

A PLAYBOOK FOR MODERNIZING THE DISTRIBUTION GRID

Volume 1

GRID MODERNIZATION GOALS, PRINCIPLES
AND PLAN EVALUATION CHECKLIST



ABOUT THE PLAYBOOK

Developed by the Interstate Renewable Energy Council (IREC) and GridLab, The Playbook for Modernizing the Distribution Grid (hereinafter, the GridMod Playbook) is an evaluation toolkit to help regulatory stakeholders navigate, analyze and make more informed decisions about grid modernization proposals, distribution plans and grid investments. The GridMod Playbook aims to ensure more efficient and impactful grid modernization efforts in support of state public policy goals, such as clean energy adoption, across the United States and U.S. territories

The first volume, *Grid Modernization Goals, Principles and Plan Evaluation Checklist*, consists of goals and principles for grid modernization, and an evaluation checklist – combined, they provide an initial framework to help utility regulators and regulatory stakeholders assess the merits of proposed grid modernization plans, investments and initiatives. The GridMod Playbook concept was developed at Rocky Mountain Institute (RMI)’s 2019 eLab Accelerator. This volume was developed by IREC and GridLab with peer review and input from the following individuals. No part of this document should be attributed to these individuals or their affiliated organizations.

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About IREC

IREC builds the foundation for rapid adoption of clean energy and energy efficiency to benefit people, the economy and our planet. IREC develops, informs and advances the regulatory reforms, technical standards, and workforce solutions needed to enable the streamlined, efficient and cost-effective installation of clean, distributed energy resources. www.irecusa.org



About GridLab

GridLab is an innovative non-profit that provides technical grid expertise to enhance policy decision-making and to ensure a rapid transition to a reliable, cost effective, and low carbon future. www.gridlab.org



GOALS OF GRID MODERNIZATION

Over 150 states, local governments and prominent businesses have adopted ambitious renewable and clean energy goals to rapidly reduce carbon emissions in an effort to address climate change and improve the resilience of the electric grid. Concurrently, states and utilities are undertaking “grid modernization” efforts that could enable strategic investments in new technologies for the distribution grid and allow for increased grid integration of distributed energy resources (DERs) and accompanying technologies — e.g., solar, energy storage, advanced meters, smart inverters, smart devices, demand response and electric vehicle (EV) charging infrastructure. These grid modernization efforts have the potential to leverage the deployment of DER technologies to meet policy and customer goals, while also creating more transparency and minimizing the risks associated with future grid investments.

Utilities across the country are proposing investments that add up to billions of ratepayer dollars over the next several years. Although considerable investments in the distribution grid will be needed in the coming decades to address aging infrastructure and changing demands on the electricity grid, not all grid modernization investments may be warranted or beneficial,

either economically or for carbon emission reductions.

Although state policymakers, regulators and utilities may articulate discrete goals for their respective grid modernization efforts, we believe the overarching goals of grid modernization plans and ensuing investments should be to enable the swift evolution of the grid to integrate modern technologies that meet public policy and clean energy objectives, such as reducing carbon emissions and achieving 100% clean energy goals. In particular, grid modernization plans and investments should cost-effectively enable, not hinder, the electrification and decarbonization of the vehicle and building sectors, support increased energy efficiency, facilitate the deployment of DERs and improve grid reliability and resilience. The latter is especially critical given the increased frequency and intensity of natural disasters, which will only be further exacerbated by climate change. In addition, grid modernization should avoid costly and unnecessary investments in legacy grid infrastructure that may crowd out or impede the adoption of proven, cost-effective clean energy technologies and the transition to a clean energy future.

PRINCIPLES OF GRID MODERNIZATION

The following principles support and reflect the above goals of grid modernization and should be present in some form in any proposal. These principles can be used as an initial filter and framework to assess the merits of proposed grid modernization plans, investments and initiatives.

Grid Modernization should...

- 1. Support and enable policy goals, including the decarbonization of the electricity system and the beneficial electrification¹ of the transportation and building sectors.** Grid modernization proposals should support relevant policy and regulatory objectives for reducing carbon emissions and enabling the electrification of the transportation and building sectors. Grid modernization investments should take into account other incentives or programs that spur increased consumer and community adoption of DERs, such as EVs and EV fast charging, electric appliances, solar, wind, energy storage, demand response and/or energy efficiency measures. Rather than duplicate utility investments, consumer investments in DERs should be leveraged and properly accounted for in grid modernization plans, particularly as optimal alternatives to more costly grid investments.
- 2. Enable the adoption and optimization of distributed energy resources (DERs).** Grid modernization investments should enable, not hinder, the adoption of DERs, which can offer economic, reliability, resilience and environmental benefits to consumers, communities and utilities.² Grid modernization efforts should aim

to increase the transparency of the grid and improve grid modeling procedures such that consumers, local governments, developers and technology providers can support the accelerated customer adoption of DERs. In addition, concurrent with grid modernization investments and plans, efforts should be made to streamline and automate interconnection processes and reduce the overall cost of DER adoption and integration for the benefit of all ratepayers.

