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Case Studies Applying the Reference Coordination Architecture

August 2026

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Acronyms and Abbreviations

AMI	advanced metering infrastructure
BA	balancing authority
BESS	battery energy storage system
D	distribution
DER	distributed energy resource
DO	distribution operator
DMO	distribution market operator
DSO	distribution system operator
ERCOT	Electric Reliability Council of Texas
GO	generator owner
GOP	generator operator
GW	gigawatt
kV	kilovolts
LDDL	Large Dynamic Digital Load
LEN	logical energy network
MISO	Midcontinent Independent System Operator
MO	market operator
MW	megawatt
NERC	North American Electric Reliability Corporation
SCADA	Supervisory Control and Data Acquisition
SPP	Southwest Power Pool
T	transmission
TO	transmission operator
TSO	transmission system operator

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Reference Coordination Architecture Case Studies

Introduction

To assess the reference coordination architecture, case study modeling will be performed to inform several aspects of coordination between market operators (MOs), transmission operators (TOs), and distribution operators (DOs), and customers or their agents (e.g., aggregators). This will help identify functional gaps that may exist in the RCA (Touhiduzzaman et al. 2026). The results will help refine functional requirements, including the information that actors must exchange, and how these requirements will evolve as increased levels of coordination are achieved. These evolving maturity levels will be referenced as the *Walk, Jog, and Run* phases, each reflecting increasing levels of coordination that can be used to support additional grid capabilities. It is expected that the team will identify and prioritize capabilities that are required during different states of grid evolution to enable a resilient, affordable, and flexible system. Understanding that the architecture will need to be implemented in stages and that jurisdictions may have different objectives and timeframes to modernize their grid, the report exemplifies its value by relying on a series of blue sky, grey sky, and black sky case studies that highlight the benefits of increased coordination. Each case study focuses on modeling prototypical operations, as modeled under the distinct capabilities provided by the *Walk, Jog, and Run* phases, allowing for incremental adoption paths that can be adapted to satisfy distinct timeframes and jurisdiction requirements.

The following case study examples were used to illustrate implementation of the reference coordination architecture and to perform various validations through stakeholder engagement and architectural modeling to assess interactions, interfaces and capability requirements (Yip et al. 2026). The cases will apply techniques based on expectations of near-term and long-term capabilities in stages (i.e., *Walk, Jog, Run*). This staged approach will demonstrate how strategic investment can address long term challenges while meeting near term needs.

1.0 Large Dynamic Digital Loads

1.1 Objective

The objective of this case study is to demonstrate how the reference coordination architecture (RCA) might enable opportunities to spur strategic infrastructure investment and to monetize customer-sited resources on the sub-transmission and distribution systems while mitigating the operational and reliability challenges posed by the operation of Large Dynamic Digital Loads (LDDLs) such as AI data centers. Hence, this case study considers the adoption of LDDL in a power grid and explores potential impacts and opportunities across operational, coordination, and market standpoints.

To achieve the case study goal, this RCA enables a progressive response across three phases: **Walk**, emphasizing energy scheduling, reserve services, and modern situational awareness (transmission-level Supervisory Control and Data Acquisition [SCADA] and distribution-level SCADA); **Jog**, focusing on the rapid deployment of reserve services, enhanced situational awareness (leveraging sensors and advanced metering infrastructure [AMI] data), and precise estimation of participation rates to help manage dynamic system conditions; and **Run**, which achieves advanced grid-edge coordination, with ubiquitous high-resolution sensors for linear state estimation, and effective voltage services to effectively manage challenges created by

LDDL behavior. These techniques are anticipated to relieve congestion on both transmission and distribution, increase reliability, and offer additional revenue and value opportunities for resource owners.

1.2 Case Study Summary

A recent increase in the construction of LDDL is introducing challenges for Transmission Operators and Balancing Authorities. At first glance, it would appear that LDDLs are just large industrial loads (with most LDDLs being 75 megawatts [MW] and above). However, their rapid demand ramps pose unique grid management challenges, especially as some LDDLs have power ramps that exceed hundreds of MW per second. Furthermore, developers have been submitting interconnection applications at an unprecedented and unforeseen pace. In fact, there have been hundreds, if not thousands, of applications very recently in the range of 75 MW–GW scale (DMC n.d.).

A few challenges emerge from this trend. First, transmission development cannot progress at the pace of interconnection applications, resulting in massive interconnection queues. Second, and more relevant to this project, many of these LDDLs execute AI processes that introduce operational challenges not common to other large loads:

- **Sharp ramps:** These have load patterns that exhibit very sharp ramps of very high-power spikes during the inference stage of AI processes, such as shown in Figure 1 (Li et al. 2024; Shehabi et al. 2024) and openly reported by several TOs, such as ERCOT, which recorded instantaneous power drops exceeding 500 MW (NERC 2025).
- **Rapid and uncontrolled disconnection:** Hosting sensitive electronics, LDDLs are easily affected by voltage and frequency variations and are hence not subject to ride-through requirements in the way inverter-based resources are. As a result, regional transmission organizations and utilities, such as Electric Reliability Council of Texas (ERCOT) and Dominion, have reported instantaneous tripping of LDDLs in response to minor system disturbances that led to alarming frequency rises with limited remediation available to the TO (Gooding 2025).
- **Unpredictable behavior as a byproduct of explosive growth:** LDDL interconnection applications have been growing exponentially, and TOs cannot keep up with applications. Connection queues and study procedures are onerous, and capacity expansion and network buildouts may take orders of magnitude longer than the time to construct a LDDL facility. Given the large number of LDDLs proliferating in concentrated areas, operators are faced with scenarios that were not predicted.
- **Congestion and price hikes:** LDDL operation is expected to cause transmission congestion and further increase locational marginal prices, causing electricity price hikes. AI usage tends to increase during evenings, which is concurrent with increased residential load and coincides with night-peak conditions. This will further strain the transmission network.

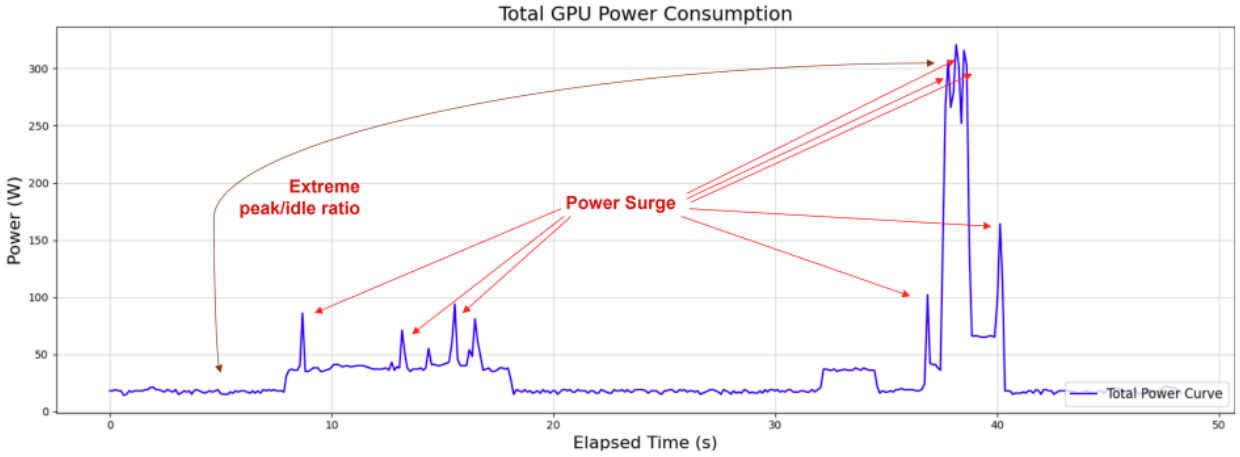


Figure 1. Data center load profile; reproduced from Li et al. (2024)

To illustrate the implications of this trend and evaluate potential solutions, this case study highlights the importance of implementing coordinated operational strategies among MOs, DOs, aggregators, and customers who own LDDLs or distribution connected end users. Key measures of effectiveness for this approach will include affordability, grid reliability, and resource adequacy to enable supplying this growing load category effectively and cost-efficiently.

The conventional (current state) way to deal with large electric loads is to drive infrastructure buildout while ensuring the transmission system is secure (i.e., ensure *N-1* contingencies do not lead to voltage or thermal violations) (NERC TPL-001-5.1). This requires complex system studies and potential capital investment which take years to acquire; processes that cannot be achieved at the pace required to satisfy the rate at which these interconnections need to occur for the US to meet AI and data center development objectives. Additionally, capital investment typically affects energy rates for customers.

In addition, interconnection processes need to be streamlined, including studies that identify system upgrade requirements, such as those introduced by Federal Energy Regulatory Commission (FERC) Order No. 2023-A (2024) for generation resources. These challenges could potentially benefit from a range of market capabilities at transmission and distribution levels, such as those defined by FERC Order No. 2222 (2020). Further opportunities would be enabled when day-ahead and five-minute market signals are present at the retail level, further increasing system coordination through market signals. Distribution pricing could enable the use of power sharing mechanisms in the distribution system to relieve transmission constraints, thereby reducing costs associated with large generation plants and transmission infrastructure. A summary of the RCA different phases is shown in Table 1.

Table 1. RCA characteristics across the different phases

	Current State	Walk	Jog	Run
Goal	Data center increases loading and requires buildout of infrastructure	Distribution supports known or planned transmission constraints through	Distribution sourced service supports dynamic operation of transmission assets and can respond to	Distribution pricing enables power sharing between consumers and/or distribution nodes. This relieves

	and backup power. Unforeseen scenarios are generated.	energy schedules or reserve services.	real-time (5 minute) service requests.	transmission constraints and reduces the cost of energy at both distribution and transmission.
Market Timing	Day ahead	Day ahead and real-time adjustment	Real-time (e.g., five-minutes)	Minutes to sub-minute
Data Quality	Real time substation data only	Behavioral inference	Distribution feeder sensors and leverage AMI	Edge leveraging ubiquitous high-resolution sensors
Market Participation	Demand response	Energy schedule, reserve service	Energy schedule, reserve service with greater precision and participation rate, distribution services	Voltage service

1.3 Actors, Roles, and Requirements

The primary actors responsible for load growth use cases are summarized in Table 2. Note that LDDLs are listed as an actor because they can provide grid services (as a customer) and potentially mitigate challenges created by other loads, including LDDLs.

Table 2. Roles and requirements of different actors

Actors	Roles	Requirements
Market Operator (MO)	Coordinate electricity markets Offer service opportunities and manage grid service clearing process.	Forecast LDDL demand growth and coordinate generation resources to meet peak demand Market policies for flexible load solutions; create ancillary service requirements
Transmission Operator (TO)	Coordinate with MO to procure grid services based on forecasting and real time operation. Utilize market mechanisms to ensure system reliability (voltage/frequency stability) Share state and forecast information related to T&D Node.	Coordinate with MO for market services to enable deferring infrastructure upgrades (lines, auto-transformers, substations). Interconnect and coordinate with LDDLs; participate in transmission and distribution visibility
Distribution Operator (DO)	Share state and forecast information related to T&D Node. Coordinate with TO and MO to validate, and eventually implement distribution grid service programs and markets	Sensing, AMI (2.0), distributed controls, equipment to account for bidirectional power flows, advanced switchgear, and other infrastructure upgrades Implement grid service and policies, refine forecasting methods for load, generation, and weather.
Aggregator	Manage distributed energy resources (DERs), behind-the-meter (BTM) battery energy storage system (BESS)	Coordinate BTM energy storage charge and discharge with TO and DO.

Actors	Roles	Requirements
	Provide grid services	Group DER's according to service capability and offer grid services. Coordinate market validation with DO, TO, and MO
LDDLs	Collaborate with TO and MO to adapt to peak load conditions and provide grid services.	Coordinate on-site load and generation (on-site storage, co-generation) for market participation.

1.4 Case Study Timeline and Model

This case study will be modeled by simulating the coordination architecture of transmission and distribution systems experiencing proliferation of AI-based LDDLs, combined with varying customer behavior. The model incorporates temporal and spatial load profiles, DER response behaviors, grid constraints, and market signals.

By representing different actors' decision-making processes, for example, the DO managing grid operational limits, the aggregator grouping and scheduling flexible DER, and the market operator sourcing grid services based on economic signals—the proposed use case explores potential operational conflicts, inefficiencies, or reliability issues that emerge across both distribution and transmission systems and that are resolved through the RCA. In this case, the integration of LDDLs into the grid presents unique challenges, including their significant and often unpredictable localized energy demands, which make coordination even more critical.

Comparing coordinated and uncoordinated scenarios, the use case demonstrates how timely information exchange, role-based responsibilities, and coordinated optimization across actors can mitigate stress caused by electrification and digitization-induced grid impacts. The results are expected to highlight the critical need for actor collaboration in future grid operations to address dynamic and rapid load growth sustainably, reliably, and affordably.

