

PNNL-37902

Reference Coordination Architecture

April 2026

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operated by
BATTELLE
for the
UNITED STATES DEPARTMENT OF ENERGY
under Contract DE-AC05-76RL01830

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Prepared for
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Acknowledgments

This project was supported by the Department of Energy, Office of Electricity. The authors would like to thank Joe Paladino, William Parks, and Sandra Jenkins for their support and contributions to shaping the scope and direction of this work. The authors would also like to acknowledge the following for their contributions and invaluable insights and feedback received throughout the architectural development process.

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Executive Summary

The electric power grid is becoming more complex and harder to manage because of third-party connected assets and devices, aging infrastructure, changing physics, and electricity demand growth (DOE 2024b). Asset coordination for both operations and planning are important to maintain and improve grid affordability, security, and reliability. Improved coordination of existing and planned assets will also enhance grid services, lower energy delivery complexity, and defer capital investments (EPRI 2021). Industry experts have also acknowledged the need for significant evolution in how grid assets are coordinated with operations and evolving market structures to reduce cost and complexity.[2] Additionally, new system capabilities and stacked value streams will enable coordinated optimization of resources on both transmission and distribution, as well as market and program participation.

The Department of Energy has undertaken the development of guidance to support industry stakeholders, which includes the development of a reference coordination architecture (RCA) that provides a framework that can reduce integration challenges and address key requirements when developing solutions to meet near- and long-term objectives. The RCA includes details to support a standards-based approach to meet the needs of roughly 3,000 utilities with their various operational, regulatory, and market structures, where interactions with multiple entities exist. This RCA provides the principles, requirements, and structure for the coordination framework, which consists of coordination modules designed to accelerate customer access to power system value streams.

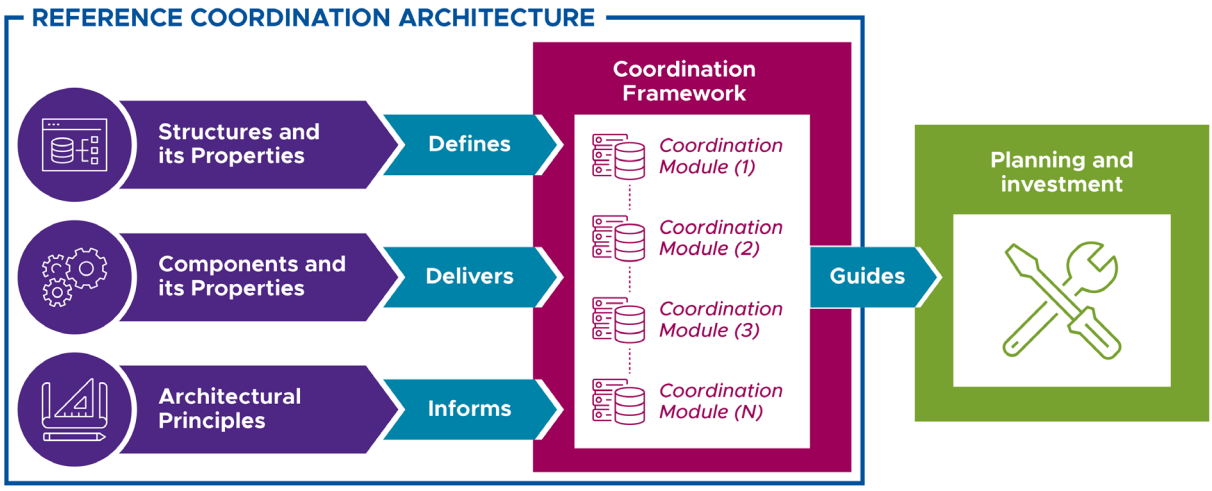


Figure ES-1. Reference Coordination Architecture Composition

The RCA describes how components of the grid must interact and the requirements for those interactions, as illustrated in Figure ES-1. This RCA composition, specifically architectural principles, has been adapted from grid architecture elements (Taft 2016b). Roles and responsibilities are assigned based on the ownership of a system or subsystem functionality, allowing the proposed framework portability to a variety of jurisdictions with differing requirements or compositions. This type of Grid Architecture-based framework allows decision-makers to invest in solutions that address short-term goals without losing sight of long-term objectives. Consequently, it guides investment planning to help reduce costs and prevent

wasted investment in temporary solutions that would need to be re-engineered to meet future needs.

Example benefits to coordination are the ability to strategically procure and optimize resources. Current distribution resource sourcing methods often involve uncertainty and risks regarding operational performance (DOE 2024a). Risks include the complexity of coordinating the provision of grid services among multiple entities (DOE 2023a). For example, aggregators bidding distribution resources into wholesale markets without the Distribution Operator's awareness and approval, which could negatively impact the distribution network. As distribution service opportunities and sourcing methods evolve, coordination will not only be desirable for optimization but required for efficiency and reliability. Based on Grid Architecture interdependent structures and highlighted in Figure ES-2, the RCA aims to address these capabilities to evolve with power system needs and market opportunities.