- 3. Empower people, communities and businesses to adopt affordable clean energy technologies and clean energy solutions.** Grid modernization plans and investments should help, not hinder, consumers' ability to adopt technologies and solutions that reduce the impact of their energy usage, enable easier ways to manage energy costs, and support their carbon reduction, energy consumption and/or financial goals. In addition, all interested and vested stakeholders should have easy access to information about the grid. Grid modernization investments should help support the adoption of more streamlined processes for installing, interconnecting and integrating these technologies (without impacting grid safety and reliability).
- 4. Support secure and transparent information sharing and data access.** Grid modernization plans should facilitate the increased understanding of grid needs and operations among all stakeholders, including regulators. In addition, investments should enable enhanced interoperability, improved visibility and coordinated control of the grid. Improvements in transparency should allow all parties — utilities, developers, customers, local governments, regulators and other decision-makers — to access information about the grid such that DERs and other low-carbon clean energy technologies are deployed strategically, swiftly and affordably in preferred locations on the grid.

5. Enable innovation in technology and business models. Grid modernization plans and investments should encourage the participation of third-party stakeholders in providing information, technologies, services, and technical and financial support to consumers. To the extent applicable and appropriate, economic development and job creation goals could also be taken into account when evaluating the merits of grid modernization plans. Non-wires alternatives (NWA) should be identified and supported as viable solutions to serve identified grid needs,

ahead of traditional, more capital-intensive investments (which may lead to stranded assets or more costly infrastructure). Grid modernization plans should also address whether financial incentives, penalties and/or pilot programs are needed to address the limitation of existing utility business models to encourage consumer-based technology innovation, and particularly the underlying regulatory incentive for utilities to prioritize capital expenditures to increase their profits based on the prevalent return on investment-based business model.



In addition to the above principles, we suggest that regulators and stakeholders evaluating Grid Modernization (GridMod) plans consider the following questions in their assessments (please refer to endnotes for additional explanation).

1) Does the GridMod plan include specific, measurable goals and objectives?

- a) Does the plan align with and support existing state policy goals and/or commission orders?
- b) Is it clear what specifically the utility is trying to achieve with its plan?
- c) Is it clear how the utility will measure the success of the plan?

2) Does the GridMod plan include a credible Benefit/Cost Analysis (BCA) to demonstrate the plan's cost effectiveness or cost reasonableness?

- a) Has the utility applied an appropriate BCA methodology (e.g., least-cost/best-fit, benefit/cost ratio, Utility or Societal Cost test, etc.) for each category of GridMod expenditures?³
- b) Does the plan include disclosure of all planned GridMod expenditures including those beyond the initial period of the request?
- c) Do the costs reflect the full revenue requirements and customer bill impacts over the life of the assets?⁴
- d) Has the utility explicitly included cost contingencies and provided a corresponding range of potential BCA results?⁵
- e) If the BCA includes benefits from improved reliability, are the identified benefits reasonable and credible?⁶
- f) Does the plan include a qualitative assessment of how it will improve resilience?⁷
- g) Has the utility applied an appropriate discount rate in its BCA calculations?⁸
- h) Has the utility provided support for its key BCA assumptions and provided a sensitivity analysis of those assumptions?⁹

3) Does the GridMod plan include detailed metrics to track progress?

- a) Are the metrics tied to the stated goals/objectives of the plan, the BCA, and the underlying BCA assumptions?
- b) Has the utility provided baselines and targets for each metric?
- c) Has the utility defined a process for ongoing tracking and reporting of metrics including costs and benefits?

4) Will the GridMod plan enable beneficial electrification?

- a) Has the utility quantified and planned for the potential impact on load and demand from on-road, non-road¹⁰ and building electrification?
 - b) Are the utility's assumptions about electrification consistent with state policy goals?
 - c) Does the plan reflect input from other relevant transportation and building sector programs/agencies (e.g., public transportation office, large fleet vehicle users, state transportation agency, building codes and standards, etc.)?
 - d) Has the utility identified barriers to EV adoption in its service territory, and does the plan adequately address the barriers?
 - e) Does the plan include investments in the grid to accelerate EV adoption and deployment of EV charging infrastructure?
 - f) Does the plan include an appropriate balance between utility ownership and private ownership of EV charging infrastructure?
 - g) Will the utility offer rate structures to encourage off-peak EV charging and, if so, by when?
 - h) Does the plan include programs and incentives for the electrification of space and water heating?
-

5) Is the GridMod plan a requirement and/or outcome of a credible Integrated Distribution Planning (IDP) process?¹¹

- a) Will the plan help accelerate the adoption and integration of DERs?
 - b) Does the plan enable or enhance identified IDP objectives, capabilities or tools (i.e., improved load and DER forecasting, hosting capacity analyses, identification/ publication of grid needs and locational value, explicit consideration of non-utility owned DERs as non-wires alternatives (NWA) and NWA acquisition)?
 - c) Will the plan result in increased transparency and understanding of distribution system data (e.g., historical loads and load forecasts, hosting capacity, grid needs, beneficial locations for non-wires alternatives, etc.)?
-

6) Are the GridMod plan's proposed investments based on a demonstrated need?¹²

- a) Has the utility defined all of the capabilities¹³ the plan will enable or enhance?
 - b) Has the utility adequately explained how these capabilities relate to the overall goals and objectives of the plan?
 - c) Has the utility provided benchmarking or other credible analysis supporting the need for the new or enhanced capabilities?
-

7) Is the GridMod plan synergistic with other existing or planned investments (e.g., Advanced Metering Infrastructure (AMI) supporting metering as well as distribution planning/operations, etc.)?

