Grid Modernization: Metrics Analysis (GMLC1.1) – Selected Literature Review and Mapping

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Grid Modernization: Metrics Analysis (GMLC1.1) – Selected Literature Review and Mapping

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Primary Author:
Gian Porro[1]
Monisha Shah[1]

Grid Modernization Laboratory Consortium Members:
Emily Chen[1]
David Hurlbut[1]
Jeffrey Cook[1]

PIs: Michael Kintner-Meyer[2], Joseph Eto[3]

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Pacific Northwest National Laboratory
Richland, Washington 99352

[1] National Renewable Energy Laboratory
[2] Pacific Northwest National Laboratory
[3] Lawrence Berkeley National Laboratory

Abstract

The objective of this report volume is to provide the Grid Modernization Laboratory Consortium (GMLC) 1.1 Metrics team and U.S. Department of Energy (DOE) project managers with a summary of the metrics currently being used to inform public decision making in the electric sector, including decisions related to system planning and investment, system operations, policy, and regulation, based on a non-exhaustive literature review. The results of this review help identify the value of the metrics development work conducted in the current phase of the project (2016-2019). Gaps and other insights from this effort serve to inform longer-term DOE and Grid Modernization Initiative (GMI) metrics and valuation activities. This metrics mapping is complementary to the stakeholder engagement elements of the GMLC 1.1 project in which the project team asked stakeholders to validate the gaps in metrics identified by the project team and proposed approaches and methodologies for addressing those gaps.

Summary

Lab Team: Gian Porro and Monisha Shah, Emily Chen, David Hurlbut, Jeffrey Cook, National Renewable Energy Laboratory, NREL.

In order to further contextualize the metrics being developed by the GMLC Metrics Analysis team, this project team systematically collected and categorized metrics that are in current use for grid modernization-related decisions by a wide range of stakeholder groups. This activity complements stakeholder engagement efforts already undertaken by the Metrics Analysis team to validate and test out metrics and methodologies that were the focus of this project.

S.1 Motivation

At the beginning of the Metrics Analysis project, each of the metric category teams determined which metrics to focus on enhancing or developing based on their own technical knowledge, an inventory of existing metrics in each category and validation from relevant stakeholders. Each of the metric category teams also partnered with one or more key stakeholders to validate the usefulness or applicability of the metrics that each team was developing through a demonstration with the stakeholder(s). The focus, however, was limited to the specific metrics targeted by each team.

As a complement to these activities, there is also a need to look beyond these activities and ask broader questions regarding stakeholder's future needs for grid metrics. To that end, one important method of documenting the current use of metrics is via the records that emerge from critical grid modernization proceedings and decisions. Different types of proceedings can represent a wide range of stakeholders, and include specific metrics being used to inform or make decisions. This type of literature review can indicate what metrics are in current use, what metrics are not represented and how the GMLC Metrics Analysis contributes to this body of knowledge.

S.2 Outcomes/Impact

The Metrics Analysis team identified and reviewed 20 examples of grid modernization decisions related to investment decisions, market design or policy issues. The examples were drawn from proceedings in seven states and four regional transmission organizations or independent system operators. They addressed supply and demand-side generation, transmission, cost allocation, research development and demonstration, and market monitoring. They also varied in terms of the stakeholder perspectives considered (i.e., ratepayers, load serving entities, grid operators, and public utility commissions) and a range of technology decisions (i.e., distributed energy, nuclear, and smart metering). Table S.1. illustrates the types of grid modernization decisions, the examples selected to examine how they were made, and the types of analyses or considerations that were involved.

Table S.1. Review Summary: General Methods

			Cost-Benefit Analysis											
Decision/ Investment Area	Decision/ Investment Sub-Area	Jurisdiction/ Docket or Report	Project	Project/ Portfolio	Performance Reporting	Levelized Energy Cost	Reliability Assessment	Cost of New Entry	Cost Allocation Protocol	Proposal Evaluation Criteria	Competitive-ness Analysis	Market Power Analysis	Qualitative	Varied by Specific Issue
Generation, Storage, Demand-side	Performance-based ratemaking	IL- ComEd (11-0772)												
	Distributed generation	NY - REV (14-M-0101)												
		TVA - DG-IV												
	Smart metering	IL - Ameeren (12-0244) ComEd (14-0212)												
	Energy storage	CA - SCE (16-03-002)												
	Resource planning & procurement	CO - PSCO (Related to C17-0316)												
	Net metering	NV - NV Energy (17-07026)												
	Generation retirement	IL - Nuclear (HR 1146)												
		NY - CES												
		CA - PG&E (18-01-022)												
	Reliability	NERC - Reliability Assessment												
	Capacity	PJM - CONE												
Transmission	Portfolio	MISO - MVP												
	Clean energy zones	TX - CREZ												
	Economic assessment	CAISO - TEAM												
Cost Allocation	Multi-state	OR - PacifiCorp (UM 1050)												
Research, Development and Demonstration	State program solicitation	CA - EPIC												
		NJ - Microgrid Feasibility												
Market Monitoring	Market competition	TX - Market Competition												
		TX - TXU (34061)												
		ISO-NE - Market Assessment												

Notes
Primary method applied
Secondary focus/application, or subset of a broader set of criteria

S.3 Potential White-Space for Additional Metrics

The study results of grid modernization decisions reveal some potential white-space for additional metrics to be introduced to analyses that inform decision making. The white-space relates to more in-depth metrics or indicators in metric categories already reported in the case studies, as well as in the categories that are not reflected in the case studies. They include:

- For the existing categories already represented in the case studies:
    - <u>Affordability</u>: cost-burden assessments that reflect equity considerations for investment decisions or policy questions
    - <u>Reliability</u>: value-based reliability improvements, which may identify and prioritize the reliability improvements based on expected value outcomes.
    - <u>Sustainability</u>: water implications related to the addition of specific grid assets, which may be addressed early in the decision-making process rather than later during permitting.
- For the additional metric categories not currently represented in the case studies:
    - <u>Flexibility</u>: consideration of the retrospective or prospective impacts of the addition or retirement of a grid asset on supply-side flexibility, demand-side flexibility, or supply-demand balance.

- o Resilience: assessment of the current state of the electricity system infrastructure's resilience to hazards, and consideration of the prospective impacts of the addition of a grid asset or the implementation of other measures designed to improve the ability of the grid to maintain services during, or recover from damage caused by, extreme weather events.

- o Security: assessment of the current physical and cyber-security stance of electricity system infrastructure and facilities, and consideration of the prospective impact of investments designed to improve that stance.

Table S.2. identifies which of the six GMLC metric categories and sub-categories were used primarily or secondarily in informing the decisions that were made in each example.

Table S.2. Review Summary: Metrics Sub-Categories Applied to Inform Decisions or Investments

		Generation, Storage, Demand-side												Transmission			Cost Allocation	RD&D		Market Monitoring		
		PBR	DG		SM	ES	IRP	NEM	Generation retirement			Rel	Cap	Port	CREZ	Econ	Multi-state	State program		Market competition		
Metric Category	Metric Sub-Category	IL	NY	TVA	IL	CA	CO	NV	IL	NY	CA	NERC	PJM	MISO	TX	CAISO	OR	CA	NJ	TX	TX	ISO NE
Affordability	Consumption/ Revenue	■			■	■					■						■	■	■	■		
	Investment Costs		■										■		■							
	Integration Costs					■	■		■					■	■	■	■					
	Compliance Costs		■	■						■												
	Program Costs	■	■	■	■	■				■				■			■	■				
	Avoided Costs		■	□	■		■				■			■		■		■				
	Value of Reliability		■		□								■			■						
	Retail Rates		■						■		■									■		
	Benefit-Cost		■							■	■			■	■	■						
	Equity				□	□				■									■			
	Market Power																				■	■
Reliability	Outage	■																				
	Resource Adequacy					■	□		■			□	■	■					■			
	Dynamics											■										
Sustainability	Environmental		■		□				■	■					■			■				
	Economic Impact				□				■	□	■							■				
	Health				□																	
	Equity	■																				
	Safety					□																
	Other Societal				□									■	■			■				

Notes
■ Considered in decision
□ Presented or recommended, but not necessarily considered in decision

The knowledge gained from this metrics mapping exercise supports several follow-on Metrics Analysis activities that could support the broader implementation and institutionalization of extended or newly developed metrics produced by the project.

- Development of decision criteria to assess proposals for further DOE investment in grid modernization RD&D, particularly focused on identifying the broader impacts associated with RD&D success.
- Engaging custodians of existing cost-benefit analysis methodologies and performance ratemaking frameworks in targeted discussions about including specific refined metrics in future versions of their products.
- Engaging custodians of existing cost-benefit analysis methodologies to make more explicit consideration of specific resource adequacy metrics in net benefit calculations, including at the distribution system level.
- Working with system planners and operators to explore how traditional assessments conducted to understand the reliability implications of bulk power system additions and retirements could be extended and strengthened with the inclusion of flexibility metrics.
- Partnering with community and utility planners to develop and use cost-benefit analysis methodologies specifically designed to assess resilience and security-related investments.

Acknowledgments

The authors thank Project Manager Mr. Joseph Paladino (DOE) for his recommendations to initiate the mapping task as part of the Metrics Analysis project (GMLC1.1) and for his guidance in scoping the work. The authors would also like to thank Thomas Jenkin (NREL) and Mark Ruth (NREL) for their contributions to the documentation of case studies and the review of this report.

Acronyms and Abbreviations

APPA	American Public Power Association
CAISO	California Independent System Operator
CBA	Cost-Benefit Analysis
CEC	California Energy Commission
DG	distributed generation
DHS	Department of Homeland Security
DOE	U.S. Department of Energy
EEI	Edison Electric Institute
EIA	Energy Information Administration
EPA	U.S. Environmental Protection Agency
EPIC	Electric Program Investment Charge
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
FEMA	Federal Emergency Management Agency
FERC	Federal Energy Regulatory Commission
GMI	Grid Modernization Initiative
GMLC	Grid Modernization Laboratory Consortium
GMLC1.1	Grid Modernization Laboratory Consortium Project Metrics Analysis
IEEE	Institute of Electrical and Electronics Engineers
ICC	Illinois Commerce Commission
IOU	Investor-Owned Utility
ISO	Independent System Operator
LSE	Load Serving Entity
NARUC	National Association of Regulatory Utility Commissioners
NASEO	National Association of State Energy Officials
NEM	Net Energy Metering
NERC	North American Electric Reliability Corporation
NRRI	National Resources Research Institute
NYISO	New York Independent System Operator
MVP	Multi-Value Project
PG&E	Pacific Gas and Electric Company
PUC	Public Utilities Commissions
RD&D	Research Development and Demonstration
REV	Reforming the Energy Vision
RFP	Request for Proposal
RTO	Regional Transmission Organization

Acronyms and Abbreviations Cont'd

SAIFI	System Average Interruption Frequency Index
SASB	Sustainability Accounting Standards Board
UTC	Washington State Utilities and Transportation Commission
WECC	Western Electricity Coordinating Council

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1.0 Introduction

The Grid Modernization Laboratory Consortium (GMLC) was established in 2016 as a partnership between the U.S. Department of Energy (DOE) and the national laboratories to support grid modernization activities, such as renewable energy integration, resilience, and grid security.[4] The DOE's 2015 Grid Modernization Initiative (GMI) Multi-Year Program Plan (MYPP) suggests that as the US electric grid transitions to a modernized electric infrastructure, grid stakeholders, policy makers, regulators, grid planners, and operators should seek balance among six overarching grid attributes: (1) reliability, (2) resilience, (3) flexibility, (4) sustainability, (5) affordability, and (6) security (DOE 2015a).

The GMLC Metrics Analysis (GMLC 1.1) project was established to enhance the existing state of metrics in these six areas in order to: 1) provide federal, state, and municipal regulators more comprehensive information about the current state of the electricity system to measure impacts of grid modernization and technology deployment; 2) support self-assessment by utility organizations across multiple attributes of grid operations; and 3) enable DOE to better set priorities on modernization research and development (R&D).

To achieve this outcome, the six metric category teams, one for each of the above grid attributes, were established and comprised of relevant members of the eight National Laboratory project teams.[5] The teams adopted the following approach to metrics enhancement: 1) engage with key stakeholders and data partners in each of the six metrics areas to understand industry needs, data availability, access to data, and potential use of metrics and concerns about misuse of metrics results; 2) define new metrics or enhancements to existing metrics based on stakeholder validation and inventory of existing metrics (PNNL 2017); 3) validate metrics in real-world conditions; and 4) support the adoption of metrics through standards bodies or use by key data partners.

Extensive stakeholder engagement was conducted to validate the focus of the GMLC 1.1 work, including:

- Identifying and engaging with primary stakeholders for each of the six metric categories, including potential users (e.g., utilities, regulators, policymakers, grid operators), subject matter experts (SMEs), and data providers (e.g., Energy Information Administration (EIA), Federal Energy Regulatory Commission (FERC)) to validate, test and institutionalize the metrics.
- Engaging with the Working Partners, or multi-faceted strategic electric sector organizations (e.g., Electric Power Research Institute (EPRI), FERC, and electric sector trade associations), to socialize the project intent and focus areas, receive strategic feedback, and identify SMEs or relevant work at key organizations.

Specifically, the following stakeholders and Working Partners were engaged for each metric category:

- Reliability: North American Electric Reliability Corporation (NERC), Institute of Electrical and Electronics Engineers (IEEE), American Public Power Association (APPA)
- Resilience: DOE/Office of Energy Policy and Systems Analysis (DOE/EPSA), U.S. Department of Homeland Security (DHS), City of New Orleans, PJM Interconnection, EPRI

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[4] https://www.energy.gov/grid-modernization-initiative-0/grid-modernization-lab-consortium.

[5] Pacific Northwest National Laboratory, Argonne National Laboratory, Lawrence Berkeley National Laboratory, Sandia National Laboratories, National Renewable Energy Laboratory, Lawrence Livermore National Laboratory, Oakridge National Laboratory, Brookhaven National Laboratory

- Flexibility: FERC, Pacific Gas and Electric Company (PG&E), California Independent System Operator (CAISO), EPRI, Electric Reliability Council of Texas, Inc. (ERCOT)
- Sustainability: U.S. Environmental Protection Agency (EPA), EIA, Arizona State University, National Resources Research Institute (NRRI), Sustainability Accounting Standards Board (SASB)
- Affordability: EPRI, Minnesota Public Utilities Commission (PUC), Colorado State Energy Office, Washington State Utilities and Transportation Commission (UTC), National Association of Regulatory Utility Commissioners (NARUC), Alaska Energy Authority
- Security: DHS, EPRI, National Association of State Energy Officials (NASEO), Edison Electric Institute (EEI), Exelon Corporation

Stakeholders were asked to validate the focus of each metric category team's work both at the beginning and end of the project's first year. The results of these engagements are outlined in the GMLC Metrics Analysis Reference Document 2.1 (PNNL 2017). Stakeholders were also asked to provide technical input to ensure that the GMLC 1.1 project team's approaches were novel and built on the state-of-the-art in each metrics category. In other cases, stakeholders were asked to jointly develop or test out new metric methodologies, especially if representing a particular jurisdiction or grid system. For example, CAISO and ERCOT were engaged to conduct historical analysis of flexibility metrics; two different resilience metric approaches were applied with the City of New Orleans. Lastly, certain stakeholders were asked to consider opportunities for institutionalizing new metrics in national survey instruments, such as new sustainability metrics with EIA, or in trade association offerings, such as updates to reliability metrics with APPA.

The project team also developed an inventory of current metrics (PNNL 2017) for each of the six metrics categories. The purpose of this inventory was to identify the existing state-of-the-art and then help each metric category team to contextualize its GMLC 1.1 project approach of enhancing existing metrics or developing new metrics. While this inventory relied on a number of sources (PNNL 2017) and use-cases, the use of these metrics in recent grid modernization investment proceedings was not catalogued nor characterized.

1.1 Motivation for Metrics Mapping

The objective of the metrics mapping effort is to provide the GMLC 1.1 Metrics Analysis team and DOE project managers with a summary of the metrics currently being used to inform public decision making in the electric sector, including decisions related to system planning and investment, system operations, policy, and regulation. This exercise was expected to identify the value of the work being conducted in the current phase of the project (2016-2019). Gaps and other insights from this effort might serve to inform longer-term DOE and GMI metrics and valuation activities. Identification of any metrics important to decision making that had not been considered in the six metrics categories, such as those included in the original inventory (PNNL 2017), was an expected outcome of particular interest. This effort is complementary to the stakeholder engagement elements of the GMLC 1.1 project described above, in which the project team first asked stakeholders to validate identified metrics gaps and then proposed approaches and methodologies for addressing those gaps.

1.2 Report Content and Organization

The remainder of this report focuses on the requested mapping exercise and insights gathered from the process. The GMLC 1.1 project team has collected 21 case studies to describe a range of criteria or metrics to help decisionmakers screen and select grid modernization investment projects and address other related policy or market design issues. Section 2 describes the approach used to identify and document metrics used to inform public decision making, including selecting the case studies and specific information collected for each study. Section 3 provides a synthesis of the case studies, including a description of the metrics data collected and the set of resulting observations. Section 4 identifies implications for ongoing DOE metrics and valuation activities. Appendix A catalogues the original inventory of metrics collected at the beginning of the GMLC 1.1 project and includes metrics being enhanced or developed by the GMLC 1.1 project team. Appendix B includes summaries of the information collected for each of the case studies and Appendix C provides more detail on the specific methodologies and metrics identified from each case study.

2.0 Approach

This section provides more detail on the process of selecting and characterizing the case studies chosen for this effort. The case studies were identified through a non-exhaustive review of the literature and selected based on the following informal criteria: the topic is timely and of concern to the regulatory community; and publicly available data exists on the decision-making process, the metrics adopted in the process, details on the methodologies employed to operationalize those metrics, and the results of the related analysis.

The 21 cases selected represent proceedings or reports in seven different states and four independent system operators (ISOs). These cases reflect a wide range of grid modernization decisionmakers, stakeholders, infrastructure, metrics, and policy decisions. For example, the case studies reflect a variety of policy, investment, and other energy market design questions, including supply and demand-side generation, transmission, cost allocation, research development and demonstration (RD&D), and market monitoring. The cases also vary in terms of the stakeholder perspectives considered (e.g., ratepayers, load serving entities (LSE), ISOs, and public utility commissions (PUCs)) and a range of technology decisions (i.e., distributed energy, nuclear, and smart metering). Some of the cases document or reflect the application of assessment methodologies, including New York's Benefits-Cost Analysis Framework developed as a part of its Reforming the Energy Vision (REV) process, the California Energy Commission's (CEC) evaluation framework for its Electric Program Investment Charge (EPIC) program, and NERC's long-term reliability assessment framework. Summaries of the information collected for each of the case studies can be found in Appendix B.

The case studies documented in Appendix B were developed through a review of archival data related to each case, such as public utility commission orders, published cost-benefit methodologies, and integrated resource plans, among others. This material was used to catalogue the type of decision in each case, the jurisdiction of the decision, and related reports or proceeding details. The rationale for each grid modernization proceeding was also documented and ranged from efforts to reform state energy markets in New York to assessments of the estimated impact of the potential retirement of financially at-risk nuclear generators on the electricity grid and its stakeholders in Illinois.

The methodology used in each case study was described, including its type (e.g. cost-benefit or cost allocation), and any analytical tools, models, or engineering approaches used to apply the methodology. Within each methodology, the metrics of input, output, and those generated through data collected as part of the proceeding or assessment were identified. The outcomes of the proceedings were also documented where available. These data were then compared across cases to demonstrate the types of grid attribute categories and related metrics that have been considered to date. The cases and related observations are organized by topic area and grid attribute category in Section 3.

