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Toward DyMonDS Framework for Resilient and Clean Electricity Services: The Puerto Rico Study

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ABSTRACT

This monograph focuses on changing electric energy systems and shows how today's operating and planning practices can be enhanced by relying on data-enabled predictions and decision-making software. In particular, we describe how the Dynamic Monitoring and Decision Systems (DyMonDS) framework can be utilized as a critical unified computer platform for enabling both operations and planning. An extended AC optimal power flow (AC OPF) software designed by SmartGridz, Inc. is used to advise grid operators and planners for managing critical services during hurricanes and other extreme events, and to support the grid enhancement process for decarbonization in Puerto Rico, where many large fossil plants are scheduled for decommissioning. Estimates are given of: (1) about 50% critical load still served during hurricane conditions; (2) 40% total fuel cost decrease; and, (3) reduced requirements for new resource capacity, including microgrids, needed to replace old power

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plants. Based on the approach described, we suggest that huge opportunities exist to make the most out of what we have by deploying these methods in the Continental United States (CONUS) and elsewhere. Instead of pursuing high-cost build-up, we recommended enhancing the utilization of what exists and using data-enabled decision tools to decide systematically, according to well-defined and quantifiable performance objectives, the best upgrades and infrastructure enhancements.

1

Current Operating Problems and Proposed Technical Innovations

Section 1 of this monograph provides a high level discussion of today's operating/planning practices by the electric power providers. This section identifies several problems representing the major road-blocks to reliable, resilient, cost-effective and clean electricity services, and it suggests solutions to these problems. While the illustrations are mainly based on the MIT Lincoln Laboratory (LL) Puerto Rico Report (Ilić *et al.*, 2019b), the problems and solutions discussed are general and applicable to assessing any other utility.

1.1 Current Grid Operations

The industry's current practice 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 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 some detail later in the text.

1.1.1 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. The worst blackouts are triggered by either widespread storm damage or by vegetation management issues that cause random, minor transmission or distribution line failures. Typically, these equipment failures cause protection relay logic to disconnect other overloaded equipment, and lead to cascading equipment disconnects. The history of power outages makes it clear that the current industry practice is incapable of handling hard-to-predict equipment failures.

The industry state of the 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 most critical *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. Puerto Rico's electric service provision company LUMA operates their large fossil-fuel generation plants, transmission network, and distribution network in an effort to meet 100% of the demand even if one or two system components fail. LUMA and other utilities do not currently have the technology or the expertise to prevent cascading power outages during large-scale events.

1.1.2 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 often exhibit counter-intuitive, 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 failures, (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.

1.1.3 High-cost Response to Demand Uncertainty

LUMA 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 have them stand by to respond to unexpected variations.

An extensive 2014 study by Siemens Industry, Inc. (2019) 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 the utility'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, PR utility has implemented constraints on the use of distributed energy resources (DERs) 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 LUMA won't

[1]The assessment assumes $1,100 per kW, 25 year life, 9% discount rate.

accept more" (Webster, 2018). Similarly, Pattern Wind Farm in Santa Isabel has a *101 MW capacity* but *only generates 5 MW* "because LUMA can't handle more" (Webster, 2018).

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 based on 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.

1.1.4 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 automatic voltage regulators, and employing controllable shunt capacitors. Modern DERs also provide voltage control capability at the power distribution level.

Properly selected voltage adjustments can significantly increase the feasible operating range of a power grid. 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 1.1 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.

The non-linear relationship between power transfer and voltage, at thousands of nodes on the power system, makes it virtually impossible for

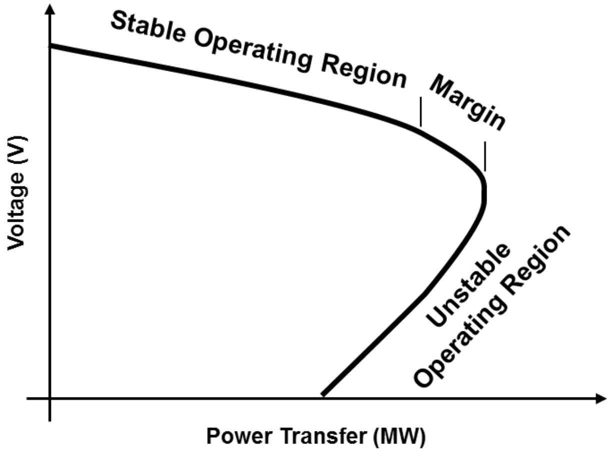


Figure 1.1: Power transfer curve.

a human operator to use intuition to control voltages for system stability or optimal power transfer. Later in this monograph, 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.

1.1.5 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 and thus are likely to crash when faced with more than two contingencies at the same time (N-3, or more). These events generally lead to unacceptably low voltages. Typically used power flow software solves for load receiving voltages, given generation power and grid parameters. It can be seen from the power transfer curve figure that under some conditions, the power flow solution will be on the lower part of the curve. This solution is not physically intuitive because the decrease in power transfer results in the decrease of receiving end voltage. Power flow solvers have numerical problems when attempting to solve for such low voltage operating conditions. With commercial power flow solvers, 25% of extreme event simulations fail to converge (Thomas, 2015), 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 (Chuck *et al.*, 2015) 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 the grid (Oyekanmi *et al.*, 2017; Heyde *et al.*, 2011). As an alternative, LUMA 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.

1.1.6 Today's Grid Control: Preventive Dispatch

Figure 1.2 illustrates current grid optimization control and manual control. The main 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 bulk power system (BPS) operator.

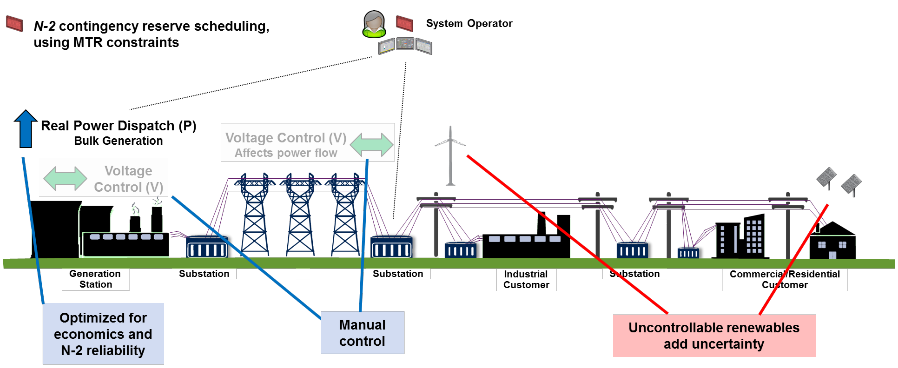
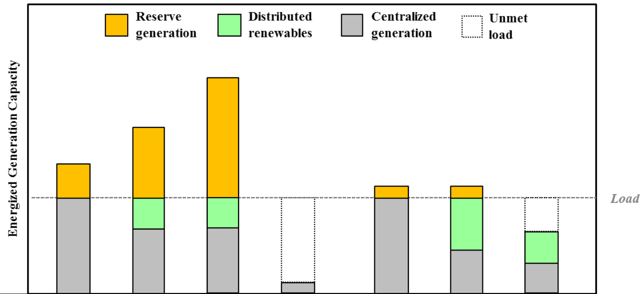


Figure 1.2: Control levers and optimization objectives under today's preventive dispatch method.

Figure 1.3 illustrates the impact on total generation preventive dispatch cost and spinning reserve for four grid operating configurations introduced in Section 2 for PR system (cases 1-4), and compares them to operations with the corrective dispatch introduced later, when discussing cases 5 to 7. An important general observation is that different architecture organization (AO) results in very different reserve requirements. In particular, AO1-AO4 (cases 1-4) require considerably



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 1.3: Traditional preventive dispatch effect on reserve requirements (cases 1-4) (Ilić *et al.*, 2019b).

higher spinning reserve when scheduling is done using today's preventive dispatch, than when on-line corrective dispatch is utilized (cases 5-7). Moreover, today's preventive dispatch generally considers distributed intermittent resources to be negative hard-to-predict load, and, because of this, require higher preventive reserves than when corrective dispatch is done in anticipation of deviations of the resources. It can also be seen that the effect is much more pronounced when attempting to ensure reliable service using preventive dispatch, because reserves are needed for the worst case scenarios. Detailed discussion considering these issues is provided in Sections 2 and 3 of the monograph.

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 reserve shown as the orange 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, the 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 the unmet load (white). Description of Cases 5-7 and the software innovations required to implement corrective dispatch are given in Sections 2 and 3.

1.2 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.

1.2.1 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 (NYC Mayor's Office, 2017).

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 (IEEE Standards Board, 2003) and IEEE 1547.1-2005 (Photovoltaics, Distributed Generation and Storage Energy, 2018). 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 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]

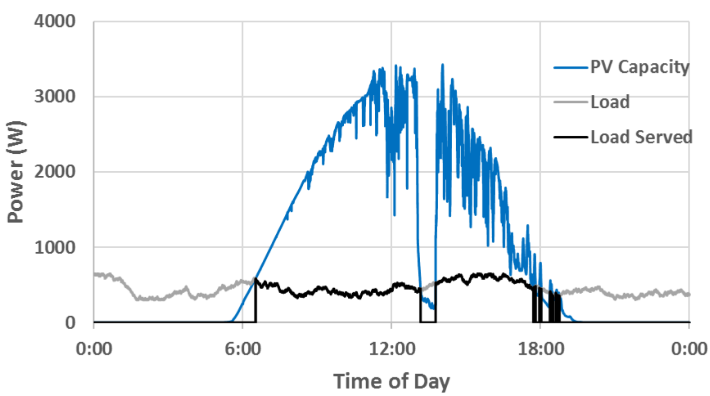


Figure 1.4: Maximum power point tracking (MPPT) vs. load tracking behavior.

[2]Trip on +1.1 p.u./-0.88 p.u voltage deviation (IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems, 2009, Table 1). Trip on +0.5 Hz/-0.7 Hz frequency deviation (IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems, 2009, Table 2).

[3]IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems (2009, Sections 4.4.1 and 5.7).

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 1.4, 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.

More recently solutions to both of these issues and recommendations for their implementation are becoming readily available.

1.2.2 Problem 2: Grid Planning Ignores Performance under Extreme Events

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 (Thomas, 2015). Prior to 2016, NERC required extreme event analysis only for select *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 (Chuck *et al.*, 2015). 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.

In this monograph, we present results from a more robust power flow solver as one of the key innovations needed to simulate, used on several *N-k* resilience scenarios and thousands of *N-2* cases. Our recommendations include automating the process, so that LUMA can perform a statistical analysis of millions of resilience outage scenarios on the Puerto Rico grid (Section 3, and using resilience analysis in LUMA's investment decision-making (Section 1.3.2).

1.2.3 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 5-15 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, and recommend a "sidecar"[4] demonstration in LUMA's control center (Section 2.11.5), where the tool can use real-time data for analysis without interfering with existing operations.

1.2.4 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.

[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.

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 and control framework (Section 1.3.5) 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 (Section 2.11.7).

1.3 Power System Technical Innovations and Applications

The MIT Lincoln Laboratory (MIT LL) team has identified several power system engineering innovations to address the problems the Puerto Rico power grid is facing.

1.3.1 Solution to Problem 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 1.5 illustrates this behavior in red.

Resilient inverters can implement all the functionality shown in Figure 1.5. When the grid fails, they can isolate their local power system while continuing to safely provide power to their local loads.