8) Does the GridMod plan meaningfully reflect input from stakeholders, including consumer advocates, clean energy advocates, customers, large energy users, technology vendors, transportation interests and local governments?

- a) Will the utility meaningfully incorporate Commission and stakeholders' input throughout the plan's design and implementation?

In addition to the above questions, the following table lists the categories of investments that may be included in a GridMod plan, along with specific examples or components in each category. The questions are intended to help evaluate the merits of the GridMod plan and may highlight the need for additional analysis and/or evidence to support proposed investments. Please refer to the Glossary for definitions of terms and acronyms, and please refer to endnotes for additional context and perspective.

Within the GridMod plan:

**IF YOU SEE INVESTMENTS FOR
ADVANCED METERING**

EXAMPLES OR COMPONENTS INCLUDE...	THEN ASK...
<ul style="list-style-type: none">• Advanced Metering Infrastructure (AMI)¹⁴• Smart Meters• Meter Data Management System (MDMS)• AMI Head-end System• Mesh Network• Backhaul Network• Field Area Network (FAN)	<ul style="list-style-type: none">• Do the benefits exceed the costs (as measured by present value of revenue requirements or bill impacts)?<ul style="list-style-type: none">- <i>If not, is there a credible rationale for why the AMI investment is needed?</i>• How will AMI support distribution planning/operations (e.g., load forecasting, voltage monitoring, communications with intelligent grid devices, etc.)?• Will customers be able to download and share their usage data using a standardized format, such as Green Button data? If so, by when?• What time-varying rates will the utility offer and by when?<ul style="list-style-type: none">- <i>What are the projected energy/demand savings from the proposed rates?</i>- <i>Are the projections credible and based on actual results from other utilities?</i>• What new AMI-enabled energy efficiency and/or demand response programs will the utility offer and by when?<ul style="list-style-type: none">- <i>What are the projected energy/demand savings from these programs?</i>- <i>Are the projections credible and based on actual results from other utilities?</i>• What other tools will the utility deploy to help customers manage energy usage, and by when?• What plans does the utility have for customer education, and are the plans sufficient?• Are there well-defined metrics with targets to track implementation progress and benefit realization?

IF YOU SEE INVESTMENTS FOR GRID AUTOMATION AND SENSING

EXAMPLES OR COMPONENTS INCLUDE...

- Distribution Automation (DA)
- Substation Automation
- Supervisory Control and Data Acquisition (SCADA)
- Fault Location, Isolation and Service Restoration (FLISR)
- Self-Healing Grid
- Remote Fault Indicators
- Line Sensors
- Intelligent Grid Devices
- Telemetry
- Installation of Reclosers

THEN ASK...

- Is there credible proof of cost reasonableness or cost effectiveness?
- Is the utility claiming that the automation will improve reliability? If so:
 - *Is there a demonstrated need for the reliability improvement (e.g., benchmarking results, legislative mandates, poor customer satisfaction, etc.)?*
 - *Are the projected improvements in SAIDI (System Average Interruption Duration Index), SAIFI (System Average Interruption Frequency Index) and CAIDI (Customer Average Interruption Duration Index) credible?*¹⁵
 - *Is the utility using the Interruption Cost Estimate (ICE) Calculator to quantify the benefits from improved reliability? If so:*
 - » *Are the inputs to and outputs from the ICE Calculator credible?*
 - » *Has the utility accounted for the impact of momentary interruptions?*
- What steps has the utility taken to minimize the risk of technology obsolescence?¹⁶
- Are there well-defined metrics with targets to track implementation progress and benefit realization?

IF YOU SEE INVESTMENTS FOR OTHER RELIABILITY IMPROVEMENTS

EXAMPLES OR COMPONENTS INCLUDE...

- Grid Hardening
- Undergrounding¹⁷
- Voltage Conversions
- Line Rebuilds
- Battery Energy Storage Systems (BESS)
- Microgrids
- Asset Replacements
- Installation of Reclosers

THEN ASK...

- Is there credible proof of cost reasonableness or cost effectiveness?
- Is there a demonstrated need for reliability improvement (e.g., benchmarking results, legislative mandates, poor customer satisfaction, etc.)?
- Is the utility using the ICE Calculator to quantify the benefits from improved reliability? If so:
 - *Are the inputs to and outputs from the ICE Calculator credible?*
 - *Has the utility accounted for the impact of momentary interruptions?*
- Has the utility sufficiently considered customer- and third party-owned DERs as NWA?¹⁸
- What steps has the utility taken to minimize the risk of technology obsolescence?¹⁹
- Are there well-defined metrics with targets to track implementation progress and benefit realization?

