reached by the time the proposed DERMS is fully depreciated in 2030, let alone by the end of the upcoming rate planning period in 2025. Further, Georgia Power already maintains systems and processes to manage distributed energy resources. We recommend this proposed spending be postponed until a future rate case, when the level of distributed energy resources on Georgia Power’s grid provides sufficient justification for such a system.” (Direct testimony Alvares and Stephens p4 2022)

- “We recommend the Commission reject the Company’s capital request to install DERMS in its entirety due to the small incremental benefits and relatively low DER penetration the Company expects on its grids by the end of the rate case period.” (Direct testimony Alvares and Stephens 2022 p70)

Commission order – DERMS

"The Company will not move forward with a full Distributed Energy Resource Management System ("DERMS") at this time. To prepare the electric system for higher levels of distributed energy resources ("DER"), the Company will be allowed to begin the following preliminary steps, which will include system modifications to allow for modeling and visibility of DER, integration of these modifications with the Company's real-time operations platforms such as EMS, DMS, and SCADA, and the establishment of DER remote configuration capabilities." (GA PSC Order p10 2022)

Pacific Gas & Electric

Regulatory context

- Large energy utilities in California are required to file an application in a general rate case (GRC) proceeding every four years. (CPUC Order 2020)
- Utilities must submit a Grid Modernization Plan in the GRC filing that provides a 10-year grid modernization vision and information for each proposed grid modernization program, and defined grid modernization as having “any relationship with DER integration” (CPUC Order p8 2018).
- PG&E filed their GRC requesting $3.6B test year increase in 2023, and additional revenue requirements of $924 million in 2024, $438 million in 2025 and $247 million in 2026. (CPUC Order p8 2023)
- The grid modernization technology example for PG&E is ADMS and DERMS.
- PG&E capital expenditure forecast for ADMS and DERMS was approved as requested - $81.882 million in 2021, $126.88 million in 2022 and $109.049 million in 2023. (CPUC Order p468 2023)

Grid modernization technology and cost recovery – Utility justification – ADMS and DERMS

"The ADMS will become PG&E's core distribution operations technology tool to enable the visibility, control, forecasting, and analysis of a more dynamic grid. Greater visibility and control of the grid are needed for PG&E to continue providing safe and reliable service to customers in the face of the increasing complexity of the grid due to DER adoption, the apparent 'new normal' of weather-related emergencies, evolving California energy policy requirements, and increasing cyber-security threats. When fully deployed, the ADMS platform will bring Distribution Supervisory Control and Data Acquisition (D-SCADA), Distribution Management System (DMS), and OMS into a single, modernized platform." (PGE Exhibit 4 Chapter 21 p19, 2021)

"To address these issues [e.g., increasing DER penetration, distribution system capacity constraints, power qualities issues] PG&E proposes to build a DERMS to complement the foundational technology improvements and grid management tools built by the ADMS Program." (CPUC Order p464 2023)

PG&E proposes to build a DERMS with five capabilities: Monitoring, Dispatch, and Program Management of DER Systems; full integration with ADMS; and DER Interconnection and Market Participation Facilitation; Operation of DER-Based Deferral Solutions and Enablement of DER-Based Resilience Solutions. (PGE Exhibit 4 Chapter 21 p22, 2021)

Grid modernization technology and cost recovery – Public advocate comments – ADMS and DERMS

"Cal Advocates recommends removing the capital forecast related to ADMS Release 3 and DERMS, which total $27.735 million in 2023, from this GRC due to the interrelated nature of PG&E's ADMS and DERMS to the Commission's separate and ongoing proceeding to *Modernize the Electric Grid for a High Distributed Energy Resources Future*, R.21-06-017.1681 Cal Advocates states that consideration of these grid modernization projects and costs is more appropriate in a proceeding dedicated to distributed energy resources, such as R.21-06-017." (CPUC Order p466 2023)

Commission order –
ADMS and DERMS

"…the Commission determined that software, such as the ADMS Release 3 and DERMS, could be included in PG&E's grid modernization plans in the GRC for review and evaluation….Therefore, including the 2023 capital cost of $27.735 million for ADMS Release 3 and DERMS is consistent with the direction in D.18-03-023.

Accordingly, the Commission denies the removal of the cost of ADMS 3 and DERMS from PG&E's request and Cal Advocates' recommended reduction of $27.735 million for PG&E's 2023 forecast for ADMS Release 3 and DERMS associated with their proposed removal." (CPUC Order p466 2023)

Xcel Energy

Regulatory Context

- Northern States (Xcel Energy) sought approval to increase rates through a three-year multiyear rate plan in October 2021. They included grid modernization projects in their application.
- Xcel requested three consecutive annual rate increases under its Multiyear Rate Plan: 2022 $396 million increase (2022), $151 million increase (2023), and $131 million (2024) (MN PUC Order p1 2023).
- The grid modernization technology example for Xcel is Distributed Intelligence (DI). Xcel requested $40.2 million for DI and did not receive approval. (MN PUC Order p55 and 59, 2023)

Grid modernization technology and cost-recovery — Utility justification – DI

"Xcel proposed to procure DI software and computer hardware that would allow the Company to **leverage advanced meter data to offer new services to customers and help the utility to manage its distribution system more efficiently**. Xcel identified the following initial uses for its proposed DI program: energy analysis, home area network connectivity, EV detection, outage and voltage fluctuation detection, and a connectivity pilot." (MN PUC Order p55 2023).

"Xcel asserted that the primary benefit of DI is the potential to **provide information to customers that allows them to change their behavior in ways that promote energy efficiency and demand response**, save on energy bills, and reduce carbon emissions. Additionally, Xcel stated that DI analytics will extend the Company's advanced capabilities for the distribution grid to allow more precise monitoring and control at the edge of the grid, leading to **greater reliability** and **lower costs** for managing the system." (MN PUC Order p55-56 2023).

Grid modernization technology and cost-recovery – Staff comments – DI

"The Department argued that Xcel's DI **cost-benefit analysis was not reliable**, citing concerns with the benefits measure used and with several assumptions underlying the model. The Department challenged Xcel's use of general market research for digital products to estimate the percentage of enrolled customers leaving the program annually (referred to as "churn rate") and further contended that Xcel's selection of the highest churn rate was self-serving because the benefit-to-cost ratio improves as annual churn increases under Xcel's model. Finally, the Department opposed Xcel's proposal to change its accounting structure from treating DI as a shared asset owned on an enterprise-wide basis to an asset owned by Northern States Power–Minnesota (NSPM), which would add $37.8 million in capital to its 2024 plan-year rate. base, approximately $14.3 million above the Company's original recommendation. The Department argued that this revised accounting structure would unreasonably shift business risk from shareholders to NSPM customers because Xcel's claim that other jurisdictions will contribute to the cost in the form of licensing fees in the near future relies on assumptions that Xcel's other jurisdictions will timely adopt DI programs." (MN PUC Order p56-57 2023)

Commission order – DI

- “The Commission will reject Xcel’s proposal to include DI costs in rates. The Commission concurs with the ALJ’s finding that Xcel has not met its burden to show that its proposed DI costs are just and reasonable. The Department raised important **concerns about the assumptions and methodology underlying Xcel’s cost-benefit analysis, and Xcel has not satisfactorily resolved those concerns**. Although Xcel has identified potential uses of DI to help customers understand and control their energy usage and help the Company manage its distribution system more efficiently, the Commission is not persuaded that approval of Xcel’s proposed DI program is justified based on the current record.” (MN PUC Order p59 2023).

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