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

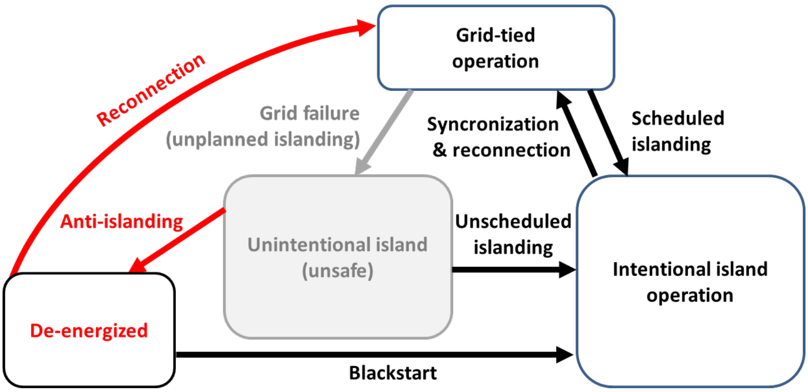


Figure 1.5: Operating modes and transitions for grid-tied inverters (red) and resilient inverters (black).

60 Hz voltage source or follow the 60 Hz voltage source provided by another local DER.

Load tracking

At the time of writing the MIT LL report, there were 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, 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

[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/.

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

irradiance. Figure 1.4 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 1.4) and provides that power when sufficient solar irradiance exists (black in Figure 1.4). If the inverter has this functionality and is paired with an appropriately sized load, then batteries and system controllers become optional.

The new version of IEEE 1547 (Photovoltaics, Distributed Generation and Storage Energy, 2018), 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 types of 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 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 help dampen out frequency oscillations on the power grid.

1.3.2 Solution to Problem 2: Robust AC power flow solver

In the MIT LL study, we used the NETSS AC-OPF solver which is computationally robust, particularly for *N*-*k* resilience scenarios. 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 next. In 2017, the first version of NETSS software was implemented by the New York Power Authority (NYPA) (Cvijić *et al.*, 2017) and the Independent System Operator (ISO) New England verified solutions from extreme event simulations on their power systems (Ilić, 2018b).

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.

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 (Willis and Loa, 2015). 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 (Judson *et al.*, 2016). Figure 1.6 depicts results from one such assessment.

[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.

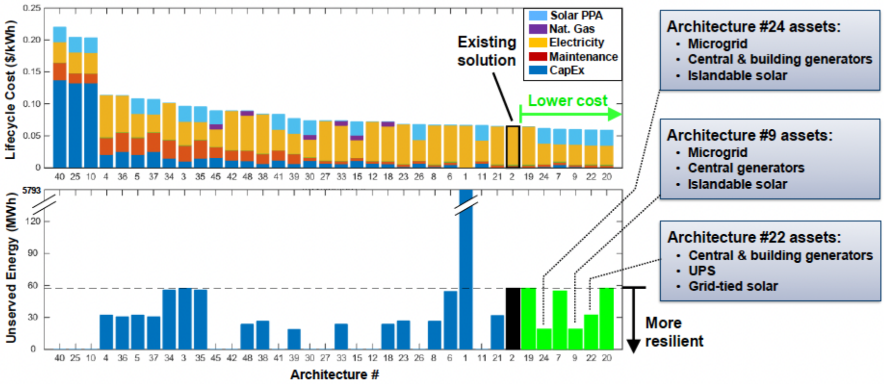


Figure 1.6: Example results from a Dept. of Defense installation energy resilience assessment (Ilić *et al.*, 2019b).

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 1.6 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:

Metric 1: Lifecycle cost: 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: LUMA, 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.

1.3.3 Solution to Problem 3: Extended AC Optimal Power Flow (AC XOPF)

AC power flow analysis is required as a post-dispatch feasibility check to ensure operational viability. Unlike DC OPF, AC power flow does not assume a flat voltage profile, considers both active and reactive power balance, and accounts for system losses by modeling lines with both resistance and reactance. While still linearized around an initial condition, iterative methods are often used that approximate the non-linearity in the system at each iteration.

The AC power flow problem aims to solve for the bus voltages in a power system under steady-state conditions (Glover *et al.*, 2015). It uses the network's physical parameters and the known quantities (such as power injections and demands) to calculate the unknown voltages and angles at each bus. Both basic formulations of DC OPF and AC OPF are reviewed in Appendix A, and are taken from Anton (2024).

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 1.10.

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:

Control mechanisms: As indicated in Figure 1.10, 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 (Ilić *et al.*, 2015b; Ilić *et al.*, 2015a) 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 1.7 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).

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 2.9).

Application: Voltage Management

Voltage management should be an integral part of power grid control. Particularly during extreme events, it is critically important to manage

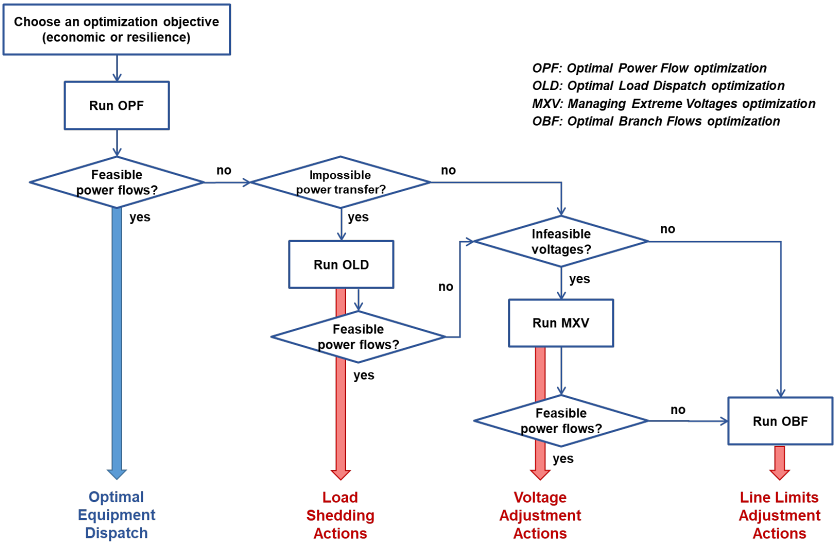


Figure 1.7: Corrective dispatch analysis flowchart (Cvijić *et al.*, 2017).

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 IEEE 1547-2018), transformers and capacitors taps on the delivery system, and demand consumption. An AC-OPF can perform this optimization.

As indicated in Figure 1.2, existing power grid operations only optimize for real power dispatch (P). In Figure 1.8, 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) (Ilić, 2018b; Cvijić *et al.*, 2017) and NYPA (Ilić and Lang, 2012).

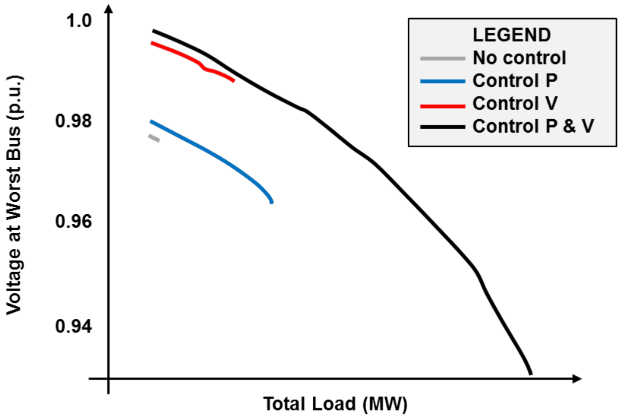


Figure 1.8: Power transfer capability with different levels of control (Texas interconnection simulation).

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.

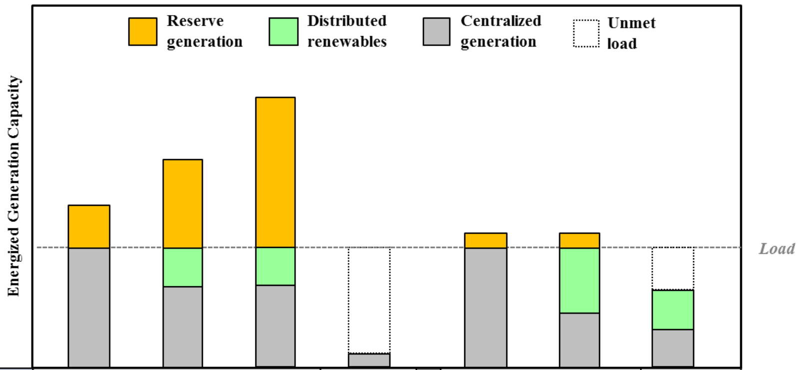
Table 1.1: Optimization objectives.

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. • 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

Corrective dispatch determines asset dispatch commands based on the logic and optimization sub-routines shown in Figure 1.7, while meeting the operating constraints listed in Table 1.1. 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 1.9 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 1.9 Case 2, which uses traditional preventive dispatch.

Full text available at: http://dx.doi.org/10.1561/3100000025



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 1.9: Corrective dispatch effect on reserve requirements (cases 5-7).

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 blackouts—without the need for increased spinning reserves and flow gate reserves. This is illustrated in Figure 1.9, Case 7 (compare with Case 4).

In Figure 1.10, 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.

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 LUMA's control center (Section 2.11.5).

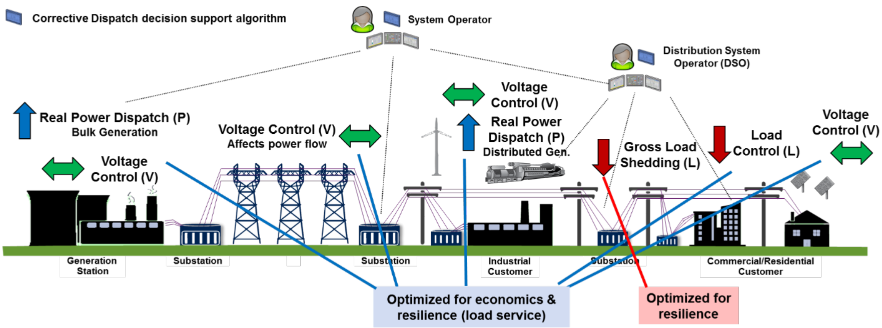


Figure 1.10: Control levers and optimization objectives under the proposed corrective dispatch method.

1.3.4 Solution to Problem 4: Dynamic Monitoring and Decision Systems (DyMonDS) Framework

Instead of just using AC-OPF to dispatch resources from the LUMA 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 the Azores Islands (Ilić *et al.*, 2013).

MIT LL team 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 summarized next. In Section 2, several scenarios documenting potential benefits are described. Notably, the framework is implementable through a deliberate investment in LUMA's supervisory control and data acquisition (SCADA) system.

1.3.5 DyMonDS: 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 Ilić (2018a) the DyMonDS, a theoretically-sound framework that uses price signals (illustrated in Figure 1.11) and hierarchical communications (illustrated in Figure 1.12) 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.