IF YOU SEE INVESTMENTS FOR FOUNDATIONAL TOOLS AND SOFTWARE

EXAMPLES OR COMPONENTS INCLUDE...

- Load Forecasting
- DER Forecasting
- Power Flow Modeling
- Load Flow Modeling
- Fault Analysis
- Geographic Information System (GIS)
- Distribution Management System (DMS)
- Outage Management System (OMS)
- Advanced Distribution Management System (ADMS)
- Customer Information System (CIS)
- Customer Information Platform (CIP)
- Enterprise Asset Management System (EAMS)

THEN ASK...

- Has the utility sufficiently demonstrated the need for the requested tools/software (i.e., in the context of stated goals/objectives)?
- Is the utility claiming that the tools/software will improve reliability? If so, are the projected improvements measurable and credible?
- Is the utility claiming that the tools/software are needed to integrate DERs? If so, has the utility sufficiently demonstrated this need and explained how the tools/software will address this need?
- If the utility plans to use commercial-off-the-shelf (COTS) software, do the selected technologies and associated cost estimates reflect a rigorous Request for Proposals (RFP) process?²⁰
- If custom software, what is the basis for the estimated costs and how do these costs compare to COTS?
- Does the utility currently have the staff and expertise to take full advantage of the software tools? If not, does the utility have an appropriate training or hiring plan?
- If COTS software is used, what steps has the utility taken to minimize the risk of technology obsolescence?²¹
- Has the utility explained how the technologies will enable or enhance IDP capabilities?
- Will the utility provide the inputs, assumptions and outputs of the tools and software in a transparent, easily understandable manner?

IF YOU SEE INVESTMENTS FOR ADVANCED TOOLS AND SOFTWARE

EXAMPLES OR COMPONENTS INCLUDE...

- Distributed Energy Resources Management System (DERMS)
- Demand Response Management System (DRMS)
- Locational Net Benefit Analysis (LNBA)
- Locational Value Analysis
- Advanced Analytics
- Optimization Analytics

THEN ASK...

- Has the utility sufficiently demonstrated the need for the requested tools/software?
- Do existing and forecasted DER penetration levels warrant the need for the investment?²²
- Are the requested tools/software commonly used by other utilities?
- If COTS software is used, are the selected technologies and associated cost estimates reflective of a rigorous RFP process?
- If custom software is used, what is the basis for the estimated costs and how do these compare to COTS?
- Will the requested tools/software enable communications with smart inverters?
- What steps has the utility taken to minimize the risk of technology obsolescence?²³



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IF YOU SEE INVESTMENTS FOR TELECOMMUNICATIONS

- Broadband Fiber
- Broadband Microwave
- Wide Area Network (WAN)
- Field Area Network (FAN)

THEN ASK...

- Is there credible proof of cost reasonableness or cost effectiveness?
- Has the utility appropriately considered and incorporated public solutions (e.g., leasing lines from existing telecommunications infrastructure providers)?
- Will the proposed field area network (FAN) enable and/or support communications with advanced inverters?
- If the utility is also deploying AMI, can the AMI communications network also function as the FAN? If not, why?
- What steps has the utility taken to minimize the risk of technology obsolescence?²⁴

IF YOU SEE INVESTMENTS FOR VOLTAGE AND REACTIVE POWER MANAGEMENT

EXAMPLES OR COMPONENTS INCLUDE...

- Voltage Optimization (VO)
- Integrated Volt/VAR Control (IVVC)
- Integrated Volt/VAR Optimization (IVVO)
- Conservation Voltage Reduction (CVR)

THEN ASK...

- Has the utility appropriately considered and utilized the capabilities of advanced inverters and secondary VAR controllers?
- What are the expected peak demand and energy usage reductions, and how will the utility measure and verify the savings?
- What are the expected line loss reductions, and how will the utility measure and verify the savings?
- If the utility is also deploying AMI, how will AMI support or enhance the proposed voltage management solution?
- What steps has the utility taken to minimize the risk of technology obsolescence?²⁵

IF YOU SEE INVESTMENTS FOR DER INTEGRATION OR INTERCONNECTION

EXAMPLES OR COMPONENTS INCLUDE...

- Hosting Capacity Analysis (HCA)
- DER Interconnection Tools
- Information Sharing Portals
- Reconductoring
- Voltage Conversion
- Relay and protection upgrades or replacements
- Voltage regulator installation or replacement
- Recloser installation or replacement
- Transformer replacement
- Capacitor installation or replacement
- Upgrades to address reverse power flow

THEN ASK...