1.5 Walk, Jog, Run Scenarios

Walk – A Walk scenario will be characterized with moderate proliferation of LDDLs on the transmission network, with TOs experiencing challenges related to LDDL ramping and lack of ride-through, resulting in issues with grid frequency. Localized congestion and voltage violations are often determined by using the transmission state estimator (hybrid or linear), addressed reactively, and distribution assets and edge devices are operated using traditional load estimation models, i.e., behavioral inference and forecasting. Aggregators participate in wholesale markets (e.g., scheduling a reserve service for the day-ahead market, or signing up for on-call services, such as Emergency Demand Response), with basic grid services using broad, non-targeted signals, providing energy schedules or reserve services, and resulting in limited flexibility.

Jog – The increased prevalence of LDDLs causes the bulk system to experience variable and localized voltage problems, and system-wide frequency problems. The scenario envisions that the challenges identified above are exacerbated. The TO is expected to have increased observability via linear (phasor-measurement-unit-based) state estimation that includes the transmission system and substations. The TO will identify active and reactive power setpoints desired at each boundary node through the T&D visibility module, which is provided to the DO.

Based on bids received, the TO performs a network constraint analysis using DO's relevant operational data through the T&D optimization module and provides MO transmission constraints. The DO will have feeder observability to enable operational validation. This visibility will come from sensors providing high-quality power, voltage, and frequency sensing at SCADA rates, and will also leverage AMI, which can be refreshed every 15 minutes or better. The DO will utilize DER availability (received from Aggregator) and its own operational data to create a new forecast through the T&D node visibility module. Through the T&D optimization module, the DO will receive cleared bids from MO and boundary conditions from TO as inputs, and after its operational validation will provide the Aggregator operating envelopes. Market participants in the day ahead and load following real-time (five-minute hour ahead adjustments) can align their operations with distribution system priorities, also responding to dynamic signals (location-specific) based on feeder-level load conditions, sensed parameters, and system needs, ensuring services do not affect distribution-level power quality. Grid services related to grid congestion are dispatched proactively based on market signals and forecasts generated in the minutes-second timeframes.

Run – In the Run phase, the grid must contend with exceptional prevalence of LDDLs. Even with adoption of co-generation and energy storage, LDDL load patterns are more unpredictable and require multi-prong solutions. Enhanced visibility, real-time edge computation, and distributed computation enable accurate distribution load forecasting, active coordination among neighboring feeder segments, and distribution-level pricing to optimize and relieve both transmission and distribution constraints and reduce energy cost. Decision making processes leverage quasi-real time data (two seconds or less), encompassing TO linear state estimator, edge measurements, and ubiquitous high-resolution sensors on distribution that enable real-time visibility and distribution state estimation. Wholesale and retail MOs operate in the minute and sub-minute timeframe to ensure fast response and event management (subject to communication limitations). Customer participation in the frequency regulation market is expected, in addition to participation in distribution-side grid services. Where suitable, distributed controls will enable distribution customer load operation in intentional island modes with adaptively delineated boundaries, to alleviate transmission grid congestion. This case study examines how executing this architecture in a distributed way might result in distribution-side grid services having the effect of mitigating the LDDL associated grid problems via advanced market coordination. Distribution locational marginal pricing is calculated, and resources are shared among customers connected to various feeders or portions thereof, effectively reducing electricity cost to all and mitigating peak load challenges at both the transmission and distribution levels.

1.6 RCA Characteristics in the Walk Scenario

Managing AI-based LDDLs creates a challenging scenario that primarily impacts the transmission system and requires coordination with distribution systems in the reserve service market. This case study simulates multiple aggregators managing flexible resources in response to bulk system events.

A scenario was created where these resources provide services in both wholesale and distribution markets, with at least one market participant offering multiple services across different operational layers. LDDL may limit ramps by dispatching co-located generation, where existing and available, or energy storage (subject to capacity/state of charge). Currently, there are a few jurisdictions with interconnection requirements for co-location of generation or storage. However, if such requirements exist, any co-located generation plants should be used to manage ramps and to counter-act LDDL load drops (islanding). This usage should be limited,

as they can be exposed to stress and subsequent damage, whereas transmission connected energy storage may be more suitable to the task if configured and controlled (Ross et al. 2026). While this may become a future trend, today's LDDL do not use these technologies to mitigate these issues. Nearby independent generation plants or energy storage systems may participate in the reserve and/or capacity market to regulate frequency, but this type of support to LDDLs is still a new paradigm.

The second objective is to demonstrate system reliability leveraging aggregated edge resources. Energy and reserve services will be used to mitigate ramp and load drop effect by aggregated distribution edge resources. Market participant bids will need to be validated through coordination processes where TOs and DOs jointly assess system constraints and engage MOs to request customer grid services. A bid for reserve service (either day-ahead or emergency demand response) that appears feasible from the transmission system's perspective may pose operational issues in the distribution system. Conversely, distribution system flexibility sourced by DOs can be coordinated with TO to help mitigate transmission system stress through T&D node visibility.

- **Transmission System Impacts:** AI-based LDDLs introduce high peak demand spikes and unpredictable consumption patterns that strain transmission capacity and resource allocation. Further challenges arise from their inability to ride through disturbances, dropping and creating system-level frequency challenges.
- **Distribution System Impacts:** By supporting transmission-level grid services in response to MO, TO, and DO needs, edge devices can create local voltage problems that must be managed.

In this use case, TOs can coordinate directly with DOs—for example, through the *transmission and distribution node visibility* module—to better understand constraint. MOs will provide market opportunities to engage DERs in the distribution network as a way to manage forecasted drops and peak demand spikes caused by LDDLs. For example, flexible DER dispatch could be used to increase load consumption (BESS charge commands) or reduce it (BESS discharge commands), thereby coordinating with TOs to schedule their operations strategically to reduce strain on the transmission network. Aggregators will craft bids to provide these transmission services, which may be procured as a wholesale service in the day-ahead market or increased prices could be offset through distribution programs. LDDLs are large enough that they can participate in the wholesale market directly to support others and, if they have generation, real-time dispatch of co-located generation is procured at the spot price to adjust to demand. Figure 2 illustrates the process flow for the Walk phase.

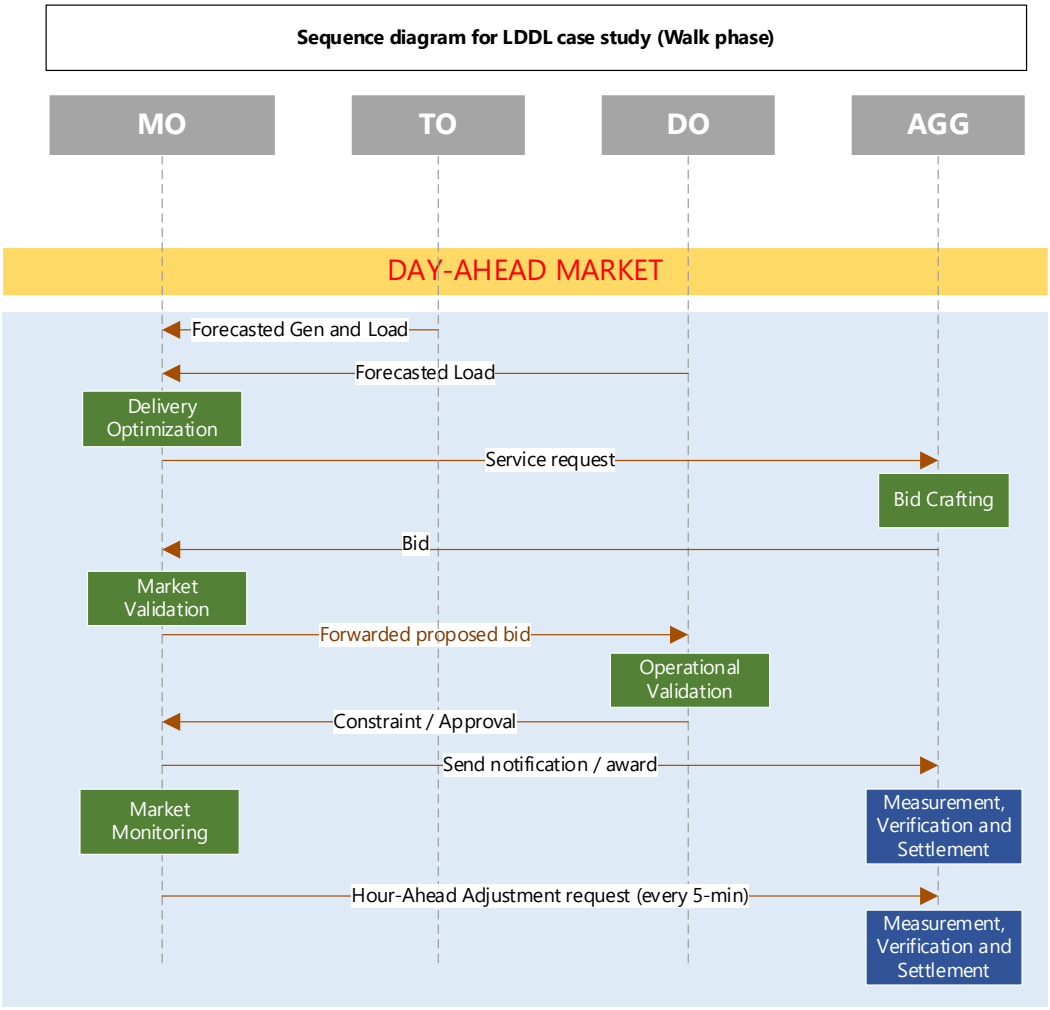


Figure 2. Process diagram for the RCA during Walk phase

In accordance with these needs, this phase is expected to rely on the modules shown as green boxes. A description of how these modules are activated and used is provided below.

- *Delivery Optimization module*: activated by the MO and intended to identify and parameterize the service required. The output is the service requirements.
- *Bid Crafting module*: activated by the Aggregator in response to the service request and leveraging the DER registry, market participation rules, and T&D optimization constraints. The output is a bid package.
- *Market Validation module*: resided in the Market Clearing House, it is activated by the MO to verify market participation rules and prevent market conflict and dual participation. The output is an approval or rejection.
- *Operational Validation module*: activated by the DO using as inputs the bid, DER registry, and operational forecasting and constraints. The output is an approval or identification of constraint violations.
- *Market Monitoring module*: activated by the MO, this module continuously monitors the status of the market.

- *Measurement, Verification, and Settlement function*: performance monitoring of the participating DER.

In summary, during the Walk phase, the RCA satisfies its architectural principles (e.g., scalability, observability, resilience-by-design) by 1) Facilitating access to extended grid information from an increasing number of sensors and DER devices to enhance visibility, 2) Facilitating coordination and data sharing between different entities; 3) Enabling DERs to participate in grid support functions; and 4) Continue to support resilient, predictable day-ahead market operations. These capabilities can be further enhanced by leveraging resilient communication networks to ensure aggregators can actively participate in service offerings and enhance system response where LDDLs proliferate.

1.7 RCA Characteristics in the Jog Scenario

In the Jog scenario (5-10 years ahead), real-time market (five, 15 or 30 minutes ahead) will enable service identification and requests by the market operator, introducing a layer that caters for any uncertainty resulting by the conventional day-ahead and real-time markets). Furthermore, distribution services evolve beyond programs, which will enable DOs to procure these services through MOs to satisfy localized distribution system needs. Markets might have adapted to host aggregators in the real time market, receiving bids prior to the scheduled time, and will be called upon by the MO based on their operational plans every five, 15, or 30 minutes in response to this real time service identification and request. The energy value provided by aggregators will be evaluated considering distribution LMPs and factored into their bid evaluation.

At the same time, in the Jog timeframe LDDLs will become much more prevalent given the recent government proposed rules that target expediting their interconnection, in addition to growing market opportunities (U.S. Department of Energy 2025). Today, system operators and industry groups are still trying to understand and craft reasonable interconnection standards and are exploring possible market opportunities and revenue streams that can be enabled by the capabilities such as the one proposed in this document.

Transmission solutions housed in GETs and ATTs, such as power flow controllers, will be part of the TO grid management to handle grid congestion and voltage oscillations caused by fast ramps, but these technologies are expensive, and the effectiveness of these solutions is localized near their installations. Part of the broader solution requires market participants to coordinate their operations and capabilities to reduce the need for capital investment through optimization.

By increasing the maturity of grid services available at the TO and DO, any rate increases may be offset by incentivizing customer participation into market. Required transmission services will be issued considering both the expected and unexpected behavior of LDDLs into the day-ahead market, and bids will be received from aggregators to manage these expectations:

1. LDDL behavior that causes slow frequency rises, or voltage deviations over several minutes will be managed by the RCA. For example, the TO will alert the MO of the service need (load increase), which will engage location-specific aggregators to respond accordingly through the real time market.
2. LDDL rapid ramps will have to be managed at the interconnection level by employing power quality measures that may include co-located generation response, energy storage or interconnection-driven FACTS devices. However, the effect of these load additions can

result in longer-term overall load increases or decreases due to likely operation of energy storage co-located with these facilities. In a similar fashion to the point above, real-time market can be used to manage the need.

