A Framework for Evaluating Electric Power Grid Improvements in Puerto Rico

Marija Ilic

Reynaldo Salcedo Ulerio

Edward Corbett

MIT Lincoln Laboratory, Group 73

Eric Austin

Michael Shatz

MIT Lincoln Laboratory, Group 75

Erik Limpaecher

MIT Lincoln Laboratory, Group 73

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PREFACE

On August 8, 2018, the Government of Puerto Rico submitted to Congress their economic and disaster recovery plan, as required by the Bipartisan Budget Act of 2018 (Public Law 115-123). Under contract with Federal Emergency Management Agency, the Homeland Security Operational Analysis Center (HSOAC) provided substantial support in developing the plan by soliciting and integrating inputs from a wide variety of stakeholders, contributing analysis where needed, and assisting to draft the plan. The plan included an overview of damage and needs, courses of action to meet those needs, costs of the courses of action, and potential funding mechanisms for those costs.

This report is based on analysis performed by the Massachusetts Institute of Technology's (MIT) Lincoln Laboratory from March 2018 to July 2018 in support of Puerto Rico's recovery plan, *Transformation and Innovation in the Wake of Devastation: An Economic and Disaster Recovery Plan for Puerto Rico*. In support of the Energy sector analysis done at HSOAC for the recovery plan, this Lincoln Laboratory project explored possible new architectures for providing electricity service in Puerto Rico at reasonable cost during normal conditions, and, at the same time to serve as many end users as possible during extreme conditions when major equipment fails to function. Architectures of interest are combinations of physical hardware deployment/hardening and information technology (IT)-enabled enhanced operations. Retrofits to existing large-scale power plants; integration of non-utility owned gas power plants; integration of utility scale solar photovoltaics with or without storage; and widely dispersed small solar photovoltaics (PVs) with or without storage were all considered. With "IT-enabled enhanced operations," grid operators receive guidance from modern optimization algorithms that make better use of voltage control, real power dispatch, and load shedding than a human can. This enables continued system operations as system conditions degrade.

The purpose of this document is to show how various Puerto Rico power grid improvements could be evaluated, against metrics for both economics and resilience. Next, we illustrate a low-cost enhancement using a model of the Puerto Rico power grid. Analysis shows that a modern grid control method, corrective dispatch, could significantly reduce energy costs and also arrest cascading power blackouts as seen following the 2017 hurricanes, Irma and Maria.

It is indeed possible to modernize Puerto Rico electric energy system to be clean, reliable, and resilient at a much lower cost.

This research performed by MIT Lincoln Laboratory was sponsored by the Federal Emergency Management Agency for a research effort conducted within the Strategy, Policy, and Operations Program of the Homeland Security Operational Analysis Center federally funded research and development center (FFDRC). HSOAC created a subaward to MIT Lincoln Laboratory to perform the analysis documented in this report.

About MIT Lincoln Laboratory

MIT Lincoln Laboratory is a FFRDC operated on a no-profit-no-fee basis by Massachusetts Institute of Technology (MIT) under Air Force Prime Contract FA8702-15-D-0001.

About the Homeland Security Operational Analysis Center

The Homeland Security Act of 2002 (Section 305 of Public Law 107-296, as codified at 6 U.S.C. § 185), authorizes the Secretary of Homeland Security, acting through the Under Secretary for Science and Technology, to establish one or more FFRDCs to provide independent analysis of homeland security issues. The RAND Corporation operates HSOAC as an FFRDC for the U.S. Department of Homeland Security under contract HSHQDC-16-D-00007.

The HSOAC FFRDC provides the U. S. government with independent and objective analyses and advice in core areas important to the department in support of policy development, decision making, alternative approaches, and new ideas on issues of significance. The HSOAC FFRDC also works with and supports other federal, state, local, tribal, and public- and private-sector organizations that make up the homeland security enterprise. The HSOAC FFRDC's research is undertaken by mutual consent with DHS and is organized as a set of discrete tasks. This report presents the results of research and analysis conducted under Task Order 70FBR218F00000032, "Puerto Rico Economic and Disaster Recovery Plan: Integration and Analytic Support."

The results presented in this report do not necessarily reflect official DHS opinion or policy.

For more information on HSOAC, see www.rand.org/hsoac. For more information on HSOAC's support of disaster recovery in Puerto Rico and other recovery plan supplemental reports, see www.rand.org/hsoac/puerto-rico-recovery.

EXECUTIVE SUMMARY

This report is motivated by the recognition that serving highly distributed electric power load in Puerto Rico during extreme events requires innovative methods. To do this, we must determine the type and locations of the most critical equipment, innovative methods, and software for operating the electrical system most effectively. It is well recognized that the existing system needs to be both hardened and further enhanced by deploying Distributed Energy Resources (DERs), solar photovoltaics (PV) in particular, and local reconfigurable microgrids to manage these newly deployed DERs. While deployment of microgrids and DERs has been advocated by many, there is little fundamental understanding how to operate Puerto Rico's electrical system in a way that effectively uses DERs during both normal operations and grid failures. Utility companies' traditional reliability requirements and operational risk management practices rely on excessive amounts of centralized reserve generation to anticipate failures, which increases the cost of normal operations and nullifies the potential of DERs to meet loads during grid failures. At present, no electric power utility has a ready-to-use framework that overcomes these limitations. This report seeks to fill this void.

GRID IMPROVEMENTS STUDIED: BOTH PHYSICAL AND CONTROL UPGRADES

The performance of an electric power system is determined by how well generation is coordinated with demand. Coordination is achieved through the design of the physical grid architecture and operating protocols, which involve both computer software and human decisions to schedule power generation, delivery, and, in some cases, demand. Typically, during normal operation, the fuel cost is the main performance metric. During extreme conditions, the main metric is load served.

Current standards require grid operators anticipate only a few failures. Operators meet these standards by maintaining spinning reserves, which involves keeping some centralized generation ready but only delivered in the event of a failure. As a result, spinning reserves are essentially wasted during normal operations, increasing energy costs for ratepayers. Moreover, humans are often driving decisions made during grid failures, a clear limitation given the complexities of the power system and latencies inherent in human decision making.

Current grid operating procedures also require spinning reserves to accommodate DERs. As designed and operated, most DERs will stop delivering power during grid failures given historical safety concerns. These existing grid architectures and operating procedures thus over rely on expensive spinning reserves, reducing the effectiveness of DERs during both normal operations and grid failures.

New grid architectures and operating procedures are needed to make Puerto Rico's electrical grid for resilient. To assess the potential benefits of innovative architectures and procedures, we collected publicly available physical grid architecture data to model Puerto Rico electrical system as of July 2018. This model was used to evaluate four physical grid architectures: (1) with existing generation only; (2) with both existing generation and new fossil-fueled generation; (3) with both existing generation and new large-scale utility solar PV resources; and, (4) with existing generation and a large number of small DERs dispersed close to rural/urban loads.

To assess the relevance of operating methods on system performance, these four physical architectures were simulated using two quantitatively different power system control methods. One control method—preventive dispatch—is a top-down control approach that resembles operation by the Puerto Rico Electric Power Authority (PREPA) as of July 2018. The other control method—corrective dispatch—supports on-line, optimized, active response to changing grid conditions, including extreme outage events.

Lastly, for the electric power system architectures that contain high power penetration of widely varying solar PVs, we evaluated model-predictive scheduling software, which could address the problem of unpredictable renewable power generation using power flow studies to analyze the system's capability to adequately supply the connected load.

This report's main objectives are:

- Assess how several candidate grid architecture designs—both physical architectures and various operating methods and computer algorithms—would affect electricity services in Puerto Rico during both normal and extreme conditions, as measured by fuel cost during normal operation and load served during extreme conditions.
- Describe the method established for performing this assessment and selecting the grid architectures that provide the best societal performance.
- Document analysis supporting recommended actions for the Puerto Rico recovery plan for the Energy sector, including actions to improve resilience to future disasters.

KEY FINDINGS AND RECOMMENDATIONS

Our primary findings and recommendations are summarized in Table 1. We identified four fundamental problems with the Puerto Rico power system as of July 2018, and validated solutions based on four new technologies. If implemented, these solutions could: (1) **save Puerto Rico's ratepayers annual fuel costs from tens of millions (5% savings) to a billion dollars (60% savings) per year**, and (2) **maintain power service to 50% or more of the island's population during extreme events**, such as the devastation seen in September 2017 after hurricanes Irma and Maria. This is achievable by retrofitting existing power plants for more flexible generation dispatch, by utilizing low-cost clean solar PVs, and by dispatching power dynamically without requiring large stand-by generation with reserve capacity synchronized to the grid system, e.g. spinning reserves.

We show how Puerto Rico's electricity cost and resilience can be improved through the use of specific new technologies: (a) intentional island capable inverters/power converters, (b) a robust power flow solver, (c) an optimal power flow algorithm, (d) model-predictive control (MPC), and (e) interactive MPC. Our accompanying technical report [19] integrates all of these into a new power system framework developed at Carnegie Mellon University called the Dynamic Monitoring and Decision Systems (DyMonDS).

With these technologies, we show a method for identifying the most critical grid contingencies, and that minimal investments in delivery infrastructure and software can avoid outages. This approach also largely eliminates the need for spinning reserve, which would provide significant cost savings for Puerto Rico's ratepayers.

These improvements can also enable advanced dispatch during extreme conditions, to minimize unserved load during widespread extreme events. Our simulations show that modernized grid controls with intelligent generation assets could continue serving 50% of Puerto Rico's load in "power enclaves" which still have loads electrically connected to existing generation.

This study shows tools that Puerto Rico's utility engineers and leadership could use to improve energy affordability and island resiliency. Their options range from no-cost adoption of the newest standards for resilient solar inverters (recommendation 1a), to a few million dollar investments to incorporate extreme event analysis software in power system planning (recommendations 2a and 2b). For dramatic improvements to cost and resilience, a few tens of millions of dollars would allow the implementation of modern power system controls (recommendations 3a and 3b). We also present a fundamental rearchitecting of the Puerto Rico power system and its control, which merit further study (recommendations 4a, 4b, and 4c).

Table 1

Summary of This Report's Findings and Recommendations

Disclaimer: All "impact" metrics are notional, since they are based on simulations using an approximate model of Puerto Rico's power system created using publicly available geographic information system (GIS) data. Also, the estimated savings numbers are those expected from the recommendations, and are not net of the required costs of the associated investments.

Problem	Technologies	Application	Recommendation	Impact
1. Grid-tied solar PV provides no resilience	Islandable inverters	Solar and battery DERs	Require standard IEEE 1547-2018 (Rec. 1a)	Community and home resilience
2. Performance under extreme events not evaluated by grid planners	Robust AC Power Flow Solver	Grid planning	Apply both voltage limits & power flow thermal limits (Rec. 2a)	Grid operators better identify vulnerable nodes in the power system
	Robust AC Power Flow Solver	Grid investment decision-making	Use an energy resilience analysis methodology (Rec. 2b)	Best-value investments made for resilience and cost
	Robust AC Power Flow Solver	Grid planning	Perform extreme event analysis (Rec. 2c)	Grid operator gain understanding of likely cascading outages
3. No decision-making support for grid operators under abnormal conditions	Robust AC Power Flow Solver + Optimal Power Flow Algorithm	Grid operations	Demonstrate voltage management (Rec. 3a) Demonstrate corrective dispatch software (Rec. 3b)	3x greater grid control range;[a] $790 million/year grid operational savings;[b] 54% of Puerto Rico with power following Maria-scale damage[b]
4. Top-down grid control as of 2018, that cannot capture the value of DERs	Model-predictive control (MPC)	DER control	Implement distributed MPC (Rec. 4a)	$80 million/year grid operational savings[c]
	Interactive MPC	Grid planning & operations	Further research DyMonDS interactive framework (rec 4b, 4c)	$1.04 billion/year grid operational savings;[d] 74% of Puerto Rico with power following Maria-scale damage[d]

[a] Illustrated in section 3.3.13.3

[b] Architecture Option 6, described in section 7; modeling results in sections 9 (cost and reliability) and 10 (resilience)

[c] Architecture Option 4s, described in section 7; modeling results in sections 9 (cost and reliability) and 10 (resilience)

[d] Architecture Option 8s, described in section 7; modeling results in sections 9 (cost and reliability) and 10 (resilience)

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1. INTRODUCTION

Two major hurricanes—first Irma then Maria—hit Puerto Rico within the span of two weeks in September 2017. Within a week after Irma, 80% of the islands' power service were restored. However, Maria passed directly over the archipelago days later, causing a near complete power grid failure. It took several months to restore power to 50% of normal service capacity, and there were still places on the islands still not fully restored even as the 2018 hurricane season began.

In light of the collapse of the power grid and the hardship and danger that this imposed on the people of Puerto Rico, several organizations were asked to provide input on the best way to invest in rebuilding the Puerto Rico grid. The range of organizations that provided input spanned federal agencies, commercial providers, universities, FFRDCs, and non-profit organizations. As proposals are solicited from industry to build a new grid, we expect that there will be multiple approaches presented and that it will be necessary to select a final grid architecture based on several factors. The overall cost to build the new grid will be a major consideration, but the ability of the grid to reliably meet the demand load and to substantially minimize the disruption caused by hurricanes or other extreme damaging events will also be prime considerations. Industry proposers will submit their own assessments of performance and cost, but different proposals may use different metrics to evaluate themselves and will likely rely on proprietary information. This will make it difficult for decision makers to make fair comparisons across multiple performance categories, including cost, reliability, resilience, and the environment.

The goal of this study is to provide tools to help the Puerto Rico Electric Power Authority (PREPA), the Government of Puerto Rico, and U.S. government understand and compare the various proposals for rebuilding the electric grid. The analysis was conducted between March 2018 and July 2018, as input to the economic and disaster recovery plan. We introduce new electric grid modeling techniques to understand the operation of each potential grid architecture and to predict performance during damaging events, both moderate and severe. We characterize grid performance in three ways: cost, reliability, and resilience. Cost includes both capital and operating fuel costs. Reliability refers to the grid's ability to withstand a small number of "contingencies" (outage of individual power lines or power generation plants) while still supporting the full demand load. Resilience refers to the grid's ability to withstand widespread damage and recover to support critical infrastructure.

This study uses a model of the Puerto Rico electric grid to test various generation portfolios—from large, traditional oil and gas fired plants to newer photovoltaic (PV) sites—under different transmission and distribution configurations. More importantly, this report stresses that grid performance critically depends on operating and planning protocols. Traditional protocols result in high baseline costs, do not guarantee reliability, significantly constrain the potential of distributed renewables to improve grid performance, and provide no guidance on preventing cascading power failures during extreme events. This report introduces an improved operating protocol that can exploit the full benefits of renewable generation by compensating for unexpected variations in generation capacity, in a manner that reduces costs, and improves grid resilience and reliability.

2. CURRENT GRID OPERATIONS AND PROBLEMS

2.1 CURRENT GRID OPERATIONS

The industry's current practice, as of 2018, for electric power grid operations is to analyze the presumed worst-case outage scenarios and estimate worst-case demand variability *off-line*, not using real-time data. This off-line analysis then guides how much excess generation capacity (spinning reserve) to run and which downstream transmission lines (flow gates) to operate well below capacity. In the event of an outage or a sudden increase in load, the reserve generation can quickly ramp up and power can be re-routed to underutilized transmission lines to prevent any loss of load. This approach is termed preventive dispatch, described in Section 2.1.6.

2.1.1 Reliability, Not Resilience

The current industry approach prioritizes reliability—the ability to meet full demand during a few equipment failures—over resilience—the ability to withstand or recover from widespread damage. In the past, the worst-case scenarios evaluated by grid operators considered only the failure of two major transmission system components at any given time. However, these have never been sufficient to trigger cascading blackouts. Instead, the worst blackouts are triggered by either widespread storm damage or by vegetation management issues that cause random, minor transmission or distribution line failures. Very infrequently, these minor failures interact with hidden protection relay logic hardware, which can lead to cascading equipment disconnects or component outages. The history of power outages makes it clear that the current industry practice is incapable of handling hard-to-predict equipment failures.

The industry term of art is to describe a power system with one component outage as being in an *N-1* state. If there are two component outages then the grid is in an *N-2* state, etc. *N-k*, where *k* is much greater than two (k>>2), are termed extreme events. Typically, electric power utilities maintain sufficient capacity to handle *N-2* events. If the number of grid failures is greater than *N-2*, the industry has only limited established plans for providing resilient service during extreme conditions. PREPA operates their large fossil-fuel generation plants, transmission network, and distribution network in an effort to meet 100% the demand even if one or two system components fail. PREPA and other utilities do not currently have the technology or the expertise to prevent cascading power outages during large-scale events.

2.1.2 Limitations in Human-centered Response to Extreme Events

Human grid operators face numerous decision-making challenges during extreme power system resilience events. This is because (a) overloaded transmission system networks exhibit counterintuitive, highly non-linear behavior, (b) the industry has minimal procedures for handling extreme events, (c) training can only cover a small number of the combinatorial millions of possible failure combinations, (d) no guidance software is integrated into operations because grid power flow software is non-robust when analyzing extreme events, and (e) with electricity flowing at the speed of light, a cascading system can degrade quickly.

Later in this report we introduce technologies that solve many of these issues. The recommendations include a test of new operator guidance software.

2.1.3 High-cost Response to Demand Uncertainty

PREPA must also accommodate surges in demand. Large fossil fuel-based power generation plants take time to ramp up their output, typically no more than 20% per hour. This is inadequate to support changes in demand that occur within minutes. Even worse, solar PV and other renewables are uncontrolled and unpredictable under today's grid control paradigm. This means renewables are seen by the utility as fast-ramping negative demand.

Preventive dispatch software currently used in control centers is not predictive, so utilities require fast-responding power plants, such as combined cycle gas generation plants, to follow fast variations in system demand. It is expensive to build these plants and having them stand by to respond to unexpected variations.