- Has the utility sufficiently demonstrated the need for the investment?
- Do existing and forecasted DER penetration levels support the need?
- Are the issues allegedly caused by DERs supported with evidence?
- Has the utility appropriately considered the capabilities of advanced inverters and secondary VAR controllers to defer or eliminate the need for the investment?
- Are state level discussions underway to adopt the The Institute of Electrical and Electronics Engineers (IEEE) *Standard 1547-2018 for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces (IEEE Std 1547-2018)* for smart inverters? If so, do the assumptions in the GridMod plan reflect the impact of this new standard?
- If the utility is proposing investments in interconnection tools, how will the utility incorporate customer and developer feedback into creation/refinement of the tools?
- If the utility is proposing an HCA:
 - *Has the utility clearly defined the HCA use cases?*
 - *What HCA methodology is the utility proposing, and is it appropriate for the use cases?*
 - *Are the utility's plans for publishing HCA results sufficient?*²⁶
 - *How frequently will the utility update the HCA, and is this sufficient?*
 - *How will the utility incorporate customer and developer feedback into the creation/refinement of its HCA?*
- To what extent will the investments enable sharing of distribution system information (e.g., historical loads and load forecasts, hosting capacity, grid needs, beneficial locations for non-wires alternatives, etc.)?

IF YOU SEE INVESTMENTS FOR PILOT PROJECTS

EXAMPLES OR COMPONENTS INCLUDE...

- Battery Energy Storage Solutions (BESS)
- Non-Wires Alternatives
- Microgrids
- Time-of-use rates
- Managed EV Charging
- Demand Response programs

THEN ASK...

- Has the utility established clear goals and objectives for each proposed pilot? Are these aligned with the overall GridMod goals and objectives?
- Has the utility demonstrated that each pilot is designed based on lessons learned and best practices from other utilities?
- Does the plan call for cross-functional collaboration and stakeholder engagement during pilot design and implementation?
- For each pilot, is there a plan for replicating or scaling to support full deployment if successful?

ENDNOTES

¹ Beneficial electrification is a term for replacing direct fossil fuel use (e.g., propane, heating oil, gasoline, natural gas) with electricity in a way that reduces overall emissions and energy costs.

² See e.g., “Whereas many States recognize that DER, if interconnected and operated in a safe and reliable manner with uniform standards across multiple jurisdictions, can offer economic, reliability, resilience, and environmental benefits to consumers, communities and utilities.” *EL-1/ERE-1 Resolution Recommending State Commissions Act to Adopt and Implement Distributed Energy Resource Standard IEEE 1547-2018*, Resolution Passed by National Association of Regulatory Utility Commissioners (NARUC) Board of Directors 2020 Winter Policy Summit, 12 February 2020, page 1, available at: <https://pubs.naruc.org/pub/4C436369-155D-0A36-314F-8B6C4DE0F7C7>

³ See a forthcoming Berkeley Lab report, *Benefit-Cost Analysis for Utility-Facing Grid Modernization Investments: Trends, Challenges, and Considerations*, by Woolf, T., B. Havumaki, D. Bhandari, M. Whited (Synapse Energy Economics) and L. Schwartz, Berkeley Lab.

⁴ In addition to capital and O&M costs, the BCA should include full financing costs and taxes over the life of the assets, as measured by revenue requirements. It is also informative to understand how much typical customer bills are likely to increase or decrease as a result of the proposed GridMod investments.

⁵ Cost contingencies are amounts added to base costs in a spending plan to account for risks and uncertainty. Good project management practices call for the use of cost contingencies, particularly for large, complex projects deploying new technologies over a long time period. Risks and uncertainties that could impact GridMod plan costs include, but are not limited to, unknowns related to the integration of new and legacy IT systems; equipment deployment delays due to weather or other factors; emergence of new viable technologies; new security threats or vulnerabilities; and changing legislation or regulations. Cost contingencies effectively provide a range of expected costs and best- and worst-case benefit/cost ratios. As with all BCA assumptions and calculations, it is important that the utility’s inclusion of cost contingencies be explicit and transparent.

⁶ Although the determination of reasonable and credible benefits is subjective, the GridMod plan should include clear, understandable, and verifiable data/analysis in support of claimed benefits. The ranges of benefits should be consistent with what the utility has demonstrated in pilots or with what other utilities have realized deploying similar technologies.

⁷ A 2019 report written for NARUC concluded that, although DERs and other GridMod investments

can offer resilience benefits, it is unclear how to determine their value. See Rickerson, Wilson, J. Gillis, M. Bulkeley, *The Value of Resilience for Distributed Energy Resources: An Overview of Current Analytical Practices*, Prepared by Converge Strategies for the National Association of Regulatory Utility Commissioners, April 2019, available at: <https://pubs.naruc.org/pub/531AD059-9CC0-BAF6-127B-99BCB5F02198>

⁸ A utility often uses its own weighted average cost of capital (WACC) as the discount rate in its BCA. However, according to the Synapse/LBNL report referenced in endnote 3, the appropriate BCA discount rate should reflect the time preference chosen by regulators on behalf of all customers (i.e., the regulatory perspective). The regulatory perspective should account for many factors, including low-cost, safe, reliable service; intergenerational equity; and other regulatory policy goals. The regulatory perspective suggests a greater emphasis on long-term impacts than what is reflected in the WACC, and that a discount rate lower than the WACC may be appropriate for the BCA. GridMod plans can use sensitivities to consider the impact of different discount rates (e.g., use the utility WACC as a high case, use a low-risk or societal discount rate as a low case)