Aggregators responses must be validated to ensure edge resources won't cause operational violations. DOs will monitor availability and performance of resources to prove grid services by leveraging AMI measurements in various points across distribution feeders. AMI data will also be leveraged to provide situation awareness through hybrid distribution state estimators, which will include other sensors (e.g., those in capacitor banks and voltage regulators) to perform a hybrid estimation calculation and activate distribution feeder observability. This will be a requirement for the distribution operational validation, which will estimate voltage and thermal violations in the distribution grid during bid evaluations. Shared T&D node visibility will include forecasting to aid in optimization at that interface.

Voltage and frequency regulation services will be crafted into bids. Voltage fluctuation mitigation capability will be provided by the aggregator as part of its bid offer. It is not expected that oscillations will be completely mitigated because these are observed at the transmission level, whereas edge resources are connected far away and may not have the intelligence nor the access to the telemetry need to mitigate them. Distribution voltage service can also be procured to support voltage impacts at the edge including those excursions due to providing other services to support the grid services provided at the T&D node. Figure 3 illustrates the process flow for the Jog Phase.

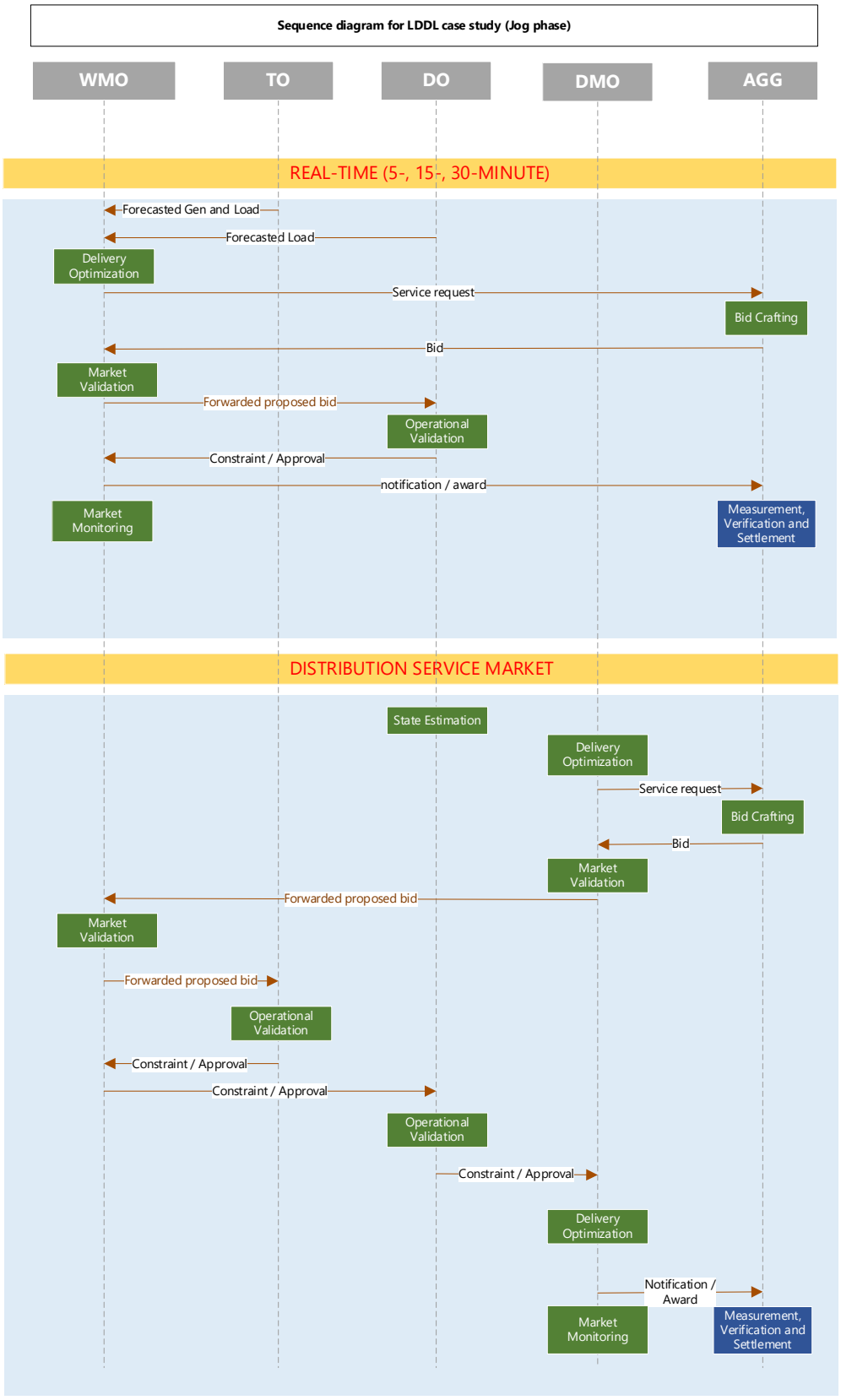


Figure 3. Process diagram for the RCA during Jog phase

The Jog phase is expected to rely on the modules shown as green boxes. During the Jog phase, the modules are activated in a manner closely resembling their operation in the Walk phase. Below is a list of modules with their descriptions:

1.8 Real-Time Market

All modules are used in a very similar manner as to how they were used in the Walk phase. However, timing in the real-time market is significantly different, as interactions are faster and take place in a 5- to 30-min timeframe (as opposed to day-ahead) and without an adjustment period.

1.8.1 Distribution Services Market

The most notable difference in this market is that the DO will rely on a Distribution Market Operator (DMO), which is a separate actor. In the current construct, the DSO encompasses both the DMO and DO, and each of these actors is represented separately.

In addition to the real-time elements, the distribution services market, although using most of the same modules, activates them in a different manner:

- *Distribution System State Estimator:* this module runs continuously within the DO. It relies on input from the TO states and the output is continuous situational awareness within the distribution system.
- *Delivery Optimization module*: here it is activated by the DMO and intended to identify and parameterize the distribution service required. The output is the service requirements.
- *Bid Crafting module*: activated by the Aggregator in response to the service request and leveraging the DER registry, market participation rules, and T&D optimization constraints. The output is a bid package delivered to the DO.
- *Market Validation module*: resided in the Market Clearing House, it is activated by the DMO to verify market participation rules and prevent market conflict and dual participation. Similarly, the same module is active by the MO for verification at the bulk system level. The output of both instances is approval or rejection.
- *Operational Validation module*: here it is activated by both the DO and TO using as inputs the bid, DER registry, and operational forecasting and constraints. The output is an approval or identification of constraint violations.
- *Market Monitoring module*: activated by the DMO, this module continuously monitors the status of the market.
- *Measurement, Verification, and Settlement function*: performance monitoring of the participating DER.

1.9 RCA Characteristics in the Run Scenario

In the Run scenario (15-20 years ahead), other market mechanisms will be present in very short timeframes (seconds ahead) to enable service identification and requests by the bulk system and distribution market operators (MO and DMO, respectively), enabling services such as on-call frequency regulation and disturbance compensation. LDDL owners are already operating and developing load forecasts seconds to minutes ahead to best dispatch any on-site energy storage. In the Run phase, it is expected that they will be able to create forecasts with great

accuracy and these will be provided to the TO, who will exchange system needs to MO for new service opportunities. Another key advancement is that distribute computation and control, and future distribution equipment will enable the concept of control areas. Consequently, distribution service opportunities will materialize in very advanced fashion, where all power flow inputs and outputs in individual control zones are monitored, and grid separation in the form of intentional island systems will be possible to both manage upstream system needs as well as to maintain local reliability. Markets will have adapted to host aggregator bids up to a few seconds prior to performing, in alignment with forecasted load spikes. Besides the Jog phase description, energy values will be assessed based on distribution LMPs and their transient timescale capability.

By further increasing the maturity of grid services available at the TO and DO, Aggregator participation into market will serve as driving force to maintain energy costs low while providing additional reliability.

1. LDDL behavior that causes frequency and voltage deviations over several minutes will be managed; the TO will alert the MO and DMO of the service need (load increase), which will engage location-specific aggregators to respond accordingly through the real time market.
2. LDDL rapid spikes will be forecasted minutes ahead and provided to the TO and used to analyze through the delivery optimization module a service need. The TO will alert the MO and DMO to issue service opportunities that will meet the TO demands. The Aggregators will be able to respond in many ways, either dispatching individual DER or deciding, if previously contracted, to create intentional islands to remove some customers from the distribution system while ensuring their reliability.

Aggregators' responses must be validated both at the DO and TO levels to ensure edge resources won't cause operational violations. DMOs will monitor availability and performance of resources to prove grid services by what-if analysis based on linear distribution state estimators that rely on ubiquitous sensors.

Figure 4 illustrates the process flow for the Run Phase.

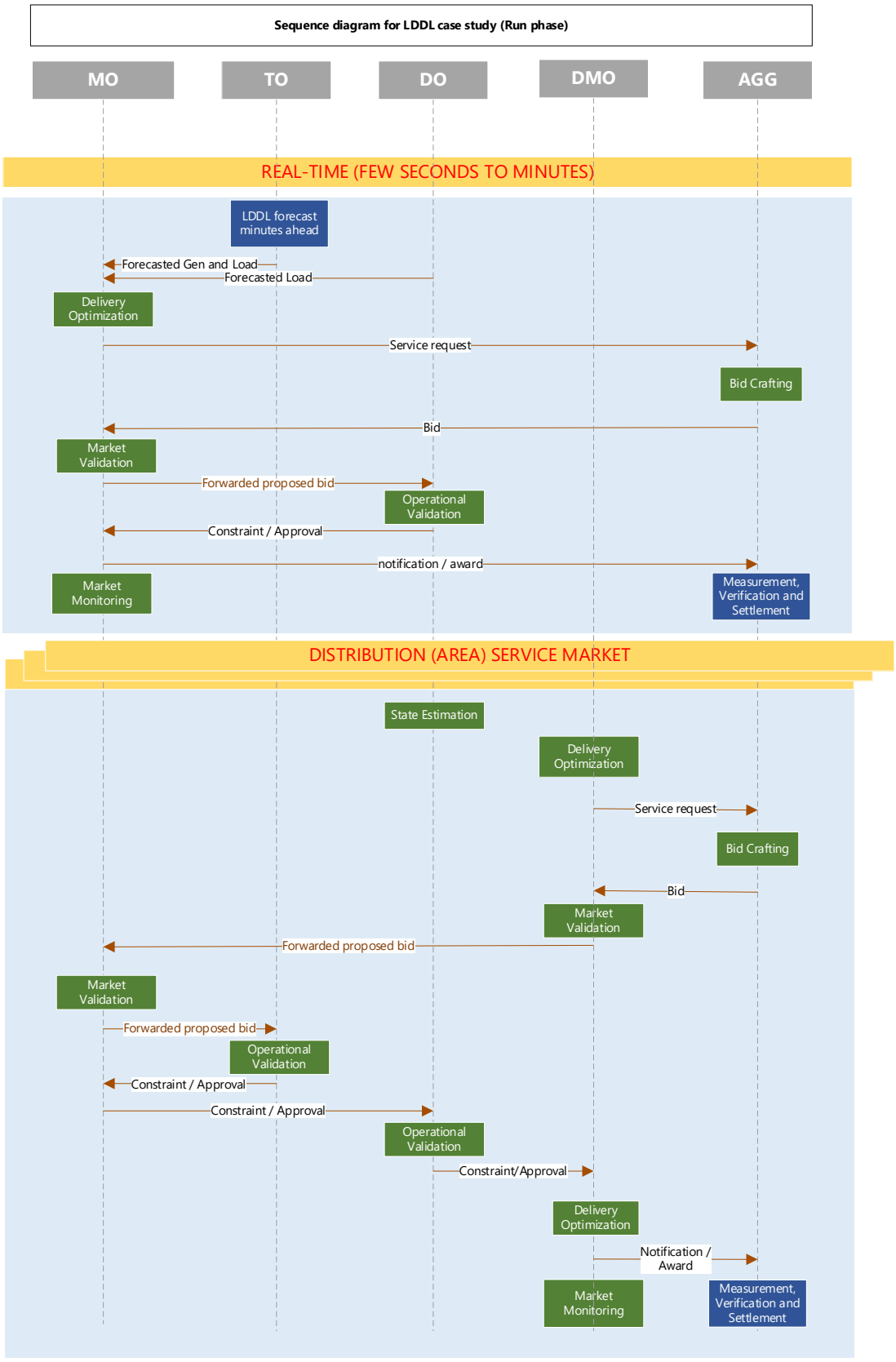


Figure 4. Process diagram for the RCA during Run phase

The Run phase is expected to rely on the modules shown as green boxes. The modules are activated in a manner almost identical to their operation in the Jog phase. A few fundamental differences:

- *Timeframe:* both the real-time as well as distribution service markets will perform in the second-to-minutes timeframe.
- *Distribution System State Estimator:* this module will perform a linear (much faster) state estimation based on synchronized measurements.
- *Delivery Optimization module*: this module will also be performed by the Aggregator. The aggregator will not simply enlist DER participants but will have purview over control zones and optimize their response topologically. For example, Aggregators can choose to form intentional island systems if this helps the system overall while enhancing the reliability of the participating in-island customers, potentially enhancing reliability and affordability.
- *Bid Crafting module*: package created in the sub-minute timeframe and submitted to the MO and DMO depending on the service response.
- *Market Validation module*: performed in the millisecond timeframe by the MO and DMO.
- *Operational Validation module*: performed in the second timeframe by the TO and DO.
- *Market Monitoring module*: activated by the MO and DMO, this module continuously monitors the status of the market.
- *Measurement, Verification, and Settlement function*: performance monitoring of the participating DER.