While the cases selected offer a variety of insights about decisions related to grid modernization, they are not exhaustive in terms of the potential decisions or options and initiatives that could be carried out to improve grid planning and operations. Rather, these cases are illustrative of some, but not all, grid modernization decisions. In addition, there are some emerging areas that are not covered in this analysis, including some in flexibility, resilience, and security metrics space, in part because of the lack of publicly available data. Given this and other limitations, the results and conclusions presented here can be considered informative, but not comprehensive.

3.0 Synthesis of the Case Studies – Data Description and Observations

Metrics are currently used across a broad range of decision types, often documented with formal methodologies. The cases broadly considered decisions related to investment (e.g., generation or transmission capacity), regulation (e.g., performance-based ratemaking, cost allocation), and policy (e.g., net energy metering, Clean Energy Standard). Cases were characterized into the following decision/investment areas:

- Generation, Storage, Demand-side (including performance-based ratemaking, distributed generation, smart metering, energy storage, resource planning and procurement, net metering, generation retirement, reliability assessment, and capacity),
- Transmission (including portfolio management, clean energy zones, economic assessment),
- Cost Allocation,
- RD&D, and
- Market Monitoring.

Table 3.1 provides a summary of the overall decision/investment areas and sub-areas, the specific cases considered, and the primary methodology applied in each case.

Table 3.1. Review Summary: General Methods

			Cost-Benefit Analysis											
Decision/ Investment Area	Decision/ Investment Sub-Area	Jurisdiction/ Docket or Report	Project	Project/ Portfolio	Performance Reporting	Levelized Energy Cost	Reliability Assessment	Cost of New Entry	Cost Allocation Protocol	Proposal Evaluation Criteria	Competitive-ness Analysis	Market Power Analysis	Qualitative	Varied by Specific Issue
Generation, Storage, Demand-side	Performance-based ratemaking	IL- ComEd (11-0772)			●									
	Distributed generation	NY - REV (14-M-0101)	●											
		TVA - DG-IV	●											
	Smart metering	IL - Ameeren (12-0244) ComEd (14-0212)	●											
	Energy storage	CA - SCE (16-03-002)	●				○							
	Resource planning & procurement	CO - PSCO (Related to C17-0316)				●	○							
	Net metering	NV - NV Energy (17-07026)											●	
	Generation retirement	IL - Nuclear (HR 1146)	●				○							
		NY - CES	●											
		CA - PG&E (18-01-022)												●
	Reliability	NERC - Reliability Assessment					●							●
	Capacity	PJM - CONE					○	●						
Transmission	Portfolio	MISO - MVP	○	●			○							
	Clean energy zones	TX - CREZ	○	●			○							
	Economic assessment	CAISO - TEAM	●				●							
Cost Allocation	Multi-state	OR - PacifiCorp (UM 1050)							●					
Research, Development and Demonstration	State program solicitation	CA - EPIC	○							●				
		NJ - Microgrid Feasibility		○						●				
Market Monitoring	Market competition	TX - Market Competition									●			
		TX - TXU (34061)										●		
		ISO-NE - Market Assessment										●		

Notes
● Primary method applied
○ Secondary focus/application, or subset of a broader set of criteria

3.1 Methodologies Applied

Several different methodologies were employed for calculating metrics used to inform the decisions. Cost-benefit analysis (CBA) methodologies dominate the reviewed proceedings, with half of the cases employing some form of cost-benefit analysis approach. Most of the cost-benefit analyses were conducted at the project level, while a few also considered portfolios of projects. While common in overall concept, the methodologies show variation in detail, including the specific component costs and benefits metrics considered and the ultimate aggregate measure of merit (e.g., net benefit). Other methods represented were often specific to the type of decision being informed, such as levelized cost of energy (new generation procurement), cost of new entry (capacity market compensation), cost allocation protocols (for assigning shared costs across states served by a single utility), and competitiveness analysis (for assessing the actual operation of competitive markets). More information on the methodologies applied and the decision context for each of the proceedings can be found in Appendices B and C (Table C.1).

3.2 Metrics Characterization

Metrics were identified and categorized for each of the proceedings shown in Table 3.1. As summarized in Table 3.2, 166 metrics were identified among the 21 cases, with 88 characterized as distinct. Metrics were first categorized by system attribute, using the six metric category areas defined and applied in the GMLC 1.1 project (PNNL 2017): Affordability, Reliability, Sustainability, Flexibility, Resilience and Security. To enable more granular characterization of the metrics collected, reported metrics were also grouped into sub-categories for three of the six category areas.

Table 3.2. Review Summary: Metrics by Sub-Category

Category	Distinct	Instances
Affordability	**59**	**114**
Consumption/Revenue	11	17
Investment Costs	3	3
Integration Costs	3	10
Compliance Cost	1	3
Program Costs	10	19
Avoided Costs	9	28
Value of Reliability	3	6
Retail Rates	3	6
Benefit-Cost	6	10
Equity	3	4
Market Power	7	8
Reliability	**15**	**24**
Outage	3	3
Resource Adequacy	11	20
Dynamics	1	1
Sustainability	**14**	**28**
Environmental	4	14
Economic Impact	3	6
Health	1	1

Category	Distinct	Instances
Equity	1	1
Safety	1	1
Other Societal	4	5
Flexibility	**0**	**0**
Resilience	**0**	**0**
Security	**0**	**0**
Total	**88**	**166**

Additionally, certain *concept*s were also characterized for each of the proceedings or assessments that did not qualify as distinct and measurable *metrics*. As summarized Table 3.3. , these concepts include reference to grid attributes that are assessed in separate exercises (e.g., an entity conducts a reliability assessment and then submits a filing), or may refer to concerns for which metrics have not yet been developed.

Table 3.3. Concepts Expressed in Proceedings

Category	Concept
Affordability	Maximize program cost-effectiveness, prevent cross-subsidization, eliminate energy theft
Reliability	Maintain transient stability and voltage stability, avoid short-circuits
Sustainability	Avoid land impacts, increase non-energy benefits, minimize health impacts, effectively disseminate information to customers and suppliers, encourage technological innovation
Other	Ensure project viability, stakeholder transparency, and consistency of screening criteria with public interest aims

3.2.1 Affordability Category

Based on this characterization of the case study metrics, more than two-thirds of the distinct metrics identified (59 of the 88 total) were included in the Affordability category. Most of these metrics can be considered either inputs to or components of traditional electric sector cost-benefit analyses and are primarily focused on the cost of an investment and related costs to the electricity system associated with it (e.g., energy integration costs), and the quantifiable benefits associated with the investment, including associated savings in other parts of the system (e.g., avoided costs) and the impact on utility bills. Some metrics outline the types of data that can be collected from Advanced Metering Infrastructure (AMI) and inform customer usage data and revenue collection issues. Other Affordability metrics describe the cost impacts of implementing or complying with environmental or energy efficiency programs or assess the exercise of market power by generators that could impact costs to customers. The three largest Affordability sub-categories include: metrics that report energy consumption or the utility revenue derived from that consumption (Consumption/Revenue); costs associated with the implementation and administration of energy programs (Program Costs); and various facets of avoided cost (Avoided Costs). Notably, there we only three instances of metrics in the cases associated with the equity of rates among classes of customers.

3.2.2 Reliability Category

Reliability metrics are also well-represented in the cases. The largest sub-category in this area are metrics related to resource adequacy, including those focused on achieving resource adequacy in a system planning context (e.g., loss of load expectation, reserve margin, operating reserves). Other Reliability metrics reported include those used in capacity market design and planning, and those that assess the role of energy storage in providing resource adequacy. Other metrics report on actual outages or interruptions in service (e.g., System Average Interruption Frequency Index (SAIFI) and Customer Average Duration Index (CAIDI)) and assess the dynamic stability of the bulk power system in light of certain investments. The nature and application of Reliability metrics reported from the case studies is somewhat clouded by a few issues, and as a result may be under-reported. In some cases that apply cost-benefit methodologies to consider investments in new generation capacity of various types, approaches to assessing resource adequacy are not explicitly identified (referred to as *concepts* above); in some of these cases, consideration of separate reliability studies, outside the cost-benefit methodology, may be assumed or implied. In other cases, general reference is made to the application of specific techniques (e.g., production cost modeling), but specific Reliability metrics are sometimes not identified—instead, adherence to NERC standards and regional reliability requirements is pointed out.

3.2.3 Sustainability Category

There is some representation of Sustainability metrics in the cases considered, not limited to just environmental sustainability. Reported environmental metrics include consideration of greenhouse gas (GHG) emissions, criteria air pollutants, land impacts, and water consumption. Consistent with a broader definition of sustainability, this category also includes metrics reported for human health, broader economic considerations (e.g., employment, GDP, tax impacts, and labor implications), safety, and other societal impacts (e.g., reflecting other attributes of investments like clean energy).

3.2.4 Remainder Category: Flexibility, Resilience, Security

Finally, based on the case study research, no metrics were identified in the Flexibility, Resilience, and Security categories. This lack of metrics reporting may reflect a general dearth of public information on these measures given their general emerging nature and possible limitations in the case study selection and metrics characterization processes. In the latter case, Flexibility metrics may currently be considered as a component of broader reliability assessments, particularly those related to resource adequacy in both systems planning and systems operations contexts. Resilience metrics may also be considered as a component of reliability, or in some cases economic sustainability. Decisions on resilience-related investments may also occur at a local or municipality jurisdictional level that is not represented in the state-level approach adopted in case study selection. Decisions on security-related investments (related to improving the physical and cyber-security stance of electricity system infrastructure and facilities), may also currently be considered components of other categories, like Reliability, or rolled into administrative costs that are considered in the Affordability category. In the broader stakeholder engagement work conducted for the project, other ISOs, utilities, and municipalities have each indicated the use of and need for metrics in these areas. As such, the lack of metrics reporting in these categories among the cases should not be construed as a general indicator that these types of metrics are either not in use or not important to electricity system decision makers.

3.3 Metrics Occurrence Across the Case Studies

Table 3.4 identifies the occurrence of the metrics sub-categories across the 21 case studies examined. The application of Affordability metrics is most prevalent across the studies, both in terms of the number of instances across the cases (114), as well as in the number of cases that include this category of metric (19). Sustainability metrics are the next most frequent in occurrence, with 28 instances spread across 10 cases. Reliability metrics have 24 instances spread across 8 cases. Identification of and mapping of the complete set of unique metrics to the specific cases in which they were found are shown in Appendix B.

Table 3.4. Review Summary: Metrics Sub-Categories Applied to Inform Decisions or Investments

		Generation, Storage, Demand-side												Transmission			Cost Allocation	RD&D		Market Monitoring		
		PBR	DG		SM	ES	IRP	NEM	Generation retirement			Rel	Cap	Port	CREZ	Econ	Multi-state	State program		Market competition		
Metric Category	Metric Sub-Category	IL	NY	TVA	IL	CA	CO	NV	IL	NY	CA	NERC	PJM	MISO	TX	CAISO	OR	CA	NJ	TX	TX	ISO NE
Affordability	Consumption/ Revenue	●			●	●					●						●	●	●	●		
	Investment Costs		●										●		●							
	Integration Costs					●	●		●					●	●	●	●					
	Compliance Costs		●	●						●												
	Program Costs	●	●	●	●	●				●				●			●	●				
	Avoided Costs		●	○	●		●				●			●		●		●				
	Value of Reliability		●		○								●			●						
	Retail Rates		●						●		●									●		
	Benefit-Cost		●							●	●			●	●	●						
	Equity				○	○				●									●			
	Market Power																				●	●
Reliability	Outage	●																				
	Resource Adequacy					●	○		●			○	●	●					●			
	Dynamics											●										
Sustainability	Environmental		●		○				●	●					●			●				
	Economic Impact				○				●	○	●							●				
	Health				○																	
	Equity	●																				
	Safety					○																
	Other Societal				○									●	●			●				

Notes
● Considered in decision
○ Presented or recommended, but not necessarily considered in decision

The majority of the cases examined, including all those employing some form of cost-benefit analysis, report metrics from multiple categories, indicating that multiple categories of metrics were used in the decision-making processes. The exceptions are the cases that consider cost allocation and market competition decisions. Five of the cases reported at least one metric in the Affordability, Reliability, and Sustainability categories: Illinois Performance-based ratemaking, California EPIC, Illinois Nuclear retirement, Midcontinent Independent System Operator (MISO) Multi-Value Project (MVP) Portfolio, and Texas Competitive Renewable Energy Zones (CREZ). In some cases, specific underlying methodologies that were applied called for the consideration of these metrics from multiple categories and defined their integration into more aggregate net benefit measures. In other cases, the metrics from multiple categories were calculated and generated independently and not integrated or synthesized.

Metrics also served different roles in the decisions characterized in the case studies. In general, the metrics identified in the cases were used to *inform* a decision; the criteria that were used to make the decision were not specified in the publicly available proceedings, nor were the relationships between the metrics and the criteria. In two cases, there was a more direct relationship between the specific metrics and decision criteria. In the California Diablo Canyon proceeding, specific metrics were required by the California Public Utilities Commission for decisions to be made about the various order considerations. In the California EPIC program, the metrics identified reflect a subset of a broader set of decision criteria used to evaluate and select RD&D investment projects.

4.0 Implications of the Case Study Results to the GMLC Metrics Analysis 1.1 Project

4.1 Relationship to the GMLC 1.1

The objective of this mapping effort is to, through a literature review and case study process, collect metrics that have been used in recent grid modernization proceedings or decisions, and then to compare these metrics with those that have been the focus of the GMLC Metrics Analysis 1.1. project. There are currently three different sets of metrics that can be mapped and are categorized in Appendix A:

1. **The inventory**. At the beginning of the GMLC 1.1 project, each metric category team identified the broader landscape of readily available metrics in the category (e.g., reliability). These metrics were identified and defined in the Appendix of the GMLC 1.1 Reference Document 2.1 (PNNL 2017). This inventory helped inform each of the metric category teams determine where to focus effort in enhancing or developing new metrics for the project.

2. **The GMLC 1.1 project metrics**. The six metric category teams identified and validated with stakeholders input metrics that could be enhanced if already existing in some form or developed if not already available. These metrics and associated methodologies are described in detail by category in the GMLC Metrics Analysis Reference Document 2.1 (PNNL 2017).

3. **The case study metrics**. Through the case studies reviewed and described in this report, 88 specific metrics were identified in the literature review and are captured in Appendix C.

Case Study v. Inventory. In general, the set of metrics reported in the case studies are largely in common with the metrics identified in the broader inventory, with the following notable exceptions:

- The case study metrics feature more granularity in the Affordability category than in the inventory.
- Case study metrics in Sustainability include economic and societal aspects that are not considered in the inventory, which is limited to consideration of environmental sustainability.
- There is no overlap between Resilience, Flexibility, or Security metrics in the inventory.

Case Study v. GMLC 1.1 Project. In general, the set of metrics being extended or developed as part of the GMLC 1.1 project in the Affordability, Reliability, and Sustainability categories are largely complementary to, rather than directly overlapping with, those identified in the case studies:

- Affordability: Most of the Affordability metrics reported in the case studies do not relate to the cost-burden metrics developed as part of the GMLC 1.1 project. Only two of the 59 reported Affordability metrics focus on cost equity among classes of ratepayers, a sub-category related to cost burden.
- Reliability: One case study reflects the use of traditional outage metrics (e.g. SAIFI, CAIDI) and a few others to report the value of reliability metrics quantifying avoided outage costs. The project's focus is to extend the usefulness of these distribution system measures by considering them in the context of different customer classes and improving the understanding of the economic impacts associated with actual outages. Several other cases report resource adequacy metrics related to NERC reliability standards (e.g., Loss of Load Expectation (LOLE), reserve margin). Another focus of the project's work in reliability explores the development of other resource adequacy measures to improve the robustness of reliability assessments.

- Sustainability: The project's work on sustainability metrics has focused on understanding the completeness of existing national data sources for historical GHG emissions, identifying a need to more completely include emissions from distributed energy resources (DER). While GHG emissions metrics are among the environmental metrics reported in the case studies, the sources considered in the cases mostly concern generators on the bulk power system. A few of the cases also identified metrics related to water consumption. The project's work extends the consideration of water in electricity generation to additional measures, including a synthesis measure assessing water availability risk.

As discussed in Section 4.2 above, the set of metrics identified in the case studies have no overlap with those being developed in the GMLC 1.1 project in the Resilience, Flexibility, and Security categories. This lack of metrics reporting in these categories may reflect the following:

- There are a set of compliance requirements that must be met regardless of the decision, such as safety.

- A general dearth of public information on these measures, given their general emerging nature or limitations in the case study selection and metrics characterization processes.

- Decisions on investments related to these categories (e.g. Resilience) may occur at a local or municipality jurisdictional level that is not represented in the state-level approach adopted in case study selection.

- Consideration of the grid system attributes reflected by these categories may be considered as an aspect of other categories. For example, security-related investments (related to improving either the physical and/or cyber-security stance of electricity system infrastructure and facilities) may be considered components of other categories, like Reliability, or rolled into administrative costs that are considered in the Affordability category.

- Lack of definitions and supporting calculation methodologies for measures in these categories (e.g., flexibility, resilience) given their general emerging nature.

4.2 White-Space for Additional Metrics

The case study results reveal some potential white-space for additional metrics to be introduced to analyses that inform decision making. The white-space relates to more in-depth metrics or indicators in metric categories already reported in the case studies, as well as in the categories that are not reflected in the case studies. The content of the white-space draws from the work that was performed with the 6 GMLC1.1 metric categories. They include:

- For the existing categories already represented in the case studies:

    - Affordability: cost-burden assessments that reflect equity considerations for investment decisions or policy questions.

    - Reliability: value-based reliability improvements, which may identify and prioritize the reliability improvements based on expected value outcomes.

- Sustainability: water implications related to the addition of specific grid assets, which may be addressed early in the decision-making process rather than later during permitting.

- For the additional metric categories not currently represented in the case studies:
  - Flexibility: consideration of the retrospective or prospective impacts of the addition or retirement of a grid asset on supply-side flexibility, demand-side flexibility, or supply-demand balance.
  - Resilience: assessment of the current state of the electricity system infrastructure's resilience to hazards, and consideration of the prospective impacts of the addition of a grid asset or the implementation of other measures designed to improve the ability of the grid to maintain services during, or recover from damage caused by, extreme weather events.
  - Security: assessment of the current physical and cyber-security stance of electricity system infrastructure and facilities, and consideration of the prospective impact of investments designed to improve that stance.

4.3 Opportunities for Application of Metrics Emerging from Metrics Analysis

Given the complementary nature and increased depth of the project's focus on Affordability, Reliability, and Sustainability metrics as described above, there appears to be strong potential for these extended metrics to one day inform the types of decisions that are considered in the case studies.

- Affordability: The prevalence of Affordability metrics used to inform the decisions examined suggests an opportunity. One challenge is that most of the reported metrics directly contribute to the calculation of net benefits. Cost-burden metrics are complementary measures meant to estimate the distribution of net benefits across income classes. This additional information would seem particularly useful in assessing the Affordability of investments to generation, storage, and demand-side capacity for both the bulk power and distribution systems. Burden metrics might also be a useful extension to reporting on the state of market competition.
- Reliability: Extensions of outage-related metrics focused on the distribution system could provide additional information to inform performance-based ratemaking decisions. Extensions of traditional resource adequacy measures could be useful in improving forward-looking reliability assessments focused on understanding the implications of additions and retirements of generation and storage assets. This could be used initially for the bulk power system.
- Sustainability: Improvement of historical GHG emissions reporting through consideration of distributed sources, and additions of water availability metrics, could improve the robustness of assessment of the environmental implications of investments or retirements of generation, storage, and demand-side capacity, transmission, and RD&D.

As described in Section 3 above, there are several potential reasons why Resilience, Flexibility, and Security metrics did not explicitly appear among the cases examined. While this mapping exercise does not provide any direct insights to the potential application and take-up of project-developed metrics in these categories, extending the scope of cases considered to include systems operations decisions or market monitoring, as well as investment decisions made at the local/municipality jurisdictional level, may provide some visibility.