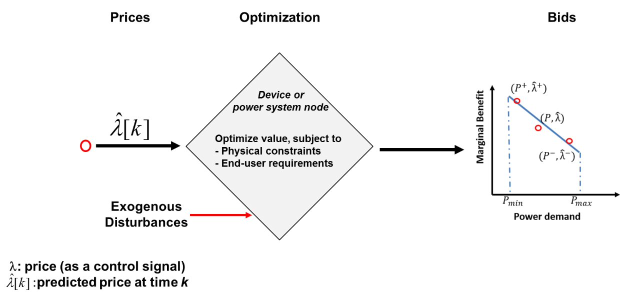


Figure 1.11: Building block of DyMonDS framework: prices and bids are used to communicate control signals and allowable operating region

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 (Ilić, 2018a), including its

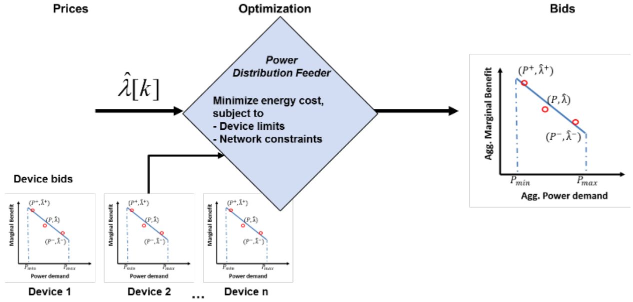


Figure 1.12: DyMonDS hierarchical communications: Power distribution and transmission nodes aggregate bids from lower-level devices, ensuring the system is balanced, efficient, and can be segmented.

implementation, key benefits, and a comparison with existing dispatch rules when applied to integration of renewables.

We applied DyMonDS to the Puerto Rico power grid to demonstrate how LUMA could modernize operations and planning, including coordination with distribution systems and microgrids.[8] DyMonDS simulates minimally coordinated interactions between end users, resources, and the power grid, and enables these interactions so that stakeholders' subobjectives 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

[8]This framework has been previously explored in the 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.

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 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 has 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, the 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, LUMA 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.

Appendices

A

Review of Today's DC OPF and Extended AC OPF

In North America, power system operation is performed by Balancing Authorities (BAs), either Independent System Operators (ISOs) and/or Regional Transmission Organizations (RTOs) (U.S. Department of Energy, 2023). Within these organizations, several functions are required that are divided among different offices, depending on the regional regulatory framework. These include power systems operation, administration of wholesale electricity markets where applicable, and power system planning. These offices are responsible for the generation mix available and their dispatch signals throughout each day (ISO New England, 2023b).

Electricity Dispatch

The way in which generators and load-serving entities interact with BAs vary significantly between operational territories. In regulated territories a single utility company typically controls the generation, transmission, and distribution of electricity. These utilities are monopolies closely regulated by state Public Utility Commissions (PUCs) or Public Service Commissions (PSCs). The utility has centralized control over its power plants and dispatches electricity based on its own system's operational needs and the regulatory guidelines (Environmental Protection Agency, 2023).

In deregulated territories, production, transmission, distribution, and retail are unbundled, creating a need for a market where these services can be competitively auctioned. Multiple markets are needed for adequate operations, with the most prominent being the Day-Ahead Market (DAM) and the Real-Time Market (RTM). In the DAM, Independent Power Producers (IPPs) and load-serving entities submit (typically) hourly bids for each hour of the next operating day. The market is then cleared at every hour based on these offers, with the aim of optimizing the generation dispatch schedule to meet the forecasted demand at the lowest cost while considering transmission and security constraints. Locational Marginal Pricing (LMP) are obtained through this optimization, which determine the price of electricity at different locations on the grid, taking into account the cost of energy, transmission congestion, and losses. On the day of, the RTM is cleared in shorter intervals, typically between 5 and 15 minutes, wherein adjustments to the schedule are made as demand forecasts become clearer (Federal Energy Regulatory Commission, 2023). This allows control room operators to issue dispatch instructions to generators based on near real-time conditions. Market operators then communicate with system operators to ensure all assets are aligned for nominal operating conditions.

Market and System Operators

There is often structural separation between those who operate the power system from a control room and those responsible for administering the markets. This division is designed to ensure that the day-to-day management of the electricity grid's physical operations remains impartial and unaffected by the commercial aspects of electricity trading, where it exists (ISO New England, 2023a). Control room operators are focused on the real-time and near-term operational integrity of the power system. Their primary objective is to "keep the lights on", by ensuring that electricity supply meets demand every minute of the day, maintaining system reliability, responding to emergencies, and ensuring that generation matches consumption while maintaining the grid's frequency and voltage within safe limits. Market administrators are tasked with managing the electricity markets, including the day-ahead and real-time markets, where energy, capacity, and ancillary services are bought and sold. These entities design market rules, oversee market operations, and ensure that transactions are settled correctly. While they operate closely with control room operators to ensure market decisions are feasible from a grid reliability perspective, their roles are distinct to avoid conflicts of interest and to promote transparency and fairness in the market.

Power System Planning

The generation available on the market, whether in a regulated or deregulated territory, must first be approved by a BA for interconnection. This involves an array of studies required to assess what grid infrastructure is needed to support predicted demand. The process yields a Regional System Plan (RSP) or Integrated Resource Plan (IRP) that consider a range of technical and economic factors for multiple future scenarios, often based on interest solicited from market participants, where applicable (Connecticut Department of Energy and Environmental Protection, 2023). IRPs are dynamic and iterative in nature.

Optimal Power Flow for Operations and Planning

Whether system and market operations are separated or a competitive market exists or not, the BA needs to decide on a dispatch signal for all participating generators that will serve the system load. Likewise, planners need to determine the performance of various generation portfolios under specific loading conditions. Planning and operations today mainly determine and assess generator dispatch by solving an approximate Optimal Power Flow (OPC) problem known as DC OPF, and validating with AC power flow. DC OPF simplifies the power system by using linearized power flow equations, ignoring losses and assuming a flat voltage profile across the network. This approximation makes it computationally efficient and has been historically used to optimize the economic dispatch of generation over large power systems with thousands of generation units and demand points.

A.1 Economic Dispatch with DC Optimal Power Flow

The constrained DC OPF problem can be formulated as:

$$\text{minimize} \quad \sum_{i \in \mathcal{G}} c_i(P_{Gi}) \tag{A.1}$$

$$\text{subject to:} \quad P_{Gi}^{\min} \leq P_{Gi} \leq P_{Gi}^{\max}, \quad \forall i \in \mathcal{G} \tag{A.2}$$

$$P_{Di}^{\min} \leq P_{Di} \leq P_{Di}^{\max}, \quad \forall i \in \mathcal{D} \tag{A.3}$$

$$\sum_{i \in \mathcal{G}} P_{Gi} - \sum_{i \in \mathcal{D}} P_{Di} = 0 \tag{A.4}$$

$$\left|\frac{\delta_i - \delta_j}{X_{ij}}\right| \leq F_{ij}^{\max}, \quad \forall (i,j) \in \mathcal{L} \tag{A.5}$$

$$\theta_{\text{ref}} = 0 \tag{A.6}$$

where

- $\mathcal{G}$, $\mathcal{D}$, and $\mathcal{L}$ are the set of generators, demands (loads), and transmission lines, respectively,
- $c_i(P_{Gi})$ is the cost function of generator at bus i, typically quadratic,
- P_{Gi} is the active power output of generator at bus i,
- $P_{Gi}^{\min}$ and $P_{Gi}^{\max}$ are the minimum and maximum P-limits of generator at bus i, respectively,
- P_{Di} is the power demand at i,
- $P_{Di}^{\min}$ and $P_{Di}^{\max}$ are the minimum and maximum P-load at bus i, respectively,
- $F_{ij}^{\max}$ is the maximum power flow limit on the transmission line from bus i to bus j,
- δ_i and δ_j are the voltage angles at buses i and j, respectively,
- X_{ij} is the reactance of the transmission line from bus i to bus j, and

- δ_{ref} is the reference voltage angle, typically set to zero for a reference bus in the system.

The DC OPF model, while valuable for economic dispatch and market clearing, is never physically feasible due to the simplifications made (Baker, 2021). In particular, lines are assumed to be lossless. Only reactance is considered to compute approximate flows. Losses thus needed to be calculated in post processing, and added into Constraint A.4 later. Further, voltages are assumed to be flat (1.0 per unit) across the networks, not accounting for real voltage profiles in the system. Consequently, reactive power, Q, is ignored, which can have a substantial impact in the feasibility of the solution. Lastly, the linear approximation used in DC OPF does not accurately represent the non-linear nature of power system operations, especially under stressed conditions or in systems with significant reactive power flows.

Feasibility Assessment via AC Power Flow

Given these limitations, AC power flow analysis is required as a post-dispatch feasibility check to ensure operational viability. Unlike DC OPF, AC power flow does not assume a flat voltage profile, considers both active and reactive power balance, and accounts for system losses by modeling lines with both resistance and reactance. While still linearized around an initial condition, iterative methods like Newton-Raphson are often used that approximate the non-linearity in the system at each iteration.

The AC power flow problem aims to solve for the bus voltages in a power system under steady-state conditions (Glover *et al.*, 2015). It uses the network's physical parameters and the known quantities (such as power injections and demands) to calculate the unknown voltages and angles at each bus. For each bus i in the system, formulation with polar bus admittances is given by:

$$P_i = V_i \sum_{j=1}^{N} V_j |Y_{ij}| \cos(\delta_i - \delta_j - \theta_{ij}) \tag{A.7}$$

$$Q_i = V_i \sum_{j=1}^{N} V_j |Y_{ij}| \sin(\delta_i - \delta_j - \theta_{ij}) \tag{A.8}$$

where

- P_i and Q_i are the real and reactive power injections at bus i, respectively.
- V_i and V_j are the voltage magnitudes at buses i and j, respectively.
- $|Y_{ij}|$ is the magnitude of the admittance between buses i and j.
- θ_{ij} is the phase angle of the admittance between buses i and j.
- N is the total number of buses in the system.

Buses are categorized based on which two of the four quantities (P - real power, Q - reactive power, V - voltage magnitude, δ - voltage angle) are specified and which two are to be determined. The main types of buses are:

- **Slack (or Reference) Bus:** For the slack bus, the voltage magnitude (V) and voltage angle (δ) are specified. This bus serves as a reference for voltage angles across the system and balances the active power in the system to account for losses. Typically, there is one slack bus per system.
- **PV (Generator) Buses:** For PV buses, the real power injection (P) and the voltage magnitude (V) are specified, while the reactive power (Q) and the voltage angle (δ) are to be determined. These buses represent generator buses where the generator's output real power and terminal voltage are controlled.
- **PQ (Load) Buses:** For PQ buses, both the real (P) and reactive (Q) power injections are specified. The voltage magnitude (V) and angle (δ) are the unknowns. PQ buses typically represent load buses where the consumption of real and reactive power is known.

When a solution to the AC power flow is found, several checks are required that are not considered in the solution. First, while PV buses have specified real power (P) and voltage magnitude (V), we must also check that the reactive power (Q) generated or absorbed by the bus does not exceed the generator's capability. If a generator's Q exceeds its limits, the bus may need to be converted to a PQ bus, to maintain reactive power within its operational limits. Second, AC power flow does not inherently ensure that bus voltage magnitudes remain within their specified limits. Post-solution, it is necessary to verify that all bus voltages are within acceptable ranges. Violations indicate the need for reactive power support or adjustments in operational strategies to bring voltages back within limits.