An extensive 2014 study by Siemens [1] on the Puerto Rico power system dramatically illustrated the limitations of preventive dispatch. Siemens concluded that given spinning reserve and ramp rate limitations back in 2014, the Puerto Rico power system could generate only 6.6% of its energy via renewables; even this low level would increase energy costs from spinning reserve by $23 million/year. The study found that meeting PREPA's goal of reaching 12% of renewable penetration as soon as technically possible would increase fuel costs by $169 million/year and require the construction of two fast-ramping combined cycle power plants (2x 334 MW) with an annualized capital cost of $83 million/year.[1]

To avoid these costs, PREPA has implemented constraints on the use of DER into its grid. For instance, the AES Solar Farm in Guayama has a *20 MW* capacity, at an agreed rate of $0.18/kWh, but *only generates 2 MW* "because PREPA won't accept more" [2]. Similarly, Pattern Wind Farm in Santa Isabel has a *101 MW capacity* but *only generates 5 MW* "because PREPA can't handle more" [2].

In April 2019, Puerto Rico enacted the Puerto Rico Energy Public Policy Act (Act 17-2019) eliminating the renewable energy targets previously in effect, which were the basis for the 2014 Siemens study. This law mandates renewable energy targets of 40% by 2025, 60% by 2040, and 100% by 2050. This is a dramatic mandate. Both the PREPA's *Puerto Rico Integrated Resource Plan (IRP) 2018-2019* and Act 17-201 do not offer any model based analysis as to whether and how current operating and control practices should be enhanced to enable resilient and efficient integration of renewables in Puerto Rico's existing electric power grid.

2.1.4 No Voltage Optimization

Since transmission systems are networks, voltage adjustments can—without changing the generation amount—affect how much power flows along a line. Grid operators can adjust voltage at hundreds to thousands of nodes on a transmission grid. At the output terminals of bulk power generation stations, for instance, this can be achieved by adjusting transformer tap settings, using voltage regulators, and employing controllable shunt capacitors. Modern DERs also provide voltage control capability at the power distribution level.

[1] $1,100 per kW, 25 year life, 9% discount rate

Properly selected voltage adjustments can significantly increase the feasible operating range of a power grid (described in section 3.3.1). A few select voltage adjustments can also rapidly stabilize a grid following a failure, without relying on fast-ramping generators and spinning reserve.

Grid operators, however, control voltage manually only infrequently—or not at all—because voltage curves are highly nonlinear and non-intuitive to human operators. Figure 1 illustrates the power transfer curve at just one node in the power system. When the power transfer at a node goes into the unstable operating region, neighboring voltages can quickly collapse and fall out of normal operating range.

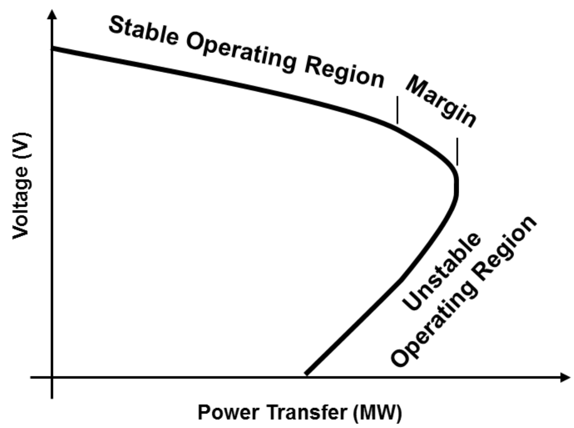


Figure 1. Power transfer curve

The non-linear relationship between power transfer and voltage, at thousands of nodes on the power system, makes it virtually impossible for a human operator to use intuition to control voltages for system stability or optimal power transfer. Later in this report, we introduce technologies that solve this shortcoming. The recommendations include a test of a new operator guidance software capable of optimal voltage dispatch considering power system constraints and operational stability.

2.1.5 Manual, Trial-and-error Analysis

Today, utilities use power flow solvers for both planning and operation. Commercially-available power flow solvers often have convergence problems, meaning they cannot mathematically solve the nonlinear problem—as illustrated for just one node in Figure 1—and thus are likely to crash when faced with more than two contingencies at the same time (N-3, or more). With commercial power flow solvers, 25% of extreme event simulations fail to converge [3], meaning they run into numerical instabilities and crash before finding a solution. This technical limitation has been embedded into regulations, with the North American Electric Reliability Corporation (NERC) historically requiring only *N-1* and *N-2* contingencies for transmission system planning and transmission system operations. NERC's recent changes [4] for simulation of extreme events only applies to transmission system planning, not operations. Although Puerto Rico does not fall within NERC or the Federal Energy Regulatory Commission (FERC) jurisdiction and is not required to adhere to NERC reliability standards, the convergence problems encountered in commercially-available power flow solvers still affects Puerto Rico contingency studies because simulation results could mislead transmission system engineers.

For normal grid operations planning, due to these mathematical convergence problems, utility analysts use an off-line trial-and-error approach to find the most effective adjustments in anticipation of the worst-case *N-2* scenario. This analyses-based approach can be very time consuming, generally producing sub-optimal results for operating cost and actual system reliability. Furthermore, as PV and DER deployment increases, traditional tools based on off-line studies that do not provide recommended operator actions, e.g. Static Security Assessment (SSA) and Dynamic Security Assessment (DSA), may be insufficient or inadequate to analyze future scenarios that challenge the secure operation of PREPA's grid. [5][6] As an alternative, PREPA could shift towards the use of on-line DSA methods and real-time simulations of the power grid in-the-loop with corrective action guidance software to inform system operators during challenging scenarios.

Typically, grid planners first perform approximate linearized screening of contingencies to identify those events which would violate *thermal line flow limits*. In some cases, planners will also evaluate *both thermal line flow and nodal voltage limit violations*. They will only further evaluate those outages that violate a limit to determine whether a power flow solution exists for those outage scenarios. When the power flow solver crashes or has numerical problems, planners will tag those outage scenarios as the systems' operating limit, even though it is typically unclear if the power flow solver failed due to numerical problems or due to an actual grid operational limit. Because of this issue, and the limited regulatory requirements and shortcut analytical approach that has developed over time, it is critically important to have robust numerical power flow solvers.

2.1.6 Today's Grid Control: Preventive Dispatch

Figure 2 illustrates current grid optimization control and manual control. The primary control mechanism is an economic dispatch algorithm, which optimizes operating costs by controlling real power settings, while maintaining *N-2* reliability. Grid operators independently, but infrequently, manually control voltage to adjust power flows. In the present grid control architecture, DERs remain uncontrollable by the system operator.

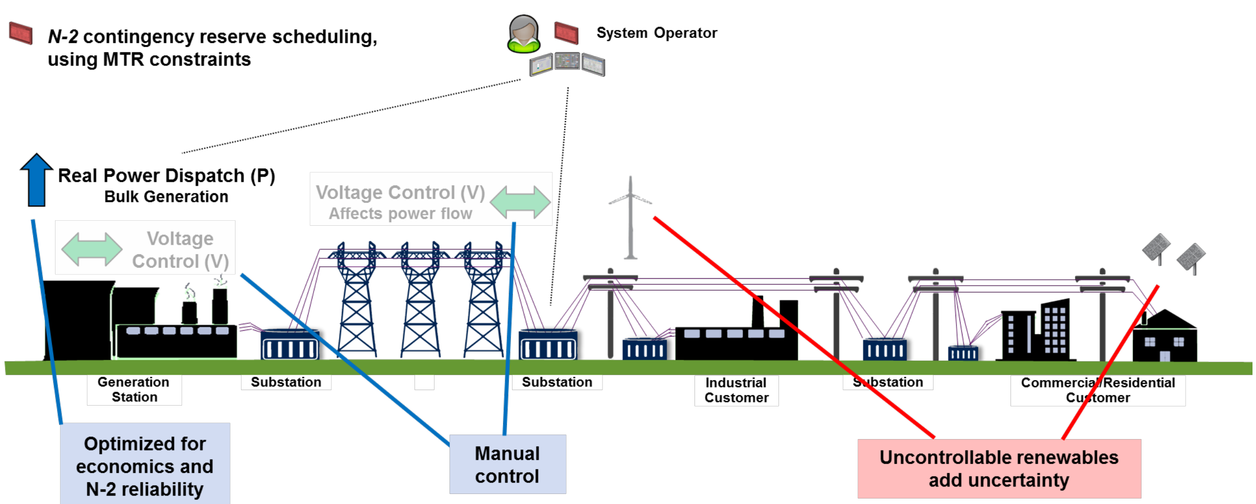
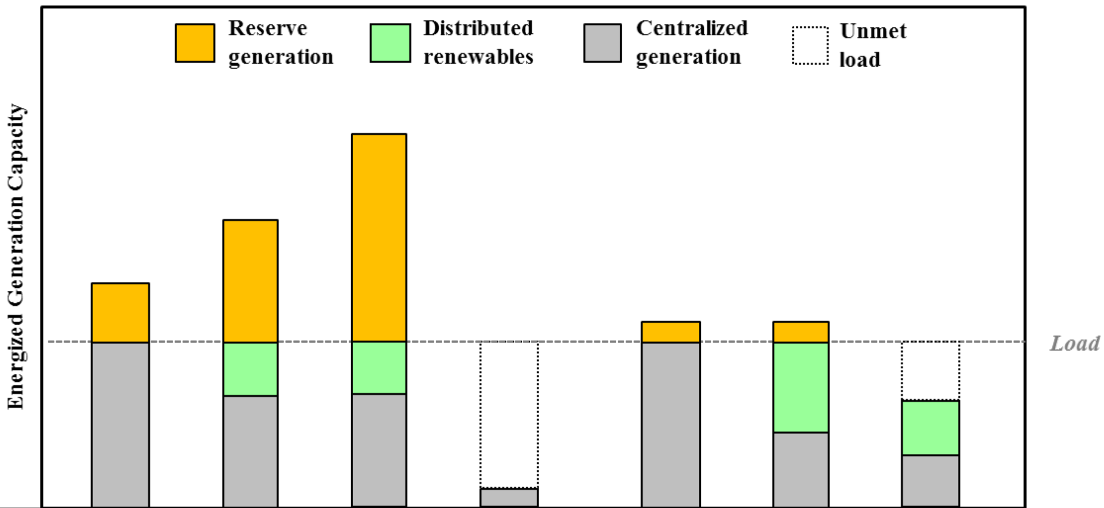


Figure 2. Control levers and optimization objectives under today's preventive dispatch method



Operating Conditions	Normal			Extreme	Normal		Extreme
Reserve Capacity	Existing *N-2* reserves		Increased *N-k* reserves		*N-k* reserves		
Dispatch Method	Traditional preventive dispatch				Corrective dispatch		
Case	1	2	3	4	5	6	7

Figure 3. Traditional preventive dispatch effect on reserve requirements (cases 1-4)

Figure 3 illustrates preventive dispatch's impact on total generation for four grid operating configurations (cases 1-4), and compares them to operations with the corrective dispatch introduced alter in this report (cases 5-7). Case 1 shows the generation capacity required to serve the load (gray) plus spinning reserve required to handle the two largest component failures (orange).

Traditional preventive dispatch does not handle well the inclusion of generation assets that are intermittent or those out of the direct control of the transmission system operator. The preventive dispatch approach compensates for intermittency and unpredictability by increasing spinning reserves, which adds to the expense of building and maintaining the power grid. Case 2 illustrates this: even though the same amount of load is being served as in case 1, the utility runs more spinning reserve (orange) because a portion of the generation is uncontrolled and unpredictable DERs (green).

The issue of how one enables uninterrupted service during extreme events, such as hurricanes, becomes particularly difficult if the approach is simply to extend current operating practices. Extreme events are generally very low probability and very high impact. It is practically impossible to build and have sufficient reserve ready for large-scale events. Case 3 illustrates this, if the utility were to use the preventive dispatch approach to protect against *N-k* component failures. The increase in the size of the orange reserve box implies a significant cost in building, maintaining, and operating unused generation and transmission capacity.

Our analysis shows that even with increased spinning reserve, the power system is still not robust to large-scale failures. Under a large number of component failures, as experienced during Hurricane Maria, system still experiences cascading failures and serves only a very small portion of the load. This is illustrated in Case 4, with the large portion of unmet load (white).

For a description of Cases 5-7, see section 3.3.2 *Application: Corrective Dispatch*.

2.2 CURRENT GRID PROBLEMS

The section above provided the necessary background information for us to describe the key problems preventing the Puerto Rico power grid from becoming more resilient.

2.2.1 Problem 1: No Resilience from Grid-tied Solar PV

The 2017 hurricanes destroyed most of the small number of PV installations on the island. The few that remained provided no resilience because of the utility safety regulations described below. For example, on Culebra Island, which was even more isolated from aid than the main island, the mayor's office was puzzled by and frustrated that the newly installed multi-kilowatt PV array on the roof of the Culebra school provided no backup power to their emergency communications equipment [7].

The reason for this dates back 20 years. When solar PV deployment increased significantly in the 1990s, the utility industry was concerned about electrocution risks for its linemen and instability on its power systems. The concerns were (1) that solar inverters—the power converters that transform the solar modules' DC power into 60 Hz AC grid power—might backfeed their power into a de-energized power grid while it was undergoing repairs, and (2) the inverters might worsen grid instabilities by continuing to inject power into an unstable grid.

The industry took a brute force approach in the form of the standard IEEE 1547-2003 [8] and IEEE 1547.1-2005 [9]. These standards required inverters to disconnect from the system at the first sign of trouble on the grid, based on voltage and frequency deviations.[2] IEEE 1547-2003 also required inverters to detect and trip when connected to a weak grids, such as those formed by backup generators and battery systems, or when these backup generators or battery systems are under-sized for backup power needs.[3]

A separate issue further increases the cost of PV-based backup power systems. Grid-tied solar inverters implement maximum power point tracking (MPPT), shown in Figure 5, which tries to extract the maximum amount of power from the solar array. When such an inverter tries to run off-grid, it also needs a battery system to store the excess energy and a supervisory controller to avoid over-charging the batteries. This adds significant cost and complexity.

Later in this report, we present readily available solutions to both of these issues (section 3.1) and recommend that PREPA implement them within its jurisdiction (section 11.1).

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[2] Trip on +1.1 p.u./-0.88 p.u voltage deviation (IEEE 1547-2003, Table 1). Trip on +0.5 Hz/-0.7 Hz frequency deviation (IEEE 1547-2003, Table 2)

[3] IEEE 1547-2003, Section 4.4.1, and IEEE 1547-2005, Section 5.7

2.2.2 Problem 2: Grid Planning Ignores Performance under Extreme Events

As explained in section 2.1.5, traditional commercial power flow solvers are unreliable at calculating power flows for extreme outage events. Due to this fragility in the software, simulations of such extreme conditions must be adjusted manually to provide meaningful results. Solutions found through human intuition are not guaranteed to be optimal. Even for reliability analyses, the software has imposed limits on the number of reliability outage cases grid planners evaluate.

The utility industry is only beginning to develop methods for evaluating, let alone operating under, wide-area extreme events [3]. Prior to 2016, NERC required extreme event analysis only for *N-2* scenarios and for local events that affected multiple assets. In 2016, NERC expanded its requirements for transmission system planning to require simulation of wide-area extreme events, including severe weather, e.g., hurricanes. [4]. Planners must now also identify mitigation actions for events that would have the most severe impact. However, Puerto Rico does not fall within NERC or FERC jurisdiction and is not required to adhere to NERC reliability standards. Furthermore, Puerto Rico system operators do not receive formal training nor are required to comply with NERC training requirements.

We present results from a more robust power flow solver later in this study, used on several *N-k* resilience scenarios and thousands of *N-2* cases (section 10). Our recommendations include automating the process, so that PREPA can perform a statistical analysis of millions of resilience outage scenarios on the Puerto Rico grid (section 11.4), and using resilience analysis in PREPA's investment decision-making (sections 3.2.2 and 11.3).

2.2.3 Problem 3: Grid Operators Lack Decision-making Support During Abnormal Conditions

Ideally, grid operators would employ guidance software with optimization algorithms to determine the best course of action in any scenario. Due to the size, nonlinearity, and complexity of existing power systems, however, commercial power flow solvers frequently struggle to find a power flow solution for extreme *N-k* operating conditions. Running an optimization routine, such as AC *Optimal* Power Flow (AC-OPF), is computationally challenging, not to mention, doing so for both power and voltage dispatch and within the 5- to 15-minute dispatch window

Later in this report, we present results from a software tool that appears to meet the challenges of power flow solvers and AC-OPF (sections 3.3 and 10), and recommend a "sidecar[4]" demonstration in PREPA's control center (section 11.5), where the tool can use real-time data for analysis without interfering with existing operations.

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[4] For a sidecar demonstration, a control box that contains the new algorithm—the sidecar—is installed next to the existing operational control system. The sidecar receives the same exact data inputs as the operational system and presents its results side-by-side with the operational system's results. This allows operators to evaluate the new algorithms' performance in the real environment, without putting the operational system at risk.

2.2.4 Problem 4: Preventive Dispatch Does Not Capture DER Value

Current top-down power grid controls are unable to observe or influence end users or DERs, including distributed renewables. This severely limits the potential of DERs to displace centralized generation. Instead, top-down control turns DERs into a liability—because they are uncontrollable and unpredictable—instead of a resource. The inflexible control of a limited number of centralized resources necessitates large amounts of centralized spinning reserve.

Industry also lacks methods for enabling groups of customers (distributed communities) to manage their own needs and to coordinate these with their regional grid operators. This shortcoming has stymied deployment of community microgrids throughout the U.S.

Later, we introduce a control solution (section 3.4) and control framework (section 3.5) that could capture this value from DERs, and our recommendations include stakeholder engagement in Puerto Rico, initial implementation, and further study prior to wide scale deployment of a solution (sections 11.5 and 11.7).

3. POWER SYSTEM TECHNICAL INNOVATIONS AND APPLICATIONS

We, at MIT Lincoln Laboratory (MIT LL), have identified several power system engineering innovations to address the problems Puerto Rico power grid is facing.

3.1 ISLANDABLE INVERTERS

Traditional, non-resilient solar, wind, and battery inverters operate in grid-tied only mode. If the grid fails, they must detect this and quickly de-energize, to avoid creating an unsafe “unintentional island”. They can only re-energize themselves when the grid is back online. Figure 4 illustrates this behavior in red.