4.4 Implications for Additional Work in Metrics Analysis

Knowledge gained from this metrics mapping exercise supports several follow-on Metrics Analysis activities that could support the broader implementation and institutionalization of extended or newly developed metrics produced by the project.

- Development of decision criteria to assess proposals for further DOE investment in grid modernization RD&D, particularly focusing on identifying the broader impacts associated with RD&D success.
- Engaging custodians of existing cost-benefit analysis methodologies and performance ratemaking frameworks in targeted discussions about including specific, refined metrics in future versions of their products.
- Engaging custodians of existing cost-benefit analysis methodologies to take more explicit consideration of specific resource adequacy metrics in net benefit calculations, including at the distribution system level.
- Working with system planners and operators to explore how traditional assessments conducted to understand the reliability implications of bulk power system additions and retirements could be extended and strengthened with the inclusion of flexibility metrics.
- Partnering with community and utility planners to develop and use cost-benefit analysis methodologies specifically designed to assess resilience and security-related investments.

The long-term goal for the GMLC metrics analysis work is to develop a set of relevant metrics that can be used to measure overall progress in the evolving grid or inform specific decision making. To support this goal, the predefined universe of potential grid attributes was made very broad (the six metric categories discussed above). As such, the scope of metrics consideration at the start of the project was defined from a very holistic prospective. The results of this mapping analysis indicate that the decisions examined were not necessarily informed by metrics that draw from the holistic set of categories (i.e., cover all six categories). Rather, a smaller set of metrics was often used to estimate cost and benefits.

As such, to advance the breadth of metrics considered in decision making, one might take an incremental approach by identifying the next highest value or benefit that could help inform a decision rather than attempting to expand the scope of cost and benefits to all six metrics areas. Furthermore, the decision space for future focus might be limited to system planning and related investments rather than a broader scope of PUC proceedings related to grid modernization.

4.5 Potential Further Work in Stakeholder Metrics Mapping

This initial metrics mapping work could be usefully extended in the following ways:

- Validate with stakeholders the initial observations from the case studies, implications for metrics analysis, and identify additional cases for future examination.
- Identify the subset of metrics identified in Appendix A of most importance to specific stakeholder groups.

- Extend the case study examination to consider applications of metrics in Resilience, Flexibility, and Security categories, perhaps at the local/municipality jurisdictional level.
- Convene a stakeholder workshop to share initial and additional observations and identify opportunities for useful follow-on metrics analysis work related to grid modernization.

5.0 References

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Appendix A

Updated Impact Metrics Inventory

Impact Metrics Inventory

Adapted from the Grid Modernization: Metrics Analysis Reference Document, Version 2.1 May 2017

Category	Impact Metrics (circle all that apply)				
Reliability	SAIFI	SAIDI	CAIDI	CAIFI	CTAIDI
	ASAI	MAIFI	CEMI	CEMSMI	CI
	CMI	ASIFI	ASIDI	CELID	SARI
	COR	DELI	DEMI	ACOD	ACSI
	TACS	FOHMY	Interruption Cost		
Resilience	Cost per outage	Cumulative customer-hours of outages	Cumulative customer energy demand not served	Average (or %) customers experiencing an outage during a specified time period	Cumulative critical customer-hours of outages
	Critical customer energy demand not served	Average (or %) of critical loads that experience an outage	Time to recovery	Cost of recovery	Loss of utility revenue
	Cost of grid damages	Loss of utility revenue	Cost of grid damages (e.g., repair or replace lines, transformers)	Avoided outage cost	Critical services without power
	Critical services without power after backup fails	Loss of assets and perishables	Business interruption costs	Impact on Gross Metropolitan Product (GMP) or Gross Regional Product (GRP)	Key production facilities w/o power
	Key military facilities w/o power				
Flexibility	Variable energy resource penetration	Flexibility turndown factor	Net demand ramping variability	Flexible capacity need	System regulating capability
	Demand response	Flexible resource indicator	Periods of flexibility deficit	Insufficient ramping resource expectation	Flexibility metric (ISO-NE)
	Loss of load due to flexibility deficiency	Binding flexibility ratio	Renewable curtailment	Percentage of unit-hours mitigated	Control performance standards
	Ratio of peak to min daily net load	Solar curtailment	Wind curtailment	Negative prices	Max ramp rate in net load
	Positive price spikes	Out-of-market actions	Net load forecasting errors		
Security	Physical Security Protective Measures Index (infrastructure agnostic)	Security Force Protective Measures Index (infrastructure agnostic)	Security Management Protective Measures Index (infrastructure agnostic)	Information Sharing Protective Measures Index (infrastructure agnostic)	Annualized Loss Expectancy
	Reportable cyber security incidents	Reportable physical security incidents	Copper theft instances	Intrusion or attacks, successful and unsuccessful	False or nuisance alarms
	Monitoring equipment condition	Security personnel performance in exercises and tests	Vandalism instances	Incidents requiring manual cleanup	Mean-Time-to-Fix (MTTF)
	Mean cost to mitigate vulnerabilities	Cost of incidents			
Sustainability	Electric sector GHG emissions (measure)	Electric sector hourly GHG emissions (continuous monitoring)	Electric sector criteria pollutant air emissions (measure)	Electric sector hourly criteria pollutant air emissions (continuous monitoring)	Total water withdrawal and consumption
	Water use intensity	Water availability	Relative water risk	Pollutant discharges to water	Land-use change

Category	Impact Metrics (circle all that apply)				
	Depletion of natural resources	Impact on human health			
Affordability	Levelized cost of electricity (LCOE) - utility	Internal rate of return (IRR) - utility	Simple payback period - utility	Net revenue requirements - utility	Avoided cost - utility
	Household electricity burden - customer	Household electricity affordability gap - customer	Household electricity affordability gap index - customer	Household electricity affordability headcount index - customer	Annual average customer cost - customer
	Average customer cost index - customer	Affordability threshold			

Potential Impact Metrics Detail

Adapted from the Grid Modernization: Metrics Analysis Reference Document, Version 2.1 May 2017

Reliability		
Metric	**Additional Definition**	**Data Needed**
SAIFI	System Average Interruption Frequency Index	Total customers served
SAIDI	System Average Interruption Duration Index	
CAIDI	Customer Average Interruption Duration Index	Customer interruption duration
CAIFI	Customer Average Interruption Frequency Index	
CTAIDI	Customer Total Average Interruption Duration Index	
ASAI	Average Service Availability Index	Customer-hours service availability; customer service hours demanded
MAIFI	Monthly Average Interruption Frequency Index	Total customer momentary interruptions
CEMI	Customers Experiencing Multiple Interruptions	Total customers experiencing more than *n* sustained outages
CEMSMI	Customers Experiencing Multiple Sustained Interruption and Momentary Interruptions	Total customers experiencing more than *n* momentary interruptions
CI	Customers Interrupted	Customers interrupted
CMI	Customer Minutes Interrupted	Customer minutes interrupted
ASIFI	Average System Interruption Frequency Index	Total connected kVA of load interrupted
ASIDI	Average System Interruption Duration Index	Total connected kVA served
CELID	Customers Experiencing Long Interruption Durations	Total number of customers that have experienced more than eight interruptions in a single reporting year
SARI	System Average Restoration Index	Circuit outage number and duration
COR	Correct Operation Rate	Number of correct operations; total number of operations commanded
DELI	Devices Experiencing Long Interruptions	Total distribution equipment experiencing long outages
DEMI	Devices Experiencing Multiple Interruptions	Length of interruption (by equipment type)
ACOD	Average Circuit Outage Duration	Transmission circuit outage and duration
ACSI	Average Circuit Sustained Interruptions	
TACS	Transmission Availability Composite Score	Total amount of equipment that have more than N # of interruptions in a single year
FOHMY	Forced Outages per Hundred Circuit Miles per Year	Outages per hundred miles per year
Interruption Cost	Customers interrupted (by type of customer)	
	Characteristics of interruptions by customer type (e.g., duration, start time)	

Resilience		
Metric	**Additional Definition**	**Data Needed**
Cost per outage		
Cumulative customer-hours of outages		Customer interruption duration (hours)
Cumulative customer energy demand not served		Total kVA of load interrupted (by customer?)
Average (or %) customers experiencing an outage during a specified time period		Total kVA of load served (by customer?)
Cumulative critical customer-hours of outages		Critical customer interruption duration
Critical customer energy demand not served		Total kVA of load interrupted for critical customers
Average (or %) of critical loads that experience an outage		Total kVA of load served to critical customers
Time to recovery		
Cost of recovery		
Loss of utility revenue		Outage cost for utility ($)
Cost of grid damages	e.g., repair or replace lines, transformers	total cost of equipment repair
Loss of utility revenue		Outage cost for utility ($)
Cost of grid damages (e.g., repair or replace lines, transformers)		Total cost of equipment repair
Avoided outage cost		Total kVA of interrupted load avoided
Critical services without power		Number of critical services without power; total number of critical services
Critical services without power after backup fails		Total number of critical services with backup power; duration of backup power for critical services
Loss of assets and perishables		
Business interruption costs		Average business losses per day (other than utility)
Impact on GMP or GRP		
Key production facilities w/o power		Total number of key production facilities w/o power (how is this different from total kVA interrupted for critical customers?)
Key military facilities w/o power		Total number of military facilities w/o power (same comment as above)

Flexibility		
Metric	**Additional Definition**	**Data Needed**
Variable energy resource penetration	Ratio of the variable resource nameplate capacity to the system peak load	Variable resource nameplate capacity; system peak load
Flexibility turndown factor	Ratio of the must run and non-dispatchable energy (wind, solar, and nuclear) to the annual sales	Must run capacity (MW/year); non-dispatchable capacity (MW/year)
Net demand ramping variability		Total load; load less VERs
Flexible capacity need	Monthly measure of the maximum 3-hour contiguous ramp in the net load plus the larger of the most severe single contingency or 3.5% of the monthly peak load	Max 3-hour ramp in net load; monthly peak load
System regulating capability	Ratio of the regulating reserve, demand response, quick start capacity to the system peak load	Regulating reserve; demand response
Demand response	DR as a % of total installed capacity	% of total installed capacity
Flexible resource indicator	Ratio of natural gas-fired combustion turbine nameplate capacity and 15% of hydropower capacity to the nameplate capacity of wind	Natural gas-fired combustion turbine nameplate capacity; 15% of hydropower capacity; wind nameplate capacity
Periods of flexibility deficit	Quantity by which potential demand for flexibility exceeds the potential to supply flexibility (i.e. react to a change in the net load) for any hour	Hours
Insufficient ramping resource expectation	The expected number of observations when a power system cannot cope with the changes in net load, predicted or unpredicted	Maximum and minimum rated output; start-up time; ramp up and ramp down rate; forced outage rate; production levels
Flexibility metric (ISO-NE)	Comparison of the largest variation range (i.e. the flexibility supply) with the target range (the flexibility demand) to reflect excessive availability of the system relative to the target variation range	Expected load over time period *t*; expected variable load over time period *t*
Loss of load due to flexibility deficiency		All data needed for production cost model
Binding flexibility ratio	Measures the ratio of the flexibility demand to the flexibility supply in the operational time interval where flexibility is most binding	All data needed for production cost model
Renewable curtailment	Percentage of the available renewable energy that must be curtailed due to flexibility limitations	MWh of wind and solar curtailment
Percentage of unit-hours mitigated	Percentage of unit-hours for which prices were set at the mitigated price on an annual basis	Out-of-market transaction data
Control performance standards	Control performance standards measure a balancing area's Area Control Error (ACE) which indicates how well the system operators maintain a balance between supply and demand. Balancing Area's (BA) need to meet NERC-mandated performance standards to show that they are maintaining an adequate balance	CPS1 and CPS2 data
Ratio of peak to minimum daily net load		Peak and minimum net load by season
Solar curtailment		Curtailed solar load (MWh) by season and time of day

Flexibility		
Metric	**Additional Definition**	**Data Needed**
Wind curtailment		Curtailed wind load (MWh) by season and time of day
Negative prices		Negative prices by season and time of day
Max ramp rate in net load		Ramp rate (MW/min) by season and time of day
Positive price spikes		Fraction of hours upper limit hit annually; $/MWh maximum price; fraction of hours price increase by x% by season and time of day
Out-of-market actions		MWh annual
Net load forecasting errors		Day-ahead, 4 hours ahead, and 1 hour ahead forecasts; Realized hourly net loads

Security		
Metric	**Additional Definition**	**Data Needed**
Physical security protective measures index (infrastructure agnostic)		Input from facility owners/operators; default aggregated data from DHS by electric infrastructure type; publicly available data
Security force protective measures Index (infrastructure agnostic)		Input from facility owners/operators; default aggregated data from DHS by electric infrastructure type; publicly available data
Security management protective measures Index (infrastructure agnostic)		Input from facility owners/operators; default aggregated data from DHS by electric infrastructure type; publicly available data
Information sharing protective measures index (infrastructure agnostic)		Input from facility owners/operators; default aggregated data from DHS by electric infrastructure type; publicly available data
Annualized loss expectancy		Single loss expectancy; annualized rate of occurrence
Reportable cyber security incidents	Number of reportable cyber security incidents that result in a loss of load, summed on a quarterly basis	Number of cyber incidents that result in loss of load
Reportable physical security incidents	Number of physical security reportable events that occur over time as a result of threats to a facility or control center or damage or destruction to a facility, summed on a quarterly basis	Number of physical incidents
Copper theft instances	Number	
Intrusion or attacks, successful and unsuccessful	Number	Number of successful and unsuccessful attacks
False or nuisance alarms	Number	Number of false or nuisance alarms
Monitoring equipment condition	Number of times that security system is unable to detect or respond	Number of malfunctions of security equipment
Security personnel performance in exercises and tests	Description of preparedness	Score on security training exercises; score on security tests
Vandalism instances	Number	Number of incidents of vandalism
Incidents requiring manual cleanup	Number of incidents requiring manual cleanup	Number of Incidents requiring manual cleanup
Mean-Time-to-Fix (MTTF)		
Mean cost to mitigate vulnerabilities		
Cost of incidents		All incident types

Sustainability		
Metric	**Additional Definition**	**Data Needed**
Electric sector GHG emissions (measure)	CO_2, N_20, CH_4, HFC, PFC, SF_6, NF_3	Fuel combustion for all generation types and capacities; emissions factor for all generation types and capacities
Electric sector hourly GHG emissions (continuous monitoring)	So_2, NOx, PM2.5 and heavy metals	Hourly average concentration for all generation types and capacities; hourly average volumetric flow rate for all generation types and capacities; hourly heat input rate for all generation types and capacities
Electric sector criteria pollutant air emissions (measure)	So_2, NOx, PM2.5 and heavy metals	
Electric sector hourly criteria pollutant air emissions (continuous monitoring)	So_2, NOx, PM2.5 and heavy metals	
Total water withdrawal and consumption		Volume of water (by generation type)
Water use intensity		Volume of water/MWh (by generation type)
Water availability	Regional physical/legal	Volume of water per day, month, year
Relative water risk		Water intensity; water scarcity
Pollutant discharges to water		
Land-use change		
Depletion of natural resources		
Impact on human health		

Affordability		
Metric	**Additional Definition**	**Data Needed**
Levelized cost of electricity (LCOE) - utility	Total cost of installing and operating a project expressed in dollars per kilowatt-hour of electricity generated by the system over its life	net present value (NPV) cost of project (costs considered vary by stakeholder, including construction, operating, taxes, financing, salvage, incentives); NPV total electricity generated over life of asset
Internal Rate of Return (IRR) - utility	Discount rate that makes the NPV of the cost and revenue stream equal to zero	Equilibrium discount rate
Simple payback period - utility	Length of time after the first investment that the undiscounted sum of costs and revenues equals zero	Time to undiscounted equilibrium after first investment
Net revenue requirements - utility	Annual stream of revenue necessary to recover the total costs of a project including capital (in the form of depreciation), operating costs including fuel, financing costs including interest and required return on rate on equity, and taxes including both costs and incentives	Fuel costs; operation and maintenance (O&M) costs; depreciation; taxes; return on rate base
Avoided cost - utility	Net change in the costs of the overall system with the development of the specified project	Energy avoided from other generators; capacity; reconfigure substations; transmission expansion or contraction; distribution expansion or contraction
Household electricity bur–den - customer	Proportion of customer income devoted to purchasing desired level of electricity service	Annual residence net electricity bill; annual household income (Census or other sources)
Household electricity affordability–gap - customer	Indication of the difference between affordable customer costs and observed customer costs	Household electricity cost burden; affordable cost burden threshold
Household electricity affordability gap index - customer	Temporal index of affordability gap compared to a base year	Previous affordability gap; current affordability gap
Household electricity affordability headcount index - customer	Temporal index of affordability gap headcount compared to a base year	Previous household exceeding affordability threshold; current households exceeding affordability threshold
Annual average customer –cost - customer	Average electricity costs (effective rates) by customer class	Total revenue (by geographic area, customer class); total consumption (by geographic area, customer class)
Average customer cost index - customer	Tracking the above effective rate through time results in an index for making relative comparisons between time periods	Previous average customer cost; current average customer cost
Affordability threshold		Percent of household income deemed affordable to spend on electricity

Appendix B

Proceeding/Report Documentation

B.1 IL – ComEd (11-0772)

Case: Final Order on the Approval of Multi-Year Performance Metrics pursuant to Section 16-108.5(f) & (f-5) of the Public Utilities Act, Docket No. 11-0772, Illinois Commerce Commission (March 15, 2012). [ComEd]

Area: Performance-based ratemaking

Jurisdiction: Illinois

Rationale: Measuring performance of grid infrastructure. As outlined in Sec. 16-108.5 of the Public Utilities Act, also referred to as the Energy Infrastructure Modernization Act (EIMA), utilities serving at least one million retail customers in Illinois are required to make significant investments for electric grid modernization, smart grid, training facilities, and low-income support programs. The utilities are permitted to retrieve costs in a performance-based formula rate calculated yearly based on actual costs and performance metrics. Failure to meet annual goals toward the 10-year performance goals is penalized with adjustment to the utility's return on equity, no more than a total of 30 basis points in the first 3 years, and of not more than a total 34 basis points in 4-6 years, and 38 basis points for years thereafter.

Methodology: Illinois's performance metrics include reliability metrics, Advanced Metering Infrastructure (AMI) metrics, and social equity metric, as shown in Table B.1 and described below.

The **reliability metrics** capture the reliability of electric service for the retail customer.

The penalty for not meeting each of these goals results in a 5 basis points ("bps") reduction for years 1 through 3; a 6 bps reduction for years 4 through 6; and a 7 bps reduction for years 7 through 10:

1. System Average Interruption Frequency (SAIFI) measures "the average number of interruptions per customer during the year."[6]
2. Customer Average Duration Index (CAIDI) measures "the average interruption duration for those customers who experience interruptions during the year."[6]
3. Service reliability targets set maximum number and duration of controllable interruptions based on voltage level.

AMI-related metrics, also referred to as Customer Benefits Metrics, measure reduced errors in billing and metering due to Smart Grid technology implementation.

The penalty for not meeting at least 95% of the annual goal in each of these metrics is 5 basis points, but consideration is given when Smart Grid technology has not been fully implemented.

4. Estimated electric bills measure the number of bills issued when a meter on an account was not read for the monthly billing period.

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[6] *See* http://www.icc.illinois.gov/electricity/electricreliability.aspx.

5. Consumption on inactive meters measures the amount of metered electricity with no customer on record to bill.
6. Unaccounted-for Energy measures the amount of unmetered electricity not billed to an individual retail customer.
7. Uncollectible Expense measures the amount of revenues that are uncollectible.

The last metric is related to **social equity,** for which there is no language for penalty if utility fails to improve on this metric.