Similarly, while AC power flow does consider maximum (electrical) power transfer limits, it does not inherently consider thermal or stability limits on transmission lines. Post-solution, line flows must be checked against their thermal limits to prevent equipment damage and ensure stability. If these limits are exceeded, generation may need to be re-dispatched, phase-shifting transformers may need to be utilized, or demand response may be needed to manage flows.

Operators have a plethora of tools at their disposal to arrive at feasible solutions which aid in determining what actions are needed to arrive from one steady state to another. An example of a systematic approach to debugging a solution is the DC-AC Tool in Wang and Tan (2022), a sophisticated tool designed to "achieve a solvable AC power flow case by modifying the power flow condition and then to try to track the AC power flow solution while gradually removing the adopted changes. If all adopted changes can be completely removed, then the original AC power flow solution is obtained. Otherwise, insights into actionable controls are derived to help in operation and planning." A flow-chart of the tool is shown in Figure A.1.

If AC power flow analysis converges and indicates infeasibilities, control room operators have several tools and strategies to achieve a feasible dispatch, including re-dispatching generation, reactive power support, topological adjustments, and demand response. If AC power flow analysis does not converge, determining what steps to take to obtain a feasible solution often requires additional assessment tools like the DC-AC tool shown above, as the AC power flow routine on its own does not provide diagnostic outputs indicating the specific cause(s) for non-convergence.

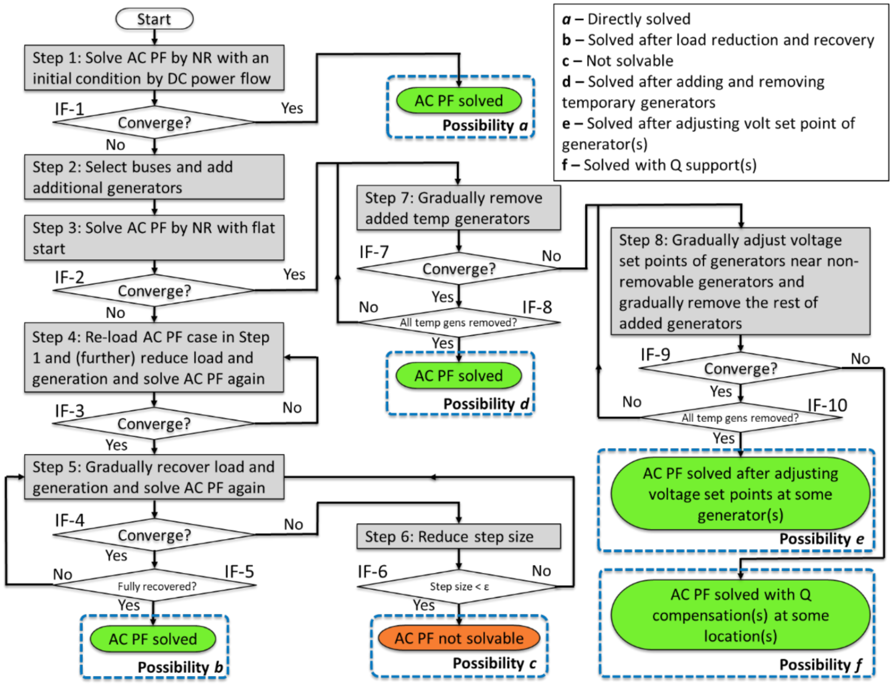


Figure A.1: Flow-chart of 2022 NREL state of the art DC-AC Tool presented in Wang and Tan (2022).

Ensuring feasible AC Power Flow

Procedures for obtaining feasible dispatch signals are often open-ended and may not result in an adequate solution in a given time-frame. In operations, standing reserves are kept to allow flexibility for operators to exercise intervention as needed under stressed conditions. This is often expensive and should be minimized in general. In this thesis, we challenge the use of DC OPF as a basis for operations and planning by using full-blown AC OPF to advise both.

In particular, we seek to address the following research questions:

> "Can AC OPF be used as a basis for physically-implementable, economically-informed dispatch signals, and can these be used to guide optimal control actions, and capacity expansion for decarbonization?"

To answer these questions, we employ an AC OPF software package, SmartGridz, to assess a real-world model of the Puerto Rican grid, created from publicly available data. This platform is used to show how insights from AC OPF can be used, under both convergence and non-convergence. We use active constraints and duality theory to guide optimal control actions, and show how this can be used with a modified model to guide capacity expansion. This analysis is performed for various contingencies and loading scenarios, forming a robust statistical assessment of systemic bottlenecks. We begin with a review of AC OPF models and their uses in academia and industry.

Economic Dispatch with AC Optimal Power Flow

The full AC OPF formulation considers as constraints the AC power flow equations shown in Equations A.7 and A.8. For constrained Economic Dispatch (ED), it can be formulated as:

$$\min_{P_G, Q_G} \quad \sum_{i \in \mathcal{G}} c_i(P_{G_i}) \tag{A.9}$$

$$\text{subject to:} \quad P_{G_i} - P_{D_i} = V_i \sum_{j=1}^{N} V_j |Y_{ij}| \cos(\delta_i - \delta_j - \theta_{ij}), \tag{A.10}$$

$$Q_{G_i} - Q_{D_i} = V_i \sum_{j=1}^{N} V_j |Y_{ij}| \sin(\delta_i - \delta_j - \theta_{ij}), \tag{A.11}$$

$$V_i^{\min} \leq |V_i| \leq V_i^{\max}, \tag{A.12}$$

$$P_{G_i}^{\min} \leq P_{G_i} \leq P_{G_i}^{\max}, \tag{A.13}$$

$$Q_{G_i}^{\min} \leq Q_{G_i} \leq Q_{G_i}^{\max}, \tag{A.14}$$

$$\theta_{ij}^{\min} \leq \theta_i - \theta_j \leq \theta_{ij}^{\max}, \tag{A.15}$$

where

- $|Y_{ij}|$ and θ_{ij} are the magnitude and phase angle of the admittance between buses i and j,
- δ_i is the voltage angle at bus i,
- V_i is the voltage magnitude at bus i,

- P_{G_i} and Q_{G_i} are the real and reactive power generation at bus i,
- P_{D_i} and Q_{D_i} are the real and reactive power demand at bus i, and
- $V_i^{\min}$, $V_i^{\max}$, $P_{G_i}^{\min}$, $P_{G_i}^{\max}$, $Q_{G_i}^{\min}$, and $Q_{G_i}^{\max}$ are the limits for voltage, active and reactive power.

This basic AC Optimal Power Flow (AC OPF) formulation was extended to address more complex and realistic scenarios encountered in power systems operation, referred to as an extended AC OPF (AC XOPF) (Cvijić *et al.*, 2018). Here, we discuss a few formulations.

Extensions to AC Optimal Power Flow

The multi-time horizon AC OPF extends the single-period optimization problem to multiple periods, typically to handle the variability of demand and generation over time. This formulation can include inter-temporal constraints like generator ramping limits and storage dynamics.

$$\min_{P_G, Q_G, \dots} \sum_{t=1}^{T} \sum_{i \in \mathcal{G}} c_i(P_{G_i}(t)) \tag{A.16}$$

Robust AC OPF formulations are designed to handle uncertainty in system parameters. They aim to find a solution that is feasible under a range of possible realizations of the uncertain parameters, such as load, generation, and network conditions.

$$\min_{P_G, Q_G, \dots} \max_{\xi \in \Xi} \sum_{i \in \mathcal{G}} c_i(P_{G_i}, Q_{G_i}, \xi) \tag{A.17}$$

Stochastic AC OPF considers the probabilistic nature of uncertainties in the power system. It typically involves the optimization of the expected cost over different scenarios, taking into account probability distributions of said uncertainties.

$$\min_{P_G, Q_G, \dots} E(\xi \sim \mathcal{P}) \left[\sum_{i \in \mathcal{G}} c_i(P_{G_i}, Q_{G_i}, \xi) \right] \tag{A.18}$$

This formulation includes additional constraints to ensure that the system can withstand a set of predefined contingencies, such as the failure of a generator or transmission line. Each of these formulations adjusts the AC OPF problem to better account for reliability, efficiency, and resilience of the electricity supply.

Alternative Objectives for AC Optimal Power Flow

The above extensions can also be applied to AC OPF with objective functions other than Economic Dispatch. Instead of optimizing over cost functions defined by active power output of generators, one can define costs associated with reactive power output, or apparent power output. Alternatively, one could define soft-constraints in the objective function to find, for example, a solution that optimizes voltage profiles, to minimize load shedding or optimize branch flows in the network.

These alternative objective functions are found in SmartGridz (NETSSWorks), a software package dedicated to solving AC OPF problems (NETSS, Incorporated, 2020). This work employs the SmartGridz platform for solving various optimization problems with two primary formulations: Economic Dispatch for Active (Real) Power, and the Manage eXtreme bus Voltages (MXV) optimization routine, which aims to minimize the deviation away from a range of voltages defined per bus.

The MXV AC OPF can be formulated as follows. Given a set of bus voltages $\{VM_i\}$, lower voltage bounds $\{VL_i\}$, and upper voltage bounds $\{VH_i\}$, the MXV optimization function to be minimized is the sum of individual bus voltage violation costs:

$$\min \sum_i \begin{cases} C_{L_i} \times (V_{L_i} - |V_i|) + C_{Q_i} \times (V_{L_i} - |V_i|)^2 & \text{if } |V_i| < V_{L_i} \\ 0 & \text{if } VL_i \leq |V_i| \leq V_{H_i} \\ C_{L_i} \times (|V_i| - V_{H_i}) + C_{Q_i} \times (|V_i| - VH_i)^2 & \text{if } |V_i| > V_{H_i} \end{cases} \tag{A.19}$$

where C_{L_i} and C_{Q_i} are the linear and quadratic cost coefficients, respectively.

Throughout this work, we use AC OPF with Economic Dispatch and MXV-based optimizations to study the Puerto Rican electic power system. We first set context by detailing key stakeholders, the electric power system and available assets, as well as key recent events as impetus for current policies for grid enhancement and decarbonization efforts.

B

Data Preparation

Public-access Data Repository

The v30 PSS®E format files used for the studies in this report are made available at the following repository for public use: https://github.com/lauanton/puerto_rico_psse_public_data

The sub-folders are dedicated to the analyses presented in the two sections:

- **LL_Report_PartII:** The PSSE files in this folder were generated using the GIS data procured by MIT-LL. The final set of files in v30 format for the different architectures presented in Section 2 of the monograph are provided.
- **MIT_Report_PartIII:** This comprises two different PSSE files used for the two sections presented in Section 3 of the monograph.
  - **Section 3.3** utilizes the file `Base_mod.raw`: This file is generated by altering certain line impedances and voltage settings to make the system data more representative of the real Puerto Rico power system data.

– **Section 3.4** utilizes the file `high HVGrid_v26.raw`: This file consists only of the high voltage system and is used to perform robustness assessment with respect to voltage stability.

This appendix provides an overview of the data preparation steps undertaken to produce files that can be processed by standard power system software to analyse and optimize Puerto Rico grid operations. The raw data was provided in the form of several spreadsheets and .csv format by MIT-LL. This section details the procedure for producing v26 PSS®E format file for use in NETSSWorks' ACOPF software.

The data was collected through multiple GIS software resulting in different variants of Puerto Rico grid data, each of which is suitable for understanding different grid phenomena under normal operations. For simulating extreme grid conditions involving widespread outages, additional data preparation steps were required.