Resilient inverters can implement all the functionality shown in Figure 4. When the grid fails, they can isolate their local power system while continuing to safely provide power to their local loads.

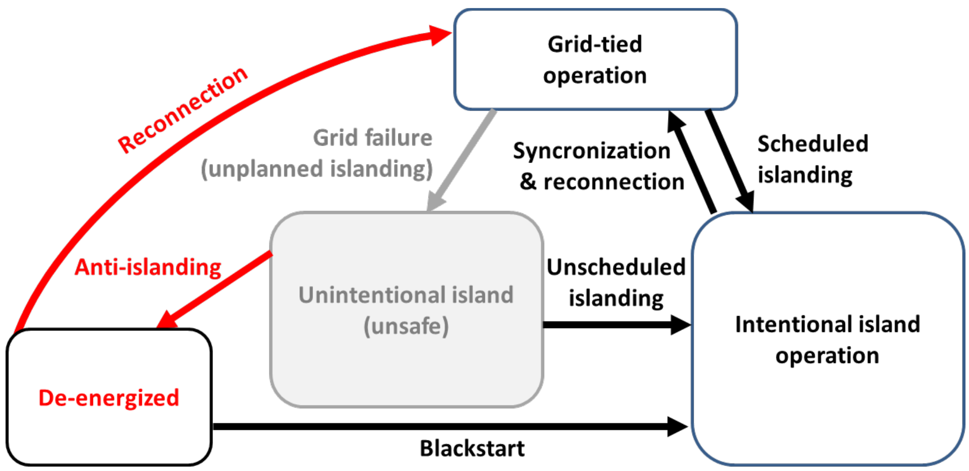

Figure 4. Operating modes and transitions for grid-tied inverters (red) and resilient inverters (black)

This approach requires new software. During transitions, resilient inverters must (a) disable their anti-islanding trip function, (b) be capable of receiving commands from an operator or supervisory controller to initiate a scheduled islanding event, (c) implement automated controls for seamless unscheduled islanding or black start, (d) implement automated controls to synchronize their output voltage with the grid and then safely reconnect with the re-energized grid, (e) automatically adjust their trip setpoints, or allow a supervisory controller to adjust those setpoints, and (f) automatically change their control mode to create a 60 Hz voltage source or follow the 60 Hz voltage source provided by another local DER.

3.1.1 Load Tracking

At the time of writing, there are almost no grid-tied solar inverters on the U.S. market capable of islanding[5] without also having a voltage source (generator or battery) and system controller. In all other cases, that

[5] We are aware of only one on the U.S. market as of July 2018, SMA SunnyBoy Secure Power Supply (SPS). See http://files.sma.de/dl/18726/EPS-US-TB-en-11.pdf and https://www.smainverted.com/how-to-explain-secure-power-supply-to-homeowners/

equipment is a required additional expense for resilient, islanded operation. Battery systems introduce significant capital cost, maintenance and replacement component costs, safety risks, design complexity, and operating temperature limitations. System controllers add to deployment costs, especially when they integrate products from multiple vendors.

It is, however, technically possible to have a PV inverter operate as a stand-alone voltage source. The inverter must perform load tracking control[6] rather than tracking the maximum power available from solar irradiance. Figure 5 shows in blue the power that a grid-tied inverter might export while performing MPPT. An islanded load tracking inverter measures the power required by the loads (gray in Figure 5) and provide that power when sufficient solar irradiance exists (black in Figure 5). If the inverter has this functionality and is paired with an appropriately sized load, then batteries and system controllers become optional.

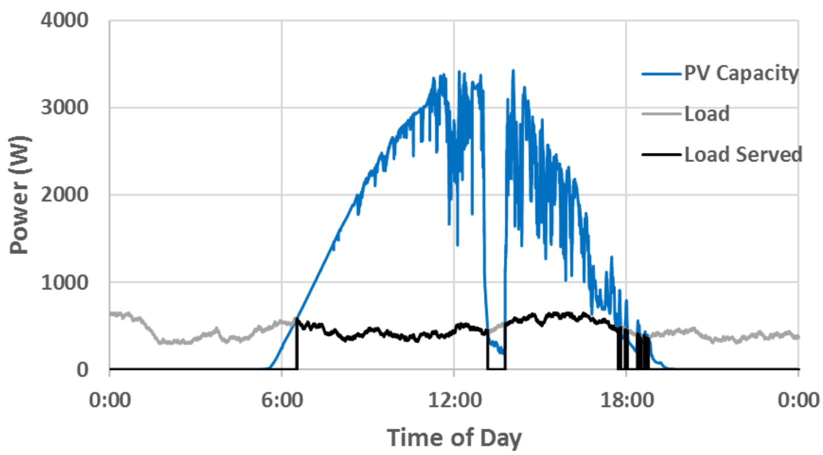

Figure 5. Maximum power point tracking (MPPT) vs. load tracking behavior

3.1.2 Application: Standard IEEE 1547-2018

The new version of IEEE 1547 [10], released in April 2018, provides requirements for the intentional islanding functionality described above. It also provides language to distinguish blackstart-capable inverters and ones capable of isochronous control/load tracking.

PV arrays with inverters capable of load tracking and isochronous control can supply a well-matched load completely on their own because these inverters can independently regulate voltage and frequency to a fixed setpoint. These features reduce the cost and complexity of creating resilient, islandable power systems by making batteries and supervisory controllers optional upgrades to these type PV systems.

IEEE 1547-2018 allows continuous DER operation under a wider range of voltage and frequency excursions than its preceding version. IEEE 1547-2018 also defines numerous grid support functions that

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[6] The industry also commonly uses "isochronous control" as a more generic term for load tracking.

would promote resilience in the Puerto Rico power grid, especially during extreme event conditions when the grid cannot fully rely on transmission system infrastructure. Key functions include:

1) Voltage and frequency disturbance ride-through, and frequency rate-of-change ride-through, whereby DER can continue feeding power into the grid rather than tripping offline during a small disturbance,
2) Intentional and unintentional islanding, whereby DER can supply the load with or without support from the main power system,
3) Dynamic voltage regulation using various types of reactive power control,
4) Frequency-droop (frequency-power) control and inertial response, whereby the DER changes its active power in proportion to the rate of change of frequency. Both functions helps dampen out frequency oscillations on the power grid.

3.2 ROBUST AC POWER FLOW SOLVER

In this study, we used the NETSS AC-OPF solver, which is computationally robust, particularly for *N-k* resilience scenarios, because it does not use the Newton-Raphson method. This solver converges on a solution under extreme events or indicates when the power system is at its operating limit. The tool also includes an optimal power flow algorithm, described in section 3.3. In 2017, the first version of NETSS software was implemented by New York Power Authority (NYPA) [11] and Independent System Operator (ISO) New England to verify solutions from extreme event simulations on their power systems [12].

3.2.1 Application: Extreme Event Planning and Operations

One application for this solver in Puerto Rico is extreme event analysis. It addresses the needs for planning (Problem 2). Since solutions are possible on a desktop computer in a matter of minutes, it could also provide dispatch guidance to operators (Problem 3). We describe this further in our recommendations (sections 11.3 and 11.4).

3.2.2 Application: Resilience Analysis Methodology and Metrics

The utility industry long ago settled on metrics for reliability[7] but still has not identified a metric for resilience. One literature survey found 105 different resilience metrics considered for electric power systems [13]. To support analysis of the Puerto Rico electric power grid, we adapted a methodology and resilience metric widely used within the Department of Defense (DoD) to evaluate options for improving the electric power resilience of DoD installations [14]. Figure 6 depicts results from one such assessment.

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[7] The most commonly used reliability metrics are System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). Utilities have only recently started including major outages in their reported SAIDI metric.

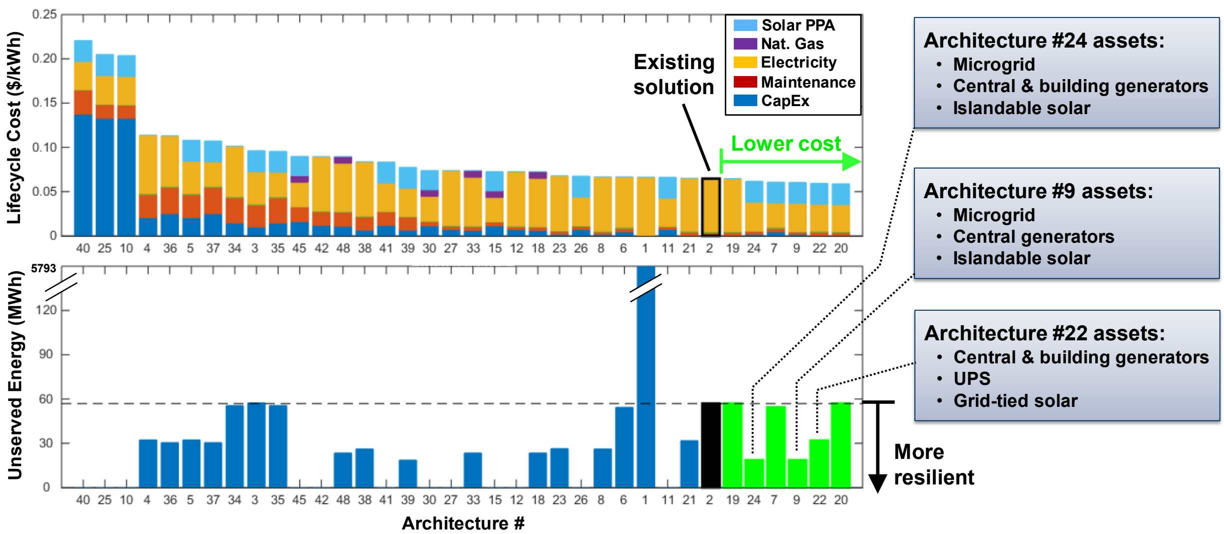

Figure 6. Example results from a Dept. of Defense installation energy resilience assessment

Every column represents a different power system architecture, meaning different combinations of generation, storage, and control technologies. The current architecture at the DoD installation—backup diesel generators installed on every building—is emphasized in black. The top bar chart shows lifecycle cost in $/kWh, which consists of capital costs amortized over 20 years, maintenance costs, and fuel and energy costs. The architectures are rank ordered, so all architectures located to the right of the existing solution are lower cost.

The bottom bar chart shows the simulation results of thousands of random power grid outages. Each power system architecture is evaluated for how well it performs in serving the *critical* mission load at the installation, not all loads on the installation. The key metric here is unserved energy (kWh) during the simulated outages, so a result of zero is best. Figure 6 shows that several Architecture Options (AO) are both lower cost and more resilient than their current backup power system. It also indicates that complete resilience—zero unserved energy—is more expensive than the current solution.

DoD evaluates several different outage durations, ranging from a couple of hours to 14 days. Even for extended multi-week outages, DoD has found affordable power system architectures that could provide resilient power service.

Based on this prior DoD work, we adapted two metrics for this study of the Puerto Rico power system. For each power system AO, we calculate (1) lifecycle cost and (2) critical load served following an extreme event:

<u>Metric 1: Lifecycle cost</u>

Lifecycle costs include capital costs amortized over the asset's life, maintenance costs, and fuel costs. Due to the short timeline for this study, we simplified the lifecycle cost to 1 day of fuel costs times 365 days per year, plus capital cost amortized over a 20 year life.

Metric 2: Kilowatts of critical load served following an extreme event

PREPA, like all utilities, operates its system to cope with *N-1* and *N-2* events so that the load served remains at 100% in those cases. But in the aftermath of an extreme event, the percentage of the load that can be served will be very small and it is not a useful metric. Much more important is how much of the *critical* load can be served after an extreme event. Critical load is defined as the power required to operate hospitals, emergency shelters, and water purification and wastewater plants. These are services that are required within a day or two of an extreme event to ensure public safety and the preservation of life until repair crews can re-establish the power grid.

In this study, we amortized capital costs assuming a fixed 6% interest rate. The daily fuel cost was simply multiplied by 365 to reflect yearly operating cost, instead of calculating varying hourly costs for an entire operating year. We did not estimate maintenance costs. As for critical load, there was no way to differentiate critical loads from interruptible loads in the data we had. So, all results in this report are a percentage of *total* load served.

3.3 OPTIMAL POWER FLOW ALGORITHM

Analysis versus optimization: It is important to understand the difference between power systems analysis and power system optimization. AC power flow software performs analysis; it calculates the likely flows within a power grid, given a set of operating conditions, and determines if there are any constraint violations. Power flow software does perform power system control. Its output is current and voltage values within the system at a snapshot in time.

Optimal corrective resource management is highly combinatorial; planners and operators cannot find optimal solutions solely using analysis rather than optimization. Typical iterative analysis that combines AC power flow with DC Optimal Power Flow (DC-OPF), a linearized real power flow for contingency screening and real power scheduling, is inadequate because it does not efficiently utilize voltage and reactive power resources. Instead, software should solve and optimize in AC, not DC, in order to manage voltage limits and balance reactive power.

Fundamentally, resilient operations depend on making good decisions on how to adjust generation resources so that the power flow balances within the operating constraints. AC-OPF software is essential in this decision-making function by running an optimization routine based on some “objective function”. It outputs control settings for power system assets, also known as dispatch. See Figure 10.

Operating constraints: In all cases, AC-OPF must keep the system within its operating constraints: thermal line flow constraints, nodal voltage constraints, and power imbalance. Since every component on the system has multiple constraints, this becomes a mathematically difficult problem to solve.

Optimization objective function: The optimization objective depends on operating conditions:

Table 2 Optimization Objectives

Operating Condition	Optimization Objective	Operating Constraints
Normal operations	Economic: Minimize fuel costs to serve 100% of the load	• Maintain sufficient spinning reserves for *N-2* reliability • Voltages within limits: 0.95 – 1.05 p.u. [8] • Real and reactive power balanced at all nodes • Delivery equipment within operating limits • AC lines and transformers flows within thermal limits
Extreme conditions	Resilience: Maximize load service/ Minimize load loss	• Prioritize critical loads over interruptible loads • Voltages within wider limits: 0.90 – 1.10 p.u. • Real and reactive power balanced at all nodes • Delivery equipment within operating limits • AC lines and transformers flows within thermal limits

Control mechanisms: As indicated in Figure 10, AC-OPF software can adjust real power output from bulk power generators and DERs and it can control voltage at multiple points in the system: at the generators' output terminals, from DER inverters, adjustable transformer tap and angle settings, voltage regulators, and switched shunts. In extreme conditions, if regular adjustments are insufficient, the AC-OPF algorithm must resort to load curtailment and load shedding. This must be done so that the most critical loads are shed last.

For this study, the NETSS AC-OPF software [15][16] could switch between economic and load loss objective functions. It could also prioritize critical loads, but we did not use this feature due to lack of load criticality information.

Figure 7 illustrates the sequencing of the AC-OPF algorithm for adaptive optimization and resource allocation, as well as various optimization sub-routines, which execute or not depending on which operating constraint violations are discovered:

- Optimal power flow (OPF): This optimization sub-routine minimizes fuel cost through economic dispatch while limiting power line thermal losses;
- Optimal load distribution (OLD): In cases when not all the load can be served, this optimization sub-routine seeks minimal load shedding and prioritized service to the most critical loads, to enable continued power and delivery of lifeline services (gradual service degradation);

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[8] The engineering term p.u. means "per unit." It indicates a percentage deviation from the nominal operating value for a system, which is 1.0 p.u.

- Managing extreme voltage (MXV): This optimization sub-routine reduces the number of voltage outliers and maintains safe voltage profiles near nominal operating values;

- Optimal branch flow (OBF): This optimization sub-routine reduces the number of power flow violations and alleviates thermal overloads

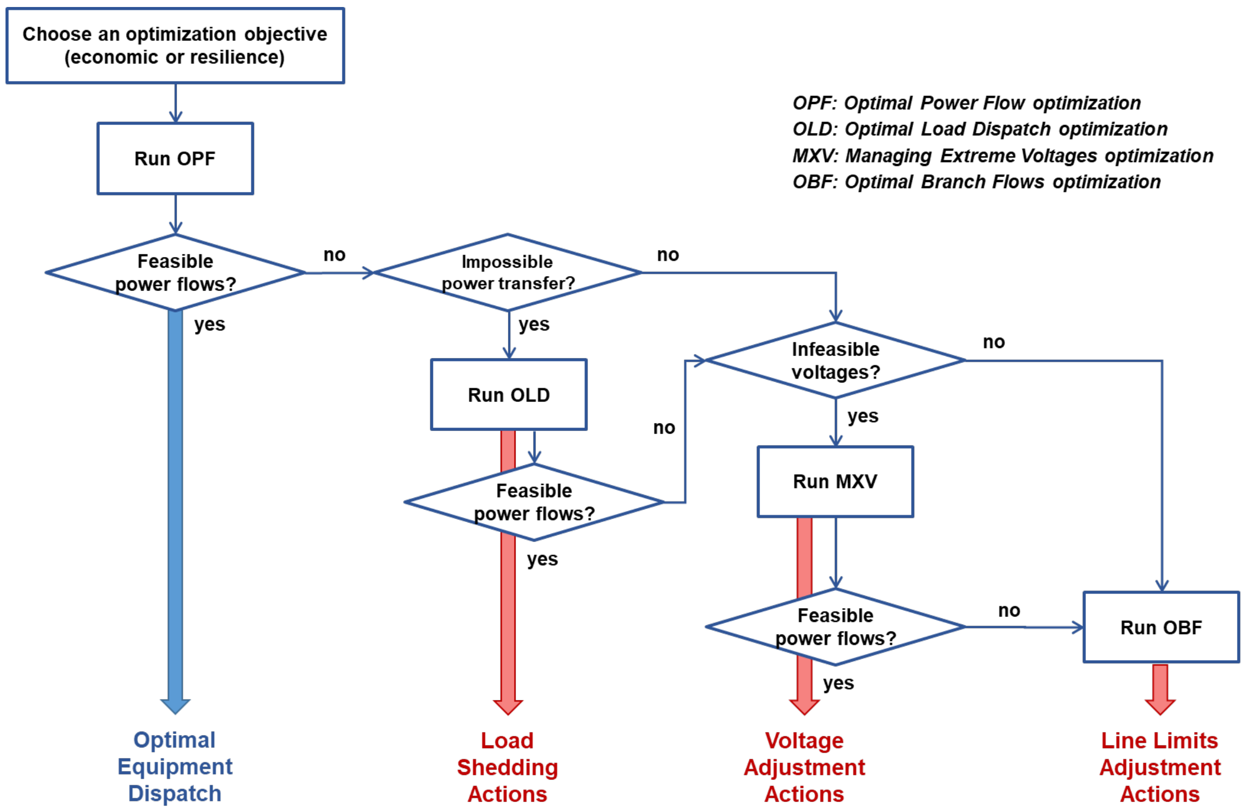


Figure 7. Corrective dispatch analysis flowchart [17]

Since AC-OPF avoids manual trial-and-error analysis, it inherently leads to better load service served during extreme events. The same software can be used for on-line adjustments by operators during *N-1* and *N-2* reliability events. Operators could thereby reduce the amount of spinning reserves during normal operation, at a significant costs savings (documented in section 9).