2.0 Extreme Cold Weather Event Case Study

2.1 Objective

The objective of this case study is to demonstrate how the RCA mitigates the operational and reliability challenges posed by extreme grid events that can be forecasted ahead of time, such as those caused by extreme cold weather events. Hence, this case study utilizes details from the cold weather event that occurred during February 2021 in the ERCOT, Midcontinent Independent System Operator (MISO), and Southwest Power Pool (SPP) balancing authorities' (BAs) respective territories as a reference. To achieve the case study goal, this RCA proposes a progressive response across three phases: **Walk**, emphasizing proactive emergency planning, increased situational awareness, and demand forecasting; **Jog**, focusing on the rapid and coordinated deployment of reserve capacity and activation of DERs to help manage changing grid conditions as an event unfolds; and **Run**, which achieves resilience through self-energization of feeders equipped with edge level decision making capabilities that can coordinate with large-scale grid-edge resources that can ride-out the event with minimal impacts.

2.2 Case Study Summary

The summary of events provided here was collected from multiple reports that analyze the Texas cold weather event (FERC et al. 2021; King et al. 2021).

The cold weather event occurred between February 8 and February 20, 2021. It involved multiple parties, including BA, Generator Operators (GOP), Transmission Operators (TO), Distribution Service Providers (DSP), natural gas producers, and natural gas transporters. The extreme weather event resulted in cold temperatures and freezing precipitation, leading to 4,124 outages, derates, and 1,045 generating units failing to start. The combined generating capacity of the generation outages totaled 192,818 MW over the ERCOT, MISO, and SPP territories. Some units experienced multiple occurrences of unavailability throughout the event. At its worst, the cold weather caused an average of 34,000 MW of unavailable generation within ERCOT between 7:00 a.m. February 15 to 1:00 p.m. on February 17.

BAs' primary mitigation methods included pre-defined early preparation strategies. These included the implementation of proactive system communications and the issuance of early alert notifications. As a final recourse, manual load shedding was employed as an emergency action and without any market-related action.

All three BAs deployed emergency measures in response to the event; however, they still had to shed a combined 23,418 MW of firm load manually, which was outside the load-shedding agreement. The outages resulted in 210 deaths, left 4.5 million people without power, and caused a financial loss of between $80 billion and $130 billion to the Texas economy, according to the Federal Reserve Bank of Dallas.

Gaps Identified

Several gaps were identified (ICF 2021). The weather event coupled with weak weatherization requirements caused key assets to freeze. In addition, a lack of coordination and prioritization among the gas and electricity sectors led to gas shortages that prevented generators from

operating. As part of the post-event investigation, there were several contributing factors that placed ERCOT in a vulnerable position, these can be summarized as follows:

1. **ERCOT's SCADA visibility was limited to only its jurisdiction**, this was despite the fact that two DC links interconnected ERCOT with the MISO and SPP systems (FERC et al. 2021). Data telemetry relied on traditional SCADA with a centralized data historian that did not incorporate local DER telemetry. This issue was exacerbated by limited data telemetry exchanges in between ERCOT's local SCADA and GO/GOP systems located within their service area.
   - **Fragmented coordination processes.** GOPs, BAs, and the Public Utility Commission of Texas determined that coordination mechanisms were inadequate (Hartley et al. 2022). Information exchange between entities was inconsistent, largely manual, and GO/GOPs operated with limited situational awareness of upstream/downstream conditions. As a result, larger than expected blackouts occurred throughout ERCOT's region. In contrast, ERCOTs communications with local distribution companies were generally effective
   - **Lack of DER aggregation capabilities.** At the time of the event, ERCOT had no active DER market aggregation capability, and DER participation for emergency response was minimal to nonexistent. ERCOT's emergency demand response relied primarily on programs designed to perform peak shaving. Although large industrial and commercial loads were pre-enrolled, no participation mechanisms for distribution customers existed. The lack of DER participation further constrained the flexibility that ERCOT operators had by limiting the number and types of resources needed to balance supply shortages.
   - **Inadequate reliability assessments.** As part of the annual reliability assessment, ERCOT performs its seasonal reliability assessments (peak load forecast, expected generation capacity, projected reserve for peak conditions) in advance to each summer/winter to determine resource availability during peak conditions (ERCOT 2023). However, this information was not always shared (or used), hence, the ERCOT peak load scenario tool failed to account for the input provided by the GO/GOP.

Table 3. Extreme cold weather event case study goal in different phases of the RCA

	Current State	Walk	Jog	Run
Goal	–	Emergency planning, demand forecasting	Deploy reserve services and initiate DER services for emergencies	Self-energized feeders that can coordinate with local and large-scale grid resources
Market Timing	–	Day ahead	Non-spin reserve -30 minutes, Responsive reserve -10 minutes, 5-minute energy market	Real-time response to events
Market Participation	Minimal DER participation in emergency demand response	Aggregator onboarding and contracts for emergency reserve service	Automated bid from aggregators based on real-time opportunities (5-minute market)	Localized energy market inside LEN for optimal dispatch
Coordination Scope	Fragmented coordination	Traditional operating picture	Real-time, automated top-to-bottom coordination	Autonomy at feeder/LEN level with supervisory BA orchestration

	Current State	Walk	Jog	Run
		across BA, TOs, GO/GOP		
Load Shed Strategy	Reliant on the traditional energy management system (EMS)	Rolling shed while keeping the critical load	Graceful degradation	Utilize resources and loads to keep the feeder energized
Situational Awareness	SCADA visibility limited to BA/TO, limited DER telemetry	Extended grid state data visibility (centralized)	Full edge level (DER, distributed energy resource aggregator data visibility)	Continuous visibility of distribution nodes

2.3 Actors' Roles and Responsibilities

The RCA document identifies four different actor roles (market operator, transmission operator, distribution operator, and aggregator) that support the execution of coordination modules. These roles could be divided amongst the actors based on jurisdiction; in the ERCOT case, the BA may assume responsibility over some coordination function. Actors' roles, responsibilities, and requirements (shown in Table 4) will evolve as increased coordination capabilities become available, enabling the case study to take advantage of these improvements.

Table 4. Actors' roles and requirements to manage extreme cold weather event case study

Actor	Actor's Roles	Actors Typically Need
Market Operator	Keep track of ancillary service requirements and other products while transmitting adequate market signals to address needs.	• Ancillary service requirements • Availability of flexible resources and generation availability • Accurate demand and weather forecasting
Transmission Operator	Maintain bulk power system stability and operational integrity under extreme cold weather events.	• Transmission and distribution visibility • Pre-contingency load shed planning • Transmission System Planning Performance Requirements (TPL-001-5.1)* • BAs boundary condition (tie-line)
Distribution Operator	Manage utility grid operations (executing rolling outages) and proper coordination with customers.	• Localized grid constraints/requirements • Rolling outage planning • Demand forecasting
Aggregator	Take the necessary preparations to mobilize large-scale grid-edge resources.	• Access to participation resources (register, verification, contract) • Adequate resources characterization (location, scale, capabilities)

* **Source:** 87 FERC 38020. https://www.federalregister.gov/documents/2022/06/27/2022-13471/transmission-system-planning-performance-requirements-for-extreme-weather.

2.4 RCA Characteristics During the Walk Scenario

Based on the gaps identified earlier and the capabilities provided by the coordination platform, a progressive approach is proposed across the Walk, Jog, and Run phases. Since the Walk phase is considered a foundational step, the goal of the Walk phase is to move from a 1:1 coordination model to a many-to-many coordination scheme that allows BAs, TOs, and GO/GOPs, to efficiently exchange load/generation demand/forecast data, improving their availability to efficiently manage grid resources by using the modules and functions defined in the RCA. This may involve the use of the *T & D delivery optimization* module to manage supply and demand across both transmission and distribution system; *Operational forecasting* function to generate comprehensive forecasts based on system-wide data feeds and participant-provided knowledge; the *T&D node visibility* function to share boundary conditions; the *DER reliability monitoring* module to identify and correct operational issues; and the *service opportunity* functions to recruit new potential participants.

Specific contributions of the RCA during the walk scenario are expected to include:

- **Increased visibility.** The RCA is expected to provide ERCOT operators with enhanced system visibility by centrally aggregating extended grid state data (e.g., DER, weather, GOP capacity). It will also increase situational awareness for transmission and distribution operators by furnishing a more comprehensive, near real-time view of conditions across both the transmission and distribution system. This will help improve forecasting capabilities during extreme cold weather events, helping them to identify grid needs and craft service opportunities that can take advantage of customer sited asset capabilities ahead of the event. In turn, aggregators and other qualifying entities can submit offers that can be cleared ahead of the event, enabling the BA to remain well prepared.
- **Reduce coordination fragmentation:** By moving from a 1:1 coordination model to a one-to-many coordination scheme; BAs, TOs, and GO/GOPs will be better equipped to exchange demand and forecast data, allowing them to efficiently manage load and generation resources via market-based mechanisms while increasing visibility. Grid actors will have to coordinate and identify rapidly evolving situations, helping to minimize the chance of blackouts, rolling or otherwise.
- **Improved DER aggregation capabilities.** The coordination platform is envisioned to enable customers and/or aggregators to participate in grid support functions via market-based mechanisms. Hence, aggregators, acting as intermediaries for residential, commercial, and community-scale DERs can provide critical reserve services that can alleviate grid stress. Additionally, their actions can be coordinated with other transmission and distribution actors to optimize outcomes and minimize potential impacts. Such interactions could employ formal contractual requirements that allow for continuous measurement and verification mechanisms that can increase operational certainty. These aggregated DERs can be ready for mobilization as part of ERCOT's energy and emergency reserve programs.
- **Responsive grid assessments:** Reliability assessments can be used to define plans that dictate when and how to deploy the reserve services, as well inform future market product's needs (e.g., what is needed and when). This can be used, for example, to refine the amount of emergency services needed ahead of an imminent storm. The coordination platform can also be used to rapidly disseminate grid assessments,

enabling relevant parties to be informed of changing conditions, enabling them to find collaborative approaches to mitigate event impacts.

In summary, during the Walk phase for the extreme cold weather event case study, the RCA satisfies its architectural principles (e.g., scalability, observability, resilience-by-design) by 1) Facilitating access to extended grid information from an increasing number of sensors and DER devices to enhance visibility, 2) Facilitating coordination and data sharing between different entities; 3) Enabling DERs to participate in grid support functions; and 4) Continue to support resilient, predictable day-ahead market operations. These capabilities can be further enhanced by leveraging resilient communication networks that provide fault-tolerant capabilities, allowing the platform to continue exchanging information even if a subset of the communication infrastructure is temporarily offline due to weather impacts.

Figure 5 illustrates the timing diagram of the ERCOT day-ahead market structure by including a few improvements (e.g., market validation, increased visibility, service availability, and proper coordination) that will be modeled during the Walk phase to achieve the case study goals. ERCOT's day-ahead market also included the day-ahead reliability commitment (DRUC) process, which helps ERCOT to bring resources online needed for reliable operation on the following day (ERCOT n.d.).

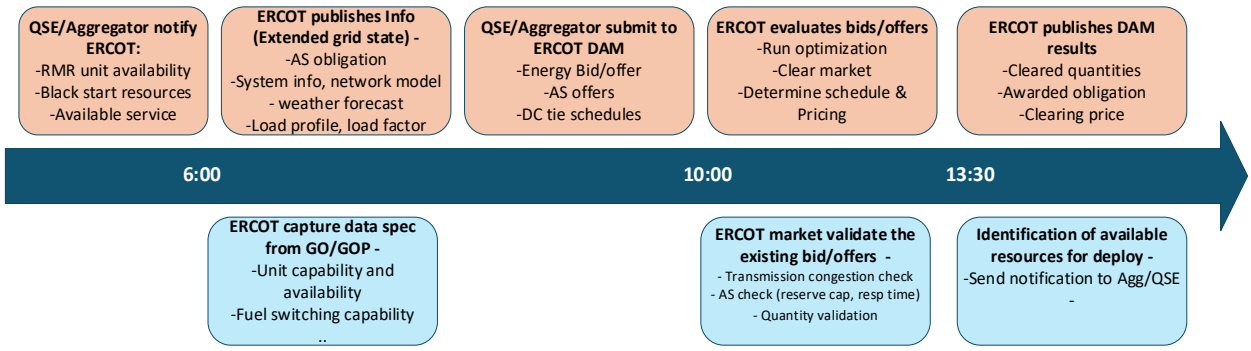


Figure 5. Timing diagram of ERCOT day-ahead market (Walk phase)

The Swimlane diagram, illustrated in Figure 6, shows how MO, TO, DO, and Agg interact with each other to prepare for an extreme cold weather event in the day ahead, to a near-real-time horizon. During this event, the RCA operates in two broad stages, with each module exchanging targeted information to keep the operational system secure and efficient.