Provided data

For normal operations, the following data files were provided:

- HV DATASET: 'HSIP_GOLD_DATA' is a spreadsheet containing multiple sheets. These sheets included list of nodes, node connectivity, generation and loads as seen by the high-voltage (HV) nodes of the grid.

- HVLV DATASET: Several additional csv files were provided to model the 38 KV grid data. This dataset included the distribution transformers connecting the HV grid to the low voltage grid substation nodes, breakers connecting the low voltage substation nodes to low voltage network nodes, and finally the low voltage connectivity information. 10 m spatial resolution was utilized to generate this data.

HV DATASET had generation and load incidence on HV nodes and as a result the system was not detailed enough to perform the study.

HVLV DATASET however was more detailed but is not complete without utilizing the HV line data from HV DATASET.

Due to the accuracy of HV connectivity in HV DATASET and the loading accuracy in HVLV DATASET, we created a PSS®E format data by combining these two data sets. We believe such a test system is good enough to gauge the relative value of one technical and/or economic policy over the other.

Creation of the PSS®E case files

There are several steps that needed to be taken to process the provided CSV files to generate a PSS®E file suitable for studying the Puerto Rico system. Each of these steps are detailed in the rest of this section.

Step 1: Extraction of required data from Excel spreadsheets and CSV files

Eight different datasets were provided as listed below. Comprehensive information is included in these datasets. However, only the ones in blue were needed to be extracted for the analysis:

- Dataset 1: 'HSIP_Gold.xlsx/Lines' – Line ID, ... From Bus Name, From Bus BasekV, To Bus Name, To Bus Base kV, Resistance (in p.u.), Reactance (in p.u.), Susceptance (in p.u.), ... Line Length (in km)

- Dataset 2: 'HSIP_Gold.xlsx/ Generators': OBJECTID, NAME, LATITUDE, LONGITUDE, Nameplate Capacity (MW), Min Operation MW, Max Operating MW, pf, Fuel

- Dataset 3: 'o38kV_Nodes_****_10m.csv': G3E_FID, circuit, from, to, length[km], R[pu], X[pu], B[pu].

- Dataset 4: 'o38kV_SSandPPandTC_****_10m.csv': SUBSTATION_NAME, G3E_FID, SUBSTATION_NODE, LINE_NODE, LINE_CIRCUIT

- Dataset 5: 'transformers.csv:' SUBSTATION_NAME, G3E_FID, FROM, TO,...

- Dataset 6: 'o38kVRuralSubstationLoads.csv': SUBSTATION_NAME, G3E_FID,SUBSTATION_NODE, MW
- Dataset 7: o38kVUrbanSubstationLoads.csv: SUBSTATION_NAME, G3E_FID, SUBSTATION_NODE, MW
- Dataset 8: 'RuralSSforPV.csv': SUBSTATION_NAME, G3E_FID, SUBSTATION_NODE, MW

The first dataset provides information on HV node connectivity. The second dataset provides information on generation incident on HV buses. Dataset 3 on the other hand provides LV node connectivity. Datasets 4 and 5 provide information on how the transformers and substations connecting LV and HV grids respectively. Datasets 6 and 7 provide information on the rural and urban loads incident of the LV nodes.

Step 2: Assigning default values to missing data entries

This step is to ensure all the required input data exists. There are certain required entries in PSS®E data format which does not exist in the provided spreadsheets. Such data fields and the method adopted to assign the default values are listed below:

- Line thermal ratings: One alternative is to assign unlimited limit (9999 p.u.) to all wires. Alternatively, a configuration file can be provided as an input to assign different line flow limit values to lines of varying voltage levels. The default limits used are 47.7 MW, 227 MW, 454 MW respectively for 38 kV, 115 kV and 230 kV lines respectively.
- Transformer thermal limits: The thermal limits are assigned based on the voltage level using a configuration file. The default ones set are 700 MVA for 230/115 kV unit and 350 MVA for 115/38 kV unit.
- Transformer impedances – One of the two options can be chosen. The configuration file can be fed with an input 'SeimensTfs' to utilize the transformer parameters provided in a Seimens report. Alternatively 'NonSeimensTfs' can be selected which then utilizes

the parameters from a typical ISO-NE system for close enough voltages. It assumes that all 230/115KV Transformers have the same parameters and all 115/38KV transformers have the same parameters.

- Breaker impedances – All breakers were assumed to have the same infinitesimally small impedance values which may can be programmed. The connections with values lower than the set thresholds would lead to collapsing of the adjoining nodes into one, thereby reducing the computational burden.
- Load power factor - Only real power load data was provided in datasets 6 and 7. As a result 0.95 p.u. of power factor is assumed at all the loads to obtain reactive power consumption.
- Categorizing the loads: The loads can be categorized as being priority, critical and interruptible loads by asssigning a pre-defined fraction of total load incident at each substation node respectively.

Step 3: Obtain usable 38 kV power system data

The data files comprise 38kV system extracted from the GIS data. Not all the nodal information is necessary to analyse the bulk power system operation. Thus we first construct the full 38kV system network data from the provided raw data and then obtain a reduced order system comprising only the required 38kV nodes for power system analysis.

Step 3.1: Construct full 38 kV network

- Extract the unique set of nodes by parsing through the from, to field of Dataset 3 and SUBSTATION_NODE of dataset 4. Keep track of these nodes utilizing a mapping variable S_{38KV}.
- The line data in Dataset 3 is then utilized to construct a network incidence matrix A_{38kV} with the the number of rows equal to number of lines and the columns equal to the number of nodes in S_{38KV} (Stevenson and Sebo, 1976). This matrix is sparse and assigns values of 1 or -1 for the columns corresponding to nodes j that each line i connects.

- The data-entires for R, X, B from Dataset 3 are then utilized to construct a network primitive admittance matrix y_{38kV}. This is a large diagonal matrix of the order of number of lines, assuming negligible mutual inductances between the wires. Here each diagonal entry is equal to $\frac{1}{R+jX}$. Furthermore, the breaker impedance values are utilized in place of the provided R, X values in assigning the matrix entries when the provided data is less than the breaker threshold. Utilizing these breaker thresholds helps overcome numerical issues.

- Finally, the nodal admittance matrix for this part of the network is constructed by utilizing the following mathematical formula (Stevenson and Sebo, 1976).

$$Y_{38kV} = A_{38kV}^{T} y_{38kV} A_{38kV} \tag{B.1}$$

Step 3.2. Construction of reduced 38 kV system

Generally 38kV nodes either connect with HV system, have generation and/or load incident. There may few 38 kV nodes with no specific functionality. These nodes can typically be eliminated to reduce the size of the system. Group the nodes to be eliminated in N_{38KV}^{elim} and the rest in N_{38KV}^{retain} based on the S_{38kV} mapping assumed earlier. Let all the node numbers retained be provided a new mapping N_{38kV}.

Apply Krons's reduction to now eliminate the rows and columns indexed by the node numbers in the set N_{38KV}^{elim}. This is computed by taking Schur's decomposition of the complete 38kV system admittance matrix as shown below:

$$\begin{aligned} Y_{38kV}^{red} = \; & Y_{38kV}\left(N_{38kV}^{retain}, N_{38kV}^{retain}\right) - \\ & Y_{38kV}\left(N_{38kV}^{retain}, N_{38kV}^{elim}\right)\left(Y_{38kV}\left(N_{38kV}^{elim}, N_{38kV}^{elim}\right)\right)^{-1} Y_{38kV}\left(N_{38kV}^{elim}, N_{38kV}^{retain}\right) \end{aligned} \tag{B.2}$$

In doing so, the nodes that are not of interest are not just eliminated but the effect of these nodes on the nodes that remain gets captured. The resulting matrix is of orders of magnitude smaller compared to the original admittance matrix.

The resulting matrix is then utilized to reconstruct the line data of the reduced network.

- Every non-diagonal element in Y_{38kV}^{red} corresponds to the existence of a connection between the nodes identified by the respective row and column index. The new row and column index has to be related to the list of node numbers in the set N^{retain}. Based on the inverse S_{38kV} map, these need to be mapped back to the nodes.
- Next, the identified node names for each entry in Y_{38KV}^{red} is used to fill the entries of 'From Node' name and 'To Node' name of a new table corresponding to the reconstructed line data.
- The respective impedance parameters are computed as follows:
  - The resistance is equal to inverse of negative of real part of the matrix element and the reactance is equal to inverse of negative of the imaginary part of the matrix element.
  - If any of the resistances are found to be negative, it is attributed to numerical inaccuracy in computation, and the resistance is set equal to zero.
  - If the imaginary part was found to be negative, it is interpreted as a shunt susceptance that can be included in the line data.
  - Finally, the sum of all entries along a row are computed. If this quantity is non-zero for any specific row, its real and imaginary parts are used to enter a non-symmetrical shunt conductance and susceptance values in the line data. Alternatively, these can be modeled as constant impedance loads to be included in load data too.

Step 4: Create 230/115 KV Transformer data

Only the transformer connecting 115 KV and 38KV network are provided in Dataset 5. The connectivity between 230 KV and 115 KV is identified by the line data in Dataset 1 which had two different voltage levels for the same node names. For nodes with such discrepancy, a duplicate node is created with the same name appended with '_HV' for the one at 230 KV level. Furthermore, a 230/115KV transformer is introduced to join them. A list of 'From' and 'To' nodes is accordingly made.

Step 5: Create the PSS®E file for the study

Step 5.1. Assign node mapping

The unique HV grid nodes are identified by taking unique node names from the HV line data after introducing new node names for the nodes with discrepancy as described in Step 4, in Dataset 1. These names along with the nodes that were retained at 38 KV level are used to form the final mapping S that is used to assign node numbers to each of the node names that will form the network that we will be analyzing.

Step 5.2. Create Branch data

The HV line data in dataset 1 along with created 38KV line data are used to construct the PSS®E branch data. We have information from Step 1 and Step 3.2. of 'From Node' Names, 'To Node' Names, R, X, B, symmetrical shunt susceptance, non-symmetrical shunt susceptance which will form the PSS®E branch data. The 'From Node' Names and 'To Node' Names are mapped to node numbers using the mapping S that was created in Step 5.1.. In addition, the thermal limits are as described by the default parameters in Step 2, will be utilized for 'RATEA' column of PSS®E branch data. 'RATEB' and 'RATEC' are assumed to be 1.2 and 1.44 times RATE A values respectively. RATEB and RATEC quantities get utilized for reliability analysis and resiliency analysis (large outages) respectively.

Step 5.3. Create transformer data

The 'From Nodes' and 'To Nodes' created for 230/115KV transformers in Step 4 and the ones in DataSet 8 are mapped to node numbers using the mapping S and then the PSS®E format of T/f data is made. PSS®E V26 file requires these transformers to also be defined in the line data, for which the thermal limits and impedance parameters as defined in Step 2 will be used.

Step 5.4. Create Load data

The rural and urban loads in dataset 6 and 7 have the names of substation nodes. These are mapped to node numbers using mapping S. The real power is also provided in the respective data files. The reactive power is computed using an assumed power factor provided as input in Step 2.

Step 5.5. Create Generation data

The generation data in Dataset 2 has all node names at which there exist generators. These are again mapped to obtain Bus Numbers based on the mapping S. The minimum and maximum capacity of real power generation exists in the data which can be used to fill the respective entries in PSS®E format. The reactive power limits however are computed using the power factor column in Dataset 2. The ramp rates also for use are filled in using the knowledge of fuel type which is included in dataset 2. The default ramp rates for different fuel types are assumed.