8. Opportunities for minority-owned and female-owned business enterprises are measured by the percentage of capital expenditures paid to the unrepresented businesses. The utility sets goal for this metric.

Table B.1. Advanced Metering Infrastructure (AMI) Metrics

	Metric	Calculation	Improve-ment	Baseline years
Reliability	System Average Interruption Frequency (SAIFI)	$\frac{\text{Total Number of Customer Interruptions}}{\text{Total Number of Customers Served}}$	20%	2000-2010
	SAIFI for its Southern Region	$\frac{\text{Total Number of Southern Region Customer Interruptions}}{\text{Total Number of Southern Region Customers Served}}$	20%	2000-2010
	SAIFI for its Northeastern Region	$\frac{\text{Total Number of Northeastern Region Customer Interruptions}}{\text{Total Number of Northeastern Region Customers Served}}$	20%	2000-2010
	Customer Average Interruption Duration Index (CAIDI)	$\frac{\text{Sum of all Customer Interruption Durations}}{\text{Total Number of Customer Interruptions}}$	15%	2000-2010
	Service reliability targets	Number and duration of controllable interruptions based on voltage level	75%	2010
AMI	Reducing the number of estimated electric bills issued	Annual sum of estimated electric bills issued	90%	2008-2010
	Consumption of electricity on inactive meters	Annual sum from total monthly kWh of consumption on inactive meters	90%	2009-2010
	Unaccounted-for energy	Annual sum of unmetered electricity that is not billed to individual retail customer (kWh)	50%	2009

	Metric	Calculation	Improve-ment	Baseline years
Social	Uncollectible expense	Amount recorded in the Federal Energy Regulatory Form 1 Account 904	$30 million reduction	2008-2010
	Opportunities for minority-owned and female-owned business enterprises	% of expenditures paid to minority-owned and female-owned business and document progress		2010

Outcome:

Commission approves the calculations and goals from the utility's annual performance report and proposed tariff mechanism. Commission specifies language that indicates penalties for AMI-related metrics may only be waived to the extent that full implementation would achieve the performance goals. A compliance filing that incorporates this language is ordered. No penalties to return on equity (ROE) are ordered.

B.2 NY – REV (14-M-0101)

Case: *Order Establishing Benefit-Cost Analysis Framework,* Docket No. 14-M-0101, New York

Department of Public Service (DPS). (issued January 21, 2016)

Area: Distributed System Implementation Plans (DSIPs) with accompanying methodology in Benefits-Cost Analysis (BCA) Handbook; tariff development

Jurisdiction: New York

Rationale: New cost-benefit analysis (BCA) needs to be developed to reform traditional utility decision making to:

- Address the marginal costs and benefits of distributed energy resources (DER) in new DSIPs and tariff development.
- Modify ratemaking and utility incentives to improve system efficiencies and develop new markets.

According to Framework Order, the four categories of utility expenditures that BCA applies to are: 1) Investments in Distributed System Platform (DSP) capabilities; 2) Procurement of DER through competitive selection; 3) Procurement of DER through tariffs, 4) Energy efficiency programs.

Methodology: Cost-benefit analysis

P.S.C. outlines general guidelines and costs/benefits to consider but leaves the detailed methodology to utilities to develop and document in the utility's BCA Handbook. Among the different measures are the Societal Cost Test (SCT), Utility Cost Test (UCT), and Rate Impact Measure (RIM); the Commission adopts the SCT as the primary measure.

- SCT is a cost-benefit test from the perspective of New York's society.

Where no method description is given, the Public Service Commission (PSC) has left this to the utility's discretion. Qualitative assessment is accepted for non-quantified benefits. BCA used to evaluate portfolios, rather than individual measures/investments.

Costs considered: most either project specific or have no developed methodology.

- Program administration (including rebates, costs of market interventions, measurement and verification costs).
- Ancillary services.
- Incremental transmission & distribution, and distributed system platform costs.
- Participant DER cost.
  - Metric: sum of participant's equipment costs and opportunity costs (assumed to be approximately 75% of incentives paid to participants)
- Net non-energy costs.
- Not included: lost utility revenue, shareholder incentives.

Benefits considered in the following areas: 1) bulk system, 2) distribution system, 3) reliability, and 4) externalities:

Bulk System

- Avoided generation capacity, including reserve margin.
  - Metric: forecast reduction in coincident peak demand. Spot capacity price and quantity at intersection of demand/supply curves. Spot market demand curves from New York Independent System Operator (NYISO), capacity reserves/supply curves from NYISO's Gold Book summer and winter capacity forecasts. Installed Capacity (ICAP) spreadsheet provided on the New York DPS website.
- Avoided system energy costs.
  - Metric: location-based marginal prices (LBMP) from NYISO's Congestion Assessment and Resource Integration Study (CARIS) 10- or 20-year forecasts, which consider: 1) compliance for regional greenhouse gas initiative and cap-and-trade markets, and 2) transmission-level line loss costs, and 3) transmission capacity infrastructure costs.
- Avoided transmission capacity infrastructure and related O&M.
  - Metric: difference between zonal ICAP clearing prices.
- Avoided transmission losses, avoided ancillary services.
- Not included: wholesale market price impacts – considered a transfer, not a net social benefit.
  - Metric: use CARIS to estimate static impact on wholesale LBMP for 1% change in level of the load that must be met. Need to use judgment to evaluate bill impact.

Distribution System

- Avoided distribution capacity infrastructure.
  - Metric: marginal cost study = load reduction * (marginal cost)$_{year.}$ Using yearly marginal costs, calculate lifetime costs using NPV.
- Avoided O&M.
  - Metric: from utility's activity-based costing system or work management system
- Avoided distribution losses.
  - Metric: difference in amount of electricity measured coming into system [NYISO] and amount measured in customer revenue meters [Utility].

Reliability

- Net avoided restoration costs.
  - Metric: compare changes in: # of outages, speed and costs of restoration before/after project.
- Net avoided outage costs.
  - Calculation: # of outage * length of outage * estimated cost for outage, compare before/after project.

Externalities

- Net avoided greenhouse gases.
  - Metric: net marginal damage costs = system load levels reduced * social cost of carbon [$/MWh]. Calculate for each year, then find NPV.
    - EPA's central value for social cost of carbon = $46 per ton, 3% discount rate.
- Net avoided criteria air pollutants.
  - Metric: using EPA's Co-Benefits Risk Assessment: marginal cost in health effects of SO_2 or NO_x emissions.
- Avoided water, land impacts, net non-energy benefits.

Additional Cases: *Order Resetting Retail Energy Markets and Establishing Further Process,* Docket No. 15-M-0127, New York P.S.C. (February 23, 2016).

Uniform Business Practices, Docket No. 98-M-1343, New York P.S.C. (February 2016).

Area: Business practices

Jurisdiction: New York

Rationale: Addressing large number of customer complaints against energy service companies (ESCOs) regarding:

- Questionable marketing practices (30%),
- Dissatisfaction with the prices charged - no savings realized (25%),
- Slamming - enrollment without authorization (22%).

Metrics Considered in Ruling:

- Eligibility criteria for ESCOs in other states: demonstrating risk management and customer service expertise; proving the financial integrity of the ESCO including posting of security or a bond; and requiring disclosure of decisions in other states denying or limiting eligibility.
- Complaints received.
- Stakeholder comments AARP, City of New York, Committee of Chief Risk Officers, ESCOs.

Ruling:

- Effective ten calendar days from the date of this Order, ESCOs shall only enroll or renew existing residential and small commercial customers if <u>one of the following conditions is met</u>:
    1. Contract guarantees that the customer <u>will pay no more</u> than a full-service customer of the utility on an annual basis.
    2. Contract provides electricity product derived from at least <u>30% renewable source</u> under the Commission's Environmental Disclosure Labeling Program (EDP) rules.
        a. Renewable sources include biomass, biogas, hydropower, solar, wind.
        b. Must receive affirmative consent from a customer to contract that does not guarantee savings.
- Must enroll customer at end of current billing cycle or return them to utility.
- Commission may impose consequences on ESCOs that violate any state, federal, or local law, rule, or regulation immediately.
- Commission should develop uniform business practices (UBP) in next 60 days.
    – Data filings from ESCOs
        ○ Quarterly: residential price fixed for minimum 12-month period, residential variable price, and number of customers.
        ○ Changes to Retail Access Eligibility Form (application), marketing plans, business/customer service.
        ○ Every 3 years, updates to Retail Access Eligibility Form.

B.3 TVA – DG-IV

Methodology Report: "Distributed Generation – Integrated Value (DG-IV): A Methodology to Value DG on the Grid" (October 2015).

Area: Integrated Resource Plan

Jurisdiction: Tennessee Valley includes all of Tennessee state, as well as regions of Kentucky, Virginia, North Carolina, Georgia, Alabama, and Mississippi.

Rationale: Tennessee Valley Authority's (TVA's) aim is to "to develop a comprehensive methodology that assesses both the representative benefits and costs associated with various forms of DG." TVA engaged with various stakeholders to develop this methodology, including local power companies (LPAs) served by TVA, the Tennessee Valley Public Power Association (TVPPA), environmental non-governmental organizations (NGOs), solar industry representatives, academia, state governments, national research institutions and the Solar Electric Power Association.

Methodology: The DG-IV cost-benefit methodology generates the net benefit of distributed energy in cents/kWh. This initial methodology was used to evaluate small solar systems (<50 kW) for a 20-year lifetime. In the DG-IV equation below, each of the components included has received consensus approval among the stakeholders. Detailed methodology for each of the components is shown in Table B.2.

DG-IV Calculation = (G + E + ENVC + T + D) * (1 + TL + DL) + ENVM

G: Generation Deferral E: Avoided Energy ENVC: Avoided Environmental Compliance Costs T: Transmission Impact D: Distribution Impact **(cents/kWh)**	TL: Transmission Losses DL: Distribution Losses **(%)**	ENVM: Environmental Market Prices **(cents/kWh)**

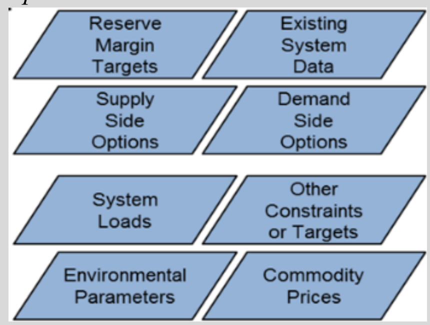
<u>Components not included in DG-IV</u>: local Power Company (LPC) costs and benefits, economic development from DG growth, customer satisfaction, and local differentiation (i.e. site-specific benefits and optimization); are advised to be considered in program design. Additional value components considered non-quantifiable or better suited for public policy discussions are omitted, including system integration/ancillary services, additional environmental considerations, security enhancement, disaster recovery, and technology innovation.

Outcome: This methodology has not yet been used in an integrated resource plan (IRP), as it was developed after the last IRP was completed in 2015. The 2019 IRP development process has been initiated, but the DG-IV methodology has not yet been explicitly named in the plans.[7]

TVA's 2017 Annual Report to the General Assembly mentions the low DG-IV value calculated in this methodology report and the mixed response to the methodology. For example, the Southern Environmental Law Center and Southern Alliance for Clean Energy have expressed concern that solar environmental and health benefits are not adequately represented.

[7] The 2019 IRP will "explore various DER scenarios and aim to improve its understanding of the impact and benefit of system flexibility as a way of adapting to the growth of renewable and distributed resources."
Maloney, Peter. "TVA's next IRP to explore various DER scenarios," American Public Power Association. https://www.publicpower.org/periodical/article/tvas-next-irp-explore-various-der-scenarios

Table B.2. Detailed Methodology for DG-IV Calculation

Term	Definition	Model/Inputs/Outputs
Generation Deferral, **G** (Capital & Fixed Operations & Maintenance)	The marginal system capacity and fixed operations and maintenance of deferred generation additions (including reserves) due to DG	Uses <u>TVA's Capacity expansion model</u> *Input*:  *Output*: Optimized capacity plans; calculated levelized value of capital and fixed O&M costs (cents/kWh)
Avoided Energy, **E** (Fuel, Variable Operations & Maintenance, Start-up)	The marginal system energy, fuel, variable operations and maintenance, and start-up value of generation displaced by DG	Uses <u>TVA's Production Cost Model:</u> hourly timesteps *Input*: - System loads, environmental parameters, other constraints or targets, and commodity prices - Optimized capacity plans from capacity expansion model *Output*: Levelized value of generation costs = fuel cost, variable operations & maintenance (VOM) cost, and start-up cost for total generation fleet (cents/kWh) *No material fuel volatility value included because dependent on market forecast
Environmental Compliance Costs, **ENVC** & Environmental Market Prices, **ENVM**	1) Compliance: addresses regulatory compliance components that are incorporated as part of TVA's system portfolio analysis (e.g., CO_2, coal ash, cooling water) 2) Market: the individual market value a DG resource adds to the valuation methodology in addition to regulatory compliance value (e.g., renewable energy credits)	1) Compliance costs uses <u>TVA's Production Cost Model</u> *Input:* - TVA's CO_2 compliance cost curve ($/ton CO_2eq in 2022) - Compliance costs for environmental regulations from TVA's system portfolio analysis *Output:* - Levelized value of environmental compliance value (cents/kWh) 2) Market value *Input:* Approximate national voluntary Renewable Energy Credit (REC) price = $1/MWh REC value with a 1.9% escalation for each year *Output:* Levelized value for environmental market (cents/kWh)

Term	Definition	Model/Inputs/Outputs
Transmission System Impact, **T**	Net change in transmission system infrastructure due to presence of DG (i.e., transmission required, deferred, or eliminated)	*Input:* TVA's point-to-point transmission service rate with peak factors for each month = savings from reducing monthly peak demand *Output:* Levelized value for transmission impact value (cents/kWh)
Distribution System Impact, **D**	Net change in distribution system capacity, voltage, and protection due to presence of DG (i.e., distribution required, deferred, or eliminated)	Electric Power Research Institute (EPRI)'s method *Input:* Detailed characteristics for each feeder and individual DG technology, unique operational response of feeder to DG, and specific placement of DG within the distribution system *Output:* Levelized value of system benefits (in distribution capacity, voltage, and protection)* *Because the calculated value ranged from 0 cents to 0.185 cents/kWh, initial value set at 0 cents/kWh.
Losses (Trans. & Distr.), **TL & DL**	Net change in transmission and distribution system losses due to presence of DG	*Method*: actual observed transmission/distribution losses, apply an average loss value or use a model to develop marginal loss value. *Output:* % losses

B.4 IL – Ameeren (12-0244), ComEd (14-0212)

Case: *Order on Reopening Verified Petition for Approval of Smart Grid Advanced Metering Infrastructure Deployment Plan*, Docket No. 12-0244, Illinois Commerce Commission (September 22, 2016). [Ameeren]

Additional Case: *Final Order on Petition to Approve Acceleration of Meter Deployment Under ComEd's AMI Plan*, Docket No. 14-0212, Illinois Commerce Commission (June 11, 2014). [ComEd]

Area: Smart metering.

Jurisdiction: Illinois

Rationale: Cost-benefit analysis is used to evaluate Ameeren Illinois Company's and Commonwealth Edison's plans to accelerate and expand previously approved Advanced Meter Infrastructure (AMI) plans. The Commission assesses per the Energy Infrastructure Modernization Act (EIMA) if: 1) whether the investment is "cost-beneficial," as defined by the Public Utilities Act, and 2) whether the investment remains under the $720 million cap.

Methodology: As outlined in Section 16-108.6(a) of the Public Utilities Act, the benefits and costs considered are shown below. The cost-benefit analysis (CBA) considers the overall net benefits of the updated AMI plan and the incremental net benefits of the proposed acceleration, which only considers the costs and benefits from the proposed change. Cost-effectiveness is evaluated by whether the net present value of net benefits (overall and incremental) over a 20-year period is positive.

Costs considered:

- All utility costs for Smart Grid AMI Deployment plan (e.g. AMI vendor contracts).

Benefits considered:

- Sum of avoided electricity costs = utility + consumer + societal.
  - *Utility*: avoided utility operational costs.
  - *Consumer*: avoided consumer power, capacity, and energy costs based on accurate metering.
    - Metrics: consumption on Inactive Meter[8], uncollectible expenses[9], and energy theft.
  - *Societal*: avoided societal costs in production and consumption of electricity + societal benefits (carbon reduction, health-related, customer engagement benefits in energy efficiency, demand response, and electric vehicles).
    - Metrics**:** no methodology provided by Illinois Commerce Commission (ICC). Utility's methodology is described as speculative and is not outlined in testimony.

Ameeren's case:

Updated CBA showed:

- Improved internal rate of return,
- Improved net present value of benefits over 20-year period,
- Sensitivity analyses eliminating customer engagement benefits (Demand Response, Energy Response, Electric Vehicle Enhancement); energy theft reduction; consumption on inactive meter benefits; uncollectible benefits; O&M benefits; O&M costs, and capital costs from 40% to 20% even without benefits to demonstrate cost-effectiveness.

ICC Staff's additional robustness check:

- Additional examination of overall net benefits and incremental net benefits: 1) with and without customer engagement benefits and costs, and 2) with customer engagement costs, but without benefits.

Time-of-use and dynamic pricing is suggested in testimony by environmental groups Citizens' United Board and Environmental Defense Fund. Barriers to tariff development (i.e. data access and marketing) are discussed by Ameeren and ICC Staff. Commission finds these pricing mechanisms beyond scope of smart metering case.

Outcome:

Commission finds that the AMI plan fulfills cost-effectiveness criteria based on the CBA Ameeren submitted for the case.

ComEd's case:

Cost-effectiveness is shown through overall and incremental CBA, in NPV of 20 years.

The Attorney General's office argues against the accelerated deployment plan because it "exacerbates intergenerational rate inequities." Commission defends formula-based ratemaking based on the Energy

[8] Consumption on Inactive Meter is the amount of metered electricity (kWh) with no customer on record to bill. Costs are recovered by spreading the costs to all customers.
[9] Uncollectible expenses submitted to FERC as an O&M expense.

Infrastructure Modernization Act, PA 97-0616, as amended by PA 97-0646 and PA 98-0015, which recovers actual costs from the year from customers. The Commission argued further that the AG's arguments would prevent any long-term investments needed to modernize the electric grid.

Outcome:

Commission finds that AMI plan fulfills cost-effectiveness criteria, citing both the overall net benefits and the incremental net benefits of the accelerated deployment plan. Further, the Commission finds that accelerating AMI deployment accelerates customer's realization of benefits from smart metering. This conclusion comes in response to AG's claims that accelerated plan increases costs borne by current customers, creating inequity as benefits are delayed.

B.5 CA – SCE (16-03-002)

Case: *Application of Southern California Edison Company for Approval of its 2016 Energy Storage Procurement Plan*. Application No. 16-03-002. Public Utilities Commission of the State of California (March 1, 2016).

Area: Storage

Jurisdiction: California

Rationale: California's energy storage order (No. 10-12-007) set targets and general program evaluation criteria. This application from Southern California Edison (SCE) Company proposes the utility's 2016 Energy Storage Procurement Plan and evaluation criteria for their request for offers (RFOs).

Methodology: The main quantitative metric is a net present value of costs and benefits per storage kW. SCE plans to procure 20 MW of resource adequacy-eligible energy storage projects and an unspecified quantity of energy storage in innovative use-cases through competitive solicitation, or RFOs.

Resource adequacy (RA) needs are determined through system, transmission, and distribution planning studies.

- Distribution need: determined by estimating the exceedance of peak demand beyond to current equipment limitations.
  - *Demand:* peak demand and substation peak loading forecasts for all SCE's feeders and substations.
  - *Supply:* loading, voltage, and protection limits based on engineering and equipment manufacturer data.
- Transmission need: system constraints identified through yearly CAISO transmission planning process.

RFO will contain specific locations and interconnections for resource-adequacy eligible storage.