⁹ A typical GridMod plan BCA includes multiple assumptions such as future reliability improvements, equipment failure rates, customer participation in DSM programs, EV adoption rates, etc. Most, if not all, of these assumptions are uncertain. A sensitivity analysis determines how much the overall costs or benefits change from a change in one or more key assumptions. A sensitivity analysis also identifies the assumptions that have the most impact on the overall costs and benefits of the GridMod plan, thus highlighting the key assumptions that the utility should further validate, monitor, and report on throughout the GridMod plan implementation.

¹⁰ Non-road electrification converts commercial and industrial equipment (such as forklifts, airport baggage handling equipment, cranes, conveyors, onshore generation for dock shipping, welding equipment, tugboats and ferries) from propane or diesel fuel to electricity.

¹¹ A credible IDP process includes the consideration of Commission, staff and other stakeholder input when developing the IDP framework and IDP priorities.

¹² A demonstrated need should include evidence that a proposed investment is actually necessary. Such evidence may include benchmarking results showing relatively poor performance, customer complaints, fines and/or penalties for poor performance, or other documented proof of poor or inadequate system conditions.

¹³ In this context, the authors define a capability to be the combination of skills, processes and technologies required to achieve a specific outcome or objective. The U.S. Department of Energy (DOE) has defined 26 grid modernization capabilities. See pp. 43-49 of Modern Distribution Grid Volume I: Customer and State Policy Driven Functionality, available at https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid_Volume-I_v1_1.pdf.

¹⁴ The authors are generally supportive of AMI but emphasize the importance of a utility taking full advantage of AMI capabilities for the benefit of its customers. For recommendations to ensure that utilities and customers realize the full value from AMI, see e.g., Gold, Rachel, C. Waters, and D. York, *Leveraging Advanced Metering Infrastructure to Save Energy*, American Council for an Energy-Efficient Economy, Report U2001, 3 January 2020, pp. 42-43, available at: <https://www.aceee.org/sites/default/files/pdfs/u2001.pdf>.

¹⁵ According to the 2016 DOE report on results from the Smart Grid Investment Grant (SGIG) program, distribution automation (DA) can reduce the frequency and duration of sustained customer interruptions by 15-55%. However, p. 24 of the report cautions, “The best way to evaluate the impact of DA technologies on system reliability is to compare reliability indices before and after deployment using a well-established pre-deployment baseline. Unfortunately, many SGIG utilities had trouble establishing accurate, reliable pre-deployment baselines from which to measure performance improvements. It is recognized that the process of developing a baseline is complex and time consuming for utilities. Simply comparing reliability indices from year to year—rather than against a baseline—cannot effectively measure the full impact of DA investments.” Additionally, utilities must take into account the increase in momentary interruptions for some customers when quantifying DA benefits.

¹⁶ It is important that the utility emphasize “future proofing” the GridMod technologies and capabilities to minimize the risk of obsolescence. Selected GridMod technologies should include characteristics such as over-the-air firmware and configuration upgrades without the need for field visits or equipment replacement; use of open standards, protocols, and standard service components that are not vendor-specific; enhanced memory size to support potential future use cases; architecture for ease of integration with existing and future systems; and re(use) of standard interfaces to reduce design and development costs.

¹⁷ Converting overhead facilities to underground is costly and almost never justified by reliability improvements alone. A 2012 Edison Electric Institute report, *Out of Sight, Out of Mind 2012 — an Updated Study of the Undergrounding of Overhead Power Lines* (available at <https://www.eei.org/issuesandpolicy/electricreliability/undergrounding/Documents/UndergroundReport.pdf>), shows an industry range of distribution overhead to underground conversion

costs of \$1-5 million per mile for urban construction, and \$0.15-2 million per mile for rural construction. The report states, “Currently, no state has recommended wholesale undergrounding of their utility infrastructure. The cost of conversion has always been the insurmountable obstacle in each of these studies ... Since 1999, an increasing number of state utility commissions have studied the possibility of mandating utilities to place all or part of their electrical facilities underground ... The conclusion in every study, has determined that the cost to achieve the desired underground system is considerably too expensive for either the utility or the electrical customers.”

¹⁸ For example, in the recent Green Mountain Power (GMP) Bring Your Own Device (BYOD) pilot, the utility offers bill credits to customers in exchange for control of customer-owned home battery backup systems, EV chargers, and water heaters during peak periods. Participating customers in the GMP BYOD pilot with backup batteries experience improved reliability while also providing peak demand reductions to benefit all customers. See <https://www.greentechmedia.com/articles/read/green-mountain-power-kept-1100-homes-lit-up-during-storm-outage>.

¹⁹ See endnote 16.

²⁰ The authors strongly recommend COTS only as utilities should not be in the business of developing custom software.