3.3.1 Application: Voltage Management

Voltage management should be an integral part of power grid control. Particularly during extreme events, it is critically important to management voltage setpoints. Voltage control is possible by adjusting the automatic voltage regulators (AVR) on generators, the outputs of inverters on renewable assets (functionality now specified in IEE 1547-2018), transformers and capacitors taps on the delivery system, and demand consumption. An AC-OPF can perform this optimization.

As indicated in Figure 2, existing power grid operations only optimize for real power dispatch (P). In Figure 8, the blue line shows the impact of this, measured by the amount of load that can be served. When voltage dispatch (V) is also optimally controlled, the black line shows a tripling of the grid's control range and a huge increase in total load service capability. Voltage management enables operators to control the *flows* on the grid, to more effectively transfer power from power generation regions to load centers. These concepts have been documented for large-scale real world power grids, such as Electric Reliability Council of Texas (ERCOT) [16][11] and NYPA [18].

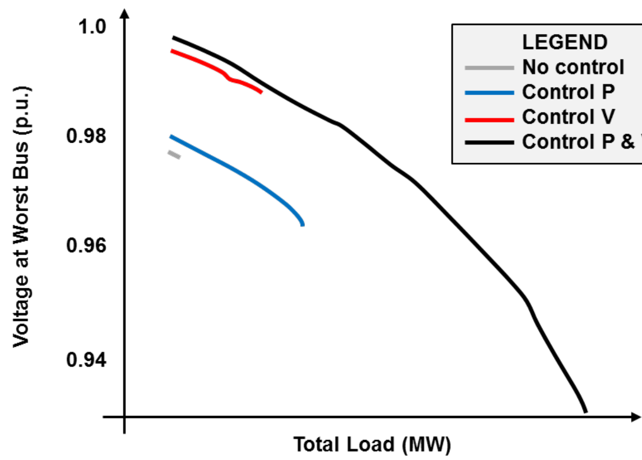
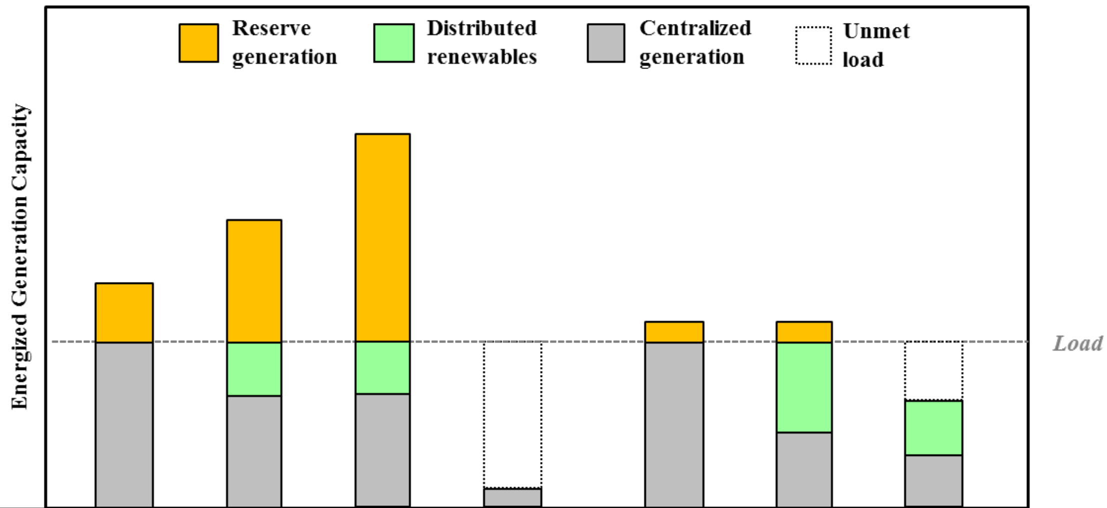


Figure 8. Power transfer capability with different levels of control (Texas interconnection simulation)

3.3.2 Application: Corrective Dispatch

Operational improvements and upgrades to grid controls are potential low-cost improvements to grid resilience. A leading option for grid control is corrective dispatch, which has been the subject of academic and industry consulting studies but has not yet been implemented in operational bulk power systems. Corrective dispatch monitors the power demand and flows throughout the grid, computes the best power system adjustments, and guides operators in the implementation of real-time corrective actions, instead of relying solely on their intuition.

The underlying premise is that during extreme system conditions, previously unseen by the system operator, only well-designed software can identify the most effective actions within the 5-15 minute time window to make control decisions and prevent cascading outages. When a hard-to-predict outage occurs, the software provides guidance to system operators on the most effective scheduling of remaining resources to serve the largest number of customers. During normal operation, available resources are dispatched optimally. Adaptive data-driven resource allocation enables both efficient, low cost services during normal operation and resilient service during extreme conditions.



Operating Conditions	Normal			Extreme	Normal		Extreme
Reserve Capacity	Existing *N-2* reserves		Increased *N-k* reserves		*N-k* reserves		
Dispatch Method	Traditional preventive dispatch				Corrective dispatch		
Case	1	2	3	4	5	6	7

Figure 9. Corrective dispatch effect on reserve requirements (cases 5-7)[9]

Corrective dispatch determines asset dispatch commands based on the logic and optimization sub-routines shown in Figure 7, while meeting the operating constraints listed in Table 2. There is a limit, of course, to the amount of compensation that corrective dispatch can handle, but it will allow grid operation with a lower amount of reserve than existing preventive dispatch. The advantage of corrective dispatch is that it allows utility operators to control the power system in real-time to compensate for component failures and for uncertainty. In Figure 9 this is illustrated in Case 5, which has a significantly lower spinning reserve (orange) than Case 1, which uses traditional preventive dispatch.

Since it handles uncertainty by responding intelligently to changing conditions, corrective dispatch also better integrates renewables into a power system's operations. The current industry approach has proven to be ineffective at integrating new energy resources reliably without excessive and inefficient reserves. As illustrated in Case 6, by using real-time system controls, corrective dispatch can accommodate more intermittent DERs (green), while also avoiding the cost of additional spinning reserve (orange). Compare this with Figure 9 Case 2, which uses traditional preventive dispatch.

Moreover, corrective dispatch is one element of grid innovation that may also successfully keep the grid functioning during extreme events such as Hurricane Maria —ones that would otherwise cause widespread

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[9] For ease of reading, Figure 9 is a duplicate of Figure 3.

blackouts—without the need for increased spinning reserves and flow gate reserves. This is illustrated in Figure 9, Case 7 (compare with Case 4).

In Figure 10, the blue screen icon illustrates the locations where corrective dispatch could be implemented within the power system, namely in a hierarchical manner, to provide resilience against communication failures.

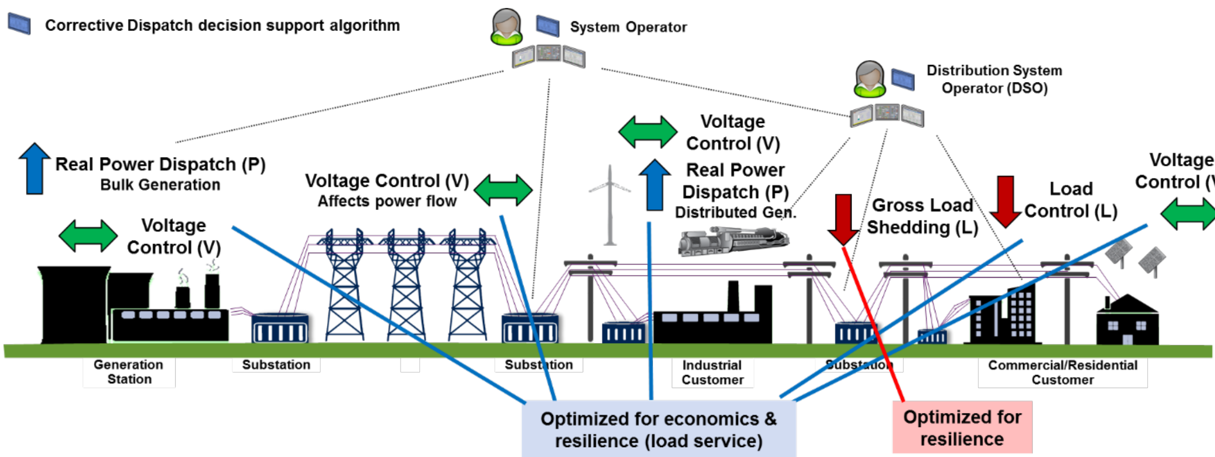

Figure 10. Control levers and optimization objectives under the proposed corrective dispatch method

Through real-time monitoring of failures and critical loads, and scheduling of participating resources, *corrective dispatch would significantly harden the grid using software. The cost of normal operation decreases while improving resilience*.

Corrective dispatch does not require expensive new hardware to implement, so one of our recommendations is a low-cost corrective dispatch evaluation via a "sidecar" deployed in PREPA's control center (section 11.5).

3.4 MODEL-PREDICTIVE CONTROL

Instead of just using AC-OPF to dispatch resources from the PREPA control center, distributed control of DERs could add additional resilience. MPC distributed decision-making software would enable DERs to decide on power consumption and production in a look-ahead manner.

It is important to understand that MPC-based optimization cannot be currently done by a centralized multi-stage optimization, as it becomes extremely time-consuming. Instead, distributed MPC-based management of uncertainties should be embedded in the DERs themselves. There is much published documentation comparing centralized MPC and distributed MPC in our previous work for Azores Islands [29].

For this study, we performed extensive simulations to document potential benefits of having this MPC ability in systems with highly varying solar PV power output, from data measured in Florida. The major benefit is that balancing can be done without requiring deployment of very expensive, although flexible resources like combined-cycle power plants or large-scale energy storage.

If the DERs communicate these decisions to the control center, the control room's AC-OPF could calculate an optimal power dispatch schedule. This would require an interactive computer application between the control center and DERs. This hierarchical, interactive MPC is described in the next section (3.5) and is implementable through a deliberate investment in PREPA's supervisory control and data acquisition (SCADA) system.

3.5 INTERACTIVE MODEL-PREDICTIVE CONTROL FRAMEWORK

Coordination becomes a challenge with the widespread deployment of microgrids, cogeneration plants, high-penetration DERs, and intermittent renewable energy resources. The power grid is no longer planned, constructed, and operated from the top down by a centralized authority. Regulatory and technical frameworks are required for planning, construction, and operation during normal and emergency conditions.

To meet this major challenge, we present in [19] the DyMonDS, a theoretically-sound framework that uses price signals (illustrated in Figure 11) and hierarchical communications (illustrated in Figure 12) to meet the needs of a modernized power system. A complex power system is simplified by requiring devices to only communicate with their most immediate neighbor.

This framework allows all energy asset owners to signal their plans and enables grid operators to dynamically identify the highest-priority loads. This is a major requirement for implementable model-predictive adjustment, particularly with large deviations in renewable resources. This is documented in the technical report [19], including its implementation, key benefits, and a comparison with existing dispatch rules when applied to integration of renewables.

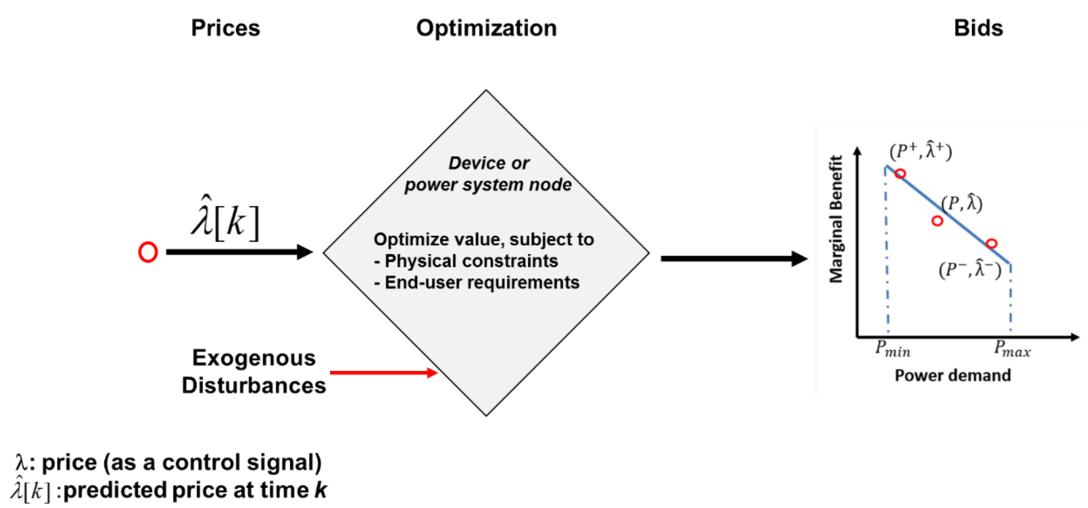

Figure 11. Building block of DyMonDS framework: prices and bids are used to communicate control signals and allowable operating region

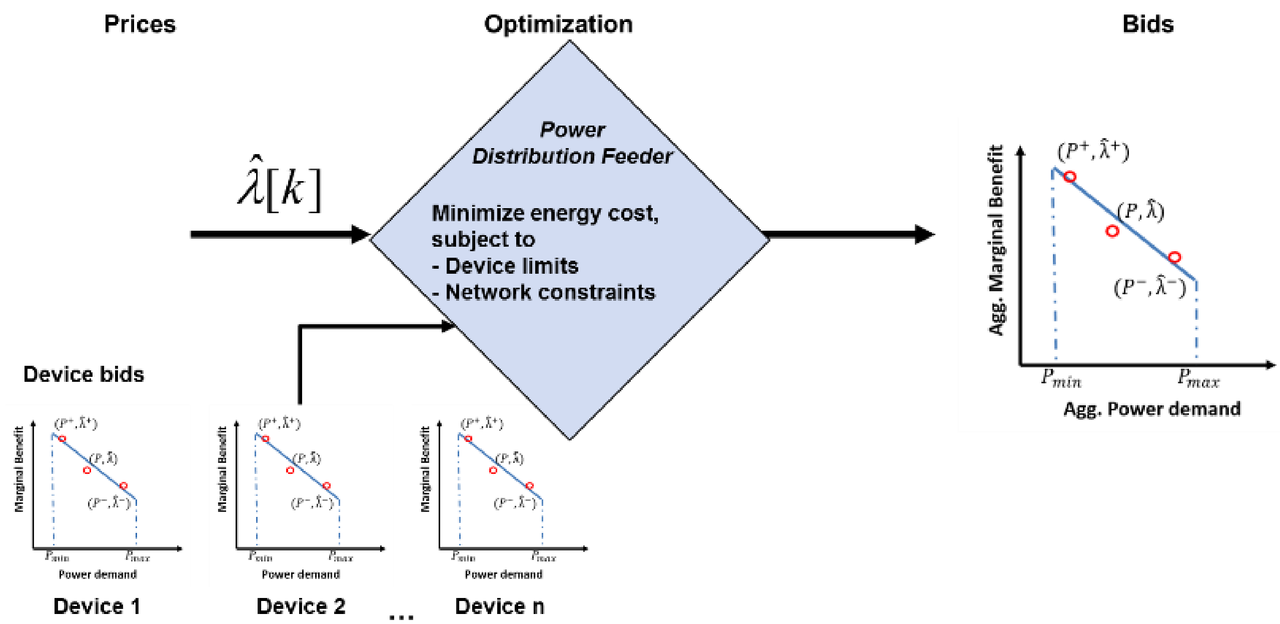

Figure 12. DyMonDS hierarchical communications: Power distribution and transmission nodes aggregate bids from lower-level devices, ensuring the system is balanced, efficient, and can be segmented.

We applied DyMonDS to the Puerto Rico power grid to demonstrate how PREPA could modernize operations and planning, including coordination with distribution systems and microgrids.[10] DyMonDS simulates minimally coordinated interactions between end users, resources, and the power grid, and enables these interactions so that stakeholders' sub-objectives are closely aligned with societal objectives. This approach supports adaptive flexible generation scheduling, adaptive electricity use, and adaptive electric power delivery. This allows us to evaluate several potential future architectures studied, as particular instantiations of the general DyMonDS architecture. This allowed detailed modeling, simulation, and analysis of candidate Puerto Rico architectures, and their reliability, resilience, and economic performance.

Distributed MPC-based dynamic dispatch can utilize weather data and other predictions. This approach, however, requires that MPC software must be embedded into the DER's controllers. Such participation can be implemented by upgrading existing power plants, so that they can be more dispatchable load-following plants. Puerto Rico's system has started this process with some power plants. The DyMonDS architecture, which has coordinated controls at multiple layers, supports on-line the information flow to and from end-users and to and from coordinating control centers. This improves overall grid coordination and end-user participation in providing efficient and resilient electricity. Given the evolution in Puerto Rico's energy sector regulation and fiscal challenges, it is critical to include end users in power balancing with both

[10] This framework has been previously explored in Azores Islands, Portugal and it was shown that IT-enabled operation with participation by stakeholders could enable large penetration of renewables while at the same time making reliable services much less expensive in the long term than when the islands were fueled by imported oil.

neighboring users within a microgrid (peer-to-peer) and with higher layers, such as transmission centers (TCs) and control centers (CCs).