- Cost-benefit: NPV per storage MW.
  - Discount rate = 10%.
  - Storage MW: maximum continuous discharge over a length of time that is appropriate for the storage device's primary application (e.g. 1 MW circuit load for four hours = 0.25 MW).
  - Costs considered:

    - Fixed contract costs.
    - Debt equivalents (considered for their effect on investor-owned utility's (IOU) credit quality and cost of borrowing).
    - Transmission and distribution upgrade costs, from interconnection studies.
    - Credit and collateral cost: cost offer based on the incremental exposure created by negotiated terms.
  - Benefit
    - Multiply quantity of qualifying RA capacity by forecasted capacity price (SCE provides this forecasted RA price for the given period).
- Qualitative factors.

Innovative use-cases may include storage with end uses such as: (1) deferring distribution upgrades, (2) facilitating microgrid projects, and (3) facilitating community storage projects.

- Quantitative metric: NPV of costs and benefits with a 10% discount rate is the main quantitative metric.
  - SCE will determine appropriate benefits and costs, if they can be reasonably estimated. These criteria may include energy benefits and costs, ancillary services benefits, and distribution deferral benefits.
- Qualitative factors:
  - Project viability: technological feasibility, developer experience, and financing and interconnection progress.
  - Project diversity: will choose a mix of use-cases.

Requirements for all projects

Safety: prevent thermal runway, a rapid uncontrolled increase in temperature that cannot be halted, which occurs when batteries are overcharged or over-discharged.

- Voltage safety monitoring and controls and fault detection mechanisms at both battery cell level and system level.
- Must adhere to Rule 21 or the Wholesale Distribution Access Tariff. These feature the national engineering standard, IEEE 1547.
- Require technical review by SCE engineers and an Electrical Inspection Release.
- Must develop written plan for safe construction and operation of energy storage resource (ESR) facility.

Reliability

- Must adhere to relevant NERC reliability standards, as well as any applicable FERC or Western Electricity Coordinating Council (WECC) requirements.

Social

- Seller is obligated to provide insurance for workers' compensation, employer's liability, commercial general liability, commercial automobile liability, pollution liability, and umbrella liability.

Outcome: SCE's Energy Storage Procurement Framework and Program Applications are approved. After selecting the projects from an RFO, SCE must apply for approval with the Public Utilities Commission. This application must include: (1) what purpose the upgrade will serve; (2) how the proposed energy storage system will meet the specific reliability needs of the area where it will be installed and operated; (3) a comparison between the costs of the deferred asset and the proposed energy storage system over the deferment period; (4) the length of the deferred asset's useful life; and (5) the deferred asset's online dates that are used to measure the deferral value of the energy storage system.

B.6 CO – PSCO (Related to C17-0316)

Case: *2017 All-Source Solicitation,* Public Service Company of Colorado (August 30, 2017). Based on the Colorado Public Service's 2016 ERP in Decision No. C17-0316.

Area: Resource procurement

Jurisdiction: Colorado

Rationale: The objective is to "identify portfolios of proposals that meet the resource needs identified in the solicitation in a reliable and cost-effective manner" under the 2016 Electric Resource Plan. Components of the all-source solicitation are shown in Table B.3.

Table B.3. 2017 All-Source Solicitation Components

Request for Proposal (RFP) Document	Resource Types	Eligibility
2017 Dispatchable Resources RFP	• Simple-cycle gas turbines • Combined-cycle gas turbines • Stand-alone storage projects	• Non-intermittent, firm thermal resource or storage facility
2017 Semi-Dispatchable Renewable Capacity Resources RFP	• Solar thermal with thermal storage or fuel backup • Any other intermittent resource with storage or fuel backup	• Utilize an intermittent energy resource and employ an integral technology that serves to lessen the intermittency effects of the energy resource
2017 Renewable Resources RFP	• Wind • Solar without storage or fuel backup • Hydroelectric (≤10 MW[a]) • Geothermal • Biomass • Recycled Energy (≤10 MW)	• Renewable energy resource, such as the types in the previous column

(a) Restriction applies to systems opening after January 2005.

All projects must have a nameplate electric rating >100 kW. The resources must meet all or a portion of the Company's resource needs during the resource and may not be coal-fired generation.

Special consideration is given to "Section 123 resources," which are new clean energy and energy-efficient resources that have not been regularly commercially demonstrated or not previously implemented in their proposed configuration.

Methodology:

Step 1: Bid Eligibility Screening

Proposals must a) include pricing estimates, b) adhere to power delivery requirements from the CPUC, c) show successful completion of development, construction, and commissioning of a utility-scale and utility grade project (Section 123 resource), with similar technology if a non-section 123 resource, d) prove that it can secure adequate and confirmed supply of generation equipment. Additional project description and plan is needed in writing.[10]

Step 2: Interconnection Assessment and Initial Economic Assessment

- The utility will a) determine or verify electric interconnection cost estimates and b) for some proposals, evaluate the general siting, permitting, and construction time requirements for Public Service transmission or distribution network upgrades.
  - Economic Metric: levelized cost of energy (LEC), which is calculated by converting fixed costs or variable $/MWh costs by assuming annual capacity factor.

    Inputs

    - Electrical interconnection costs and network upgrades not included in pricing estimate. Additional cost calculation assumes levelized fixed charge rate of 0.12 and an annual capacity factor based on type of generator.
    - Avoided line losses for projects to connect to the Public Service distribution.
    - Resource integration costs based on most recent relevant resource cost study.
    - *Inputs for dispatchable:* Gas-fired, peaking resources (with base capacity heat rates over 8,000 Btu/kWh) are assumed to have 5% annual capacity factor and a 4-hour run time per unit to start. Gas-fired intermediate resources (with base capacity heat rates of 8,000 Btu/kWh or lower) are assumed to have a 40% annual capacity factor) and a 12-hour run time per unit to start.

Step 3: Non-Price Factor Analysis

The proposal will be assessed for the following non-price areas: financial plan, experience, permitting and compliance, generator technology, property acquisition and site control, operational characteristics, community support, transmission access plan and assessment, construction and execution planning, capacity to meet reliability needs, accounting assessment.

[10] The additional written discussion should include the following areas: development experience, financial information, project description and development schedule, equipment description, energy production profile, real property acquisition description and plan, permitting plan, transmission plan, community/state reaction assessment, operations and maintenance plan, exceptions to model PPA, beneficial contributions/Section 123 resources, employment metrics.

Step 4: bidder notification of evaluation status based on first three steps (i.e. whether it will continue to computer-based modeling).

Step 5: Computer-based modeling of bid portfolios for the Public Service Company's bids equal to or greater than 10 MW.

- Simulates operation of proposals with existing resources (with some consideration of regional power market), keeps track of fixed and variable costs of the Company's entire system.
- Metric: net present value of revenue requirements through 2054.
  - Bids are selected for the least-cost portfolio.
  - *Inputs for renewable and semi-dispatchable:* wind and solar (without storage) generation is estimated using typical zonal week shape, and for each bid is modified for bidder-specified monthly peak and total generation to find the bidder's estimated annual capacity factor.
- The assumptions in this analysis include:
  - Planning period: 39 years, 2016-2054.
  - Utility discount rate: after-tax, weighted average cost of capital 6.78% with sensitivity values using 3% and 0% discount rates.
  - General inflation rate: 2.0%.
  - Capacity credit for intermittent resources:
    - Wind:16% of nameplate resources.
    - Solar: based on location and tracking technology.
    - Other: case-by-case analysis.
  - Natural gas price forecast methodology combines long-term gas price forecasts from Cambridge Energy Research Associates, PIRA Energy Group, Wood Mackenzie, and New York Mercantile Exchange.
  - Transmission cost: depending on Large/Small Generational Interconnection Studies.
- Sensitivity analyses:
  - Gas Price Volatility Mitigation Adder effects in 120-day report.
  - CO_2 price forecasts sensitivity:
    - CO_2 adder: high ($20 in 2022 to $43.26 in 2054), low ($1.86 in 2022 to $26.86 in 2054).
    - Social cost of carbon: $43/ton in 2022 and increasing to $76/ton in 2054.

Step 6: Evaluation of bids between 100 kW and 10 MW.

- Economic Metric: levelized energy cost.
  - In the least-cost portfolio from the bids greater than 10 MW, the all-in levelized energy cost for the most expensive bid for each generation type is calculated.
  - Small bids are compared to those with similar generation type; those that are less than the most expensive large bid are included in the least-cost portfolio with computer simulation checks.

Step 7: report to Commission describing cost-effective resource plans and the Public Service Company's preferred plan.

Outcome: Commission will approve, condition, modify, or reject the Public Service Company's preferred cost-effective plan based on the filed report.

B.7 NV – NV Energy (17-07026)

Case: *Order Granting in Part and Denying in Part Joint Application by NV Energy on Assembly Bill 405,* Docket No. 17-07026, Public Utilities Commission of Nevada (September 1, 2017).

Area: Net metering

Jurisdiction: Nevada

Rationale: On June 15, 2017, AB 405, the Renewable Energy Bill of Rights, was signed into law. The bill repealed previous Nevadan net metering NRS 704.7735 to return net metering to monthly netting of electricity delivered from or to the grid by customer-generators and to end different retail rates between customer-generators and other customers. The bill states its purpose is to "provide for the immediate reestablishment of the rooftop solar market in this State." This case is filed by Nevada Energy to decrease the volumetric-per-kilowatt-hour charge for electricity and increase the monthly basic charge in light of AB 405.

The PUCN's purpose in this proceeding is "to implement AB 405 and to provide as much clarity and certainty as possible to net energy metering (NEM) customers, the rooftop solar industry, and NV Energy."

Methodology: in the implementation of AB 405, the PUCN:

- Used the plain meaning "when a statute is facially clear,"
- Interpreted "in accordance with reason and public policy" when the statute is ambiguous, and
- Construed conflicting provisions "in a manner to avoid conflict and promote harmony."

The following areas were discussed and addressed in this proceed:

C. *1. Rate Design Issues*

The application to change NV Energy tariffs and rate is denied for the following reasons:

- <u>Scope of AB 405</u> permits a new tariff review only where it is necessary to implement certain provisions of AB 405 by September 1, 2017.
- <u>Rate stability</u> prioritizes the stability and predictability of the rates "until there is an impelling reason for a new general rate case."
- <u>Timing and no prejudice</u>, given the pending and upcoming general rate case for southern and northern Nevada, respectively, which includes all the parties that have intervened in this case.
- <u>Fairness</u> to both ratepayers and the utility in electricity rates and rates of return is promised for the rate c.

C. *2. Restoring NEM Customers to Same Classes as Non-NEM Customers*

- <u>Based on Section 31(5) of AB405</u>, which prohibits assigning NEM customer-generators to different rate classes than their non-NEM counterparts.

- PUCN directs NV Energy to place all new NEM customer-generators applying after June 15, 2017, into the rate class they would be in if they were not NEM customer-generators.
- All customer-generators with systems smaller than 25 kW may submit a request to migrate to the broad rate class they would be in if they were not NEM customer-generators.

C. *3. Monthly Net Energy Metering*

- Repeal of buy-sell framework[11] on an hourly basis based on previous NEM legislation.
- NEM is defined in Nevada as "measuring the difference between the electricity supplied by a utility and the electricity generated by a customer-generator which is fed back to the utility over the applicable billing period," which is month.

C. *4. 80 Megawatt Tiers*

- Four 80 MW tiers determine the percentage of retail rate that NEM customer-generators receive as credit. The retail cost of electricity includes the Base Tariff General Rate (BTGR), which covers system costs, Base Tariff Energy Rate (BTER), which covers energy (fuel) costs, and the Deferred Energy Accounting Adjustment (DEAA) which adjusts for over- or under-payment based on the annual revenue requirement.
  - 95%, 88%, 81%, and 75%.
- Reconciling Section 28.3(3)(a) and Section 28.3(5) regarding the tier assignment and 12-month deadline after application to install capacity, the PUCN establishes a guaranteed tier based on applied-for capacity and allows the next applicant to move up in rate tier if an applicant drops out without installing the capacity. Both the applied-for capacity and installed capacity by tier will be published and updated on the webs.

C. *5. Public Purpose Charges and Fees*

- Requirement to pay same public purpose charges as non-NEM customers, which help low-income Nevada residents and promote energy efficiency and renewable energy programs. These charges include: The Universal Energy Charges (UEC), Renewable Energy Program Rate (REPR), Temporary Renewable Energy Program Rate (TRED), Energy Efficiency Rate (EE), and the Merrill Lynch rate (ML) and must be excluded from the excess electricity compensation.

Outcome: the excess energy credit rate for the first 80-MW tier shall be effective as soon as possible, but not later than December 1, 2017. The general rate changes requested shall be addressed in the general rate cases. NV Energy must submit an outreach and education plan and tariffs reflecting this Order by September 30, 2017, which must be effective no later than December 1, 2017.

B.8 IL – Nuclear (HR 1146)

Report: Potential Nuclear Power Plant Closings in Illinois: Impacts and Market-Based Solutions, Report to the Illinois General Assembly Concerning House Resolution 1146, Illinois Commerce Commission, Illinois Power Agency, Illinois Environmental Protection Agency, Illinois Department of Commerce and Economic Opportunity (January 5, 2015).

Area: Generation Retirement

[11] The buy-sell framework established in SB 374 (the repealed NRS 704.7735) used hourly netted imported and exported electricity to determine the net metering charges/credit.

Jurisdiction: State of Illinois

Rationale: House Resolution 1146, adopted in May 2014, initiated the analysis process following announcements of potential closures by nuclear plant operators in Illinois. A report was prepared for the House by four agencies (published 1/5/2015), focused on identifying potential impacts that could result from the premature closure of three specific 'at-risk' Illinois-based nuclear generating plants, and market-based solutions that could be adopted by the state to avoid closures.

Methodology: A comprehensive analysis was conducted by the state agencies to estimate impacts of premature nuclear plant retirement in the following specific areas: 1) transmission expansion for nuclear energy and impacts on rates if nuclear plants are closed; 2) impacts of closures on reliability and capacity; 3) societal costs of increased GHG emissions due to closure; 4) impacts of closure on state jobs and economic climate; and 5) potential market-based options to prevent closures.

Specific methods, models, assumptions, and metrics were adopted for each analysis area, making synthesis of calculated metrics results difficult. The following metrics were reported for the component analyses:

1. Transmission expansion for nuclear energy and impacts on rates if nuclear plants are closed:
   - Financial requirements for transmission project to be included in Regional Transmission Organization (RTO) plans.
   - Changes in retail rates (where changes to wholesale were used as a proxy);
     legislation that could be implemented to provide transmission to other parts of PJM was also identified.
2. Impacts of closures on reliability and capacity:
   - Loss of Load Expectation (LOLE) was used as the primary metric.
   - Reserve Margin was also discussed.
3. Societal costs of increased GHG emissions due to closure:
   - Societal value of avoided CO_2 emissions (calculated using an estimate of the social cost of carbon).
4. Impacts of closure on state jobs and economic climate:

   Several economic impact measures were estimated, including:
   - Employment,
   - Value-added economic activity (GDP),
   - Labor income,
   - Energy sector development (wholesale power prices used to estimate induced impacts of higher electricity rates).

Outcome: Illinois' Future Energy Jobs Act (SB 2814) was passed in December 2016 (Public Act 99-0906) after consideration of several legislative proposals. The act includes updates to the state's Renewable Portfolio Standard (RPS), netmetering, and energy efficiency standards and includes a zero emissions standard (via a Zero Emissions Credit program).

B.9 NY – CES

Report: *Clean Energy Standard White Paper—Cost Study,* New York Public Service Commission (PSC) and New York State Energy Research and Development Authority (NYSERDA) Staff (January 5, 2015).

Area: Generation Retirement

Jurisdiction: State of New York

Rationale: This cost analysis was initiated by a letter from Governor Cuomo (12/2/15) directing the Department of Public Service to develop a Clean Energy Standard (CES) for presentation to the Public Service Commission (PCS) that converts 2015 State Energy Plan (SEP) targets to mandated requirements. A PSC staff-authored white paper proposed a CES program (1/25/16), including objectives to increase renewable electricity supply to achieve a 50% by 2030 goal and prevent premature closure of upstate nuclear facilities. A PSC/NYSERDA staff-authored CES Cost Study (4/8/16) estimated the cost of CES program implementation consistent with a PSC-ordered Benefit-Cost Analysis Framework (1/21/16) and examined the cost impact of variations in key cost driver assumptions, including a Zero Emissions Credit (ZEC) program for existing nuclear plants.

Methodology: A Clean Energy Standard (CES) cost study was conducted by state staff based on the State of New York's Benefit-Cost Analysis requirements (see NY-REV above), including identifying the estimated costs and benefits associated with implementation of a proposed ZEC program. The analysis considered the costs associated with implementing the ZEC program and benefits related to the social value of maintaining at-risk nuclear plants' contribution to the state's GHG emissions reductions.

The following metrics were reported in the cost study for the specific components (tiers) of the CES, including the Zero Emissions Credit program (Tier 3 of the CES):

- Gross program costs: additional payments (above energy and capacity value) independent power producers (IPPs) are required to receive to maintain financial viability.
- Avoided CO_2 emissions: the societal value of avoided CO_2 emissions (more than carbon value already included in electricity price via Regional Greenhouse Gas Initiative (RGGI)).
- Net program cost: Gross Program Cost minus Societal Value of Avoided CO_2 Emissions.
- Lifetime NPV cost (2015$) through existing plant license period.
- Percentage electricity bill impact in 2023: several forms were considered, including Gross Program Cost divided by 2014 Statewide Electricity Bill Spend.
- Economic impacts: several specific measures were reported, including employment, GDP, and tax receipts.
- Change of wholesale electricity prices.
- Other environmental impacts: several specific measures were considered, including SO_x, NO_x, PM emissions.
- Program administrative and transactional costs: the above metrics were determined primarily from SEP objectives and goals, along with associated specific cost and benefits metrics determined through application of the state's BCA Framework.

Outcome: a PSC order adopting the CES was later issued (8/1/16).

B.10 CA – PG&E (18-01-022)

Case: *Decision Approving Retirement of Diablo Canyon Nuclear Power Plan,* Docket No. 18-01-022, California Public Utilities Commission (January 11, 2018).

Area: Retirement, cost allocation

Jurisdiction: California

Methodology and Outcome by Issue: *Proposed values in italics*

C. **I.** Retirement of Diablo Canyon plant[12]—*2024 for Unit 1, 2025 for Unit 2,* approved with option to move earlier.

Metric 1: Projected PG&E bundled sales in 2025 and 2030, 2017 as reference year

- Utility Bundled Sales = Gross Service Territory Sales – Energy Efficiency Delivered Load Reduction – Distributed Generation Delivered Load Reduction – CCA/DA Sales
- Three Scenarios:
  - Reference case: expected growth of CCA, DG and EE load,
  - High load scenario: lower growth of CCA, DG, EE (25th percentile of expected growth),
  - Low load scenario: higher growth of CCA, DG, EE (75th percentile of expected growth).

Metric 2: need for Diablo Canyon Power Plant load in 2025 and 2030:

- Uses 2017 as reference year and the reference case,
- Considers sales and Transmission and Distribution (T&D) Line Losses to find the utility bundled load required,
  - T&D Line Losses = Load/0.91 – Load, which features a 9% loss factor
- Utility bundled load is then prioritized and accounted for by resource type in the following order.
  - RPS-eligible, large hydro, combined heat and power (CHP), Humboldt Power Plant for local reliability, renewable integration (CC), Diablo Canyon, other.

Testimony further clarifies need for system flexibility to support variable load from renewables (Diablo Canyon is too inflexible and large of a load).

Legislative update: SB-1090, signed September 19, 2018, approves full funding for community impact mitigation program and employee programs. It also orders the Commission to ensure integrated resource plans are designed to avoid any increase in emissions of greenhouse gases due to the retirement of Diablo Canyon. Updated funding approved in red bold italics.