²¹ See endnote 16.

²² The authors believe DERMS technologies are nascent and unnecessary even with high penetrations of DERs. For example, at the end of 2018, Pacific Gas & Electric (PG&E) had 370,000 customers with rooftop solar and a total of 4,000 MW of rooftop solar distributed generation (DG), or 20% of the private rooftop DG capacity in the U.S. PG&E also was adding 5,000 new DG customers and 55 MW of new rooftop DG to its grid each month. In its 2018 general rate case application, PG&E did not request approval of a DERMS, stating that no vendor currently provides the comprehensive set of DERMS capabilities it requires. As DERMS functionality matures, PG&E determined that it should first “invest in foundational technology including improved data quality, modeling, forecasting, communications, cybersecurity, and a DER-aware ADMS to address the near-term impacts of DERs and grid complexity while providing the groundwork for a future DERMS system.”

²³ See endnote 16.

²⁴ See endnote 16.

²⁵ See endnote 16.

²⁶ HCA results should be published via online maps illustrating the hosting capacity of each circuit line section. The maps should include quick-display boxes, allowing the viewer to easily see summary information for a given node, line section or feeder. All HCA results and underlying data should also be available for download.

GLOSSARY

ADMS (Advanced Distribution Management System) - software that integrates several operational systems to optimize distribution grid performance. ADMS components can include a distribution management system (DMS); DER management system (DERMS); outage management system (OMS); demand response management system (DRMS); fault location, isolation, and service restoration (FLISR); conservation voltage reduction (CVR) and integrated Volt-VAR control (IVVC).

Advanced Inverter - a power electronics device that transforms DER direct current to alternating current. It also provides functions such as reactive power control and voltage/frequency ride-through responses to improve the stability, reliability and efficiency of the distribution system. Also known as a “smart inverter.”

AMI (Advanced Metering Infrastructure) - a system that includes meters, communication networks between the meters and utility, and data collection and management systems that make the information available to the utility. AMI communications networks may also provide connectivity to other types of devices such as grid sensors, switches, and DERs.

AMI Head-end System - software that transmits and receives data, sends operational commands to smart meters, and stores interval load data from the smart meters to support customer billing.

Backhaul Network - a communications system for transmitting large volumes of data between the AMI/field device mesh networks and the utility.

Broadband Fiber - communication systems using optical fiber that are capable of very high bandwidths.

Broadband Microwave - high frequency radio communication systems that are widely used by utilities for substation and SCADA communications.

Bring Your Own Device (BYOD) - a type of energy efficiency or demand response program involving the use of customer-owned DER devices (e.g., batteries, thermostats, etc.), and may include aggregated dispatch to provide grid services.

CAIDI (Customer Average Interruption Duration Index) - the average duration of sustained outages in a year, measured in minutes per interruption. CAIDI = SAIDI / SAIFI.

CIP (Customer Information Platform) - software for billing and revenue collection, may also include incorporation of new capabilities enabled by AMI and an MDMS.

CIS (Customer Information System) - software for billing and revenue collection.

Cost Effectiveness - determination if a proposed investment's benefits exceed the costs.

Cost Reasonableness - determination if a proposed investment represents the least-cost/best-fit solution to address a need, regardless if the benefits exceed the costs.

COTS (Commercial-Off-The-Shelf) - software products that are ready-made and available for purchase in the commercial market.

CVR (Conservation Voltage Reduction) - intentional reduction of voltage within established limits to achieve demand reduction and energy savings for customers.

DA (Distribution Automation) - technologies including sensors, communication networks, and switches, through which a utility can improve the operational efficiency of its distribution system.

DERs (Distributed Energy Resources) - energy resources connected to the distribution system that include distributed wind and solar generation, combined heat and power, energy storage, electric vehicles, energy efficiency, demand response and microgrids.

DERMS (Distributed Energy Resources Management System) - software that provides distribution operators near real-time visibility into and control of individual DERs or DER aggregations.

DMS (Distribution Management System) - software capable of collecting, displaying and analyzing near real-time electric distribution system information. A DMS can interface with other operations applications, such as a GIS, OMS, and CIS to create an integrated view of distribution operations.

DR (Demand Response) - voluntary (and compensated) load reduction used by utilities as a system reliability or local distribution capacity resource. Demand response allows utilities to cycle certain customer loads on and off in exchange for financial incentives.

DRMS (Demand Response Management System) - software to administer and operationalize DR aggregations and other DR programs.

EAMS (Enterprise Asset Management System) - software for collecting attributes and analysis of distribution grid assets.

FAN (Field Area Network) - the communications network between distribution substations and grid devices (such as switches, sensors and AMI meters) on the distribution system.

FLISR (Fault Location, Isolation and Service Restoration) - a combination of hardware and software technologies that identify the location on a circuit where a fault has occurred, isolate the faulted line segment and restore service to all customers not connected to the faulted line segment. FLISR is also called a Self-Healing Grid.