Many organizations are introducing new solutions to help end-use devices make smarter choices. A critical piece is missing: software applications that integrate end user participation so their sub-objectives are aligned with system-level objectives to the largest extent possible. The DyMonDS architecture can fill that missing link between users' objectives and the overall system's objectives. Distributed interactive decision making have the potential to become the basis for good electricity service to society, and Puerto Rico could lead the way in this process.

To quantitatively explore these arrangements we develop algorithms that (a) allow for local grid control given locally aggregate supply and demand, (b) decompose the Puerto Rico grid into nested enclaves operating primarily at the transmission level with minimal centralized coordination, and (c) coordinate centralized management (planning and operation) of these nested entities.

Regarding planning, Puerto Rico electrical system naturally lends itself to being operated and planned according to the DyMonDS framework because of its highly heterogeneous and geographically dispersed load, and its fundamental lack of observability and controllability. As small DERs get deployed within the island's electric power systems, DyMonDS could enable their efficient and resilient use. The Puerto Rico electrical system is likely to have many non-utility-owned resources and microgrids as a result of local grid control. These represent candidate layers which, if not coordinated and operated in an interactive way, will fall short of meeting their objectives, and, at the same time, will not contribute to the societal good. The electrical sector's operations must be modernized to enable adaptive utilization of all existing resources. As of June 2018, PREPA CCs and its TCs would need to be equipped with next generation SCADA to support interactive information exchange and generation/demand management as system conditions vary. Instead of having one highly centralized top-down SCADA, this analysis proposes to start by modernizing SCADA of existing CCs with software capable of monitoring and dispatching existing generation as well as interacting with lower level TCs. Existing TCs should become intermediary coordinators between the distribution and newly deployed microgrid systems under the TC's jurisdiction, on one hand, and system-level CCs, on the other.

We show the benefits of a DyMoNDS-enabled planning approach for further hardening of the existing transmission, sub-transmission, distribution grids, deployment of large scale generation, and the deployment of public-private investments in local microgrids, solar PV, and energy storage. Advisory software could inform community initiatives by assessing available options and their likely outcomes. Based on this, communities should carefully consider their alternatives, including:

- Supply their own power in a stand-alone islanded mode, using no supply from the neighboring entities;
- Supply their own power during normal operation in a stand-alone islanded mode, while having well-defined protocols for exchanging power during extreme conditions;
- Rely on a centralized power system for normal operation, and have small local back-up systems for serving their own needs during extreme conditions; or,
- Rely completely on a centralized power during both normal and extreme conditions.

These different protocols require qualitatively different technical and financial arrangements. The next generation of Puerto Rico electricity services will probably be a combination of these architectures. For the system to evolve, it is critical to engage communities, utilities, and regulatory entities with algorithms that help assess options and coordinate preferences into a well-functioning socially-acceptable power system. By using DyMonDS in our simulations, we evaluated how this model-based algorithm could help distributed communities, in particular those not likely to be served centrally during extreme events. We assessed different solutions and proposed coordinating strategies that more fully utilize distributed resources.

4. MODELING APPROACH – OVERVIEW

For Puerto Rico's recovery plan, 27 energy sector courses of action (COAs) were identified to modernize and increase the resilience of its power grid [20]. The modeling approach described here supported the development of these COAs. These are not all mutually exclusive actions, many of them can be combined into complete grid architectures to provide improvements across the breadth of grid operations. We used these recovery plan COAs to distill five design categories that encompass all the COAs.

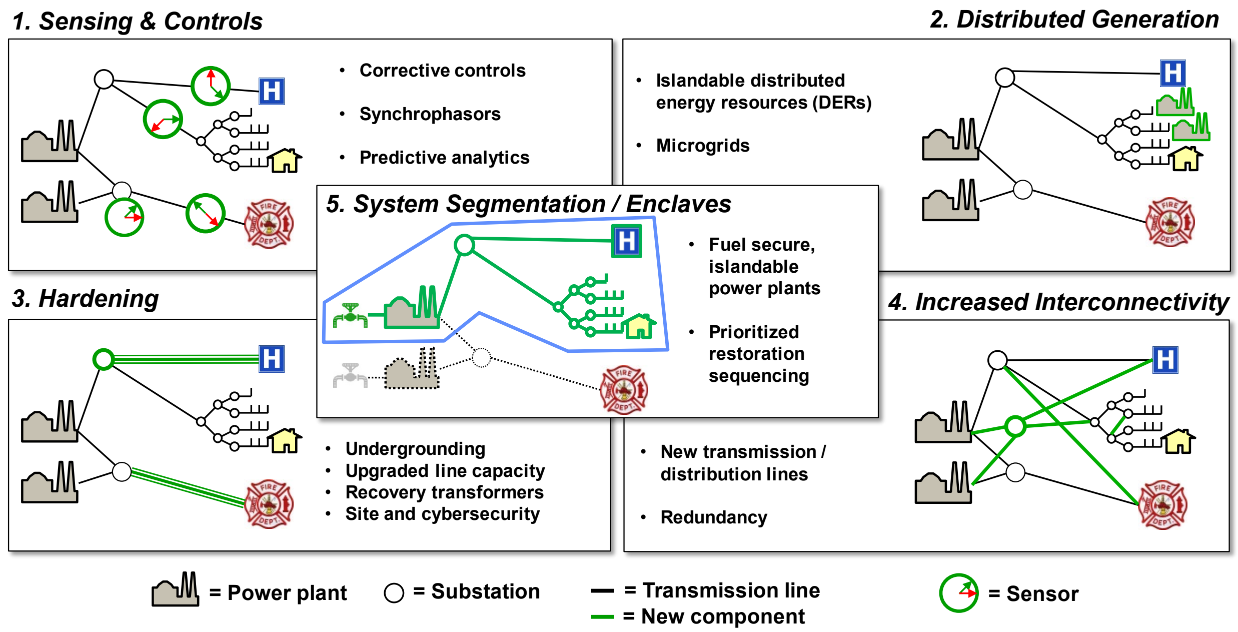

Figure 13. Five approaches for increasing grid resilience

The categories are:

1. Controls include the plan and software that determine generation and transmission operations as described by corrective dispatch.

2. Distributed generation can be increased with grid schemes that integrate generation at the distribution level, typically 38 kV and below, instead of at the transmission level, typically 230 kV or 115 kV. To provide resilience, one or more DERs must operate within a microgrid, which enables off-grid, "islanded" operation.

3. Infrastructure hardening makes grid elements physically more robust to damage, e.g., burying lines or using steel supports instead of wood for distribution lines and protecting power generation facilities and substations against flooding.

4. Interconnectivity adds transmission and distribution lines to provide redundant paths for power to flow around lines that may be damaged or from alternate generation plants.

5. System segmentation/enclaves break the power system into smaller zones, either to prevent instability in one part of the grid from cascading across the entire power system or to intentionally shed non-critical load in order to continue serving critical loads with the limited remaining assets.

6. Improved training, maintenance, and compliance with construction standards (not shown in Figure 13) are largely non-technical solutions that would bring PREPA up to industry standard practices.

Various grid architectures - or various portfolios of the above choices - will demonstrate trade-offs across grid performance, including, but not limited to, initial cost, fuel costs, reliability, and resilience. This report defines exemplary AOs intended to span realistic design choices and performance outcomes associated with rebuilding the Puerto Rico power grid. There are also likely to be environmental, economic, and political implications in selecting a particular AO, but those are not addressed in this study. This study addresses only the technical and lifecycle cost aspects of understanding and evaluating various AOs expected of industry vendors and other government labs.

There are several factors that can be used to evaluate the performance trade-offs associated with a particular architecture. There are obvious trade-offs between the initial cost to build a generator and then the lifecycle cost (cost of fuel) to operate it, since more efficient plants often cost more.

Equally important is a measure of the grid performance in serving the demand load, both with respect to reliability and resilience. As described in section 3.2.2, critical loads were undefined, so all load was treated equally; thus, identification of critical loads would further improve results.

In this report, we present a framework for evaluating proposals to improve the power grid. The framework includes a modeling tool that incorporates characteristics of the power generators and the network of transmission and distribution lines from 230 kV down through 38 kV. The model has sufficient detail to predict power flow and limitations as outages are introduced into the network. As was discussed above, the electric power industry typically makes plans for up to two outages in the grid (N-2) so that 100% of the load can be served, but industry is only now starting to plan for wide-area outages as would occur during hurricanes. The detail in our model, however, enables an understanding of the grid performance in the presence of multiple outages of varying scales. We developed eleven outage scenarios from N-1 to an extreme N-87% case (representative of a direct hit on the island by a category 5 hurricane) to understand how particular grid architectures perform in those cases according to the above metrics. In addition, we provide estimates of the capital cost of additional infrastructure above the baseline grid architecture, and of the fuel cost to run a particular set of power generators for a day. Finally, the difficulty to repair each architecture back to full operation after an N-80% event is evaluated.

Along with the eleven outage scenarios, we developed ten example AOs to represent different approaches to rebuild the electric grid in Puerto Rico. These AOs are described in section 7. Each of them has been run against the eleven outage scenarios to produce examples of modeling results that cover a range of performance from serving 100% of the load to complete grid failure. The AOs used are not being proposed as specific solutions since their design was entirely from a technical performance standpoint, other considerations were not contemplated. However, the AOs do serve to illustrate the capabilities of the model and serve as an example of the kind of analysis that could be used when evaluating actual grid improvement proposals.

5. MODELING APPROACH – PUERTO RICO POWER SYSTEM MODEL

The simulations for this study required detailed information on Puerto Rico's transmission infrastructure. It is common, however, for utility companies to treat their power system information as confidential because it documents critical electric infrastructure. PREPA did not provide us with a copy of their power system model.

As an alternative, we used public databases from the Department of Homeland Security [21] and the Government of Puerto Rico [22] to derive a model of the Puerto Rico electric power system before the hurricanes struck. These datasets contain GIS-layered information, including connectivity and specifications for transmission lines, power plants, substations, and transmission centers. The data for the model was collected between March 2018 and July 2018.

To perform technical studies and simulate the electrical response of the power system, it was necessary to extract system data from GIS layers, process those GIS layers using QGIS [23] to match PSS®E v30 format and generate links between independent GIS layers using Python routines. The layers included information on transmission line lengths, conductor type, power plant generation capacity, among other parameters. The Python routines defined connectivity nodes between components based on their geographic locations and unique feature identifiers, assigned component impedances based on typical values and available specifications [24], and distributed the load across the system. The Python routines also addressed two problems that arose from using GIS data: (a) discontinuities between transmission line segments and (b) joining power lines, substations, and power plants which appear in separate and unlinked GIS layers, but are geographically co-located. The resulting Puerto Rico power system model includes equipment down to and including 38 kV.

For the load, we distributed the aggregate system load across the 38 kV substations. The distribution assumes that 70% of the total electrical load is consumed in suburban areas and 30% in rural areas. We derived the electrical demand of the entire island based on statistical data presented in [25], with yearly data points from 2004 to 2014.

6. MODELING APPROACH – OUTAGE SCENARIOS

This section describes the grid outage scenarios used throughout this study. As discussed above, the state of the grid is characterized by the number of outages, *k*, such that N-0 is a grid where all elements are online, and N-*k* is a grid where *k* elements are not working properly. The scenarios used in this study run from no outages (N-0) up to an extreme where 87% of grid elements are disabled (N-87%). A randomized N-87% outage is a representation of the grid after an extreme damaging event like a direct hit from a category 5 hurricane [26].

Table 3 Outage Scenarios

Scenario	Variants Evaluated	Example	Description
N-0	dozens	normal operation	With the grid operating at full capability, calculate the fuel cost to operate the PREPA grid on a "normal" day. This number is useful as a baseline for evaluating the operating costs of other grid architectures.
N-1	hundreds	reliability event	Evaluate whether losing a single component (line, transformer, or generator) will result in a critical contingency and potential loss of load. We ran these simulations with both thermal and voltage constraints, and for *every possible failure* on the 230 kV, 115 kV, and 38 kV networks to identify where the critical contingencies exist.
N-2	thousands	significant reliability event	Evaluate whether the loss of any two components results in a critical contingency. Normally N-2 assessments done by industry do not impose any voltage or thermal constraints. In our analysis, we imposed *both* voltage and thermal constraints and simulated *every possible combination* of two component failures on the 230 kV and 115 kV networks.

Scenario	Variants Evaluated	Example	Description
N-4	2	industrial accident, terrorist attack	**Scenario N-4(a):** This scenario disables two turbine generators (TGs) from the Complejo Aguirre plant and two TGs from the AES coal plant on the southeastern coast of the island. See Figure 14. **Scenario N-4(b):** This scenario simulates failures for four components identified as critical contingencies in Scenario N-1: 3 generators and 1 transformer. The outage occurs simultaneously for the four components.
N-6	2	modest hurricane damage	**Scenario N-6(a):** This scenario imposes an outage of 4 generators—similar to scenario N-4(a)—plus simultaneously losing two 230 kV lines, illustrated in Figure 15. **Scenario N-6(b):** This scenario imposes an outage of 6 high-voltage 230 kV and/or 115 kV lines.
Sub-transmission outage	2	urban flooding + hurricane damage	**San Juan 38 kV Outage:** This scenario replicates the effects of a widespread subtransmission outage in the greater San Juan area. See Figure 16. **San Juan 38 kV + 6 Circuits Outage:** This scenario is a combination of the San Juan 38 kV subtransmission outage and the N-6(b) transmission 6-line outage.
N-80%	3	catastrophic hurricane damage	**N-80%(a), N-80%(b), N-87%:** These three scenarios replicate large, widespread outages in the transmission infrastructure at all three voltage levels. Transmission, subtransmission, and distribution lines were randomly disconnected or de-energized in the model. Figure 17 shows an example of one N-80% outage case. For the N-87% case, only 275 out of 2,145 lines remained connected in the model.