The first stage focuses on situational awareness and operational planning, when extreme-weather alerts from the weather notification system trigger enhanced situational awareness and T&D-focused analysis. System visibility from both the transmission and distribution ends has been enhanced by using the extended ***Grid State Estimation module*** and the ***T&D Optimization module***. This T&D optimization module is also used to perform forward-looking assessments of system constraints. These assessments/constraints are passed to the ***Delivery Optimization module*** owned by MO to identify the feasible operating range and new service opportunities.

Building on the outputs of Stage 1, the RCA transitions into market-facing and operational execution activities. With the operating envelope in hand, MO identifies the service and requests Aggregator to initiate its ***Bid-crafting module*** in the day-ahead market; the bid crafting

aggregators pick the most predictable and controllable device for aggregation in a low-risk way with the most profit. After bid crafting is complete, the *Operational Validation module* owned by DO evaluates whether specific DER locations are eligible by performing locational checks to ensure the service can be delivered without violating local grid constraints. Later, validated bids are submitted for Market Validation, where compatibility with wholesale market rules (including dual-participation constraints, if applicable) is assessed through the *Market Validation module*. Upon acceptance, Notification/Award messages are issued to the aggregator to dispatch. Throughout this stage, the *Market Monitoring module* continuously monitors system conditions as the extreme weather event unfolds. If conditions deviate from forecasts (e.g., faster load pickup or DER derating), the RCA issues hour-ahead adjustment requests.

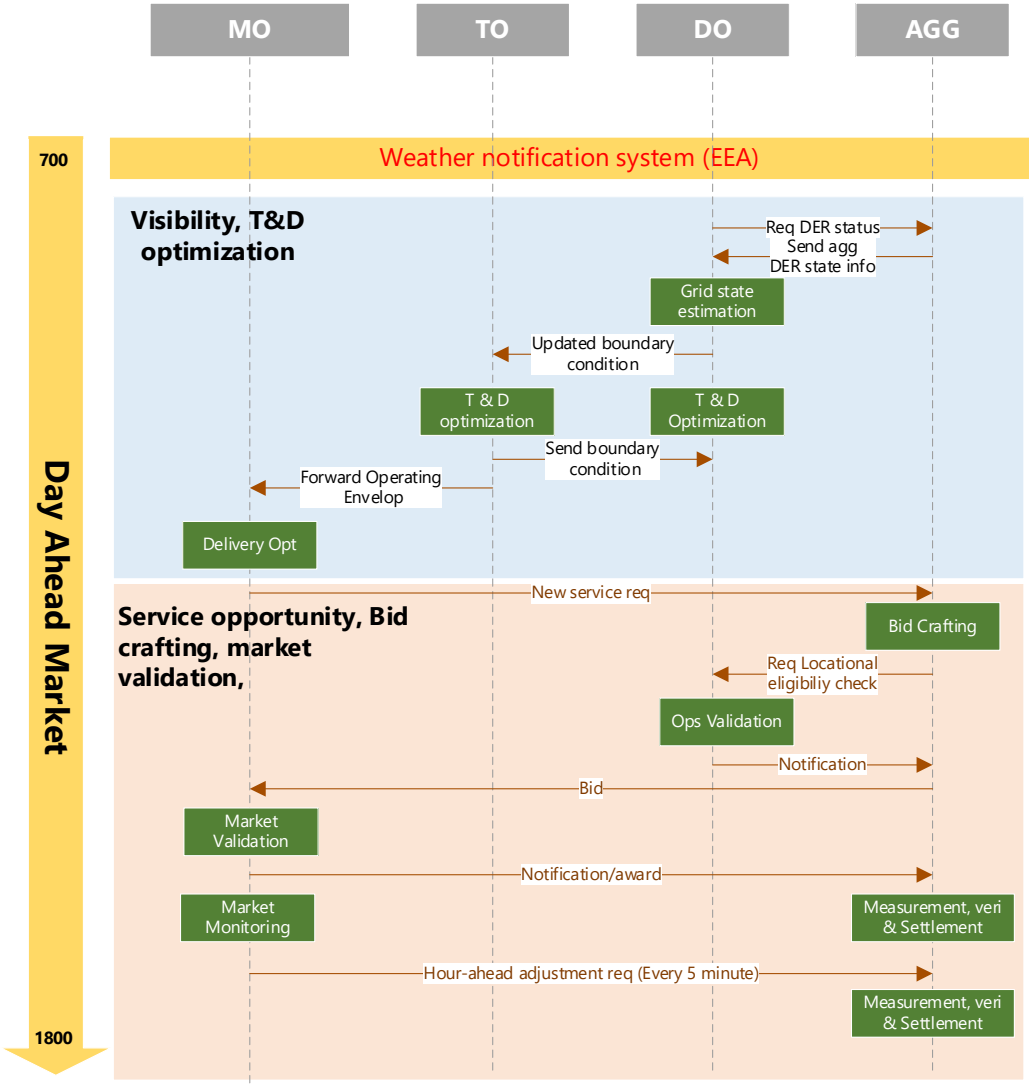


Figure 6. Extreme weather event process diagram for the Walk phase

The Walk phase includes the modules below to achieve its objectives:

- *Delivery Optimization module*: Initiated by the MO by capturing operating envelop from TO and identify service requirement.
- *Grid state estimation module* – DO activate this module by utilizing the extended grid state and identify real-time operational information on specific distribution grid outages, curtailments, and other changes to deliverability, including affected locations and expected duration.
- *Bid Crafting module*: Triggered by the Aggregator upon receiving the service request from MO. It utilizes the information from DER registry, market participation guidelines, and transmission/distribution optimization constraints.
- *Market Validation module*: Located within the Market Clearing House and activated by the MO to ensure compliance with participation rules and prevent conflicts or dual participation. The result of this validation module is either approval or rejection.
- *T & D optimization module*: Activate by both TO and DO; perform network assessment on both sides by sharing the boundary information with one another.
- *Operational Validation module*: Activated by the DO using inputs such as the bid, DER registry, and operational forecasts with constraints. The result of this module is approval or identification of constraint violations.
- *Market Monitoring module*: Continuously operated by the MO to track and oversee market status.
- *Measurement, Verification, and Settlement function*: Owned by the aggregator to monitor the performance of the participating DER.

2.5 RCA Characteristics in the Jog Scenario

During the Jog scenario, the RCA focused on two aspects of the market: real-time wholesale market (5-, 15-, or 30-minute) and the distribution service market. From a real-time market perspective, MO is expected to receive real-time market bids directly from the aggregator. Later, as part of the market execution process, bids/offers will be validated through the *Market Validation module* and scheduled for real-time operation via seamless coordination between the DO and TO via a centralized system (or a set of highly interconnected, interoperable systems), helping ensure market reliability and cost-effectiveness. In a similar manner to the LDDL use case, the MO will first perform distribution-level validation to eliminate tier-bypassing risks and reflect validated bids into the wholesale market. In this phase, operational validation of aggregator bids is expected to evolve from a simple, static, rules-based location eligibility check to a more network-model-based (power-flow-based) pre-qualification. This process will be performed by the *Operational Validation module*, managed by DO, before bids are submitted to the wholesale market. During this process, the aggregator will actively coordinate with the DO and TO to resolve any transmission constraints.

In the Walk phase, MO has limited visibility of the grid edge (DER, Aggregator), which limits situational awareness during extreme events. However, the Jog phase will expand the MO's awareness to include transmission, distribution, and aggregator information. Data will be limited to attributes deemed essential for market and system operations, thereby helping maintain privacy and foster competitiveness. During this phase, the *Distribution grid state estimation module* and *T & D optimization module* owned by the DO will ingest multiple real-time data

sources, including net metering and behind-the-meter data, to better capture current system conditions, thereby maximizing resource participation, ensuring reliability, and addressing transmission-side congestion. From an aggregator's perspective, only data deemed essential for operations (e.g., available capacity, service flexibility) will be shared to maintain reliability while ensuring fair market practices are maintained.

As part of the Jog phase, DO will perform real-time feeder analytics and coordinate with the aggregator to implement graceful service degradation and dynamic resource prioritization, using adaptive load management strategies. Distribution-level market signals can be used strategically to incentivize storage and minimize curtailment or used to achieve indirect control actions. DO will use advanced sensor analytics to disaggregate feeder load and leverage the resulting information for the emergency reserve service. They will use high-granularity, time-stamped meter data to identify which end uses (EV, HVAC, lighting, water heating) can be safely shed without requiring overly broad or blanket reductions. DERs should be dynamically grouped or shifted without compromising reliability.

During this phase, qualified emergency reserves will be grouped and bid in real time by the ***bid-crafting module*** in a targeted manner after the day-ahead energy service is cleared. Those qualified groups will be deployed in real time to different load zones according to their priority. Additionally, aggregated DERs will be grouped by their locational attributes (e.g., feeder-level groups) and will provide emergency load relief (e.g., EV charging curtailment, Volt/VAR support on stressed feeders) rather than a rolling outage.

From a coordination perspective, the DO receives only the relevant T&D node conditions (delivery point congestion, ramping needs) from TO, and the TO likewise gains visibility only into distribution-level node conditions, such as feeder loading through the RCA modules. In this phase, T&D node information is utilized to continuously optimize systems, rather than isolated systems with limited coordination.

Figure 7 shows an extreme weather event process diagram for the Jog phase (Wholesale Market view), where all modules operate in much the same way as during the Walk phase. This process diagram begins after the day-ahead market closes. Here, the key difference lies in timing: in the real-time market, interactions occur much faster—within a 5- to 30-minute window rather than day-ahead—and without any adjustment period

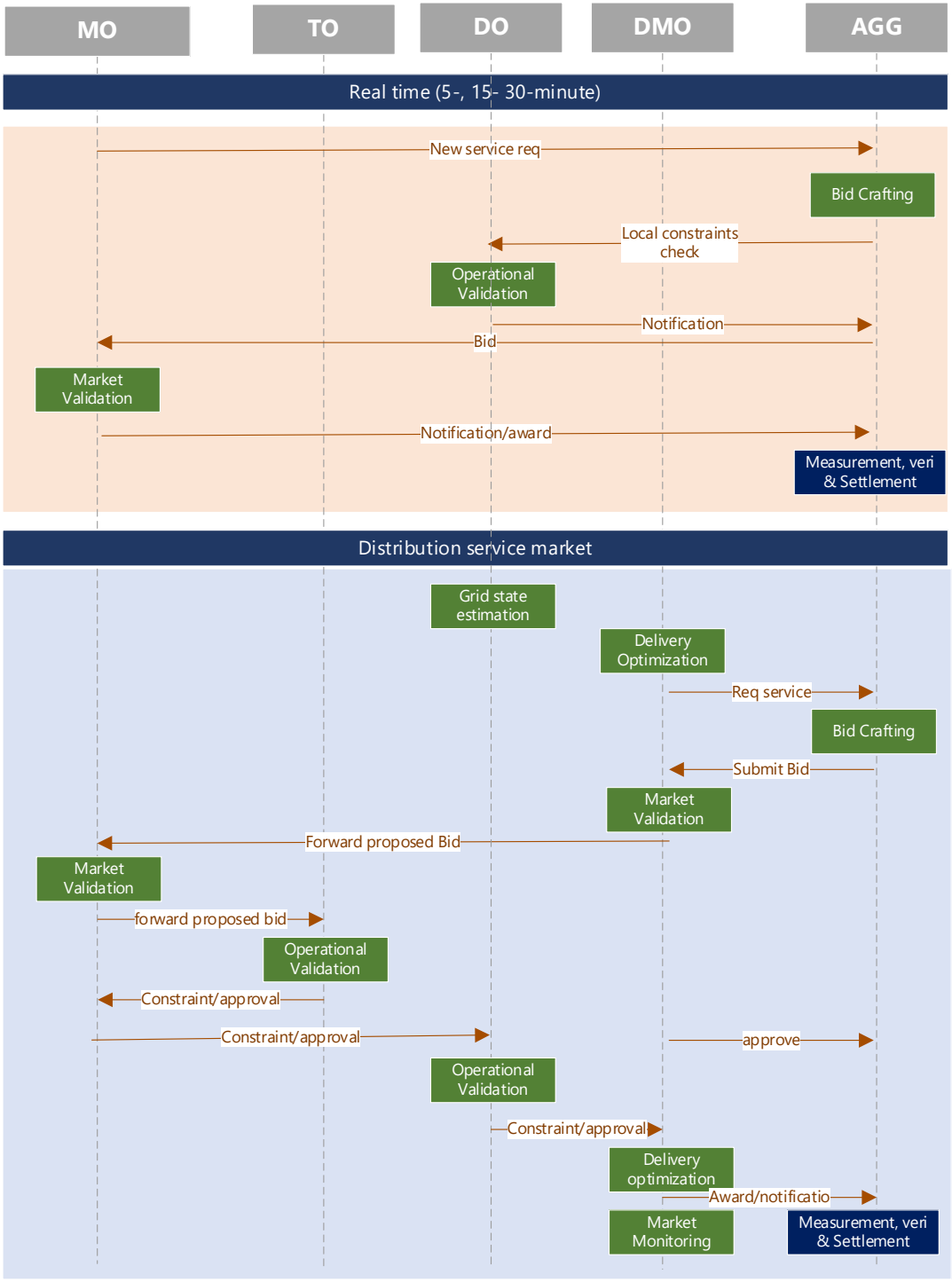


Figure 7. Extreme weather event process diagram for the Jog phase

Also, in this phase, the RCA will introduce a distribution service market designed to incentivize energy storage, minimize curtailment, and enable indirect control actions to address local distribution grid needs during extreme weather conditions. DO as a distribution service market operator play almost similar role as wholesale market operator, covering the full cycle from

service identification to operational validation, bid evaluation, and dispatch. Even though DO runs its own distribution service market operation, it validated the bid coming from aggregator with wholesale market for wholesale market validation.