Step 5.6. Create Shunt data

There are pre-specified locations that have shunt capacitors installed. These node names are again mapped to node numbers using mapping S. All of these shunts are assumed to have a constant min and max VAR rating of -14 to 40 MVAR regulating the voltage to stay between 0.9875 and 1.1275. These default values can however be changed.

Step 5.7. Create Bus data

The list of node names used for creating the mapping in Step 5.1. are assessed one by one.

- If the node name exists in the HV line data, the name of the bus is extracted and the respective BASEKV is assigned in the bus data entry. The type of the bus is also set to 1 as default.
- If the node is not found in HV line data, this node is assigned a voltage level of 38KV.

- If the node name exists in generator data, the type of the bus is changed to 2. Largest generation capacity bus is assigned a type 3 to indicate that it is a slack bus.

The node names in the bus data are assigned by extracting only the first 8 characters of the name used for node number mapping in Step 5.1.

Representative daily schedules for different architectures

The load data that is available in the public data is categorized into priority, critical and interruptible loads using a proportion of 15, 15, and 70% respectively. The tapers on the static load data are used to construct the time-varying profiles of these loads. Their hourly variations are shown in Figure B.1. It also includes the net load profiles for the cases when the local and large PV installations are modelled as negative loads. The generation profiles obtained for each of the architectures are further provided in Figures B.2-B.13. For AO5-AO8, the improved grid dispatch is done by utilizing time-varying dynamic bid functions, provided in Figures B.14-B.22. For more details on the bid function creation, refer to Ilić (2018a).

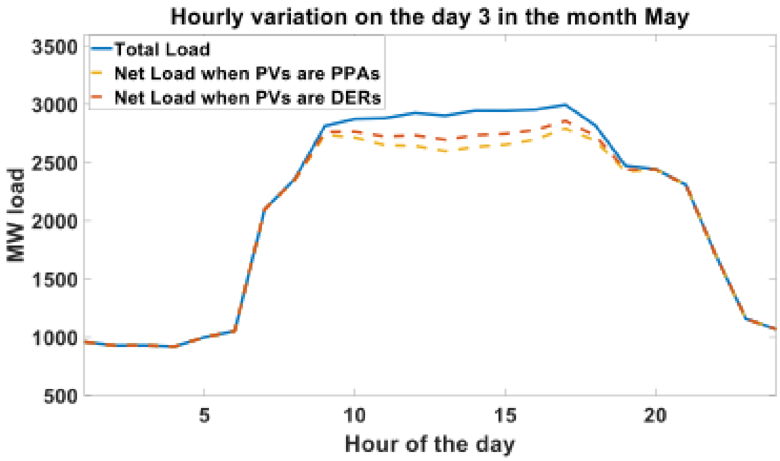


Figure B.1: Hourly profiles of load

Main disclaimer

The findings in this report are illustrated using Puerto Rico electrical power system model created from publicly available data. Because of this, the results should not be taken as being numerically prescriptive. They are notional and are intended for illustrative purposes only. However, we believe that they are based on relatively complete data; every effort was made to relate our findings to the findings in other publicly available technical documents. The system is simulated and optimizations are performed using mainly software donated to MIT Lincoln Laboratory by the New Electricity Transmission Software Solutions (NETSS), Inc.

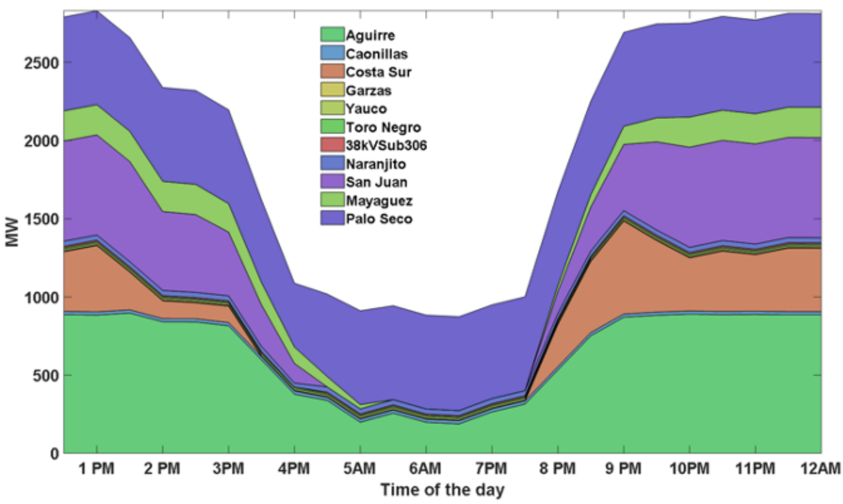


Figure B.2: Power generation schedules with conventional approach (Architecture A01).

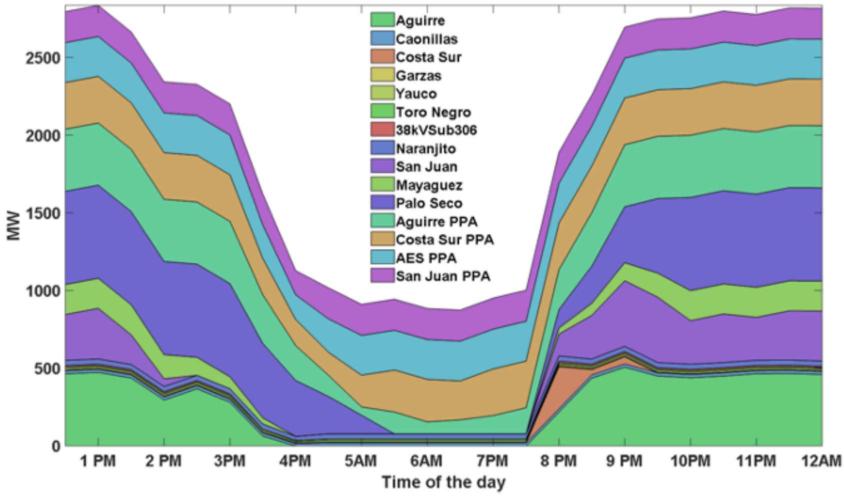


Figure B.3: Power generation schedules with conventional approach (Architecture A02).

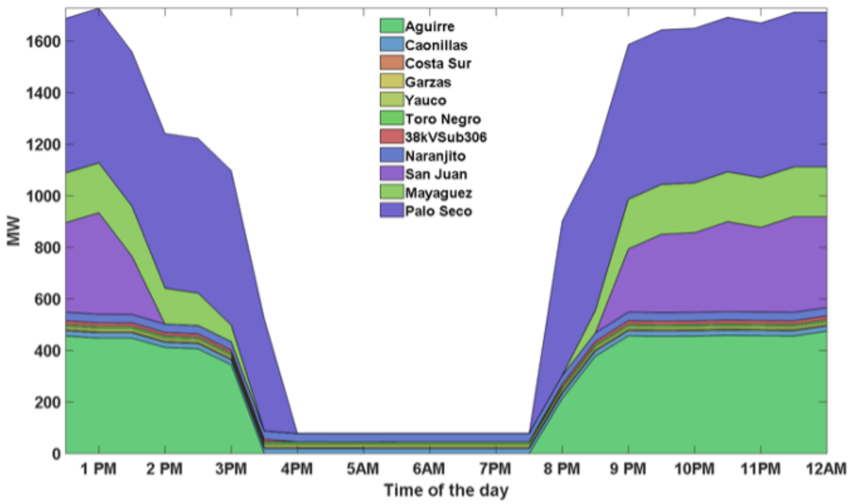


Figure B.4: Power generation schedules with conventional approach (Architecture A03(a)).

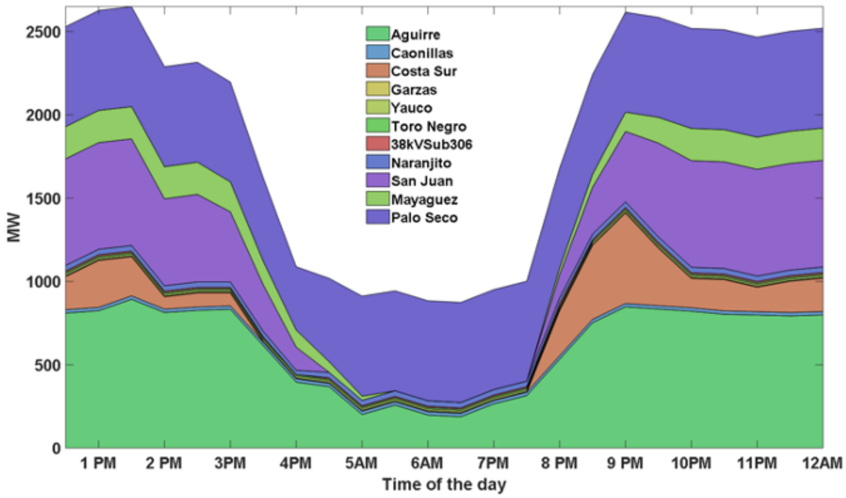


Figure B.5: Power generation schedules with conventional approach (Architecture A03(b)).

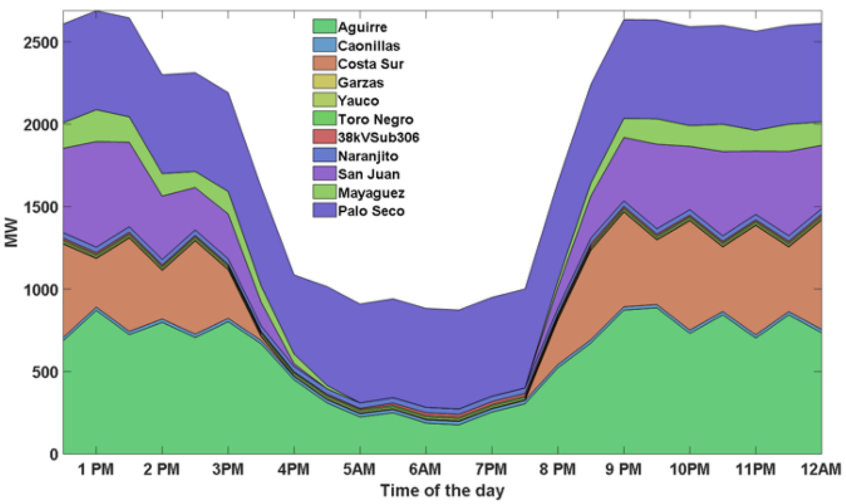


Figure B.6: Power generation schedules with conventional approach (Architecture A03(c)).

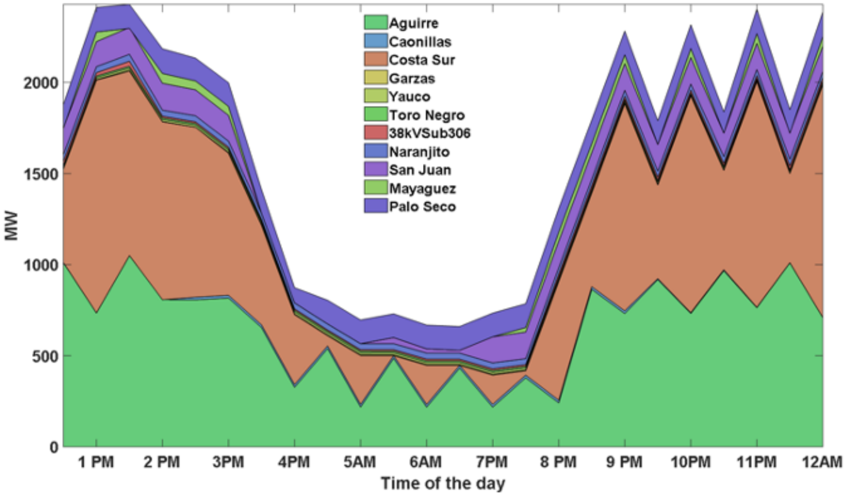


Figure B.7: Power generation schedules with conventional approach (Architecture A03(d)).