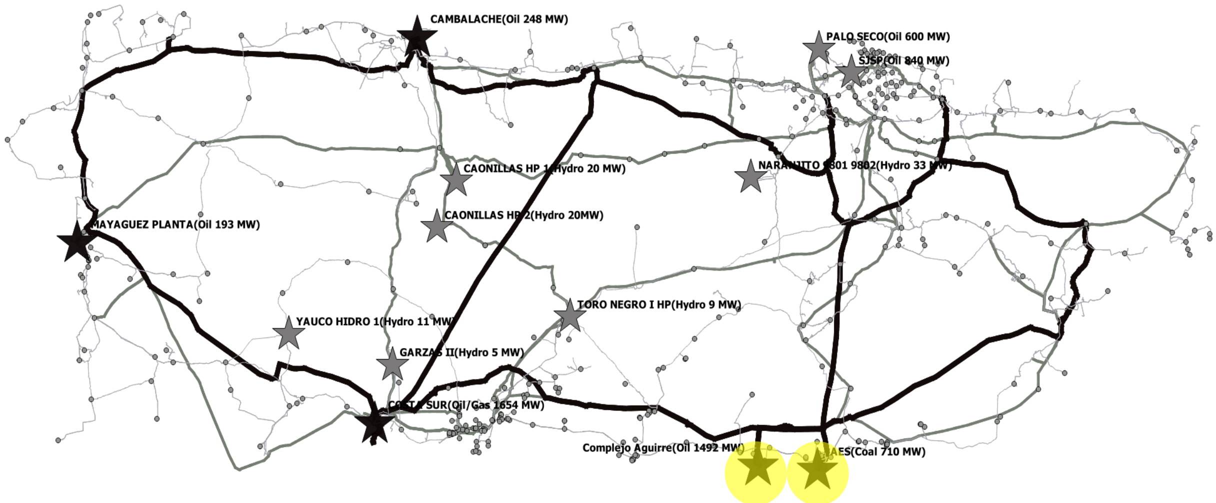

Figure 14. N-4 scenario: Removal of 4 turbine generators at 2 locations

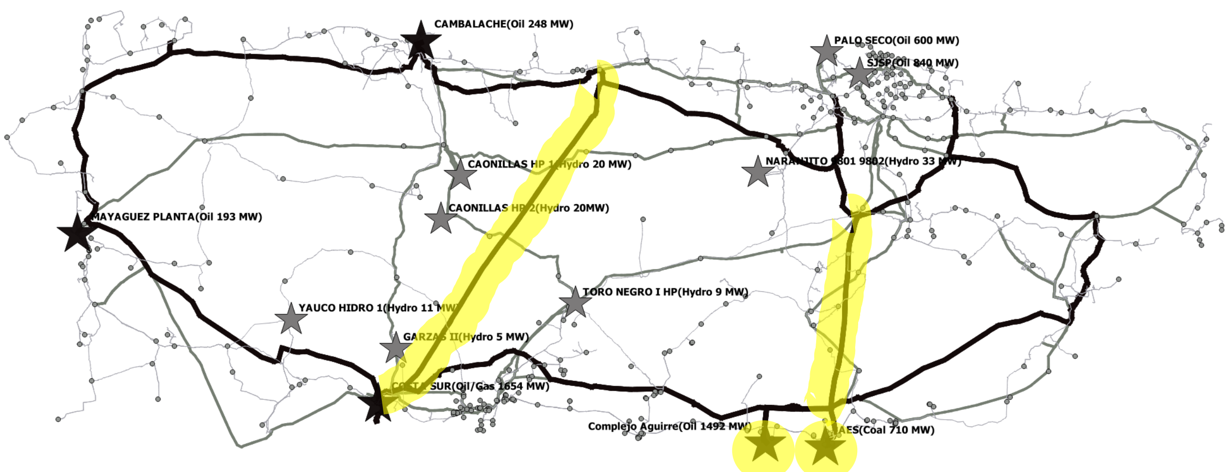

Figure 15. N-6(a) scenario: Removal of 4 turbine generators and 2 lines

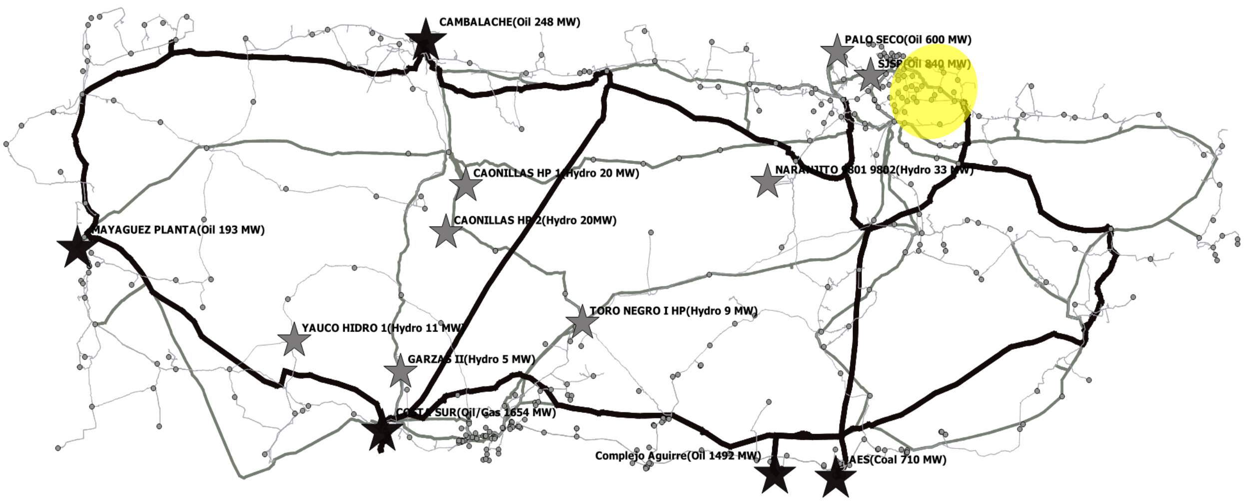

Figure 16. San Juan subtransmission outage area

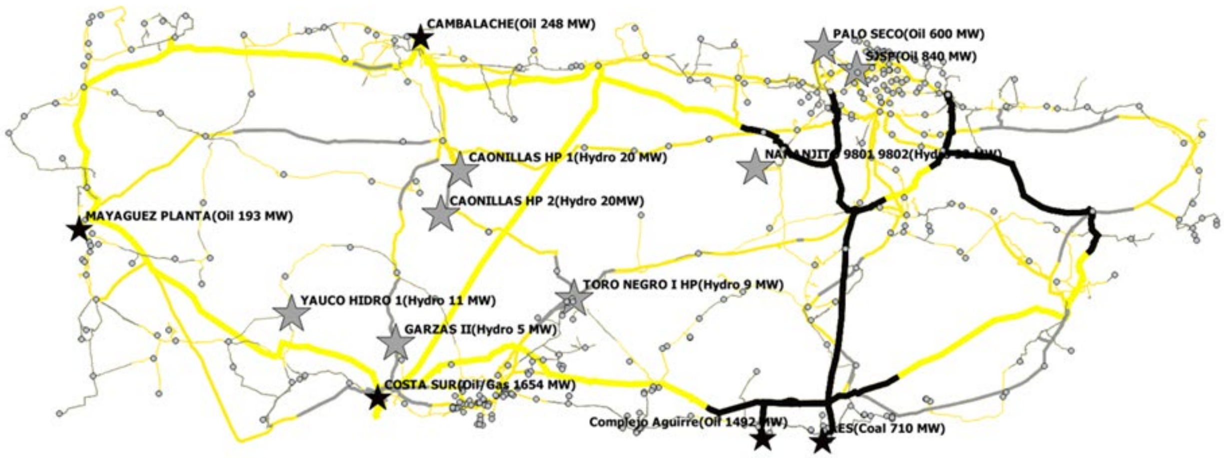

Figure 17. N-80% scenario: lines rendered in yellow are de-energized

7. MODELING APPROACH – EXAMPLE ARCHITECTURE OPTIONS

We considered nine example AOs in this study, which nominally represent those proposed by industry in response to a solicitation by the Government of Puerto Rico. AO1 and AO2 most closely align with current PREPA operating conditions.

Table 4 Example Grid Architecture Options

AO	Change	Description	Recovery Plan COAs Represented
AO1	Baseline system	The pre-hurricane Maria grid architecture has 4,878 MW of primarily fossil-fuel steam plants providing energy through a network of 2,478 miles of 230 kV and 115 kV transmission lines, and a subtransmission network of 38 kV lines. Our GIS data includes a total of 383 substations, 23 transmission centers, and 13 major power plants. This system does not include any transmission-level cogeneration units. Using preventive dispatch controls, all generators use static ramp rates, are not required to remain spinning, and can be dispatched continuously between their minimum and maximum power setpoints.	None (pre-Maria baseline system)

AO	Change	Description	Recovery Plan COAs Represented
AO2	Transmission-level cogeneration added	About 961 MW of cogeneration is added to the AO1 baseline generation mix. Most of this is located at EcoElectrica in Peñuelas and Aguirre on the southern coast.	• ENR 8 Maintain Disaster-Resilient Generation Assets • ENR 9 Design and Build Fuel Supply Chain to Provide Reliable Energy Source • ENR 14 Design and Build Grid Assets to Meet Current and Future Demand • ENR 15 Enable Private Standby Generation to Provide Emergency Power
AO3s AO3u	Transmission-level solar PV and storage instead of cogeneration	Replace the fossil-fueled cogeneration added in AO2 with 961 MW of PV power and battery storage. Depending on their level of sophistication, these assets act either as controllable sources (AO3s) or as uncontrolled “negative loads” (AO3u).	• ENR 8 Maintain Disaster-Resilient Generation Assets • ENR 9 Design and Build Fuel Supply Chain to Provide Reliable Energy Source • ENR 14 Design and Build Grid Assets to Meet Current and Future Demand • ENR 15 Enable Private Standby Generation to Provide Emergency Power

AO	Change	Description	Recovery Plan COAs Represented
AO4u AO4s	Distributed solar PV added in rural areas	Starting with AO1, add 250 MW of solar PV in rural areas at a cost of $4M per MW capital cost. See Figure 18 for the locations of rural PV. We assume that PV could be installed on residential or municipal rooftops. Each location indicated on Figure 18 represents between 1 – 20 MW of "lumped" PV capacity distributed on a 38 kV network. Depending on their level of sophistication, these assets act either as controllable sources (AO4s) or as uncontrolled "negative loads" (AO4u).	• ENR 22 Enable and Promote Distributed Generation • ENR 23 Design Best Strategies for Renewable Energy Resources • ENR 2 Design, Build, and Maintain an Electricity System with "Islandable" Portions of the Grid • ENR 9 Design and Build Fuel Supply Chain to Provide Reliable Energy Source • ENR 14 Design and Build Grid Assets to Meet Current and Future Demand • ENR 16 Provide Backup Generation to Priority Loads Requires implementation of these COAs: • ENR 3 Harden Supporting Infrastructure for the Electricity System, Including Communications • ENR 18 Right Size and Train the Future Energy Workforce • ENR 26 Establish Energy Sector Governance Responsibilities for State-Level Agencies • ENR 27 Establish Regulations to Transform the Energy Sector

AO	Change	Description	Recovery Plan COAs Represented
AO5	AO1 with corrective dispatch	These architectures are identical to those listed above, but with corrective dispatch control algorithms instead of today's preventive dispatch.	• ENR 3 Harden Supporting Infrastructure for the Electricity System, Including Communications • ENR 11 Design and Deploy Technologies to Improve Real-Time Information and Grid Control • ENR 16 Provide Backup Generation to Priority Loads • ENR 19 Design and Deploy Data Systems to Inform Response and Improve Operations and Maintenance Requires implementation of these COAs: • ENR 18 Right Size and Train the Future Energy Workforce • ENR 27 Establish Regulations to Transform the Energy Sector Simulation results illustrate these COAs • ENR 2 Design, Build, and Maintain an Electricity System with "Islandable" Portions of the Grid • ENR 24 Design Best Strategies for Affordable and Stable Energy Prices
AO6	AO2 with corrective dispatch		
AO7s AO7u	AO3s and AO3u with corrective dispatch		
AO8u AO8s	AO4u and AO4s with corrective dispatch		

AO	Change	Description	Recovery Plan COAs Represented
AO9	New transmission infrastructure	We considered adding an east-west 230 kV line from Aguas Buenas to Rio Blanco through an area south of the San Juan urban district, per recommendations in the *Build Back Better* report [27]. This architecture also adds a 20 MW PV facility at the Villa Prades substation east of San Juan, which appeared to be a critical bottleneck in analyses for the other AOs. Unfortunately, due to time constraints, we were unable to evaluate the cost or performance of this AO, which is why there are no results presented below. We recommend its inclusion in future studies.	• ENR 5 Harden Grid Assets to Support Critical Infrastructure • ENR 6 Improve Grid Assets' Resilience to Flooding • ENR 7 Improve Grid Assets' Resilience to High Wind Speeds

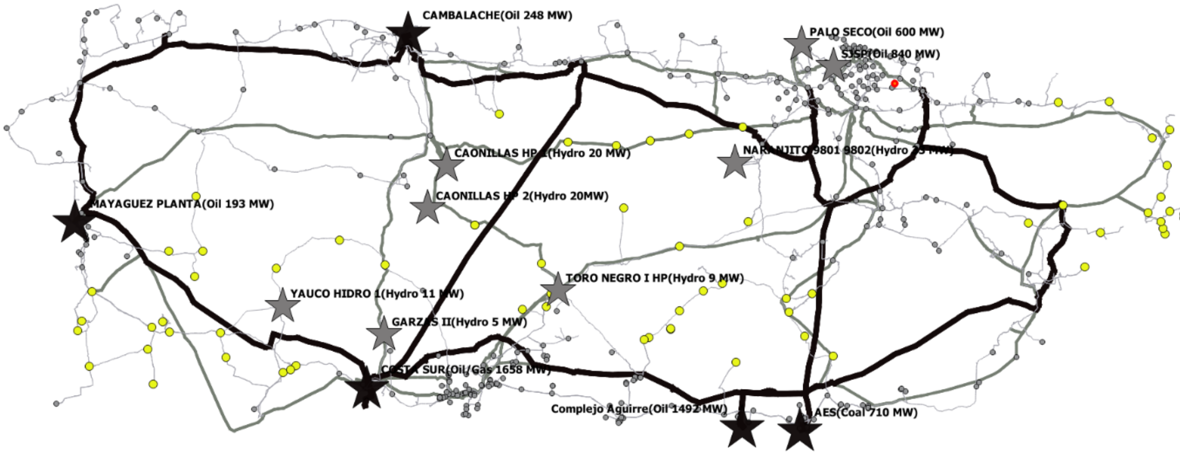

Figure 18. Locations of rural PV installations (shown in yellow) for AO4 and AO8. Due to lack of local area information, PV siting did not consider constraints such as right-of-ways or land availability.

8. MODELING APPROACH – SIMULATION ASSUMPTIONS

8.1 RAMP RATES

The Siemens report [1] cited ramp rates as a critical limitation for solar PV deployment, so we evaluated two different sets of ramp limits: constrained and relaxed, shown in Table 5. The results in Table 6 - Table 9 are based on the constrained ramp rates.

Table 5

Ramp Rates Used to Confirm Feasibility of System Dispatch

Generation Type	Constrained Ramp Rates	Relaxed Ramp Rates
Cogeneration	22% of nameplate capacity/hour	8 MW/min
Gas	20% of nameplate capacity/hour	8 MW/min
Coal	5% of nameplate capacity/hour	4 MW/min
Oil	5% of nameplate capacity/hour	5 MW/min
Hydro	20% of nameplate capacity/hour	8 MW/min

8.2 PREVENTIVE DISPATCH RULES AND RESERVES

We followed industry standard practices and preventive dispatch rules documented in the Siemens report [1]. We used PREPA's 300 MW spinning reserve for reliability, resulting in $0.3 million per day estimated cost for very fast reserve of steam power (coal-fired) at $42/MWh.

To ensure robust results, we considered three different variants of preventive dispatch:

1. Use static ramp rates, assume no generators are "must run" to recoup sunk costs, and assume that generators can be dispatched continuously between their minimum and maximum setpoints. The fuel costs presented in Table 6 for AO1 to AO4 use this method. This method reflects the best-case scenario for operational fuel cost, because generators are not required to remain online at all times.

2. Keep "must run" units hot at all times. This method does not allow dispatch flexibility for prime power plants. Thus, generators must run at either their minimum or maximum power output without settings in between. This appears to be Puerto Rico's current dispatch method.

3. Ignore ramp rates and perform ideal security constrained economic dispatch (SCED). This should be the least cost benchmark, but is not implementable in Puerto Rico because of ramp rate limits.

Note that the current operational fuel cost for Puerto Rico is likely higher than the values presented in Table 6. For the daily fuel cost calculation, Table 6 reflects industry standard practices. It assumes that no generators are "must run" and that generators can be dispatched continuously between their minimum and maximum setpoints.

8.3 CONTINGENCY ANALYSIS

We used three different methods to ensure robust results:

1. Based on current industry practices, consider only thermal limits to assess violations of power flows. Industry does this for N-1 and N-2 events. The results in Table 6 - Table 9 are based on this method.

2. Consider both voltage limits and power flow thermal limits. Industry does not typically apply this level of constraints on its analysis. This assumption is impactful. As one example, for AO2 in Table 6, there are 7 critical N-2 contingencies under the standard industry method (thermal limits only), compared to *168 critical contingencies* when both thermal and voltage limits are considered. The latter approach is more conservative and is likely to identify vulnerable nodes in the system.

3. Solve the power flow but do not apply any constraints. This is the industry approach for only a small number of critical cases identified by the first analysis method.

For the contingency analysis, the term "critical contingency" is used to identify a particular component such as a generator or transmission line that when disabled or removed from service, leads to a critical or overload condition somewhere else in the network. For example, the N-1 analysis might result in only a small set of single critical contingency components, whereas an N-2 analysis could result in a larger number of critical contingency pairs of components.

8.4 DER VOLTAGE CONTROL

The new version of IEEE 1547-2018 adds provisions for voltage control by DER inverters. For AO4, which considered deployment of 278 MW of solar PV in rural areas, we simulated the inverters both with and without voltage control capability. The results were inconclusive on the value of DER-level voltage control. Additional research is required.

9. MODELING RESULTS – ECONOMIC COST AND RELIABILITY

The results of the grid performance reliability model for AO1 to AO4, using traditional preventive dispatch, are shown in Table 6. Note the modeling assumptions in section 8: since PREPA imposes additional operating constraints due to deferred maintenance and cost recovery needs, these are best-case fuel cost numbers for Puerto Rico's present-day grid operations.

Table 6

Cost and Reliability Model Results for Architecture Options using Predictive Dispatch for (N-0) – (N-2)

AO	Description	Capital Cost	Daily fuel cost in normal operation (N-0) ($ million/day)[11]	All 230/115/38 kV N-1 contingencies		All 230/115 kV N-2 contingencies	
				# of critical contingencies	Load served	# of critical contingencies	Load served
AO1	Existing infrastructure	Baseline	**$ 4.81**	3 generators + 1 transformer	**81%**	585 combinations of (N-2) outages	Not analyzed
AO2	Add existing ~1 GW subtransmission cogenerators	Baseline	**$ 2.96**	None	Not analyzed	7 combinations	Not analyzed
AO3s	Transmission-level solar PV, controlled as sources	Baseline + $2.44B	**$ 2.26**	None	Not analyzed	7 combinations	Not analyzed
AO3u	Transmission solar PV, uncontrolled	Baseline + $2.44B	**$ 4.58**	2 generators + 1 transformer	**60%**	439 combinations	Not analyzed
AO4u	Distribution-level solar PV, uncontrolled	Baseline + $0.99B	**$ 4.64**	1 generator	**57%**	146 combinations	Not analyzed
AO4s	Distribution-level solar PV, controlled as sources	Baseline + $0.99B	**$ 1.92**	3 generators + 1 transformer	**68%**	146 combinations	Not analyzed

[11] Uses constrained ramp rates described in section 8.1. Calculated for a typical weekday in May.

The results of the grid performance reliability model for AO5 – AO8, using corrective dispatch, are shown in Table 7.

Table 7

Cost and Reliability Model Results for Architecture Options using Corrective Dispatch for (N-0) – (N-2)

AO	Description	Capital Cost	Daily fuel cost in normal operation (N-0) ($/day)	All 230/115/38 kV N-1 contingencies		All 230/115 kV N-2 contingencies	
				# of critical contingencies	Load served	# of critical contingencies	Load served
AO5	AO1 configuration + Corrective Dispatch	Baseline	**$ 4.10**	3 generators + 1 transformer	**100%**	737 combinations of (N-2) outages	Not analyzed
AO6	AO2 configuration + Corrective Dispatch	Baseline	**$ 2.64**	None	Not analyzed	156 combinations	Not analyzed
AO7s	AO3 configuration + Corrective Dispatch	Baseline + $2.44B	**$ 1.93**	None	Not analyzed	156 combinations	Not analyzed
AO7u	AO3 configuration + Corrective Dispatch	Baseline + $2.44B	**$ 3.88**	3 generators + 1 transformer	**100%**	715 combinations	Not analyzed
AO8u	AO4 configuration + Corrective Dispatch	Baseline + $0.99B	**$ 3.93**	2 generators	**100%**	434 combinations	Not analyzed
AO8s	AO4 configuration + Corrective Dispatch	Baseline + $0.99B	**$ 1.97**	4 generators + 1 transformer	**100%**	1348 combinations	Not analyzed

9.1 TAKEAWAYS FROM COST MODELING RESULTS

Figure 19 summarizes the lifecycle cost results. Since we are proposing an analysis framework in this report, these results are meant to be illustrative and informative. These are still notional results for several reasons. Most importantly, the operational fuel cost calculations for AO1 to AO4 are very optimistic; they are likely much higher for reasons explained at the start of section 9. If this framework is found to be useful, then true lifecycle cost calculations must be performed on the actual power system improvements proposed for the electric power grid of Puerto Rico.