II. Proposed Replacement Procurement

- Energy efficiency procurement –*$1.3 billion*; **$0** not approved and relegated to Integrated Resource Planning.

[12] PGE Opening Brief, Application 16-08-006 (August 11, 2016).

Recommended metric: Commission's cost-effectiveness protocol for EE[13] evaluated at the portfolio level and consists of the Program Administrator Cost (PAC) test[14] and the Total Resource Cost (TRC) test[15]. EE portfolios must be above 1.0 benefit-cost ratio for both tests.

III. Proposed Employee Program

- Employee Retainment Program—*$352.1 million;* **$211.3 million** approved, ***$352.1 million***
- Employee Retraining Program—*$11.3 million;* **$11.3 million** approved, ***$11.3 million***
  - To be paid through the existing ratemaking treatment for the operation of Diablo Canyon.

Metric: Survey of companies' retention pay as a percentage of salary. Criticized for inclusion of a range of industries, rather than nuclear energy industry.

Recommended metric: relative and forecasted supply and demand of nuclear power plant jobs and experienced nuclear power plant employees.

IV. Community Impacts Mitigation Program—*$85 million*; **$0** Not Approved, ***$85 million***

- Decision based on lack of legislation authorization to compensate lost tax revenue using ratepayers.

V. Nuclear Regulatory Commission license renewal process cancelled capital projects—*$18.6 million;* **$18.6 million** approved.

- To be paid in annual, levelized, expensive-only revenue requirement of approximately $2.4 million between January 1, 2018 to December 31, 2025 as a generation rate component.
- Evidentiary hearings and settlement agreement were used to determine reasonable direct costs paid to defer issuance of the Diablo Canyon renewed operating licenses.

Previous case based on application 10-01-022, in which PG&E proposed that the Commission find it cost-effective to renew licensing for Diablo Canyon at the cost of $85 million, and a proposed settlement would have allowed for $80 million in cost recovery.

- Case dismissed and relicensing suspended until seismic studies in the area are performed.

VI. Cost allocation for full amortization, or full cost recovery, of PG&E's investment in and return on Diablo Canyon by retirement.

Metric 1: Forecasted schedule for full cost recovery.

- *Inputs:* forecasted costs and yearly depreciation of cost, income.
- *Output:* adjustment required in rate to balance account.

Metric 2: Annual true-up.

- *Inputs:* actual costs and yearly depreciation, actual income.
- *Output:* adjustment required in rate to reflect actual.

[13] Energy Efficiency Calculator, https://www.ethree.com/public_proceedings/energy-efficiency-calculator/

[14] The Program Administrator Cost Test (PAC) compares the utility's avoided supply-side cost benefits to the utility's energy efficiency program expenditures (equipment and installation costs and program overhead costs).

[15] The Total Resource Cost Test (TRC) compares the benefits to society (avoided supply-side costs, resource savings) with the participant's cost of installing an energy efficiency measure and program overhead costs.

B.11 NERC – Reliability Assessment

Report: *2017 Long-Term Reliability Assessment,* North American Electric Reliability Corporation.

Area: Reliability

Jurisdiction: North America, including all of the US, southern provinces of Canada, and northern portion of Baja California, Mexico.

Rationale: The Long-Term Reliability Assessment is an annual report that has been developed to assess the reliability of the bulk power system in accordance with the Energy Policy Act of 2005 in the US and Electric Reliability Organization rules.

Methodology:

Metric 1: Reserve margins
Definition: The reserve margin is the amount that generation capacity exceeds net internal demand.

- Types of reserve margins:
    - *Anticipated* reserve margin considers expected generation capacity and demand.
    - *Prospective* reserve margin considers the sum of expected and prospective generation capacity and demand.
- Reference margin level is considered the appropriate level of reserve margin for reliability.
    - NERC uses a reserve margin level of 15% for a 10-year assessment.
    - Methodology varies by regional transmission organization, as shown in Table B.4.

Table B.4. Reference Margin Level Methodologies

Region	Methodology	Description
SERC, MISO, NPCC, SPP, PJM	0.1/Year LOLE	Year Loss of Load Expectation: expected value of outages per year (days/year) using scheduled generator outages and probability of generator forced outages.
FRCC	0.1/LOLP	Loss of Load Probability: probability of outages considering scheduled and forced outages.
WECC	Building Block Methodology	Considers contingency reserves, regulating reserves, reserves for generation forced outages, and reserves for 1-in-10 weather events.

- Generation capacity
    - "Expected on peak" summer and winter generation capacity values are used for variable resources, including wind (20% nameplate capacity), solar (50% nameplate), and run-of-river hydro (55%).

Metric 2: Demand projections

- 10-year compound annual growth rate (CAGR) of peak demand in summer and winter:
    - $CAGR = (\frac{ending\ value}{beginning\ value})^{\frac{1}{\#\ of\ years}}-1$

- 10-year energy growth per year

Metric 3: Resource mix

For each resource: % capacity of total capacity (nameplate), because reliance on any one resource increases vulnerability.

Metric 4: Interconnection inertia

Definition: Inertial response is a frequency response of up to a few seconds to balance large load imbalance. Used as a metric in ERCOT and Quebec; interconnections with a lower system inertia due to their smaller size.

- Synchronous Inertia Response (SIR), (GVA*s): immediate response to balance system imbalances.
- Nonsynchronous generation as a percent of system Load: with increasing nonsynchronous generation, SIR decreases.
- Critical inertia level (GW/s): the amount of system inertia level needed for the system to operate reliably.
    - Defined in ERCOT as the amount of inertia response needed if the largest two generation units trip (2,750 MW loss).

Metric 5: Fuel assurance

- Maximum capacity out of service due to lack of fuel.
- # of days with >1 outage.
- Natural gas as a percentage of current peak capacity: where greater than 40% is considered significant for reliability.

Metric 6: Transmission additions

- Based on voltage level: 200-299 kV, 300-300 kV, 400-599 kV, and greater than 600 kV.

Outcome: ERCOT and SERC-E have projected reserve margin shortfalls due to resource retirement. In light of increasing intermittent sources, NERC recommends improving methods for determining on-peak availability of wind and solar and considering inertia constraints as ERCOT and Quebec have.

B.12 PJM – CONE

Report: *PJM Cost of New Entry: Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date,* The Brattle Group (April 19, 2018).

Area: Capacity

Jurisdiction: PJM RTO, which serves all or parts of the following states: New Jersey, Pennsylvania, Delaware, Maryland, Washington D.C., Virginia, West Virginia, North Carolina, Kentucky, Tennessee, Ohio, Indiana, Illinois, Michigan.

Rationale: PJM defines a demand curve for the three-year-ahead forward capacity market, known as the variable resource requirement (VRR) curve, which incorporates the level of capacity at the cost of new entry (CONE)[16], the net cost of new entry (Net CONE)[17], and the level of capacity required for reliability. Every four years, the PJM commissions a CONE study for the next forward capacity market to reflect changes in technology choices and costs.

Methodology: This study uses a bottom-up approach to develop CONE estimates ($/MW-year or $/MW-day) for simple-cycle combustion turbine (CT) and combined-cycle (CC) with an assumed online date of June 1, 2022.

1. Reference Resource
   - PJM tariff specifies four CONE Areas,[18] or regions for which CONE values are evaluated. In each CONE Area, the likely locations, technology choices, and plant configurations for future plant development are analyzed. The reference resource location and resource specification are chosen for CONE estimates based on "revealed preferences" of plants built or in construction since 2014.
   - Assumptions:
     - *GE 7HA turbines*—one for CT, two for CC in combination with single heat recovery steam generator and steam turbine (2x1) are used as reference plants for CONE estimates in this study.
       - Based on observations since 2014:
         - Larger combustion turbines (G or H-class sized at 320 MW per turbine, compared to F-class turbines sized at 190 MW).
         - 2×1 CC plants, rather than simple-cycle combustion turbines.
       - *Environmental compliance technology*—SCR (selective catalytic reduction) system for NO_x emissions, CO catalyst system.
     - *Fuel supply*—dual-fuel capability (gas and diesel fuel).
2. Costs considered:[19]
   - *Plant capital costs*: equipment, materials, labor,
   - *Engineering, procurement, and construction (EPC)* contracting costs,
   - *Owner's capital costs*: owner-furnished equipment, gas and electric interconnection, development and start-up costs, land, inventories, emission reduction credits (ERCs) for new facilities in non-attainment areas, and financing fees,
   - *Annual fixed and variable operation and maintenance (O&M) costs*: including labor, materials, property tax, insurance, asset management costs and working capital.
     - Taxes: federal corporate tax rate, state income tax, federal and state tax deductions.
     - Weighted average working capital requirement: 0.8% of overnight costs in the first operating year.

[16] The Cost of New Entry (CONE) is "the total annual net revenue (net of variable operating costs) that a new generation resource would need to recover its capital investment and fixed costs."
[17] The Net Cost of New Entry (Net CONE) "represents the first-year revenues that a new resource would need to earn in the capacity market, after netting out energy and ancillary service (E&AS) margins from CONE.
[18] The four CONE areas are Eastern MAAC (EMAAC), Southwest MAAC (SWMAAC), Western MAAC (WMAAC), and Rest of RTO.
[19] Plant capital costs and owner capital costs were estimated using Sargent & Lundy (S&L)'s proprietary database on actual projects.

3. CONE Value:

  - CONE Value is that which makes project net present value (NPV) zero over a 20-year economic life.
  - *Metric:* Overnight Costs[20] ($/kW) * Effective Charge Rate[21] (%) + Levelized First-Year O&M ($/kW-year).
  - *Assumptions:*
    - After-tax weighted average cost of capital (ATWACC) of 7.5% for merchant generation investment in PJM Markets, assumes tax rate of 29.5%, return on equity of 12.8%, equity ratio of 35%, cost of debt 6.5%, debt ratio 65%.
    - 20-year inflation rate: 2.2%, based on Cleveland Federal Reserve's estimates.

4. Annual CONE Updates:

Each year PJM's tariff specifies that CONE will be escalated annually until the next quadrennial review to account for changes in plant capital costs. These annual updates are made by applying a composite cost index (% change) to the previous year's CONE value.

The recommended weightings for the CONE Composite Index use the Department of Commerce's Bureau of Labor Statistic indices for labor, materials, and turbines, which are:

- CT composite index: 20% labor, 55% materials, 25% turbine,
- CC composite index: 30% labor, 50% materials, 20% turbine.

In addition, PJM accounts for bonus depreciation declining by 20% starting in 2023, which should increase CT CONE by 2.2% and CC CONE by 2.5%. The report also recommends that PJM account for declining tax advantages by applying grow-up of 1.022 for CT and 1.025 for CC.

B.13 MISO – MVP

Report: Multi-Value Project Analysis: Results and Analysis, MISO (January 10, 2012)

Area: Transmission

Jurisdiction: The Midcontinent Independent System Operator (MISO) region includes all or part of Illinois, Indiana, Iowa, Missouri, Minnesota, Wisconsin, North Dakota, South Dakota, Montana, Arkansas, Mississippi, Louisiana, Texas, and Manitoba Canada.

Rationale: Transmission upgrades should enable RPS mandates to be met at the lowest delivered wholesale energy cost and be more reliable/economic than without the upgrade.

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[20] The overnight capital costs are the total capital costs without interest accrual, which is the sum of owner-furnished equipment costs, the engineering, procurement, and construction costs, and start-up and development costs including taxes and fees. In this report, the overnight capital costs per kW of needed capacity are used in calculating the CONE value.

[21] The effective charge rate is the percentage of the plant's capacity utilized.

Methodology: After compiling needs and identifying transmission projects, the MVP portfolio was optimized through three phases: 1) ensuring that each project relieved congestion and was economic compared to alternatives, 2) assessing the reliability and public policy improvements of implementing the portfolio, and 3) assessing the total Multi-Value Project Analysis (MPA) net benefit.

1. *Project valuation for each project*

Metric 1: List of thermal overloads mitigated by project

- Based on transmission studies that identified overloaded transmission lines.

Metric 2: Value of MVP compared to alternatives

- Based on cost.

2. *Reliability Assessment*

Metric 3: Transient stability analysis

- Identifies the ability of existing and proposed generation to remain synchronous under severe fault conditions.
  - Studied with no MVP and with MVP transmission additions under conditions of all the incremental wind zones added.

Metric 4: Voltage stability analysis

- Identifies voltage collapse conditions under high-energy transfer conditions from major generation resources to major load sinks.
  - Uses power flow case for 2021 summer peak conditions, with and without MVP portfolio case.

Metric 5: Short-circuit analysis

- Determines whether the installation of MVP transmission would cause existing circuit breakers to exceed their short-circuit interrupting capability.

3. *Public Policy Assessment*

Metric 6: Wind curtailment analysis

- Estimated using 2021 wind levels, linear optimization logic.

Metric 7: Wind enabled

  - First Contingency Increment Transfer Capability (FCITC) based on analyses run on 2026 model

4. *Economic Assessment*

Metric 8: Total MPA Benefit/Cost Ratio

- Under various scenarios (see Table B.5), the following benefits were compared to the total costs, which are the sum of annual revenue requirements.
  - Congestion and Fuel Savings

- Production cost models to compare how wholesale market would function with or without MVP Portfolio.

- Operating Reserves
  - Change in these characteristics with and without MVP Portfolio: reserve requirement, demand for existing operating reserve zones, day-ahead market clearing market prices.
- System Planning Reserve Margins
  - *Definition:* Planning Reserve Margin (PRM) is the amount of generation more than load that must be available so that the risk of losing firm load is one day in 10 years.
  - Loss of load expectation study with production cost simulations to determine changes to planning reserve margin based on reliability needs and congestion levels, respectively.
- Transmission Line Losses
  - Change in transmission losses from peak system losses, both with and without the MVP portfolio.
  - Wind turbine investment.
- Regional generation outlet study with and without regional transmission to assess difference in wind turbines needed.
- Cost savings based on EIA's cost estimates for onshore wind capital costs: $2.0-$2.9 million/MW.
- Future Transmission Investment
  - Pre-MVP and post-MVP summer peak steady state reliability models extended by 8 GW to simulate a 2031 Model.

Table B.5. Scenarios for Total MPA Benefit/Cost Ratio Calculation

Future Scenarios[(a)]	Wind Penetration	Effective Demand Growth Rate	Effective Energy Growth Rate	Gas Price	Carbon Cost/ Reduction Target
Business as Usual (BAU) Low Demand and Energy Growth	State RPS	0.78 percent	0.79 percent	$5	None
BAU Historic Demand and Energy Growth	State RPS	1.28 percent	1.42 percent	$5	None
Combined Energy Policy	20 percent Federal RPS by 2025	0.52 percent	0.68 percent	$8	$50/ton (42 percent by 2033)
Carbon Constrained	State RPS	0.03 percent	0.05 percent	$8	$50/ton (42 percent by 2033)

(a) Additional variations for BAU scenarios: 1) 20-year, 8.2% discount rate, 2) 40-year, 8.2% discount rate, 3) 20-year, 3.0% discount rate, 4) 40-year, 3.0% discount rate.

Outcome: The benefit-to-cost ratios of the MVP Portfolio range between 1.8-3.0 in the scenarios above.

B.14 TX – CREZ

Case: Commission Staff's Petition for Designation of Competitive Renewable Energy Zones (CREZs), Docket No. 33672, P.U.C. (15 August 2008)

Area: Transmission

Jurisdiction: Texas

Rationale: This methodology is used to choose a scenario with "the major transmission improvements necessary to deliver, in a manner that is most beneficial and cost-effective to customers, the energy generated by renewable resources in the CREZs."

Methodology: Cost-benefit analysis (CBA), weighs the net present value of the benefits to the net present value of the costs.

The Public Utilities Commission of Texas weighs the costs and benefits one-by-one to determine the scenario which best fulfills the subjective rationale outlined above.

The **key criteria** include:

- Average savings per MWh wind generation, balancing costs of ancillary services and fuel savings.[22]
- Production-cost analysis to reduce wind curtailment until 2012.[23]
- Estimated cost of constructing proposed transmission (total, per MW wind).[24]
- Reliability.[25]
- Future expansion efforts.[26]

Costs considered:

- Transmission construction costs.
  - Metric: total estimated cost, estimated cost per MW wind capacity.
  - Includes: materials costs, costs per mile for new transmission, right-of-way costs, costs for equipment to connect wind generation.[27]
- Additional ancillary services costs, fuel savings.
  - Metric: Average savings per MWh wind.
    - *Ancillary services costs*: total regulation service procured in a year, estimated cost per MWh wind generation.

[22] ERCOT Analysis of Transmission Alternatives for Competitive Renewable Energy Zones, ERCOT Ex. 1 at Ex. DW-1 at 10.
[23] Not addressed in cost-benefit analysis, but appears in conclusion.
[24] ERCOT's Competitive Renewable Energy Zones Transmission Optimization Study, ERCOT Ex. 4 at Ex. DW-1.
[25] Based on previous hearing.
[26] GE Ancillary Services study, ERCOT Resource 3 at RW-2, Executive Summary at 2.
[27] Assuming 10 miles as average length of transmission from wind facilities to collection substation, an average of 400-500 MW on each new circuit, and 138-kV or 345-kV voltage level for lines connecting wind farms to collection substations.

    - *Fuel savings*: total estimated fuel savings, fuel savings per MWh wind.
  - Includes: frequency of ancillary services from traditional thermal units, displacement of thermal units with wind generation, responsive and non-spinning reserve service, congestion costs.

Benefits considered:

- Reliability
  - Metric: none, hearing cited.
  - Includes: ERCOT's guideline for wind resource potential: 80% probability of exceedance forecast, ERCOT's rules regarding wind generation interconnection standards, performance measures, ancillary service requirements.
- Legislative intent: provide reliable and economical transmission resources ahead of renewable generation.
  - Reference: ERCOT's projection for wind generation, ERCOT's assurance of reliability.
  - Emphasize choice as *ahead* of renewable generation, and significant assurance of maintaining *reliability*.
- Commission-specified benefits: environmental benefits, future expansion capability.
  - Environmental benefits: air quality and water usage.
    - Metrics: unspecified reduction of NO_x, SO_2, CO_2; unspecified water usage reduction compared to gas and coal plants. Based on testimony.
  - Future expansion capability: ERCOT projections.

Outcomes:

1. From four proposed scenarios for new transmission capacity in various zones, the Commission chooses Scenario 2, with CREZ transfer capability of 11,553 MW and total transfer capability of 16,403 MW.
2. Commission specifies the estimated maximum generating capacity that CREZ transmission is expected to accommodate as 18,456 MW.
3. Commission orders ERCOT study on system reliability and stability issues with increased wind generation.

B.15 CAISO – TEAM

Report: Transmission Economic Assessment Methodology (TEAM), California ISO (August 8, 2017).

Area: Transmission

Jurisdiction: California ISO

Rationale: Economic assessment to determine which transmission upgrades should be approved.

Methodology: Among three economically-driven transmission evaluation criteria, the main metric used in CAISO planning is the production benefit for CAISO ratepayers evaluated from the production cost simulation.

Metric 1: Cost-benefit analysis

The net present value was calculated using the annual project costs as C_t and the estimated annual revenue as B_t.

$$NPV = \sum_{t=0}^{T}(\frac{B_t}{(1+d)^t} - \frac{C_t}{(1+d)^t}) > 0$$

where d refers to the discount rate, which depends on who funds the transmission project.

- CAISO ratepayers: social discount rate or regulated discount rate, 7%
- Independent merchant entity: private discount rate

and T refers to the amount of time considered, which is typically 5 years or 10 years in CAISO evaluations.

For transmission projects paid by CAISO ratepayers, the annual revenue is the revenue requirement calculated based on the model and assumptions of the CAISO Transmission Access Charge (TAC) model.