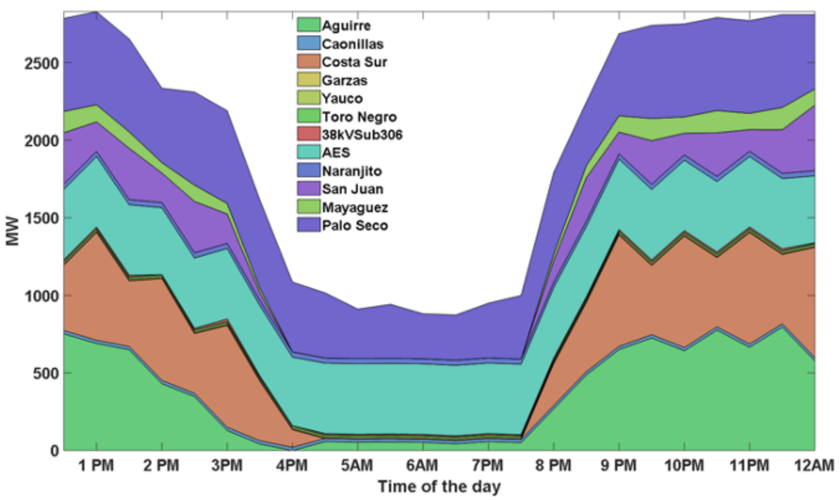


Figure B.8: Power generation schedules with proposed approach (Architecture A05).

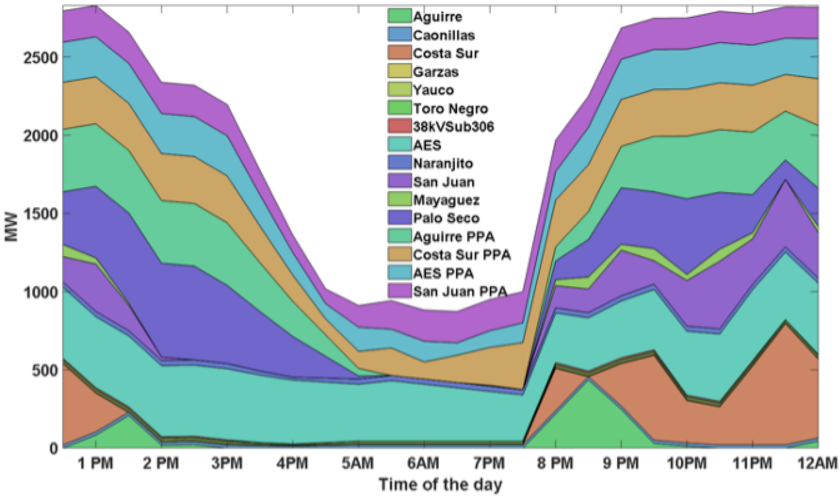


Figure B.9: Power generation schedules with proposed approach (Architecture A06).

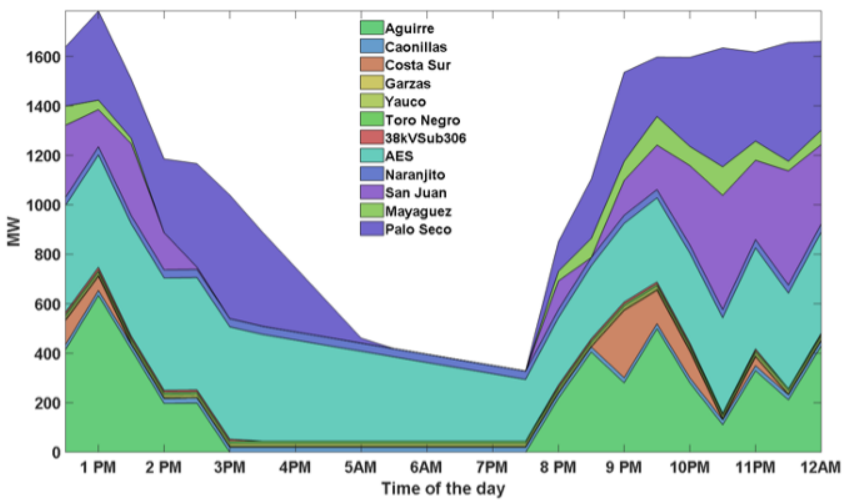


Figure B.10: Power generation schedules with proposed approach (Architecture A07(a)).

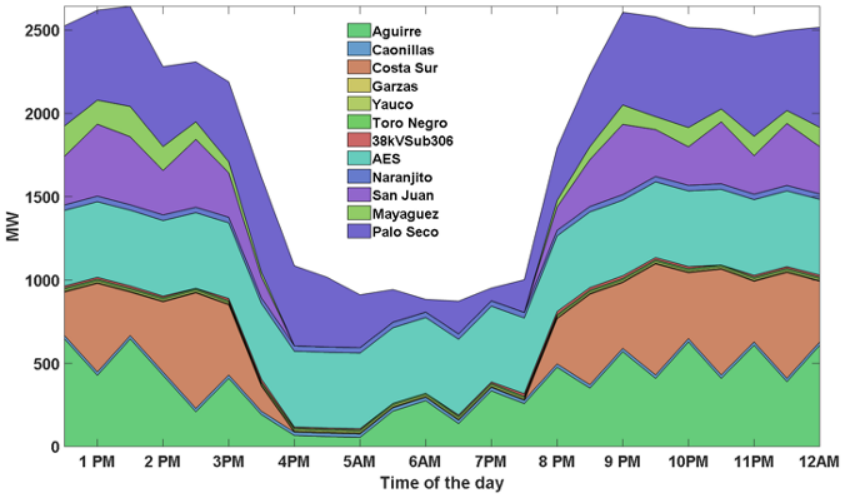


Figure B.11: Power generation schedules with proposed approach (Architecture A07(b)).

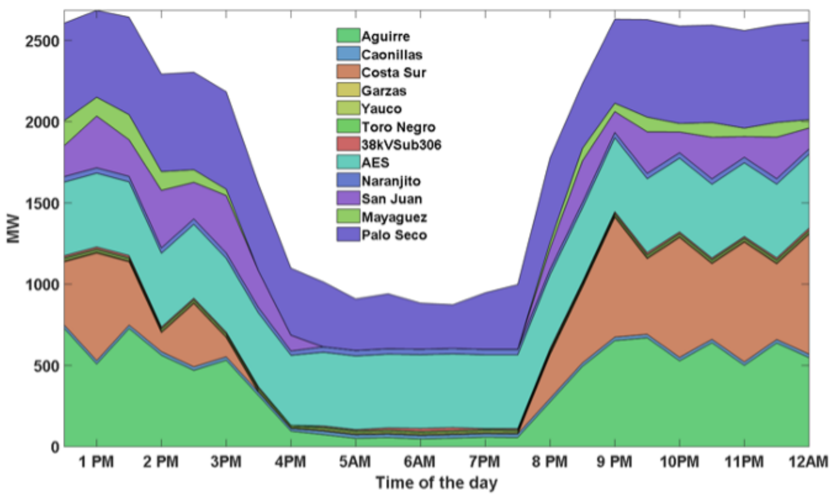


Figure B.12: Power generation schedules with proposed approach (Architecture A07(c)).

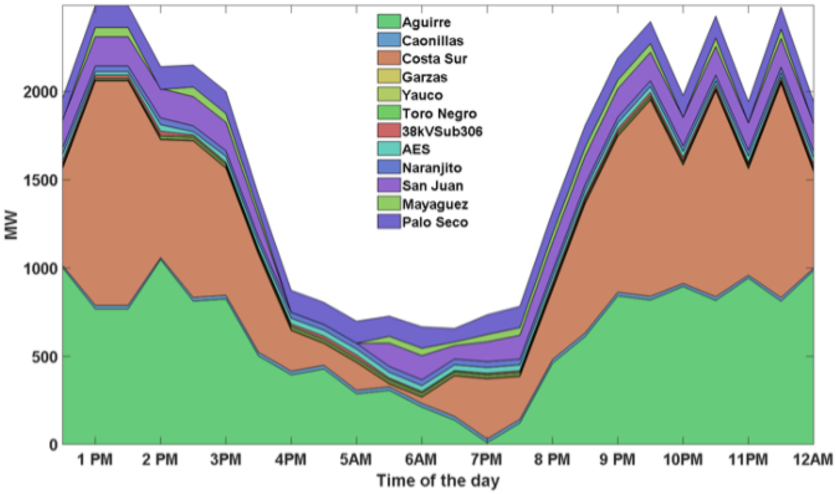


Figure B.13: Power generation schedules with proposed approach (Architecture A07(d)).