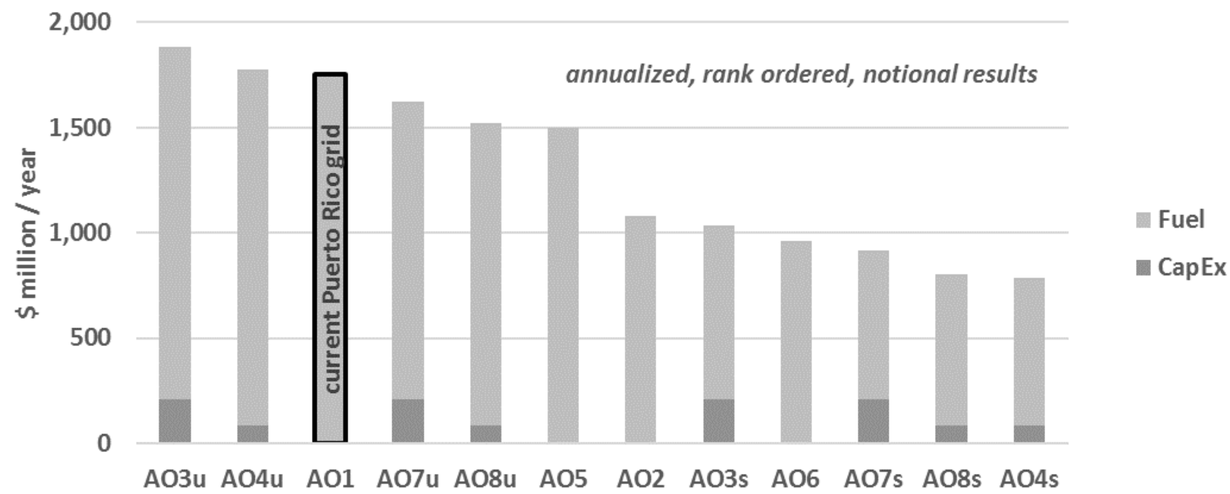

Figure 19. Lifecycle cost for each architecture option

Key takeaways from the architecture lifecycle cost analysis:

First, operational fuel costs dominate, so improvements to reduce fuel costs are worth investigating. Lower fuel costs are associated with distributed renewable energy projects (AO4 and AO8). Subtransmission renewable projects (AO3 and AO7) showed significant fuel cost savings, as well, but these were partially offset by higher capital cost associated with additional assets needed for full integration of renewables.

Second, note the difference between uncontrolled renewables (AO3u, AO4u, AO7u, AO8u) and renewables and storage that are controllable, similar to traditional generation sources (AO3s, AO4s, AO7s, AO8s). Controllable renewables provide *significant* operational fuel savings by allowing a reduction, rather than increase, of costly spinning reserves.

Third, improved grid dispatch controls (AO5 – AO8) reduce lifecycle cost. Despite the optimistic fuel cost numbers for AO1 – AO4, the corrective dispatch (AO5 – AO8) saves $300,000 to $700,000 *per day* in fuel costs. The actual savings would likely be much higher because of the additional operating constraints that PREPA imposes on the system, as described in section 8.2.

10. MODELING RESULTS – RELIABILITY & RESILIENCE

The results of the grid performance resilience model for AO1 to AO4 are shown in Table 8 for traditional preventive dispatch. Important violations—minimum voltage (Vmin), maximum voltage (Vmax), excess line flows (LF)—are also noted in italics. These violations could lead to protective relay trips and further cascading outages.

Table 8

Resilience Model Results for Architecture Options using Preventive Dispatch for (N-4) – (N-87%)

AO	N-4 (a) 4 generators out across 2 plants	N-4 (b) 4 critical contingencies	N-6 (a) 4 generators & 2x 230 kV lines out	N-6 (b) *6 lines*	San Juan 38 kV outage	San Juan + 6 circuits outage	N-80% Random failure (a)	N-80% Random failure (b)	N-87% Random failure
	Load served	Load served	Load served	Load served	Load served	Load served	Load served	Load served	Load served
AO1	72% *LF > 250 MW*	**55%**	71% *LF > 500 MW* *Vmin = 0.909*	96% *LF > 500 MW*	Not analyzed	Not analyzed	0% *Infeasible flows*	0% *Infeasible flows*	0% *Infeasible flows*
AO2	92% *LF > 320 MW*	59% *LF > 370 MW*	92% *LF > 290 MW*	78% *LF > 330 MW* *Vmin = 0.900*	Not analyzed	Not analyzed	0% *Infeasible flows*	0% *Infeasible flows*	0% *Infeasible flows*
AO3s	92% *LF > 320 MW*	59% *LF > 370 MW*	92% *LF > 290 MW*	78% *LF > 330 MW* *Vmin = 0.900*	Not analyzed	Not analyzed	0% *Infeasible flows*	0% *Infeasible flows*	0% *Infeasible flows*
AO3u	59% *LF > 375 MW*	61% *LF > 550 MW*	32% *LF > 560 MW*	93% *LF > 520 MW*	Not analyzed	Not analyzed	0% *Infeasible flows*	0% *Infeasible flows*	0% *Infeasible flows*
AO4u	**48%**	45% *LF > 330 MW*	48% *LF > 220 MW*	**57%**	Not analyzed	Not analyzed	0% *Infeasible flows*	0% *Infeasible flows*	0% *Infeasible flows*
AO4s	74% *LF > 500 MW*	63% *LF > 530MW* *Vmin = 0.895*	73% *LF > 490 MW* *Vmin = 0.915*	84% *LF > 470 MW*	Not analyzed	Not analyzed	0% *Infeasible flows*	0% *Infeasible flows*	0% *Infeasible flows*

The results of the grid performance resilience model for AO5 to AO8 are shown in Table 9 for corrective dispatch.

Table 9

Resilience Model Results for Architecture Options using Corrective Dispatch for (N-4) – (N-87%)

AO	N-4 (a) 4 gens. out across 2 plants	N-4 (b) 4 critical conting.	N-6 (a) 4 gens. & 2x 230 kV lines out	N-6 (b) *6 lines*	San Juan 38 kV outage	San Juan + 6 circuits outage	N-80% Random failure (a)	N-80% Random failure (b)	N-87% Random failure
	Load served	Load served	Load served	Load served	Load served	Load served	Load served	Load served	Load served
AO5	100%	61%	100%	100%	87% (100% inside enclaves)	87% (100% inside enclaves)	55% (96% inside enclaves)	63% (99.9% inside enclaves)	44% (83% inside enclaves)
AO6	100%	79%	92%	100%	87% (100% inside enclaves)	87% (100% inside enclaves)	55% (96% inside enclaves)	63% (99.9% inside enclaves)	44% (84% inside enclaves)
AO7s	100%	79%	92%	100%	87% (100% inside enclaves)	87% (100% inside enclaves)	55% (96% inside enclaves)	63% (99.9% inside enclaves)	Not analyzed
AO7u	95%	58%	80%	100%	87% (100% inside enclaves)	87% (100% inside enclaves)	51% (91% inside enclaves)	60% (99.9% inside enclaves)	44% (84% inside enclaves)
AO8u	97%	65%	89%	100%	86% (100% inside enclaves)	86% (100% inside enclaves)	56% (97% inside enclaves)	63% (99.9% inside enclaves)	Not analyzed
AO8s	100%	58%	92%	100%	87% (99% inside enclaves)	87% (99% inside enclaves)	87% (99.9% inside enclaves)	78% (99.9% inside enclaves)	58% (94% inside enclaves)

The resilience simulation results are summarized in Figure 20. Resilience is measured by the percentage of load served. 100% is ideal, but during extreme events anything above 0% aids in system restoration. Scenarios that resulted in voltage or line flow violations are bordered in red. These violations could result in protection relay trips, which could lead to a cascading failure and a lower percentage of load served.

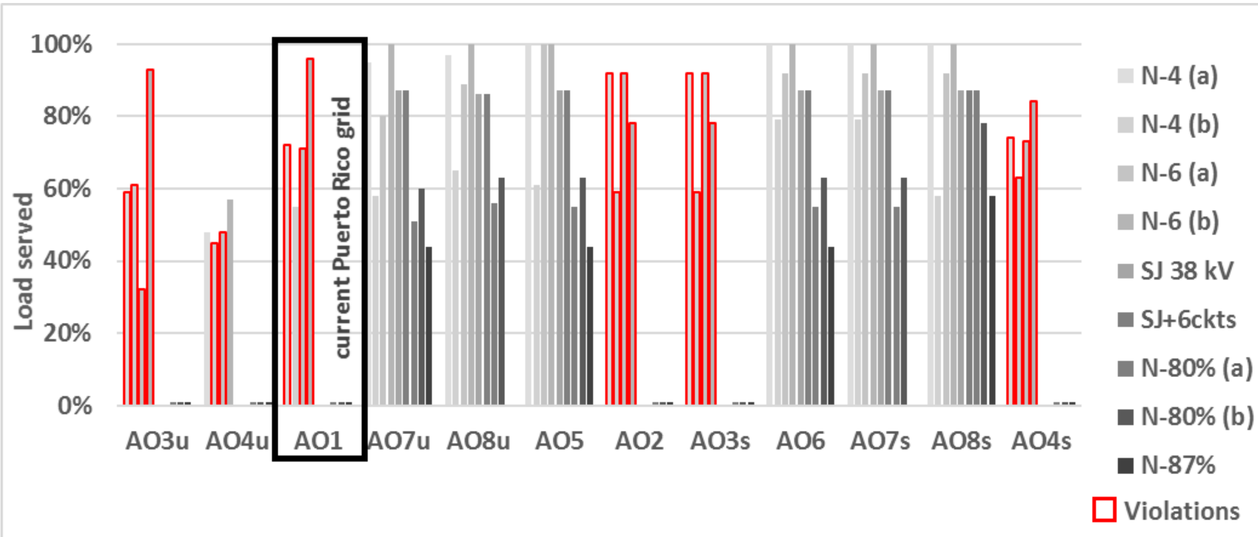

Figure 20. Load served during extreme events by various power grid architectures (ranked by lifecycle cost)

10.1 TAKEAWAY FROM RELIABILITY MODELING RESULTS

We ran N-1 contingency analyses under three different sets of assumptions and found similar critical contingencies in each case, which indicates reliability modeling results are robust. The modeled Puerto Rico system did not serve 100% of the load under every AO for N-1 because either PREPA maintains even more reserves at a higher fuel cost than what was calculated, or the load model used is not fully accurate. An iteration with PREPA engineers would be necessary to refine these results. Note that power systems under NERC jurisdiction failing to serve 100% of the load under N-1 contingencies are considered non-compliant with NERC regulations. However, Puerto Rico does not fall within NERC or FERC jurisdiction and is not required to adhere to NERC reliability standards. Also, we simulated *every single possible combination* of *N-2* component failures on the 230 kV and 115 kV networks. This guarantees that we evaluated the critical contingencies that are likely evaluated by PREPA as part of their system studies.

See Recommendation 2a: Apply Voltage Limits in Contingency Analysis and Recommendation 2c: Utility Extreme Event Analysis.

10.2 CHALLENGES IDENTIFIED FROM RESILIENCE MODELING RESULTS

The large number of "infeasible" entries in Table 8 (shown as 0% load served in Figure 20.) indicate the inability of today's Puerto Rico power system to handle extreme events without operator intervention. (This shortcoming is not unique to Puerto Rico, but is simply a matter of economics. Extra capacity and spinning reserve are expensive.) In these cases, either the system would collapse from the tripping of protective relays or operators would have to take action by shedding load to avoid an overload and eventual collapse of the power system.

These results also illustrate the lack of insight and guidance that operators face when handling extreme conditions. Due to power flow solver limitations, PREPA engineers cannot predict what would actually happen during these events. Electricity travels at the speed of light and inertia in spinning generators lasts only minutes, so when a power system experiences a sudden unbalance between generation, load, and transmission capacity, operators must respond effectively to prevent system collapse. Operators have little time to respond, under operating conditions that they have never experienced before.

See Recommendation 2b: Resilience-based Investment Decisionmaking and Recommendation 2c: Utility Extreme Event Analysis.

10.3 BENEFITS IDENTIFIED FROM RESILIENCE MODELING RESULTS

The most promising result for Puerto Rico—and quite unexpected by our analysis team—was the level of load service still possible under the most extreme N-80% and N-87% outage scenarios, with corrective dispatch implemented. These three scenarios were representative of the damage to Puerto Rico's power system by Hurricane Maria [26]. During the actual storm, 95-100% of people in Puerto Rico lost power; the load service results for AO1 (today's system) matched this experience.

For AO5-AO8, however, the corrective dispatch optimization algorithm naturally formed power enclaves. Figure 21 shows outlines for the six enclaves formed by the corrective dispatch optimization algorithm in AO5. The loads inside these enclaves, 41% of the island's total load, received power within acceptable 0.9-1.1 p.u. voltage limits. The areas outside these enclaves were blacked out due to insufficient remaining power delivery or generation capacity.

See Recommendation 2c: Utility Extreme Event Analysis.

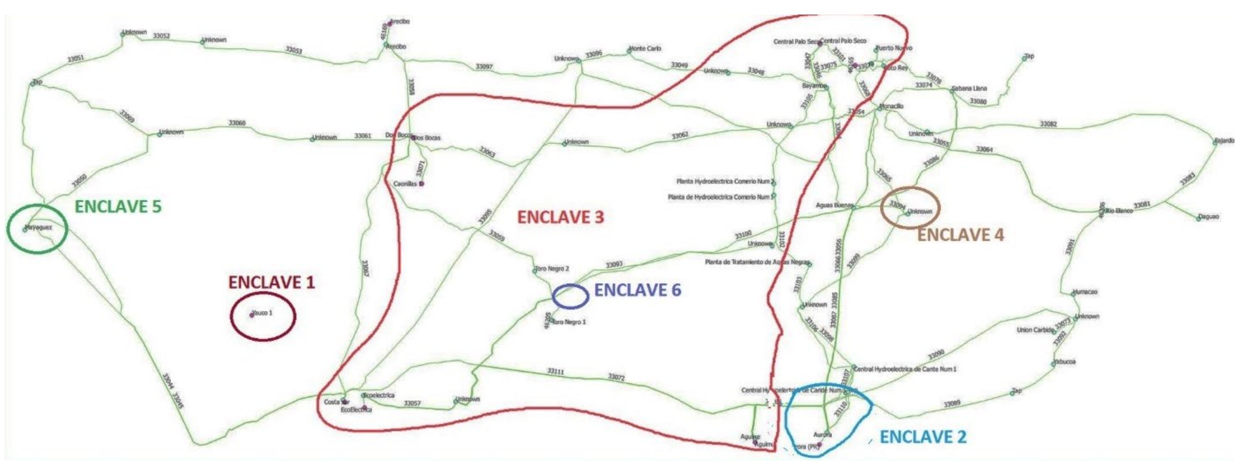

Figure 21. Power enclaves formed by the corrective dispatch optimization during outage scenario N-80%(a)

11. RECOMMENDATIONS

Table 10

Recommendations

Disclaimer: All “impact” metrics are notional, since they are based on simulations using an approximate model of Puerto Rico’s power system created using publicly available GIS data. The costs reflect training and new software enhancements.

Problem	Recommendation	Impact	Cost
1. Grid-tied solar PV provides no resilience	(1a) Require compliance with standard IEEE 1547-2018, with load following capability, to enable resilient solar PV systems.	Community and home resilience	Near-zero
2. Performance under extreme events is not evaluated by grid planners	(2a) Provide tools and training to PREPA operators to apply both voltage limits and power flow thermal limits	Grid operators better identify vulnerable nodes in the power system	< $2 million
	(2b) Use an energy resilience analysis methodology for investment decision-making	Best-value investments made for resilience and cost	
	(2c) Provide tools and training to PREPA planners in performing extreme event analysis	Grid operator gain understanding of likely cascading outages	
3. No decision-making support for grid operators under abnormal conditions	(3a) Demonstrate voltage management using a sidecar in PREPA’s operations center (3b) Demonstrate corrective dispatch software using a sidecar in PREPA’s operations center	3x greater grid control range; $790 million/year grid operational savings; 54% of Puerto Rico with power following Maria-scale damage	< $10 million

Problem	Recommendation	Impact	Cost
4. Today's top-down grid control cannot capture the value of DERs	(4a) Further research implementation of distributed MPC within Puerto Rico's bulk power plants and DERs	$80 million/year grid operational savings	< $2 million
	(4b) Organize a stakeholder workshop on implementing the DyMonDS framework (4c) Further research the DyMonDS interactive framework	$1.04 billion/year grid operational savings; 74% of Puerto Rico with power following Maria-scale damage	< $2 million

11.1 RECOMMENDATION 1A: IMPLEMENT STANDARD IEEE 1547-2018

We recommend that Puerto Rico require that new DERs, such as inverters connected to solar PV, have software in compliance with IEEE 1547-2018 for grid support and the capability to operate while disconnected from PREPA's electric grid. Specifically, per section 8.2.8 of IEEE 1547, PV inverters should be intentional island capable. It should be noted that after hurricanes Irma and Maria, many PV installations across the island did not suffer any physical damage but were unable to provide backup power due to their lack of energy storage provisions and PREPA's anti-islanding protection requirements.

Previous revisions of IEEE 1547 (2013) mandated sensitive trip settings for voltage and frequency so that inverters do not interfere with grid operations. However, IEEE 1547-2018 suggests continuous DER operation under a wider range of voltage and frequency excursions during abnormal conditions. Furthermore, IEEE 1547-2018 explicitly calls for grid support functions that would benefit Puerto Rico power grid resilience, especially during extreme event conditions. These functions include voltage and frequency disturbance ride-through, intentional and unintentional islanding, dynamic voltage and power factor regulation using various types of reactive power control, ROCOF ride-through, voltage phase angle changes ride-through, frequency-droop (frequency-power) capability, inertial response where the DER active power is varied in proportion to the rate of change of frequency, and stabilizing response to frequency disturbances.