Under extreme weather scenarios, this distribution service market invokes the coordination framework modules when local grid demand surges drastically, which may also coincide with equipment failures.

2.6 RCA Characteristics in the Run Scenario

The Run phase represents both the most demanding operational scenario, and feature-capable environment to handle an extreme weather event. In this scenario, the distribution system transitions from a pre-planned response to an active response model that can take advantage of pre-planned and real-time responses to address emerging needs. In addition, the RCA leverages the use of autonomous operations and flexible markets (from feeder-level to wholesale-level markets) to achieve coordinated resource orchestration. During this phase, it is assumed that the upstream grid would experience widespread disruptions, limiting its ability to deliver power to the downstream grid. Unlike the earlier Walk and Jog phases, which emphasized planning and graceful degradation, the run phase offers increased flexibility by taking advantage of feeder-level, autonomous capabilities that pave the way for self-sufficient operational regions (e.g., islands) that are capable of serving critical loads while maintaining coordination with the broader transmission and distribution ecosystem. In this phase, market mechanisms at both the wholesale and distribution levels will function at minute to sub-minute intervals to identify grid needs and procure critical services on an as-needed basis. The traditional market optimization shifts to more complex adequacy (microgrid level) that runs dynamically by including extended grid state information from DO and TO.

From a visibility perspective, the RCA can aggregate and fusion thousands of grid measurements (e.g., from grid managed and individual DERs) to provide contextual visibility at the various aggregation levels (from a feeder section to the transmission system) through the T&D node visibility function, coordinating local visibility with the upstream network. This increased visibility at the edge level is essential due to the evolving nature of weather-related events, and the switching actions required to isolate the faulted areas.

When feeders island from the bulk system, the distribution service market provides the economic coordination mechanism for DER dispatch while the feeder operates autonomously. At that time, the *bid crafting module* generates dynamic bids based on current DER availability, distribution system constraints, and local load requirements. One of the major shifts from Jog to Run in the distribution service market perspective is that this distribution service market can operate independently without wholesale market validation when feeders are isolated, then re-synchronize with wholesale markets when reconnection occurs.

Coordination nodes at different coordination zones (e.g., substation or edge) enables computing systems to work together to achieve a variety of local and bulk-level grid objectives. With its advanced computing capability, the coordination node is responsible for solving its local portion of the overall coordination problem. For example, when isolated, the coordination node at the edge boundary helps local resources to autonomously adjust real and reactive power output to maintain voltage within acceptable bounds while utility (and non-utility) assets support visibility by providing field data. When interconnected, the *T&D delivery optimization module* (owned by DO) can further leverage this coordination node capabilities to coordinate the aggregate real/reactive power balance across the feeder. Although each edge device would normally be

part of a distributed system that actively contributes to global goals, it may transition to decentralized control architecture with the help of the coordination node to optimize the use of local resources when the system is isolated. In this configuration, behind-the-meter exchange state information and control signals with neighboring nodes over the feeder network to ensure system-wide stability and consistency.

One of the primary objectives during the run phase is to enable autonomy at the feeder level through supervisory wholesale market orchestration. The *grid state estimation module* serves as the key interface between autonomous feeder operations and balancing authority orchestration. Even when feeders are islanded and operating in the distribution service market, this module maintains communication (when possible) with the balancing authority to report their status: load served, DER capacity available, critical loads requiring service, and estimated duration until reconnection capability.

The run phase includes below modules to achieve its objectives –

- Grid state information module - Owned by DO and creates comprehensive, real-time visibility of distribution system conditions by aggregating thousands of individual DER measurements and system state variables.
- Bid Crafting module - Activated by the aggregator to generate real-time bids for the distribution service market independently. When reconnection with the bulk grid becomes imminent, this module prepares bids for both distribution and wholesale markets, coordinating the transition from autonomous to grid-connected operation
- T & D delivery optimization module – Primary owner of this module is DO, with coordinated interface with TO when the feeder is interconnected or when reconnection is being prepared. This module performs feeder-level optimization by aggregating real/reactive power balance across islanded feeders using information from edge devices. Advanced distributed computing at the feeder level and this module works together to manage the grid across the 3 stages (interconnected, islanded, in transition)
- Operational Validation module – Managed by DO to ensure behind-the-meter devices and feeder-level resources maintain system-wide stability and consistency through decentralized control architectures. This module receives input from the Distribution Grid State Information Module and provides validated operating parameters to the Delivery Optimization Module.
- Market Monitoring module – Used by DO to monitor the performance of distribution market services and their bids. This module also provides monitoring capabilities that support post-event auditability and settlement corrections, including timestamped event logs across islanded “market partitions” and comprehensive evidence trails for emergency procurements and any rule waivers.

Figure 8 shows the process diagram for the run phase. In this phase, BTM edge devices play a significant role in managing local energy balance. Distributed computing agent, aka coordination node (blue color) embedded at the feeder and edge levels, continuously measures status (voltage, net export), performs autonomous control operations, and maintains connectivity with the neighbor node.

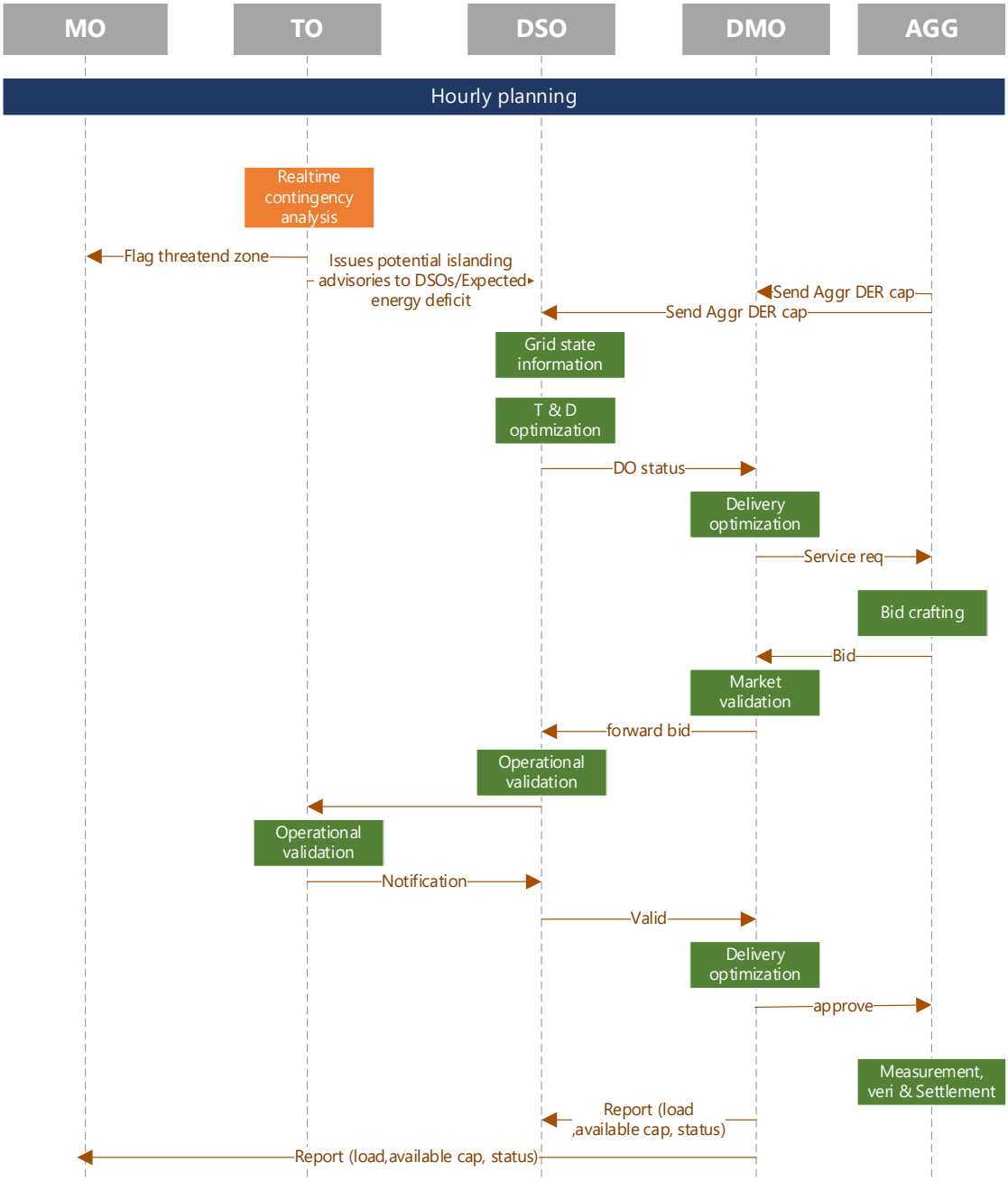


Figure 8. Extreme weather event process diagram for the Run phase

3.0 Cascading Blackout of 2003

3.1 Objective

The objective of this case study is to demonstrate how the RCA could be effective in providing critical data and services before, immediately after, and during system restoration of a system blackout to reduce the impacts and speed the recovery of the power grid. The case study will use the 2003 blackout in the U.S. Northeast as a muse. The 2003 blackout was the most severe that the United States had suffered since 1968. It affected about 50 million people, with an accumulated lost load in excess of 70,000 MW in parts of Ohio, Michigan, New York, Pennsylvania, New Jersey, Connecticut, Massachusetts, Vermont, and the provinces of Ontario and Quebec in Canada.

During the early stages after a blackout, there is much uncertainty between transmission and distribution operators as to the extent of the blackout and its cause. This case study will show that more certainty may be achieved by using modules proposed in the RCA that provide real-time data exchanges between the distribution and transmission system operators. Furthermore, module functionalities and coordination between affected actors may reduce the risk of second collapse by reducing the amount of cold pick-up load during the grid cranking stages in addition to providing more clarity of cold pick-up required at transmission and distribution interfaces. Finally, the case study will demonstrate the usefulness of providing automatic reenergization of islandable grid segments thus reducing grid downtime and better prioritization of critical loads.

3.2 Case Study Summary

The pre-cascade began around noon on August 14, when 345 kilovolts (kV), 230 kV, and 138 kV Cinergy transmission circuits tripped off-line in central Indiana, which caused critical modeling errors in MISO's state estimator, eventually crippling it. Consequently, subsequent worsening conditions were not reported to the MISO system operators. The MISO status was already compromised before the noon transmission trips because several central generating units that normally provided reactive power to the Cleveland area had been taken off-line for planned outages. Approximately one hour later, the situation deteriorated, when the Eastlake Unit 5 central generating station, rated for 597 MW, tripped off-line, resulting in a serious deficit of reactive power supply in the Cleveland, Ohio area.

The North American Electric Reliability Corporation (NERC) final report attributed the Unit 5 failure to a condition brought on by the unit operator responding to an outside request by FirstEnergy for additional voltage support for the Cleveland area. After the Eastlake Unit 5 trip, the Cleveland area suffered critical low voltage levels, which caused overloads on three additional 345 kV lines feeding Cleveland, causing them to trip and enter lockout. The load was shifted to available 138 kV transmission lines, which rapidly tripped 16 lines because of overloading. The 138 kV line trips caused the cascade at just after 4:00 p.m., Eastern Daylight Time. Figure 9 illustrates the most significant sequence of events leading up to the blackout.



Figure 9. 2003 blackout events

The 2003 blackout did not cause any physical damage to the power system, and most customers were restored within a few hours, except in scattered regions. However, the estimated losses have been reported to be $6.4 billion between lost income, perishable commodities, utility costs, and other recovery costs. While blackouts resulting in no physical damage is not always the case, such as those caused by natural disasters like hurricanes and floods, the basic practice for system restoration (or blackstart) has remained the same for decades.

3.2.1 Traditional Blackstart Process

Blackstart is a process by which a power system is reenergized after a widespread or localized outage. The process follows the following general sequence:

1. After the event, assess the grid for damage and continuity. The assessment identifies a “skeleton” grid comprising unaffected grid segments, which have either remained energized or have continuity with a source.
2. Of the unaffected grid segments, “cranking paths” are identified with transmission segments connected to a blackstart unit(s), which can be energized with available blackstart generating units.
3. Gradually restore power along transmission cranking paths, beginning with the blackstart unit and moving up the cranking path to the next generating unit. Pick up cold loads along the way to balance generation and load. Eventually, a grouping of power islands will materialize within the affected area, made up of multiples of generating units, transmission corridors, and loads.
4. The final step will synchronize the power islands (Figure 10) and interconnect them to restore the system to the nominal configuration. Cold load pickup on the distribution system will continue after and during the power island connection process.