Metric 2: Production cost simulation with the ratepayer perspective

The production cost simulation models the physical transmission network and computes locational marginal prices for every node, consisting of the short-run marginal cost of energy, the marginal cost of congestion, and the marginal cost of losses. The data used to develop these costs include operation and maintenance costs, fuel costs, CO_2 costs, and basic technical parameters including efficiency, emission rates, and ramp up and down rates.

The *CAISO ratepayer perspective* is used for ISO's planning process. The production benefit to ratepayers is calculated as the difference of net load payment pre- and post- project.

Net load payment *= ISO's Gross load payment – ISO's Generator profit – ISO's Transmission revenue*

Gross load payment *= ∑(Load X LMP)*

Generator profit *=∑(Generator revenue – Generator cost)*

Transmission revenue *= ∑(Congestion cost + wheeling cost)*

Metric 3: Production cost simulation with the societal perspective

For projects with clear interregional impacts, the *WECC societal benefit* perspective may be additionally considered. The societal benefit is the total variable production cost savings, which includes consumer benefit, producer benefit, and transmission owner benefit from upgrade. The societal benefit is the difference between the sum of welfare surpluses with and without expansion.

- The consumer surplus is the difference between the value of loss load (VOLL), which is their willingness to pay, and the market price: $CS = (VOLL - Price) * Load$
- The producer surplus is the difference between the marginal cost of production and the market price: $PS = G \cdot P_G + AS \cdot P_{AS} - VOM - Fuel\ Cost - Emission\ Cost - Start\ Cost - Pump\ Cost - AS\ Cost$, where G is generation, AS is ancillary production, and P_G and P_{AS} are their respective prices, VOM is the variable operation and maintenance cost.
- The transmission surplus considers how prices at each node change with and without the upgrade.

Additional benefits may be considered to bolster an evaluation when applicable. Unless otherwise stated, these benefits are evaluated using output from the production cost simulation:

- Resource adequacy benefit from incremental importing capability
  - RA benefit = Incremental capacity * (cost of the marginal unit in RA procurement at the receiving end – cost of the marginal unit in RA procurement at the sending end).
- Transmission loss saving benefit
  - Reduction in peak demand or increase in the net qualified capacity for the existing generation resources.
- Local capacity requirement (LCR) benefit
  - Requires LCR studies with and without transmission scenarios.
- Renewable integration benefit
  - The effect of import capability on sharing ancillary services among balancing areas.
- Avoided cost of other projects
  - Case-by-case basis on project's effect on potential reliability or policy project.

Sensitivity studies

These studies consider risks and uncertainties regarding future load growth, fuel costs, and availability of hydro resources.

- Load: High (+6% above forecast), Low (-6% below forecast)
- Hydro: High, low if applicable and data available
- Natural gas prices: High (+50%), Low (-25%)
- CA RPS portfolios, if data available.

Outcome: This methodology: a) establishes the CAISO ratepayer perspective as the metric for benefit calculations, b) provides quantification for additional perspectives and benefits, and c) outlines sensitivity studies to address uncertainty.

B.16 OR – PacifiCorp (UM 1050)

Case: *Petition for Approval of the 2017 PacifiCorp Inter-Jurisdictional Allocation Protocol*, Docket No. UM 1050, Public Utility Commission of Oregon (August 23, 2016).

In the Matter of the Application of PacifiCorp DBA Rocky Mountain Power for Approval of the 2017 Inter-Jurisdictional Cost Allocation Protocol, Docket No. PAC-E-15-16, Idaho Public Utilities Commission (October 14, 2016).

Area: Cost allocation

Jurisdiction: Oregon, California, Washington, Idaho, Utah, Wyoming

Rationale: PacifiCorp has developed a multi-state process to work with the states it serves to develop allocation protocol to divide system costs. The 2017 Protocol follows three other protocols, each approved for a specified amount of time. After the multi-state process to develop the protocol, it must be approved by the state public utility commission.

Methodology: Main aspects in the cost allocation protocol are outlined be.

C. A. State Resources

Method 1: Situs-based

The cost allocation methodology in this section is mostly situs-based, or based on the legal jurisdiction to which a property belongs. In the table below, the costs and benefits considered for each of these programs are allocated situs-based, unless otherwise noted.

Method 2: Load-based dynamic factors

Calculated using State's monthly energy usage and/or State's contribution to monthly system Coincident Peak.

• Demand-Side Management	• Costs. • Benefits: load-based dynamic factors.
• Portfolio Standards	• Costs.
• Qualifying Facility Contracts[28]	• Costs exceeding the costs PacifiCorp would have otherwise incurred.
• Jurisdiction-Specific Initiatives[29]	• Costs and benefits.

B. System Resources

System resources are allocated using the System Energy ("SE") or System Generation ("SG") Factor as noted below.

Method 3: System Energy Factor (SE)

$$SE = \frac{\Sigma\, TAE\ in\ state}{\Sigma\, TAE\ in\ all\ six\ states}$$

where TAE is the Temperature Adjusted Input Energy (MWh), calculated monthly

Method 4: System Generation Factor (SG)

Calculated for each state monthly

$$SG = 0.75 * SC + 0.25 * SE$$

where SC, system capacity, is the demand-related component to meet the maximum demand on the system, and SE is the energy-related component, or the energy delivered to customers. $SC = \frac{\Sigma\, TAP\ in\ state}{\Sigma\, TAP\ in\ all\ six\ states}$, where TAP is the Temperature Adjusted Peak Load (MW) and SE is defined above.

[28] Qualifying facilities are either small renewable, biomass, waste or geothermal power plants (<80 MW) or cogeneration plants as outlined in the Public Utility Regulatory Policies Act of 1978 (PURPA).
[29] Jurisdiction-Specific Initiatives include incentive programs, net-metering tariffs, feed-in tariffs, capacity standard programs, solar subscription programs, electric vehicle programs, and the acquisition of renewable energy certificates.

• System Resources	• Fixed costs: system generation ("SG") factor. • Variable costs: system energy ("SE") factor.
• Wholesale Contracts	• Costs and revenues: SG factor.

C. Equalization Adjustment for Shortfall from Previous Allocation Procedures

Embedded cost differential ("ECD") adjustment: comparison of pre-2005 resources cost ($/MWh) to forecasted costs and generation ($/MWh).

D. Transmission Costs

• Transmission assets, firm wheeling expenses and revenues	• SG factor
• Non-firm wheeling expenses and revenues	• SE factor

E. Distribution Costs

- Assigned to state where they are located.

F. Administrative and General Costs

• Direct Assigned	• Situs.
• Customer Related	• Customer Number Factor (CN): ratio of customers in jurisdiction to total number of customers.
• General	• System Overhead Gross Factor (SO): ratio of gross plant costs to total gross plant costs.
• FERC Regulatory Expense	• SG factor.

G: Loss or Increase in Load Less than Five Percent of System Load

- Load-based dynamic allocation factors.

Outcome:

Approved by states for 2017. Oregon adopted 2017 Protocol as contested stipulation, reserving the right to review "any stipulation for reasonableness and accord with public interest."

B.17 CA – EPIC

Case: Order Instituting Rulemaking on the Commission's own motion to determine the impact on public benefits associated with the expiration of ratepayer chargers pursuant to Public Utilities Code Section 399.8, Docket No. 11-10-003, California Public Utilities Commission (October 6, 2011).

General Funding Opportunity (GFO) Solicitation: Bringing Rapid Innovation Development to Green Energy (BRIDGE) Solicitation Manual, GFO-17-308, California Energy Commission (November 2017).

Area: R&D Funding

Jurisdiction: California

Rationale: The Electric Program Investment Charge program (2012-2020) aims to provide electricity ratepayer benefits, namely in reliability, cost, and safety, providing funding for:

- Applied research and development: pre-commercial technologies and approaches to solve specific problems in the electricity sector.
- Technology demonstration and deployment: installation and operation of pre-commercial technologies or strategies in conditions sufficiently reflective of anticipated actual operating environments to enable appraisal of the operational and performance characteristics, as well as the financial risks.
- Market facilitation: program tracking, market research, education and outreach, regulatory assistance and streamlining, and workforce development to support clean energy technology and strategy deployment.

Methodology: As defined by the Commission's Order, at least these metrics should be used for quantification of estimated benefits to ratepayers and to the state, such as:

- Potential energy and cost savings;
- Job creation;
- Economic benefits;
- Environmental benefits; and
- Other benefits.

Additional Metrics:

- Identification of barriers or issues resolved that prevented widespread deployment of technology or strategy.
- Effectiveness of information dissemination.
- Adoption of technology, strategy, and research data by others.
- Funding support from other entities for EPIC-funded research on technologies or strategies.

Grant Funding Opportunity Scoring: From California Energy Commission's scoring manual for a GFO (see Table B.6).

Table B.6. Grant Funding Opportunity Scoring Methodology

Criterion	%
Technical Merit and Need - Goals, objectives, technological advancement or innovation advancement. - How project overcomes barriers to state energy goals. - Need for EPIC funding, not supported by competitive or regulated market. - Describes clear and plausible measurement and verification plan to describe how energy savings and other benefits will be measured. - Describes the technical feasibility and achievability in the proposed schedule; how progress will be documented toward the California Environmental Quality Act. - Describes how this adds to and builds on work under previously-awarded Energy Commission or US federal agency project.	25
Technical Approach - Scope of work, how tasks will be executed and coordinated among participants and team members. - Plan that identifies and discusses critical factors, risks, and limitations. - Project schedule.	20

Impacts and Benefits for California IOU Ratepayers
- EPIC goals: "greater reliability, lower costs, and/or increased safety."
- Metrics for potential benefits[30]
    o Annual electricity and thermal savings (kWh, therms).
    o Peak load reduction and/or shifting.
    o Energy cost reductions.
    o Greenhouse gas emission reductions.
    o Air emission reductions.
    o Water use and/or cost reductions.
- Must document timeframe, assumptions, and calculations for estimated benefits.
- Identify impacted market segments (size and deployment rates).
- Discuss qualitative benefits to California IOU ratepayers.
- Cost-benefit analysis (CBA): compares project costs to anticipated benefits.
    o Explains how costs and benefits will be quantified.
	20

Team Qualifications, Capabilities, and Resources - Organizational chart and individual qualifications of team members.	10
Minimum Passing Score for Above Criteria	60
Budget and Cost-Effectiveness - Justifies "reasonableness" of request funds and fund allocation for direct labor, non-labor, subcontractor, and operating expenses by task.	10
EPIC Funds Spent in California - Funds under direct labor are paid to individuals who pay California state income taxes on wages or business located in California.	10
Ratio of Direct Labor and Fringe Benefit Costs to Loaded Labor Costs	5

[30] CEC provides an attachment with reference values and calculations for energy end-use, electricity demand, and GHG emissions. Values for annual energy intensities based on California Commercial End Use Survey (CEUS) Report. Standardized Emissions Factors for Electricity and Gas are 0.588 lbs CO2e/kWh saved (0.000283 metric tons CO2e/kWh saved) and 11.7 lbs CO2e/therm saved (0.0053 metric tons/therm saved), respectively. These are based on Energy Commission staff estimates and California Air Resources Board staff calculations. Energy costs are based on EIA's sales revenue information for electricity and natural gas.

Criterion	%
- Compares Energy Commission funds for the direct labor and fringe benefits costs with total loaded costs. - (Total Direct Labor + Total Fringe)/(Total Direct Labor + Total Fringe + Total Indirect + Total Profit).	
Minimum Passing Score for All Criteria	80
Additional Points for Matching Funding Above Minimum	10

B.18 NJ – Microgrid Feasibility

Documents: "Town Center Distributed Energy Resource Microgrid Feasibility Study Incentive Program."

"New Jersey Town Centers Distributed Energy Resource Microgrids Potential: Statewide Geographic Information Systems Analysis," New Jersey Institute of Technology (October 2014).

Area: Microgrids

Jurisdiction: New Jersey

Rationale: Facilitate development of a Town Center distributed energy resources (DER) microgrid, or "a cluster of critical facilities within a municipal boundary that may also operate as shelter for the public during and after an emergency event or provide services that are essential to function during and after an emergency situation," to increase the grid's resiliency and reliability during a major storm.

Methodology:

Microgrid Potential Centers:

The microgrid potential was mapped in the second document, a technical report from the New Jersey Institute of Technology. The report identified 24 potential Town Center DER microgrids across 17 municipalities in the nine Sandy-designated counties.[31] These locations were identified by using geographic, feature (all public facilities and buildings), socio-economic (low- and moderate-income census tracts), and energy consumption data for buildings. Using a geographic information system (ArcGIS in this case), the data were mapped and clusters of facilities with a similar classification were identified and prioritized.

Feasibility Study Application Requirements

- **Project description** of all critical facilities with: i) approximate energy load size, ii) electric and thermal load of each building, iii) square footage of each building and total project, iv) overall boundaries of project and distance between critical buildings, v) Federal Emergency Management Agency (FEMA) classification of each building.

[31] These counties include Atlantic County, Bergen County, Cape May County, Essex County, Hudson County, Middlesex County, Monmouth County, Ocean County, and Union County.

- **If not identified in New Jersey Institute of Technology (NJIT) report,** documentation indicating that it satisfies screening criteria in report including: i) criticality based on FEMA classification,[32] ii) total electric and thermal loads (Btu/square foot), iii) at least 2 category III or IV facilities within 0.5 miles with 90 M Btu/sq ft usage, iv) list of potential partners, v) description of technology, vi) overall cost and potential financing, vii) benefits, viii) timeline for completion, ix) specific modeling to be used in feasibility study, x) requested funding amount, xi) cost share by lead local agency, xii) local electric distribution company.

Feasibility Study Review Process

- Distribution of feasibility across all electric utilities; have at least one Town Center DER in each utility territory.
- Distribution of feasibility projects across state.
- Applicant demonstrates understanding of the technical, financial, and power infrastructure needs of each DER Microgrid stakeholder.
- Evaluation based on NJIT criteria:
  - Number of FEMA Category III or IV facilities.
  - Total electric and thermal loads based on Btu's per square foot.

Outcome: "The Board had established a Town Center Distributed Energy Resource Microgrid Feasibility Study program with a budget of $1 million. However, after receiving and evaluating 13 applications for proposed microgrids and the potential benefits offered, the Board approved a budget modification to fund all 13 applications at a total cost of $2,052,480" (New Jersey Business Magazine 2017).

B.19 TX – Market Competition

Report: *2007 Scope of Competition in Electric Markets,* Public Utility Commission of Texas (January 2007).

Area: Market Monitoring

Jurisdiction: Texas

Rationale: As required by Section 31.003 of the Public Utilities Regulatory Act (PURA), the Commission investigated the state of market competition since retail competition began in ERCOT in 2002. To facilitate the entry of new retail electric providers, referred to as 'competitive retail electric providers (CREP),' ERCOT placed restrictions on retail electric providers that branched out from the bundled incumbent utility, referred to as 'affiliated retail electric providers (AREP).'

Namely, affiliated retail providers were required to charge the price-to-beat, a regulated price, until they had lost 40% of customers in a given segment or until the end of 2006. Since January 1, 2005, affiliated retail providers have been allowed to offer alternative plans to the price-to-beat, such as renewable, variable, and fixed-rate plans.

[32] The Federal Emergency Management Agency (FEMA) has categorized buildings based on their criticality to life safety. Category I buildings present low hazard, Category II buildings are those not included specifically in other categories, Category III buildings represent substantial hazard, and Category IV buildings are most critical for life safety. Examples of Category III buildings include schools, colleges, and daycare facilities. Examples of Category IV buildings are hospitals, fire and police stations, emergency service facilities, and water supply facilities.

Methodology:

The competitiveness of the retail electricity market is evaluated by primarily looking at:

Metric 1: Number of customers served, and electricity sold by competitive retail providers.

- Calculated by distribution utility service territory; this is number of customers and demand (MWh) served by competitive retail providers compared to affiliated retail providers.

Metric 2: Cost of competitive retail service relative to the price-to-beat.

- Calculated by distribution utility service territory, the price-to-beat in November 2006 is compared to the lowest competitive offer in November 2006, respectively.
- The savings percentage is the percentage amount that the competitive offer is lower than the price-to-beat.

Metric 3: Average retail rates for competitive providers and affiliated providers compared to other states' gas-dependent utilities.

- The average retail price (cents per kWh) and the statewide gas share of generation for a given year is compared.
- The natural gas share of generation shows how dependent the market price of electricity is based on natural gas prices.

Outcome:

Given that natural gas prices spike and that the price-to-beat was updated only twice a year, the price-to-beat is often higher than the competitive price when natural gas prices decrease. The number of customers served by competitive retail providers in 2006 ranged from 27% and 49% in the distribution service territories; 50% of residential customers still pay the price-to-beat.

B.20 TX – TXU (34061)

Case: *Notice of Violation by TXU Corp., eta al, of PURA $39.157(a) and P.U.C. SUBST. R. 25.503(g)(7)*, Docket No. 34061, Public Utility Commission of Texas (March 28, 2007).

Area: Market Power Abuse

Jurisdiction: Texas

Rationale: The March 2007 Independent Market Monitor's report found that there was a high number of price spikes between June 1, 2005 and September 30, 2005. Commission Staff recommends that TXU be required to pay $210,000,000 ($210 million), consisting of administrative penalties in the amount of $140,000,000 ($140 million) and refunds of $70,000,000 ($70 million).

Methodology:

Because almost all the price spike intervals June 1 – September 20, 2005 were between hours 10 and 23, the scope of this investigation focused on those hours.

Metric 1: Pivotal Supplier Test

- For each interval, a supplier is identified as a pivotal supplier if its supply is needed to meet demand and reserve requirements. Hours in which there was a price spike and a pivotal supplier raise concerns of market power abuse.
- *Outcome:* TXU was found to be the pivotal supplier in 554 of the 657 or 84.3%, of the price spike intervals.

Metric 2: Bid analysis (economic withholding)

- The estimated short-run marginal cost (SRMC) is considered to be the economic price at which a supplier would run its generation. The up-balancing energy service (UBES) price is the bid at which the supplier offered its supply.
- *Outcome:* Based on the Commission's estimates of TXU's short-run marginal costs, TXU's submitted bids for up-balancing energy service (UBES) significantly exceeded their marginal cost. This indicates abuse of one's market power when TXU's supply was needed to meet demand.

Penalty calculation:

- Excess profit calculation based on Rational Bidding Strategy and balancing energy market simulations.
- Imposing penalty higher than profit gained illegally; based on regulatory guidelines and cost of illegal activities to market.

Outcome: Additional proceedings over penalty were filed and led to an eventual settlement of $15 million in 2008.[33]

B.21 ISO-NE – Market Assessment

Report: 2017 Assessment of the ISO New England Electricity Markets, Potomac Economics (June 2018).

Area: Market Monitoring

Jurisdiction: ISO New England is comprised of states Maine, Vermont, New Hampshire, Massachusetts, Connecticut, and Rhode Island.

Rationale: ISO-NE commissions an annual report which includes an assessment of the competitive performance of the energy and ancillary services markets in the past year.

Methodology:

Structural Market Indicators measure a supplier's market power based on the amount of energy it supplies to the market. Market share values used in the following metrics are based on monthly reports of seasonal claimed capability (SCC), which is the reported capacity from the supplier. Here, SCC is based on generator summer capability in July SCC.

Metric 1: Supplier market share

[33] https://www.puc.texas.gov/industry/electric/reports/scope/2009/2009scope_elec.pdf

- *Calculation:* Market shares of the largest suppliers as a proportion of total market shares in each region (%).
- *Interpretation:* The larger the market share, the more market power a firm has.

Metric 2: Herfindahl-Hirschman Index (HHI)

- *Calculation:* Sum squares of percentage market shares held by the respective firms.
  - For market with firm 1 with 30% share and firm 2 with 70% share, the HHI is $30^2 + 70^2$.
- *Interpretation:* U.S. Department of Justice considers markets with an HHI below 1500 as unconcentrated; between 1500 and 2500 as moderately concentrated; and 2500 and above as highly concentrated.[34]

The limitation of metrics 1 and 2 is that they do not account for demand-side factors (i.e. level of demand) which affects electricity production on a real-time basis.