We recommend that Puerto Rico also require that DERs—especially solar inverters—per section 8.2.8 of IEEE 1547 are blackstart capable, have load tracking and isochronous control capability. Currently, to operate a PV array in Puerto Rico during grid outages, a battery and system controller are required. However, PV arrays with inverters capable of load tracking and isochronous control can supply a well-matched load completely on their own because these inverters can independently regulate voltage and frequency to a fixed setpoint. These features reduce the cost and complexity of creating resilient, islandable power systems by making batteries and supervisory controllers as optional upgrades to these type PV systems. During a major outage, even intermittent daytime-only power could be lifesaving, especially if paired with critical lifeline loads, like water purification.

11.2 RECOMMENDATION 2A: APPLY VOLTAGE LIMITS IN CONTINGENCY ANALYSIS

We recommend that PREPA apply voltage limits—not just power flow thermal limits—in their power system analyses and planning. This is more conservative than the industry's current approach and is likely to identify vulnerable nodes in the power system. As an example, for AO2 in Table 6, there are 7 critical N-2 contingencies under the standard industry method (thermal limits only), compared to *168 critical contingencies* when both thermal and voltage limits are considered.

11.3 RECOMMENDATION 2B: RESILIENCE-BASED INVESTMENT DECISIONMAKING

For all proposed grid improvements, we recommend that Puerto Rico use the framework of *lifecycle cost* and *system resilience* to compare investment options. This will require PREPA to use a modern power flow solver to evaluate the grid's operation with the proposed improvement under a large number of extreme operating conditions. For system resilience, the metric should be critical load service (MW) following extreme *N-k* grid events.

Figure 22 shows this comparative cost and resilience approach for our example architectures. The results in the bottom chart show the average load served under all the extreme outage scenarios: N-6, San Juan sub-transmission, and N-80% scenarios. These seven events are not a large sample—a statistical analysis should be performed—but they demonstrate the recommended framework for how to assess proposed improvements to the Puerto Rico power grid. Architectures that had more than one scenarios that resulted in voltage or line flow violations are bordered in red. These violations could result in protection relay trips, which could lead to a cascading failure and a lower percentage of load served.

Future analyses should include load criticality in their optimizations. We did not have that information available for this study.

Future analyses should also evaluate an additional east-west 230 kV line from Aguas Buenas to Rio Blanco through an area south of the San Juan urban district, per recommendations in the *Build Back Better* report [28]. This architecture would also add a 20 MW PV facility at the Villa Prades substation east of San Juan, which appeared to be a critical bottleneck in analyses for the other AOs.

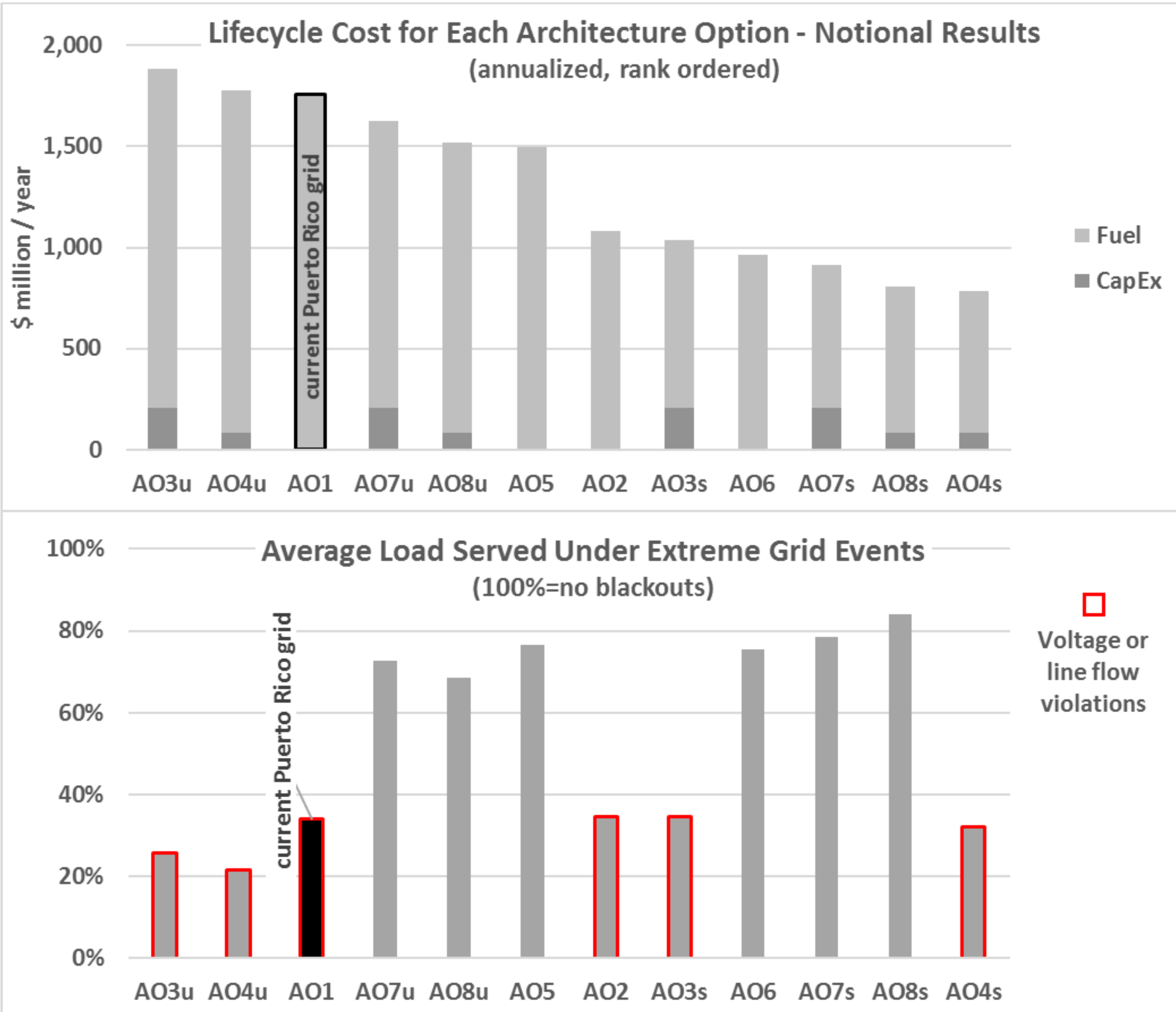

Figure 22. Puerto Rico power grid cost and resilience performance assessment

As seen in Figure 22, **the resilience simulations showed the ability to provide power to 50% of the island, even after Hurricane Maria-level damage.** This highlights the need for Puerto Rico to analyze proposed grid improvements more rigorously than the traditional industry reliability-focused approach.

This analysis approach also identified **significant fuel cost savings—$300,000 to $700,000 per day**—with the same or better resilience to extreme grid events than Puerto Rico's current system. (The exceptions are two architectures with uncontrollable solar PV, which increased operating cost and did not improve resilience.) If PREPA's additional real-life operational constraints are considered, the economic savings will likely be more significant.

11.4 RECOMMENDATION 2C: UTILITY EXTREME EVENT ANALYSIS

We recommend that PREPA perform a statistical analysis of a large number of extreme grid events impacting its power system and that it use those results for informed decision making regarding hardening investments.

Until 2016, NERC transmission planning requirement, TPL-001-00 and -0.1, required evaluation of extreme events only for N-2 scenarios and for local events that affected multiple assets. Although Puerto Rico does not fall within NERC or FERC jurisdiction, consider the following illustrative example: the loss of multiple turbine generators at the Complejo Aguirre or the AES plant, but not both plants and nearby transmission lines simultaneously—scenarios N-4(a) and N-6(a)—even though they are geographically close. These NERC planning requirements are being tightened, and to strengthen the reliability and resiliency of Puerto Rico's grid, Puerto Rico Energy Bureau (PREB) should develop and enforce reliability standards possibly adopting NERC as baseline with adjustments to the local context. Our results show that if Puerto Rico wants to design for resilience, it must analyze a large number of extreme outage events, rather than hand-picking a few. As an example, the two N-6 events had very different results: under scenario N-6(a) AO1 put nearly 30% of the island in the dark, but with N-6(b), only 4% of the load was unserved. Similarly, under the N-4(a) scenario, several architectures only dropped 10% of the load, but architecture N-4(b) blacked out almost 50% of the island.

The N-80% outage scenarios illustrate the same point, but more dramatically. Load service results differed by about 15% between the N-80%(a) and N-80%(b). This represents about half a million people in Puerto Rico being left in the dark.

The DoD's energy resilience analysis methodology runs a Monte Carlo simulation of 10,000 outages [14]. Performing a similar analysis on a bulk power system would have previously been a herculean, mostly manual task, however, the modern power flow solver project now make it feasible.

Identify power enclaves: It should also identify statistically-significant critical nodes that, if hardened, would ensure that enclaves survive around important load pockets, such as urban centers. This statistical analysis should include varying levels of load criticality. The software should also identify the remaining highly dispersed end users who are candidates for community initiatives. **Puerto Rico could use the results of the statistical analysis of extreme events to identify priority areas for proactive hardening and community resilience initiatives.**

11.5 RECOMMENDATIONS 3A & 3B: SIDECAR DEMONSTRATION IN PREPA'S OPERATIONS CENTER

MIT-LL has traditionally tested new algorithms for radars and telescopes using a "sidecar" method. A control box that contains the new algorithm—the sidecar—is installed next to the existing operational control system. The sidecar receives the same exact data inputs as the operational system and presents its results side-by-side with the operational system's results. This allows operators to evaluate the new algorithms' performance in the real environment, without putting the operational system at risk.

We recommend that PREPA evaluate the voltage management and corrective dispatch algorithm using a sidecar installed in PREPA's control center. [12] Our study produced promising results, but these are only from an off-line, steady-state analysis. An operational prototype—one that does not risk existing grid operations—is needed to confirm that these new algorithms work in an operational setting and can provide results within a 5-15 minute dispatch window. NYPA is working to set up a similar system, which PREPA could build upon [17].

To start, a team would need to investigate the cost for the necessary sensors, operation center upgrades, and training. An inventory of voltage control assets and prioritized load shedding capability is necessary for plan implementation. Second, a lab prototype system could be built to control a real-time simulated version of the PREPA grid. This could then be transitioned into a sidecar test in Puerto Rico. The side-by-side operations could quantify the cost savings and reliability improvements of the new algorithms.

A modernized control method could enable PREPA to maintain power to 50% of its citizens, or more, even if another category 5 hurricane struck the island. The results for AO5, compared to AO1, illustrate this dramatic impact on the Puerto Rico power system. Since control improvements are probably implementable using PREPA's existing SCADA hardware, this would likely be the lowest-cost approach, when compared to more expensive infrastructure upgrades.

11.5.1 Recommendation 3a: Sidecar Demonstration of Voltage Management

We recommend PREPA first test voltage management using a sidecar in their control center. Voltage management could save Puerto Rico's ratepayers millions of dollars in avoided fuel costs by more effectively delivering power and reducing spinning reserve requirements.

Optimal voltage management is necessary for effective resource allocation [15], so demonstrating it is a key first step in improving PREPA's control. It is also the necessary first step in the implementation of corrective dispatch. Much can be learned about a physical system's ability to transfer power across large geographical distances, so a side-by-side comparison of outcomes with and without voltage dispatch would be very informative to PREPA operators.

In this study, we learned that the use of AC (instead of DC) optimal power flow is key. It enables the combination of real power dispatch and voltage dispatch, which can triple the control range of a power system (Figure 8). We found that this combination of control makes a major difference in the Puerto Rico power system's ability to solve its power delivery problems over large electrical distances.

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[12] This is the "low-hanging fruit" to improve Puerto Rico's resilience. Slash energy costs and significantly improve resilience by using existing hardware and applying cutting-edge software and algorithms.

11.5.2 Recommendation 3b: Sidecar Demonstration of Corrective Dispatch

Using only existing resources, grid operators would have no response plan prepared to help them select the optimal response to the most minor events studied here. In responding to such an extreme event, *operators would rely on their intuition and experience, under highly abnormal power system conditions*.

We recommend that PREPA evaluates computationally robust optimization software using a sidecar in its control center. This is the first step in PREPA adopting dispatch guidance software that suggest control actions to grid operators to lower fuel costs during normal conditions and prioritize electrical service to critical loads during major contingencies. If any system status logs exist from control center operations during Irma and Maria, PREPA should feed that data into the sidecar to evaluate the benefit of corrective dispatch under very extreme conditions.

These analytic results reinforced the post-Maria evidence that the traditional AC power flow analysis commonly practiced by PREPA and other utilities is not sufficient to ensure reliable and resilient operation. The major reason for this is that analyses require numerous trial-and-error scenarios to find adjustments as system loading and topology change. Today's power flow software is not computationally robust for finding solutions in abnormal conditions.

Instead, a computationally robust optimization software in support of resource allocation is essential. In particular, AC-OPF is needed to ensure proper and safe voltage dispatch. Such software requires a single optimization run, which results in optimal voltage setpoints. As such, it is possible to use it as, at least, an advisory tool to system operators during both normal and abnormal conditions._The same algorithm can identify actions operators can take to establish power enclaves, which would isolate large areas against a cascading blackout.

11.6 RECOMMENDATION 4A: IMPLEMENT DISTRIBUTED MPC

We recommend that PREPA deploy model-predictive controls within DERs and controllable demand, to efficiently smooth out unpredictable renewables. This will reduce the need for fast ramping power plants, such as expensive combined cycle gas power plants. This recommendation is critical if Puerto Rico wants to significantly increase its penetration of renewable resources without increasing the cost of operating spinning reserves.

In this study, we learned that MPC is essential for balancing supply and demand to enable high solar PV penetration without relying excessively on expensive storage. We showed the potential for major savings using simulations; MPC-based software makes it possible to schedule even the slowest power plants in anticipation of predictable solar power generation.

AO3s, AO4s, AO7s, and AO8s show the value of DER that are controllable. For nearly every outage scenario, the architectures with controllable DERs provided better load service than those that acted simply as uncontrollable, negative loads (AO3u, AO3u, AO7u, and AO8u).

11.7 RECOMMENDATIONS 4B & 4C: WORKSHOP AND FURTHER RESEARCH ON INTERACTIVE, DISTRIBUTED MPC FRAMEWORK

We recommend Puerto Rico organize a workshop on using SCADA for interactive MPC and corrective dispatch in grid operations.[13] The DyMonDS interactive framework is a natural evolution of SCADA from today's top down command-and-control centers into a more interactive architecture in which all entities have their own DyMonDS decision making tools, allowing for minimal information exchange needed for coordination. The objective of the workshop is two-fold: First, to share the technical concepts and simulations-based evidence of the potential benefits from using a framework such as DyMonDS for enabling better technical performance and, second, to discuss how to base the regulatory framework using the same principles. Altogether, the workshop would help stakeholders arrive at a joint vision for moving Puerto Rico power systems operations and planning to support resilient and cost-effective clean electricity services. The participating stakeholders and advisors might include PREB, PREPA, US Department of Energy , nonprofits, and researchers from FFRDCs and universities such as MIT Lincoln Laboratory and MIT.

Notably, the framework supports gradual evolution over time. It does not require starting from a green field. As documented, much can be gained in Puerto Rico by adopting this data-enabled operating and planning framework. The next step should be a well-thought-through demo of the value of a framework, such as DyMonDS-enabled operation and planning, for Puerto Rico electricity service, developed in collaboration with PREPA planners, operators, and policymakers.

The timing of recommendation 4 is complicated. Having a framework, such as DyMonDS, in place sooner than later would probably avoid many oversights when rebuilding and enhancing today's Puerto Rico electric power system. On the other hand, it may be simpler to implement recommendations 1-3. A brainstorming workshop based on the findings of this project may be a prudent first step.

We also recommend more research into protocols for implementing a bulk grid that reconfigures during extreme events and emerges into loosely coupled microgrids with their own local generation and storage. We base this recommendation on the instabilities seen in stand-alone microgrids when they are islanded. Current standards for deploying solar PVs are not sufficient to guarantee stable interactions between the main grid and the microgrids, or within the microgrids. The complexity of deploying microgrids that are both robust and economical should not be underestimated. This could be pursued in parallel with staged implementation of the other recommendations made previously.

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[13] An upcoming publication by Ilic and Lessard considers DyMonDS as a more general decision-making tool which would interactively simulate options considered by different stakeholders and help select the ones that best align with societal needs [30].

12. CONCLUSION

This study shows that Puerto Rico's utility engineers and leadership have the ability to improve the affordability of their energy and the resilience of their islands using existing sensing and control assets. When these assets are paired with intelligent software, optimally-controlled DERs, and optimally-dispatch central generation assets, Puerto Rico has significant opportunities:

- Opportunity for roughly $800 million in annual operational fuel savings;
- Opportunity to prevent power outages to 50% of Puerto Rico under Maria-scale damage by forming power enclaves; and
- Opportunity to reduce the industry's overinvestment in spinning reserve, even under high renewable deployment and *N-k* resilience.

In the near term, we urge implementation of recommendations 1a, 2a, 2b, 3a, and 3b. These actions will enable Puerto Rico to implement a world-class power system that is resilient to extreme events and unlikely to see cascading power failures. These recommendations would:

- Require implementing the newly-released IEEE 1547-2018 standard and load tracking control, at a negligible cost;
- Apply modern power flow tools to grid planning, at a cost of under $ 2 million;
- With procedural and stakeholder engagement, apply that same tool to grid investment decision making, at a negligible cost once stakeholders are on board;
- Demonstrate the value of voltage management and capabilities of corrective dispatch, costing under $10 million.

In the longer term, we suggest the implementation of recommendations 4a, 4b, and 4c:

- Implement advanced controls within all DERs in the Puerto Rico power system;
- Overhaul the top-down planning, operating, and control of the Puerto Rico power system to fully modernize it into a robust, distributed system;
- Begin with a workshop and additional research.

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