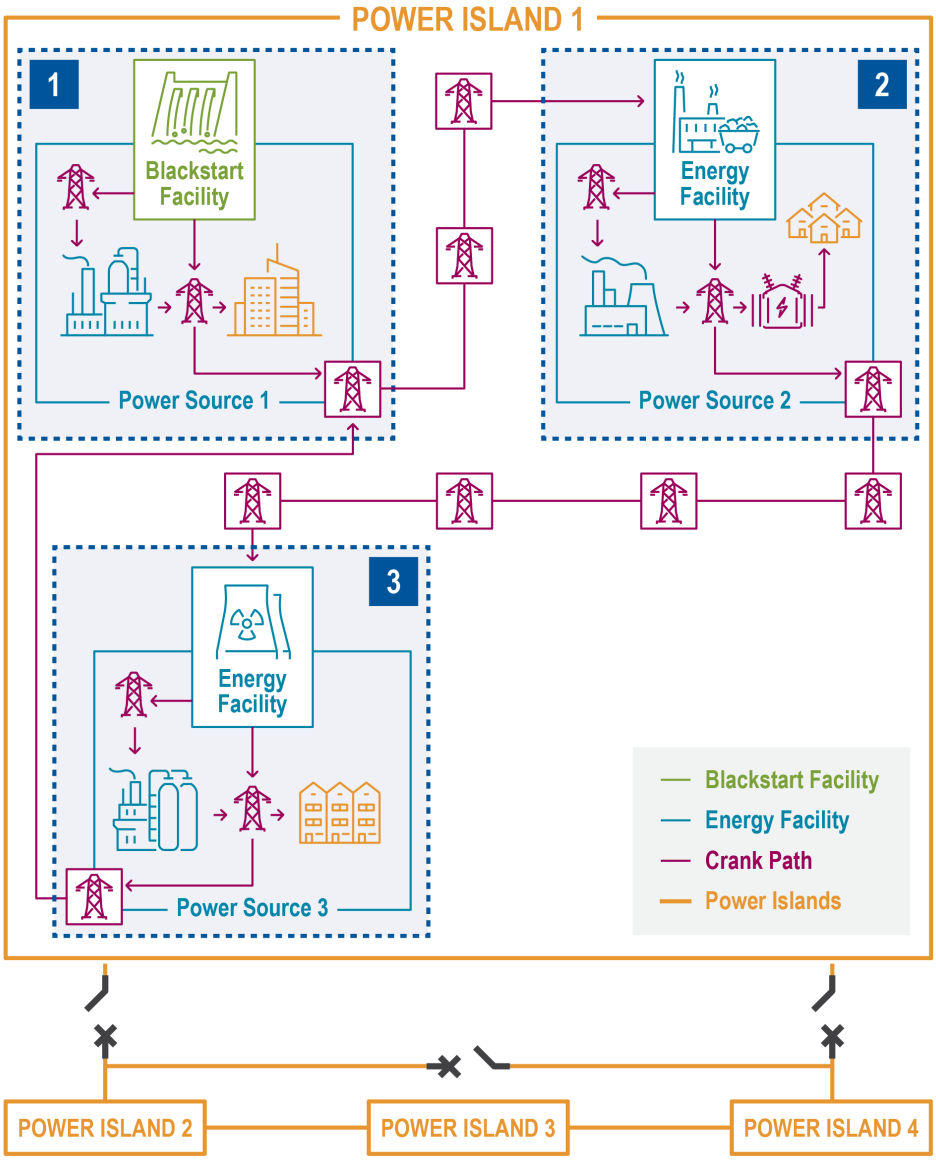


Figure 10. Power islands

The time to complete the steps above can take a matter of hours or months, depending on the circumstances that caused the blackout and the breadth of the aftereffects, including damaged lines or equipment. Key challenges that can be addressed through the use of the RCA are mainly tied to reducing the restoration time. Currently, restoration is performed unidirectionally, starting from generating units toward load centers, and does not take advantage of local resources to reduce the overall time. Furthermore, current processes may lack visibility into the edge. This case study will investigate how the traditional blackstart process may be augmented by providing critical data and enabling coordination, allowing TOs and DOs to take advantage of both centralized and edge resources using the RCA, thus shortening the amount of time required, while also reducing the number and required blackstart capacity from central units. As increased maturity levels are achieved, self-sustaining LENs or microgrids may be able to ride through an event and even initiate the blackstart process from the edge itself.

3.3 RCA Progression for Blackstart

As previously covered, the process of blackstarting the grid has traditionally been performed using centrally coordinated processes, beginning at central generating stations and progressing toward end-use loads. Thus, few precedents exist when considering blackstart from the edge. Table 5 provides goals, data needs, and functional gaps that would be required to adopt a grid-edge approach to blackstart.

Table 5. Actors' roles and requirements to provide blackstart capabilities during the Walk phase

	Current State	Walk – Implement Data Exchange from the Edge	Jog – Add Coordinated Blackstart with Edge Participation	Run – Add Automated Blackstart
Goals	"Site to site" coordination and manual process of assessment and crank path identification. No coordination or data flow between the DO/edge and TO/BA levels.	Enhance data observability between DO, TO, and BA to support restoration. Implement enhanced demand response and other load support mechanisms to reduce cold load pickup and prioritization of cranking paths. Load reductions are pre-planned or manually executed during the event.	Through coordination, engage blackstart from the edge, provide blackstart/cranking capability at the distribution substation level (e.g, the main bus), islanding/grid-forming functionality (fault location and isolation), auto synch with transmission, voltage support, real-time load and support duration projections (State of Charge and other resilience metrics). Implement market operator participation in blackstart schemes.	Perform automated blackstart. Self-energize feeders equipped with adequate grid-forming technology, blackstart capability, and sufficient capacity. Automate real-time communication and status.
Gaps	No edge data observability and no blackstart support at the edge.	No automated data exchange, sensor availability gaps.	Lack of widely dispersed grid-forming inverters, edge computing, and communications.	Method to identify LENS, peer-to-peer comm/control, seamless islanding, dynamic simulations and modeling.

	Current State	Walk – Implement Data Exchange from the Edge	Jog – Add Coordinated Blackstart with Edge Participation	Run – Add Automated Blackstart
Coordination Scope	Manual person to person between BA/ TO, and GO/GOP.	Coordination to include data exchange, projected net load at the distribution substation (main bus), and grid-edge status (assessment of readiness). Communicate demand response and critical load needs. Assess distribution feeder status (topology and fault areas),including feeder breaker status and in-line recloser status.	Ready the distribution main bus to be synched with the TSO and high-side switch. Provide data feedback to detail the degree to which feeder or sub can accommodate or assist blackstart.	Grid-edge computing, automatic configuration, localized crank paths established.
Data Type	None being exchanged from the edge.	SCADA, DNP3, Modbus, 2030.5, OCPP, etc.	Local supervisory monitoring and control.	Integrated local edge monitoring and control with TO/BA control.
Value Gained or Differentiation	NA	Data exchange will reconcile available blackstart “cranking power” and, pending load pickup, assess resource gaps more expeditiously. Also identify critical loads.	DER or aggregated groups of DER provide reactive power and voltage level at the edge while coordinating efforts with TSO/MSO, providing risk mitigation strategies for pending blackout.	DER or aggregated groups of DER with grid-forming and islanding capability provide blackstart support within LENs and coordinate restoration.

3.4 Actors and Roles in Walk Blackstart Scenario

For the Walk scenario, the various parties explained in the RCA document will play the following roles and have the listed responsibilities in Table 6.

Table 6. Actor roles

Actor	Actor's Roles	Actors Typically Need
Market Operators	Work with Aggregators to procure blackstart assets that may be called on when needed.	• Track the participation of assets participating in blackstart services at the edge level. • Aggregate assets in advance of an anticipated event such as local storms. • Accurate demand and weather forecasting. • Demand response services.
Transmission Operator	TO will coordinate with BA and DO to tie in distribution with established cranking paths and formulate power islands.	• Availability of accessible assets for blackstart on distribution. • Control of isolation switch between DO and TO.
Distribution Operator	For the Walk scenario, the DO will retain much of the responsibility under normal blackstart conditions (e.g., perform feeder segmentation) but will coordinate local actions with BA and TO.	• Localized grid constraints/requirements. • Accurate topology (switch states, faulted areas) • Segment feeder to isolate trouble or optimize available assets • Configure edge to synchronize and reconnect with the bulk power system.
Balancing Authority	The BA role will have overall responsibility for coordinating the blackstart.	• Develop regional strategy. • Issue instructions to TO. • Coordinate data streams and reports from edge and incorporate in overall blackstart strategy.

3.5 RCA Characteristics in the Walk Scenario

The Walk phase will focus on establishing requirements for data exchanges among the DO, and the TO that should improve the traditional blackstart process. In this stage the DO plays an active role in offering feeder flexibility to provide generation or reduce load as needed. The intent is to assess how potential grid-edge devices, either power generation assets or demand response, can reduce the required cold load pickup and expedite the cranking path assembly process. During the Walk phase, the RCA may be leveraged to assist blackstart operations by allowing the DO and TO to a) Better communicate demand vs power availability; b) Take advantage of pre-planned circuit configurations (e.g., by pre-planning power island formation and synchronization schemes that consider the TO/DO operational requirements); c) Take advantage of DER systems that can be used to offset net-demand; and d) Communicate and prioritize the restoration of critical loads.

When the blackstart process has progressed to the point where distribution loads are being picked up in large blocks, the final coordination step between the TO and DO is the closing of the substation “high side” isolation switch, which is owned and operated by the TO. The high-side switch is the demarcation point between the distribution system and bulk power system. The DO, subsequently, closes substation reclosing devices to pick up cold load on distribution feeders. This process is always somewhat dubious, especially if the blackstart is the result of physical damage to the grid. The risk is that an unknown fault can remain on the feeder, causing activation of reclosing devices and potential collapse of all or some portion of the blackstart cranking path. The Walk phase will serve as a first step in mitigating this risk by taking advantage of data made available through the coordination platform. For example, the TO can gain visibility into the distribution system state via the *T&D node visibility* module, while the DO can leverage the *Distribution State Estimation* module to fusion multi-domain sensor data of varying granularity and apply observability algorithms to improve fault location (and thus isolation) capabilities. This will enable the DO to coordinate feeder readiness, and reconnection attempts before cold load pickup, thus optimizing the blackstart sequence and minimizing cold pickup risk.

For the Walk phase, the following modules will be employed:

- T&D Node Visibility – energizing the crank path can be perilous as cold loads are not fully understood at the TO level before attempting to restore power. This module will exchange critical load information and dynamic behavior between the DO and TO so as to avoid possible collapse of the crank path and more efficient power restoration. Additionally, the T&D Node Visibility module may be used to identify distribution feeders that are under repair, with line personnel working, and with system clearances applied. Clearances are formal processes by which a DO physically isolates sections of feeders to protect line personnel from electric shock.
- T&D Delivery Optimization – As better data becomes available, DOs can identify high load feeder segments, and the associated switching equipment that can be used to isolate them. Similarly, key feeder segments can remain connected to take advantage of local DER support (e.g., to leverage DERs that can provide power), thereby optimizing local resource use. Similarly, the TO can use this module to ensure that reenergization of distribution feeders will not cause any adverse reactions to the transmission system.
- Distribution Grid State Estimation – this module will be used to collect and process sensor data to inform on the grid state. As increased amounts of data become available or its resolution is increased, the DO/TO will benefit from increased accuracy in load prediction, improved topology estimation, and fault location, all of which reduce the chance of a cranking path collapse.
- DER Aggregation (Bid Crafting) – The TO actor(s) will acquire services by coordinating with the MO and Aggregator actors along the proposed cranking path to assist in system restoration, grid support to prevent cranking path collapse, or to perform the blackstart facility function.

The sequence diagram in Figure 11 illustrates the interchange between the affected actors in the Walk phase blackstart process. The sequence progresses through:

1. TO and DO system status or damage assessments to eventually compose a tentative cranking path.

2. Market/aggregator interaction between the TO and transmission MO/aggregator to solicit blackstart and load reduction services to reduce time and risk of collapse while restoring the power system.
3. Operational validation of tentative cranking path with market assistance.
4. Final cranking path development and transmittal to all actors by the TO.