GIS (Geographic Information System) - as defined in the context of the electric distribution system, software containing attributes of distribution grid assets and their geographic locations to enable presentation on a map. GIS may also serve as the system of record for electrical connectivity of the assets.

Green Button - an industry standard for making detailed customer energy-usage information available for download in a simple, common format.

Grid Hardening - grid improvements such as rebuilding portions of distribution circuits or proactively replacing assets to improve reliability and resilience.

Hosting Capacity - the amount of DERs that can be accommodated on the distribution system under existing grid conditions and operations without adversely impacting safety, power quality, reliability or other operational criteria, and without requiring significant infrastructure upgrades.

HCA (Hosting Capacity Analysis) - the calculation and publication of the distribution system's hosting capacity.

ICE (Interruption Cost Estimate) Calculator - an online tool for quantifying the economic impact to customers from improved reliability. See <https://icecalculator.com/home>.

IDP (Integrated Distribution Planning) - proactive planning for DERs growth consisting of four principal components: (1) mapping circuits' hosting capacity; (2) forecasting the expected growth of DERs on each circuit; (3) prioritizing grid upgrades to integrate DERs and (4) proactively pursuing grid upgrades (including traditional capital upgrades as well as DERs themselves) to meet anticipated grid needs.

Intelligent Grid Devices - devices such as switches and sensors that provide situational awareness, grid control capability and enable two-way communications.

IVVC (Integrated Volt/VAR Control) - a process of controlling voltage and reactive power flow on the distribution system to improve overall system performance, allowing a utility to reduce electrical losses, eliminate voltage profile problems and reduce electrical demand.

Line Loss - A natural occurrence of power delivery systems, consisting mainly of power dissipation in system components. The largest component of losses is caused by the electrical resistance of equipment and is proportional to the square of the current. As system load or current increases, system components lose more energy in the form of heat, and losses increase exponentially. Losses are therefore greatest during peak loading periods.

MAIFI (Momentary Average Interruption Frequency Index) - the average number of momentary interruptions experienced by customers in a year.

MDMS (Meter Data Management System) - a software platform that processes and stores AMI interval data used for billing.

Mesh Network - a wireless method of communication in which information is transmitted through a network of transmitters/receivers en route to its final destination.

Microgrid - a group of interconnected loads and DERs able to operate when connected to the larger distribution grid and also able to operate as an "island" when there is an outage or other grid disturbance.

Momentary Interruptions - according to IEEE, momentary interruptions are outages lasting less than 5 minutes. Momentary interruptions are not included in the standard reliability indices of SAIDI, SAIFI, and CAIDI.

NWA (Non-Wires Alternative) – the deployment of DERs or combinations of DERs — owned by the utility, customers or other third parties — to defer or avoid the need for investment in conventional, more costly grid infrastructure. Also referred to as a Non-Wires Solution.

OMS (Outage Management System) - software to enable the efficient and safe restoration of outages, as well as communications with customers regarding restoration status. An OMS can serve as the system of record for the as-operated distribution connectivity model, as can the DMS or ADMS.

Reclosers - devices that, when sensing a fault, temporarily interrupt power downstream from their location and then automatically reclose and restore power if the fault has cleared.

Reconductoring - replacing existing conductor with larger conductor to address a thermal or voltage issue.

SAIDI (System Average Interruption Duration Index) - the average duration of sustained outages experienced per customer in a year, measured in minutes per customer. $SAIDI = CAIDI \times SAIFI$.

SAIFI (System Average Interruption Frequency Index) - the average number of sustained outages experienced per customer in a year, measured in interruptions per customer. $SAIFI = SAIDI / CAIDI$.

SCADA (Supervisory Control and Data Acquisition) - a system of remote controls and telemetry to monitor and control the transmission and distribution system.

Secondary VAR Controllers - devices installed on the low-voltage side of distribution transformers to assist in controlling reactive power and voltage.

Self-Healing Grid - see *FLISR*

Smart Meter - a device capable of two-way communications used for measuring electricity consumption and other end-use information and transmitting this information on demand to a central location. Smart meters provide near real-time customer usage data, as well as interface with other ‘smart’ devices in the home or business.

Sustained Interruptions - according to IEEE, sustained interruptions are outages lasting more than five minutes.

Telemetry - the automatic measurement and wireless transmission of data from remote sources.

Undergrounding - conversion of existing overhead distribution facilities to underground for improved aesthetics or to address reliability issues.

Voltage Conversion - increasing the voltage of a distribution circuit (e.g., from 4kV to 12kV) to increase its capacity to serve load or to accommodate DERs.

VAR (Volt Ampere Reactive) – a measure of reactive power. Reactive power energizes the magnetic field of alternating current power system components but does no actual work, and represents the component of the current that is out of sync with the voltage.

VO (Voltage Optimization) - a combination of CVR and IVVC, resulting in optimal flow of reactive power, reduced line losses, and reduced customer demand and energy consumption.

VVO (Volt-Var Optimization) - see *VO*.

WAN (Wide Area Network) - the communications network connecting distribution substations with operations/control centers and other utility facilities.

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