Metric 3: Pivotal Supplier Test

- *Calculation:* A supplier is a pivotal supplier when, in a given market period (hour), some of its capacity is needed to meet demand and reserve requirements.
  1. Pivotal frequency: percent of hours in a year in which there was at least one pivotal supplier.
  2. The percent of hours a given supplier was the pivotal supplier in the hours when there was a pivotal supplier (calculated for the three largest suppliers).
- *Interpretation:* The pivotal supplier test shows when a supplier has the market power (or the ability) to alter its supply to benefit economically.

Economic and physical withholding is when a supplier withholds output from entering the grid to raise prices above the competitive price.

Metric 4: Output gap (economic withholding)

- *Calculation:* Estimated difference between the amount of the unit's capacity that is economic to produce at the prevailing clearing price and the amount that is actually produced by the unit, due to economic offer parameters (start-up, no-load, and incremental energy) being set significantly above competitive levels.[35] The output gap is expressed as a percentage of output produced compared to the total nameplate capacity.
  - *In this report,* the output gap is calculated for either the largest supplier in a region or for the three largest suppliers in all New England, as well as for other suppliers in a region or in New England for each of the following load levels (GW): up to 15; 15 to 17; 17 to 19; 19 to 21; 21 to 23; and above 23.
- *Interpretation:* The significance of a difference between output gap from largest supplier(s) and other suppliers is used to determine whether large suppliers exercised their market power to reach an uncompetitive price.

Metric 5: Short-term physical deratings and outages (physical withholding)

[34] https://www.justice.gov/atr/herfindahl-hirschman-index

[35] From the report: this [estimation] may overstate the potential economic withholding because some of the offers included in the output gap may reflect legitimate supplier responses to operating conditions, risks, or uncertainties.

- *Calculation:* The percentage of short-term physical deratings and outages, which occur when the supplier/generator does not operate at full capacity out of total capacity.
- *Interpretation:* Short-term physical deratings and outages may reflect attempts to depress supply. Long-term deratings and outages are economically costly and would be unlikely to reflect market manipulation.

Outcome: Markets performed competitively in 2017; pivotal supplier analysis suggests market power concerns in Boston and market-wide under high-loads, but economic and physical withholding analysis indicates little significant market power abuses or manipulation in 2017.

Appendix C

Case Study and Metrics Synthesis Detail

Table C.1. Review Detail: General Methods Applied to Decisions or Investments

Decision/ Investment Area	Decision/ Investment Sub-Area	Jurisdiction/ Docket or Report	Approach Type	Approach Description	Methodology Basis	Decision Context
Generation, Storage, Demand-side	**Performance-based ratemaking–**	**IL - ComEd (11-0772)**	Performance reporting	Reporting of specific defined reliability, Advanced Metering Infrastructure (AMI), and social performance metrics as a basis for utility cost recovery.	Sec. 16-108.5 of the Illinois Public Utilities Act (also referred to as the Energy Infrastructure Modernization Act (EIMA)).	As outlined in EIMA, utilities serving at least one million retail customers in Illinois are required to make significant investments for electric grid modernization, smart grid, training facilities, and low-income support programs. The utilities are permitted to retrieve costs in a performance-based formula rate calculated yearly based on actual costs and performance metrics. Failure to meet annual goals toward the 10-year performance goals is penalized with adjustment to the utility's return on equity. In this proceeding, Commonwealth Edison (ComEd) seeks approval from the Illinois Commerce Commission on the calculations and goals from the utility's annual performance report.
	Distributed generation	**NY - REV (14-M-0101)**	Cost-benefit analysis	New York's Public Service Commission (PSC) outlines general guidelines and costs/benefits to consider, but leaves the detailed methodology to utilities to develop and document. Several different summary measures are described and calculated based on consideration of various components of cost and benefit, including the Societal Cost Test (SCT), Utility Cost Test (UCT), and Rate Impact Measure (RIM). PSC adopts the SCT, a cost-benefit test from the perspective of New York's society, as the primary measure.	New York State Benefit-Cost Analysis Framework.	New Benefit-Cost Analysis (BCA) framework developed with intent to reform traditional utility decision making to address the marginal costs and benefits of distributed energy resources (DER) in new Distributed System Platform (DSP) and tariff development and modify ratemaking and utility incentives to improve system efficiencies and develop new markets. According to Framework Order, the four categories of utility expenditures that the new BCA applies to are: 1) investments in DSP capabilities; 2) procurement of DER through competitive selection; 3) procurement of DER through tariffs, 4) energy efficiency programs.

		TVA - DG-IV	Cost-benefit analysis	The Distributed Generation – Integrated Value (DG-IV) methodology generates the net benefit of distributed energy in cents/kWh. This initial methodology was initially used to assess small solar systems (<50 kW) for a 20-year lifetime.	Distributed Generation – Integrated Value (DG-IV): A Methodology to Value DG on the Grid" (October 2015).	The Tennessee Valley Authority's (TVA) aim is "to develop a comprehensive methodology that assesses both the representative benefits and costs associated with various forms of DG." TVA engaged with various stakeholders to develop this methodology, including local power companies (LPAs) served by TVA, the Tennessee Valley Public Power Association (TVPPA), environmental NGOs, solar industry representatives, academia, state governments, national research institutions and the Solar Electric Power Association. This methodology has not yet been used in an integrated resource plan (IRP), as it was developed after the last IRP was completed in 2015. The 2019 IRP development process has been initiated, but the DG-IV methodology has not yet been explicitly named in the plans.
	Smart metering	**IL - Ameeren (12-0244) ComEd (14-0212)**	Cost-benefit analysis	Considers the overall net benefits of the updated AMI plan and the incremental net benefits of the proposed acceleration, which only considers the costs and benefits from the proposed change. Cost-effectiveness is evaluated by whether the net present value of net benefits (overall and incremental) over a 20-year period is positive.	Section 16-108.6(a) of Illinois Public Utilities Act.	Ameeren Illinois Company's and Commonwealth Edison's plans to accelerate and expand previously approved Advanced Meter Infrastructure (AMI) plans. The Illinois Commerce Commission assesses per the EIMA 1) whether the investment is "cost-beneficial," as defined by the Public Utilities Act, and 2) whether the investment remains under the $720 million cap.
	Energy storage	**CA - SCE (16-03-002)**	Cost-benefit analysis	Net present value of costs and benefits per storage kW.	California's energy storage order sets targets and general program evaluation criteria.	This application from Southern California Edison (SCE) to the California Public Utilities Commission proposes the utility's 2016 Energy Storage Procurement Plan procure 20 MW of resource adequacy-eligible energy storage projects and an unspecified quantity of energy storage in innovative use-cases through competitive solicitation and its evaluation criteria for its request for offers (RFOs).
	Resource planning & procurement	**CO - PSCO (Related to C17-0316)**	Levelized energy cost	Calculated by converting fixed costs or variable costs by assuming annual capacity factor. Considered in the context of a least-cost portfolio needed to meet net present value of PSCO revenue requirements through 2054 based on computer-based modeling of bid portfolios to simulate operation of proposals with existing resources.		Public Service Company of Colorado (PSCO) 2017 All-Source Solicitation to "identify portfolios of proposals that meet the resource needs identified in the solicitation in a reliable and cost-effective manner" under its 2016 Electric Resource Plan. Includes separate RFPs for dispatchable resources, semi-dispatchable renewable capacity resources, and renewable resources.

	Net metering	**NV - NV Energy (17-07026)**	Qualitative	In clarifying the implementation of the Renewable Energy Bill of Rights (AB 405), the Public Utilities Commission of Nevada (PUCN) used the plain meaning "when a statute is facially clear," interpreted "in accordance with reason and public policy" when the statute is ambiguous, and construed conflicting provisions "in a manner to avoid conflict and promote harmony." The following areas were discussed and addressed: rate design issues, restoring net metering (NEM) customers to the same classes as non-NEM customers, definition of monthly NEM, rate tiers, and public purpose charges and fees.		On June 15, 2017, AB 405 was signed into law, repealing previous Nevada net metering NRS 704.7735 to return net metering to monthly netting of electricity delivered from or to the grid by customer-generators and to end different retail rates between customer-generators and other customers. The bill states its purpose as to "provide for the immediate reestablishment of the rooftop solar market in this State." This specific case was filed by Nevada Energy with the Public Utilities Commission of Nevada (PUCN) to decrease the volumetric-per-kilowatt-hour charge for electricity and increase the monthly basic charge in light of AB 405. The PUCN's stated purpose in this proceeding is "to implement AB 405 and to provide as much clarity and certainty as possible to NEM customers, the rooftop solar industry, and NV Energy."
	Generation retirement	**IL - Nuclear (HR 1146)**	Cost-benefit analysis	A comprehensive analysis was conducted by the state agencies to estimate impacts of premature nuclear plant retirement in the following specific areas: 1) transmission expansion for nuclear energy and impacts on rates if nuclear plants are closed; 2) impacts of closures on reliability and capacity; 3) societal costs of increased GHG emissions due to closure; 4) impacts of closure on state jobs and economic climate; and 5) potential market-based options to prevent closures. Specific methods, models, and assumptions adopted for each analysis area made synthesis of calculated metrics results difficult.		House Resolution 1146, adopted in May 2014, initiated the analysis process following announcements of potential closures by nuclear plant operators in Illinois. A report was prepared for the House by four agencies (published 1/5/2015), focused on identifying i) potential impacts that could result from the premature closure of three specific 'at-risk' Illinois-based nuclear generating plants, and ii) market-based solutions that could be adopted by the state to avoid closures.
		NY - CES	Cost-benefit analysis	A Clean Energy Standard (CES) cost study was conducted by state staff based on the state's State Benefit-Cost Analysis requirements (see NY-REV above), including identifying the estimated costs and benefits associated with implementation of a proposed Zero-Emission Credit (ZEC) program. The analysis considered the costs associated with implementing the ZEC program and benefits related to the social value of maintaining at-risk nuclear plants' contribution to the state's GHG emissions reductions.	New York State Benefit-Cost Analysis Framework.	This cost analysis was initiated by a letter from Governor Cuomo (12/2/15) directing the Department of Public Service to develop a CES for presentation to the Public Service Commission (PCS) that converts 2015 State Energy Plan (SEP) targets to mandated requirements. A PSC staff-authored white paper proposed a CES program (1/25/16) that included objectives to increase renewable electricity supply to 50% by 2030 and prevent premature closure of upstate nuclear facilities. A PSC/NYSERDA staff-authored CES Cost Study (4/8/16) estimated the cost of CES program implementation consistent with a PSC-ordered Benefit-Cost Analysis Framework (1/21/16) and examined the cost impact of variations in key cost driver assumptions, including a ZEC program for existing nuclear plants.
		CA - PG&E (18-01-022)	Varied by specific retirement issue	The following issues were addressed: retirement of the Diablo Canyon plant, replacement procurement (including energy efficiency), employee program, community impacts mitigation program, and cost recovery.		To evaluate retirement of the Diablo Canyon plant, and whether cost recovery and allocation is "just and reasonable."

	Reliability	**NERC - Reliability Assessment**		This assessment was developed based on data and narrative information collected by NERC from the eight Regional Entities on an assessment area basis to independently assess the long-term reliability of the North American bulk power system (BPS) while identifying trends, emerging issues, and potential risks during the 10-year assessment period. The assessment was developed using a consistent approach for projecting future resource adequacy through the application of NERC's assumptions and assessment methods. NERC's standardized data reporting and instructions were developed through stakeholder processes to promote data consistency across all the reporting entities. The assessment includes consideration of reserve margins, changing resource mix, essential reliability services, reference margin levels, variable energy resources, fuel assurance, and transmission additions.	NERC Long-term Reliability Assessment.	The Long-Term Reliability Assessment is an annual report that has been developed to assess the reliability of the bulk power system (BPS) in accordance with Energy Policy Act of 2005 in the US and Electric Reliability Organization rules. The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the reliability and security of the BPS in North America. NERC develops and enforces reliability standards, annually assesses seasonal and long-term reliability, monitors the BPS through system awareness, and educates, trains, and certifies industry personnel.
	Capacity	**PJM - CONE**	Cost of new entry	This study uses a bottom-up approach to develop CONE estimates ($/MW-year or $/MW-day) for a simple-cycle combustion turbine (CT) and combined-cycle (CC) with an assumed online date of June 1, 2022. PJM defines a demand curve for the three-year-ahead forward capacity market, known as the variable resource requirement (VRR) curve, which incorporates the level of capacity at the cost of new entry (CONE), the net cost of new entry (Net CONE), and the level of capacity required for reliability.	PJM Cost of New Entry: Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date, The Brattle Group (April 19, 2018).	Every four years the PJM commissions a CONE study for the next forward capacity market to reflect changes in technology choices and costs.
Transmission	**Portfolio**	**MISO - MVP**	Portfolio cost-benefit analysis	After compiling needs and identifying transmission projects, the MVP portfolio is optimized through three phases: 1) ensuring that each project relieved congestion and was economic compared to alternatives, 2) assessing the reliability and public policy improvements of implementing the portfolio, and 3) assessing the total net benefit (reflected as a benefit/cost ratio).		The benefit/cost ratio of the transmission upgrade projects portfolio in MISO is estimated for four potential future scenarios to ensure that the upgrades enable RPS mandates to be met at the lowest delivered wholesale energy cost and to be more reliable/economic than before the upgrades.
	Clean energy zones	**TX - CREZ**	Portfolio cost-benefit analysis	A cost-benefit analysis is applied, weighing the net present value of the benefits to the net present value of the costs. The Public Utilities Commission of Texas weighs the costs and benefits one-by-one to determine the scenario which best fulfills the subjective rationale identified in the proceeding based on the following key criteria: average savings per MWh wind generation, balancing costs of ancillary services and fuel savings, production-cost analysis to reduce wind curtailment until 2012, estimated cost of constructing proposed transmission (total, per MW wind), reliability, and future expansion efforts.		The Commission applied the methodology to select a scenario with "the major transmission improvements necessary to deliver, in a manner that is most beneficial and cost-effective to customers, the energy generated by renewable resources in the CREZs [Competitive Renewable Energy Zones]." From four proposed scenarios for new transmission capacity in various zones, the Commission chose a scenario with CREZ transfer capability of 11,553 MW and total transfer capability of 16,403 MW, which is expected to accommodate as much as 18,456 MW of generating capacity.

	Economic assessment	**CAISO - TEAM**	Cost-benefit analysis supplemented with production cost simulation	A cost-benefit analysis is applied, weighing the net present value of the benefits to the net present value of the costs associated with transmission upgrades and based on economically-driven evaluation criteria. The principle criteria used in CAISO planning is the production net benefit for CAISO ratepayers assessed through production cost simulation.	CAISO Transmission Economic Assessment Methodology (TEAM), CAISO Transmission Access Charge (TAC) Model.	Establishes methodology for economic assessment of proposed transmission upgrades from the CAISO ratepayer perspective, including quantification of additional benefits and perspectives, and identifies sensitivity studies to conduct that address uncertainty.
Cost Allocation	**Multi-state**	**OR - PacifiCorp (UM 1050)**	Cost allocation protocol	The cost allocation protocol includes several components: 1) state resources allocation, 2) system resources allocation, 3) equalization adjustment for shortfall from previous allocation procedures, 4) transmission costs, 5) distribution costs, and 6) loss or increase in load less than 5% of system load.		PacifiCorp developed a multi-state process to work with the six states it serves (Oregon, California, Washington, Idaho, Utah, and Wyoming) to establish a protocol to allocate system costs shared among those states. The 2017 Protocol follows three protocols adopted earlier, each approved for a specified amount of time. The protocol must be approved by the states' public utility commissions.
Research, Development and Demonstration	**State program solicitation**	**CA - EPIC**	Proposal evaluation criteria, including cost-benefit analysis	Evaluation of funding proposals is founded in opportunity scoring based on CEC's General Funding Opportunity (GFO) scoring manual, which includes the following criteria: technical merit and need, technical approach, impacts and benefits to California IOU ratepayers, and proposing team qualifications, capabilities, and resources. The impact and benefits criterion are informed by guidance from California's Public Utilities Commission, who determined at least three of the following metrics should be used in the quantification: potential energy and cost savings, job creation, economic benefits, environmental benefits, and other benefits. The GFO calls for: documentation of timeframe, assumptions, and calculations for estimated benefits, identification of impacted market segments (size and deployment rates), discussion of qualitative benefits, and comparison of project costs to anticipated benefits.	Bringing Rapid Innovation Development to Green Energy (BRIDGE) Solicitation Manual (CEC).	The California Energy Commission's (CEC) Electric Program Investment Charge (EPIC) program (2012-2020) aims to provide electricity ratepayer benefits, namely in reliability, cost, and safety, through the provision of funding for: 1) applied research and development, 2) technology demonstration and deployment, and 3) market facilitation.

		NJ – Microgrid Feasibility	Proposal evaluation criteria, including portfolio perspective	Feasibility study application requirements include a description of all critical facilities within the project area, including the following: criticality of facilities based on FEMA classification, total facility electric and thermal loads, potential partners, description of the technology to be implemented, overall cost and potential financing, benefits, timeline for completion, specific modeling to be used in feasibility study, and the local electric distribution company. The evaluation process included consideration of the distribution of feasibility studies across all electric utilities and the state, applicant understanding of the technical, financial, and power infrastructure needs of each DER Microgrid stakeholder, and evaluation of New Jersey Institute of Technology (NJIT) criteria identified in its microgrids resource potential analysis.	New Jersey Town Centers Distributed Energy Resource Microgrids Potential: Statewide Geographic Information Systems Analysis (NJIT).	New Jersey's Town Center Distributed Energy Resource Microgrid Feasibility Study Incentive Program facilitates development of Town Center DER microgrids, each "a cluster of critical facilities within a municipal boundary that may also operate as shelter for the public during and after an emergency event or provide services that are essential to function during and after an emergency situation," with the goal of increasing the grid's resiliency and reliability during a major storm. After receiving and evaluating 13 applications for proposed microgrids and the potential benefits offered, the New Jersey Board of Public Utilities (BPU) approved a budget modification to fund all 13 applications at a total cost of $2,052,480.
Market Monitoring	**Market competition**	**TX - Market Competition**	Competitiveness analysis	The competitiveness of the retail electricity market is evaluated by considering the number of customers served and electricity sold by competitive retail providers, cost of competitive retail service relative to a "price-to-beat", and average retail rates for competitive providers and affiliated providers compared to other states' gas-dependent utilities.		As required by state statute, the Public Utility Commission of Texas investigated the state of market competition since retail competition began in ERCOT in 2002.
		TX - TXU (34061)	Market power analysis	Three primary assessments were made based on price spikes occurring between the same daily interval of hours across a 4-month period in 2007: A Pivotal Supplier Test, a Bid Analysis, and a Penalty Calculation.		Based on further investigation of a March 2007 Independent Market Monitor's report that found a high number of price spikes between June 1, 2005 and September 30, 2005, staff of the Public Utility Commission of Texas Commission Staff recommended that TXU be required to pay administrative penalties and refunds to customers. Additional proceedings over penalty were filed and led to an eventual settlement of $15 million in 2008.
		ISO-NE - Market Assessment	Market power analysis	Several types of metrics are calculated and assessed, including: 1) Structural Market Indicators that measure a supplier's market power based on the amount of energy it supplies to the market; 2) a Pivotal Supplier Test, applied to a supplier whose capacity is needed to meet demand and reserve requirements in a period; and 3) Economic and Physical Withholding metrics to identify instances when a supplier withholds output from entering the grid to raise prices above the competitive price.		ISO-NE commissions an annual report which includes an assessment of the competitive performance of the energy and ancillary services markets in the past year.

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