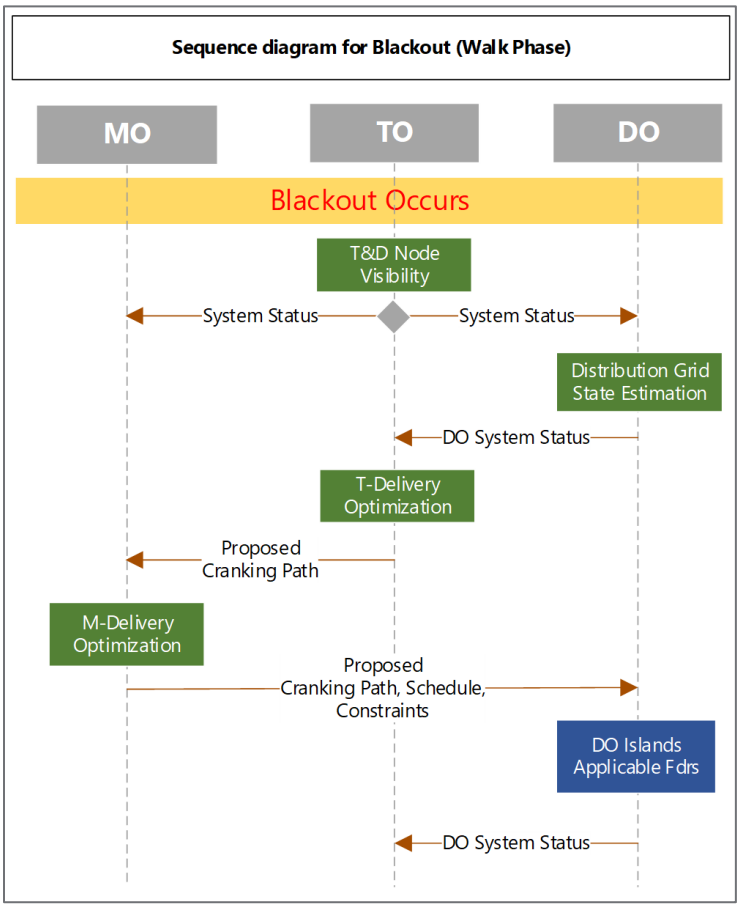


Figure 11. Cascading blackout process diagram for the Walk phase

3.6 RCA Characteristics in the Jog Scenario

While the Walk scenario largely follows the traditional blackstart sequence, it does establish a series of data and service exchanges between the involved actors, the Jog scenario will build off this initial data exchange capabilities and begin to incorporate DERs, allowing them to take a more active role in facilitating blackstart. This will mean actively deploying DERs on the distribution system in an effort to reduce cold pickup load and more expeditiously advance the blackstart process and return service to customers. Improvements will result in less time to restore the system but also reduce the likelihood of system collapse since the cold pickup load will be more predictable under the Walk scenario and will be reduced in magnitude during the Jog phase. Since the distribution system will be physically isolated from the transmission

system, the traditional MO will play a limited but important role in this distribution level coordination. This will require distribution-level market programs that enable distribution services to be incentivized based on market signals, such as distribution-level LMPs. One of these services could be a blackstart service based on the ability to export or self-support portions of the system. This new marketing role will interface with system aggregators and the DO to facilitate deploying DER and the mechanism by which the aggregators and DER owners will be compensated. Utility-owned assets, on the other hand, will be deployed by the respective DO and coordinated with the TO. The distribution MO will coordinate with the DO to develop distribution prices and grid service opportunities. Traditional energy services could also be leveraged to further reduce net load or to delay load demand upon reconnection (e.g., by delaying battery and EV charging).

- T&D Node Visibility – as was the case for the Walk phase, this module will use coordination functionality to exchange information between the transmission and distribution networks.
- Distribution Grid State Estimation – this module will be used in the Jog phase to provide distribution level status between the DO and TO, MO, and DMO actors.
- Operational Validation – As the cranking path is built, the DO can check if existing bids will violate constraints within the distribution grid and may solicit the market operator to cancel them.
- Market Monitoring – for the Jog phase, market monitoring will occur at the distribution level to track transactions between the DMO and DER operators as blackstart services are transacted.
- Market Validation – this module will be used to verify that resources participating in market programs are compatible with restoration efforts. This module could be executed by the MO or DO actors.

The Jog phase sequence diagram in Figure 12 follows closely with the Walk phase with the exception that the DO will engage the newly formed distribution level marketing actor.

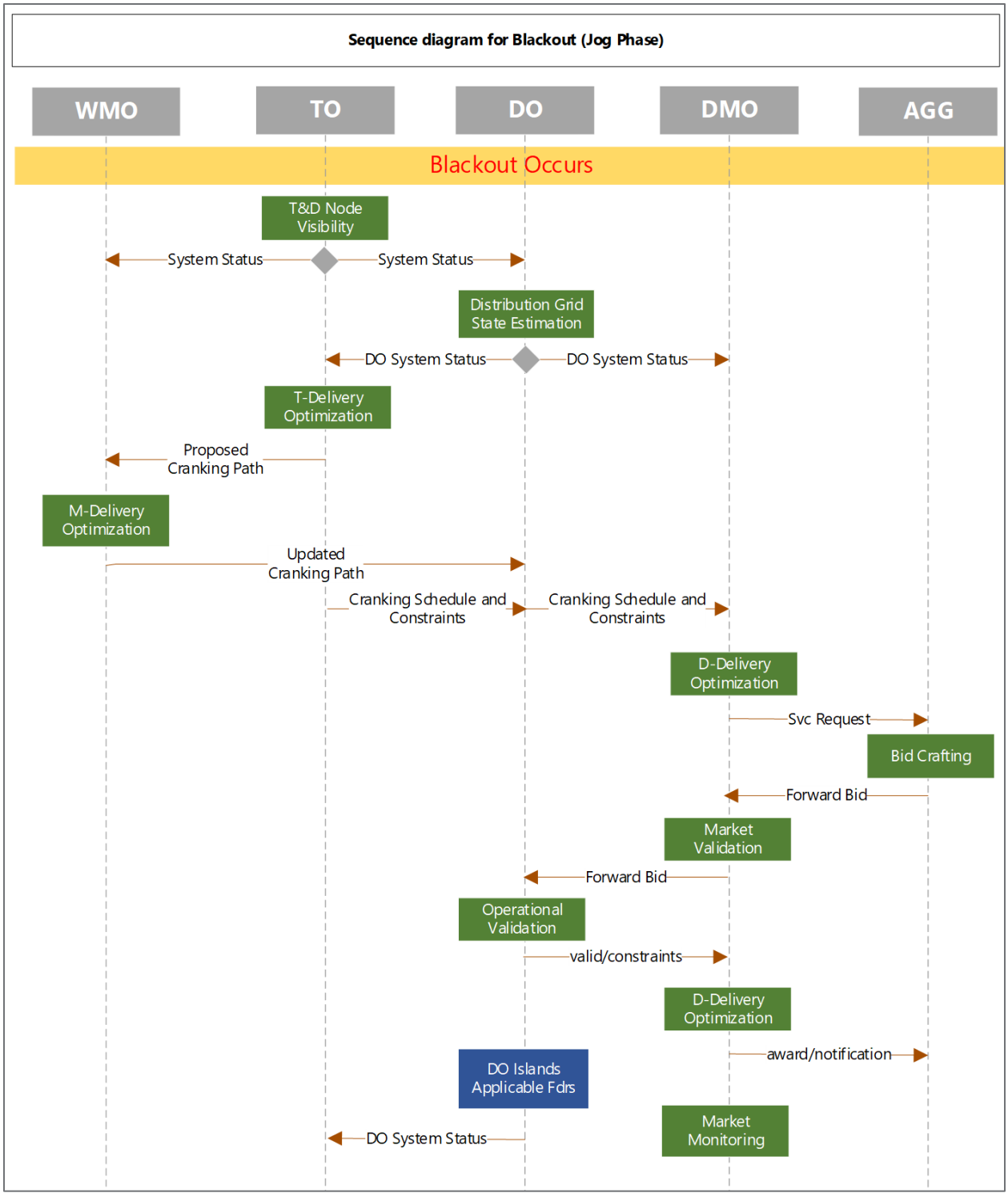


Figure 12.Cascading blackout process diagram for the Jog phase

3.7 RCA Characteristics in the Run Scenario

The Run phase will advance blackstart functionality developed during the Jog scenario to assume that multiple distribution level marketing operators will be involved in engaging distribution assets and coordinating those assets according to their particular DMO but also in lockstep consistency with the cranking path and schedule developed and coordinated between the WMO, TO, and DO. The main difference in the Run phase will be that coordination between the DO, DMO, and AGG will schedule distribution assets, isolate island able feeders from the bulk system, and blackstart those feeders without support from the WMO or TO. All related market actions and control actions will be coordinated.

The Run phase is anticipated to employ the modules in Figure 13 shown as green boxes. The modules are activated similar to the Walk and Jog phases, however more advanced functionality and coordination are developed as follows:

- *Timeframe:* the timeframe could range from minutes to many weeks depending on the severity and cause of the blackout. Plus, timeframes between events could be vastly different between the bulk and distribution levels. Therefore, modules will need to comprehend and contend with event specific conditions and timeframes commensurate with the position on the grid and conditions of the blackout.
- *Distribution System State Estimator:* this module will perform functions to predict the ongoing health of individual feeders or feeder collections at the substation level. The state estimator module will provide initial health predictions over expected time durations as determined by cranking schedule developed by the WMO and TO. Thereafter, the state estimator will provide ongoing current health and health predictions as the blackstart continues.
- *Delivery Optimization module*: this module will determine if feeders can be islanded or be operated partially to support the blackstart process.
- The remaining modules will operate as they did in the Walk and Jog phases.

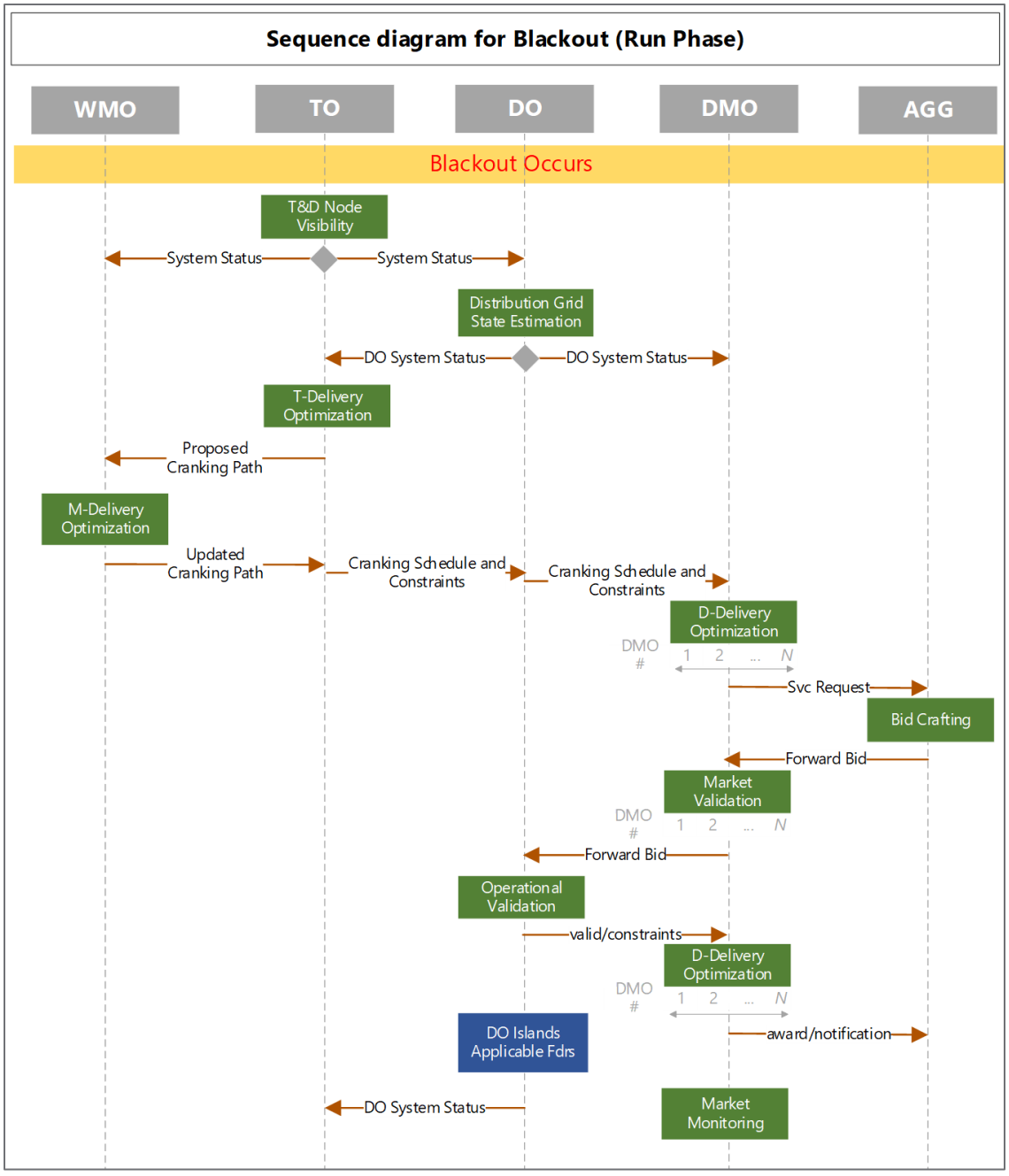


Figure 13. Cascading blackout process diagram for the Run phase

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