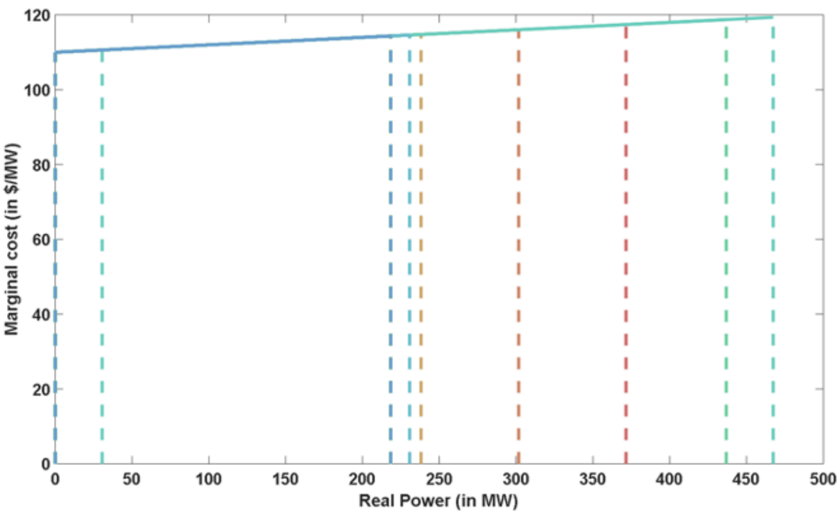


Figure B.14: Time-varying bids of Aguirre generation unit

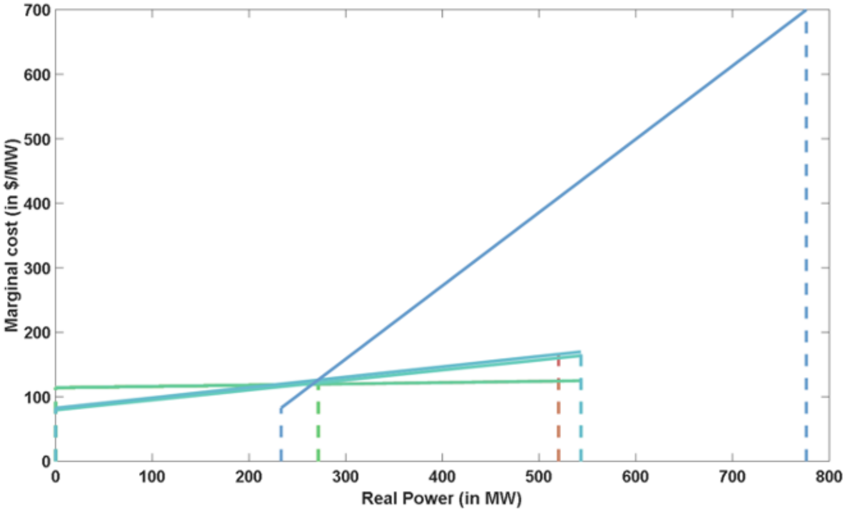


Figure B.15: Time-varying bids of Costa Sur generation unit

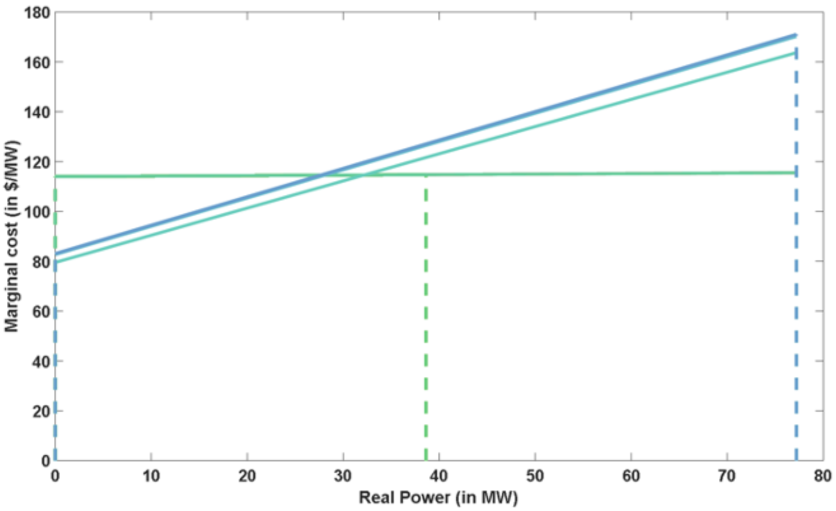


Figure B.16: Time-varying bids of Mayaguez generation unit

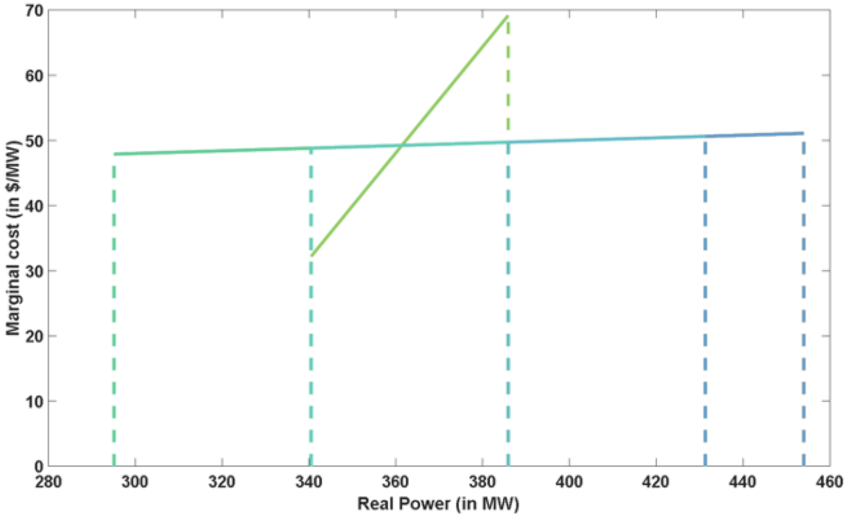


Figure B.17: Time-varying bids of AES generation unit

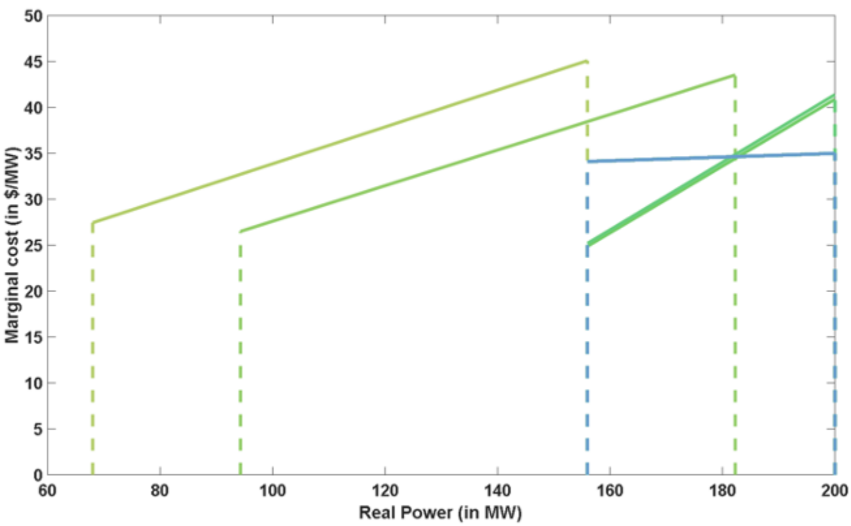


Figure B.18: Time-varying bids of PPA at San Juan

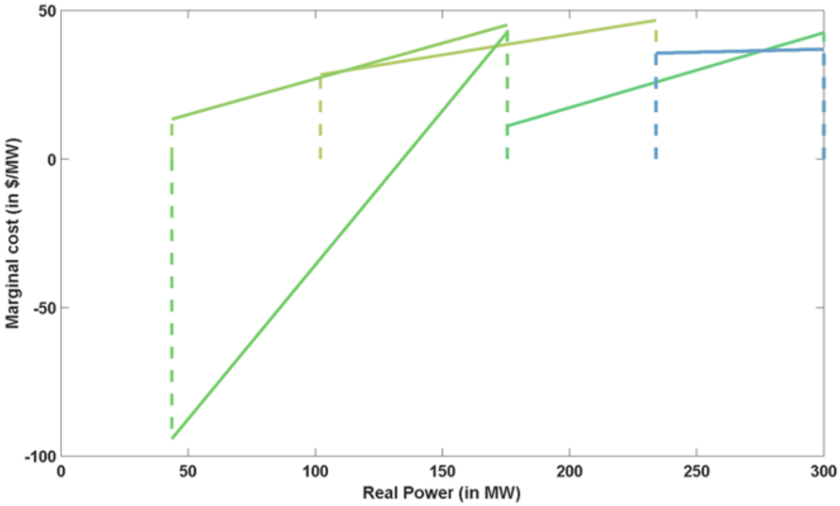


Figure B.19: Time-varying bids of PPA at Costa Sur

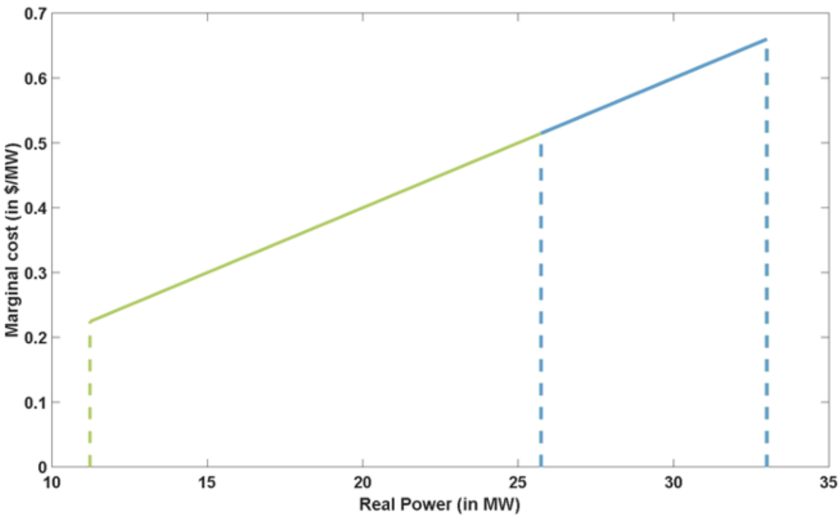


Figure B.20: Time-varying bids of Naranjito generation unit

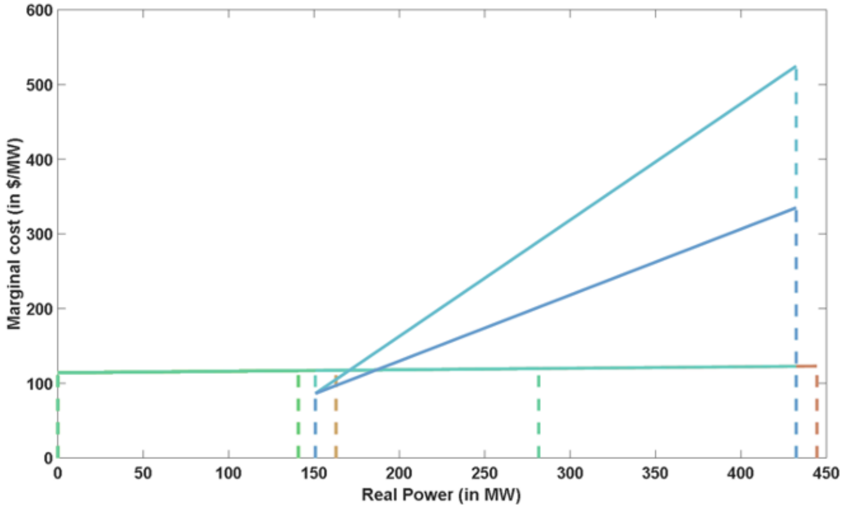


Figure B.21: Time-varying bids of San Juan generation unit

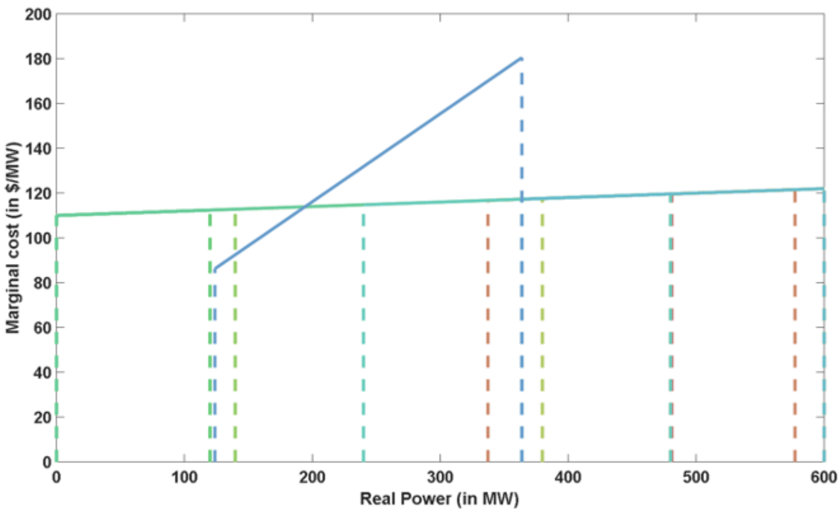


Figure B.22: Time-varying bids of Palo Seco generation unit

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