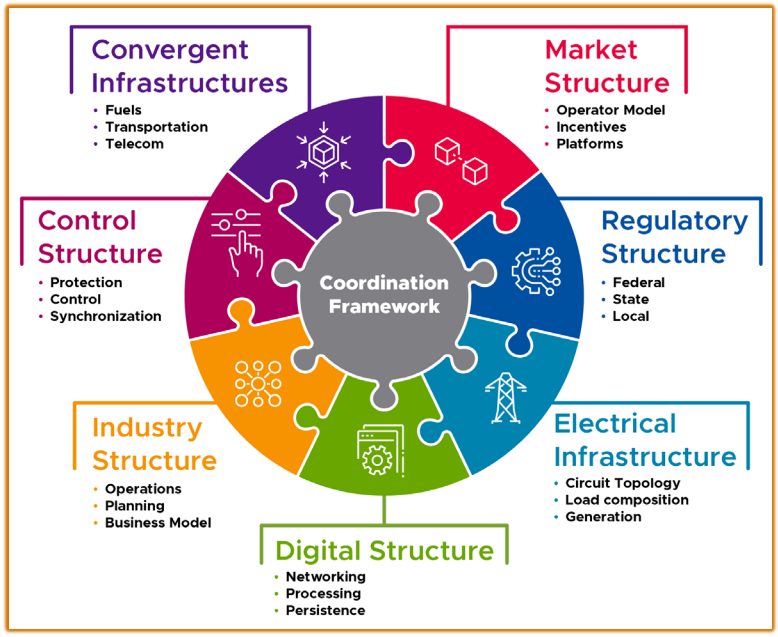


Figure ES-2. Grid Architecture Structures

The RCA is intended to have broad application across and between jurisdictions and at various levels of maturity. Initially, case studies will validate the architectural structure and interaction requirements that have been developed. This includes ensuring that market and operational data, functions, and interaction requirements have been satisfied. The next phases implement basic or otherwise "generic" modules or functions with the required inputs and outputs to meet basic application needs. This basic coordination will be referred to as the "walk" phase of the RCA, where coordination is used but decision-making is centralized within the responsible entities system characterized by the wholesale market as the main lever.

As the "jog" and "run" phases of the coordination framework are implemented, the case studies and the coordination functions evolve. For example, the jog phase will apply coordination at multiple layers within the network. This includes enabling the use of advanced sensor networks, distributed computational capability, and a data management pipeline that considers what data at what level of granularity needs to exist throughout the system. The "jog" case also reflects a fully deployed distribution service market and real-time clearing. In the "run" phase, even more advanced coordination enables the system to respond to highly localized constraints. Consider

distribution pricing nodes, energy transactions between edge assets, and autonomous distribution reconfiguration to support complex optimization or reliability issues. Each of these case study phases will aim to meet ever-increasing affordability and resilience objectives to enable system stabilization, optimization and growth.

Acronyms and Abbreviations

ADMS	Advanced Distribution Management System
AEP	American Electric Power
AMI	Advanced Metering Infrastructure
BPS	bulk power system
CAISO	California Independent System Operator
DER	Distributed Energy Resource
DERA	Distributed Energy Resource Aggregator
DERMS	Distributed Energy Resource Management System
DO	distribution operator
DOE	Department of Energy
DSO	distribution system operator
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
I/O	Input/Output
MO	market operator
MW	megawatt
NERC	North American Electric Reliability Corporation
SCADA	Supervisory Control and Data Acquisition
T&D	Transmission and Distribution
TO	transmission operator

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1.0 Introduction

The average U.S. power infrastructure is aging, while simultaneously supporting significant growth in power consumption to support consumer and commercial needs. Coupled with extreme weather events and exponential load interconnection applications, this has led to a decrease in reliability in many parts of the country. Consumers have turned to onsite generation and distributed energy resources (DER) as a means to improve the reliability of their electricity supply while simultaneously reducing their overall electricity costs. These consumer-owned and third-party resources come in many forms, including natural gas and diesel backup generators, energy storage, solar panels, and controllable loads (demand response) that are located near the point of use, rather than at a centralized power plant. These technologies can be underutilized if only supporting local consumer needs and often sit idle when not being used for that purpose.

In the United States, the DER market is anticipated to nearly double between 2022 and 2027, with behind-the-meter capacity comprising a significant portion of that growth (Wood Mackenzie 2023). With more than half of the U.S. states already pursuing the use of DER through DER programs, utility-owned energy storage, and third-party grid services (DOE 2024b), access to these resources is expected to enhance reliability and address customer affordability, including deferred and potential avoided capital investments (EPRI 2021). This is especially advantageous for DER owners and system operators in regions where pricing is expected to increase or is highly variable. While providing opportunities for DER to participate in wholesale markets, Federal Energy Regulatory Commission (FERC) Order 2222 (18 CFR 35) also recognized challenges and includes guidance related to coordination between distribution, transmission, and DER owners/operators.

Industry experts have also acknowledged the need for significant evolution in how these resources are coordinated with grid operations and evolving market structures to reduce cost and complexity (EPRI 2021). Additionally, new system capabilities and stacked value streams will enable highly coordinated optimization of grid-edge resources, transmission and distribution, and centralized generation, as well as market and program participation. This topic has received considerable attention across the industry and has been highlighted by the coordination requirements expressed by FERC.

The Department of Energy (DOE) has undertaken the development of guidance to support industry stakeholders, which includes the development of a reference coordination architecture (RCA) that provides a framework that can reduce integration challenges and address key requirements when developing solutions to meet near- and long-term objectives to a variety of stakeholders such as market operators (MOs), transmission operators (TOs), and distribution operators (DOs) (PNNL n.d.). The RCA is intended to enable customers to access the larger power grid, providing the opportunity to benefit from additional value streams and provide wider system benefits to reliability and peak reduction. The RCA includes details to support a standards-based approach to meet the needs of roughly 3,000 utilities with their various operational, regulatory, and market structures, where interactions with multiple entities exist. This RCA provides the principles, requirements, and structure for the coordination framework, which consists of coordination modules designed to accelerate customer access to power system value streams; see Figure 1.

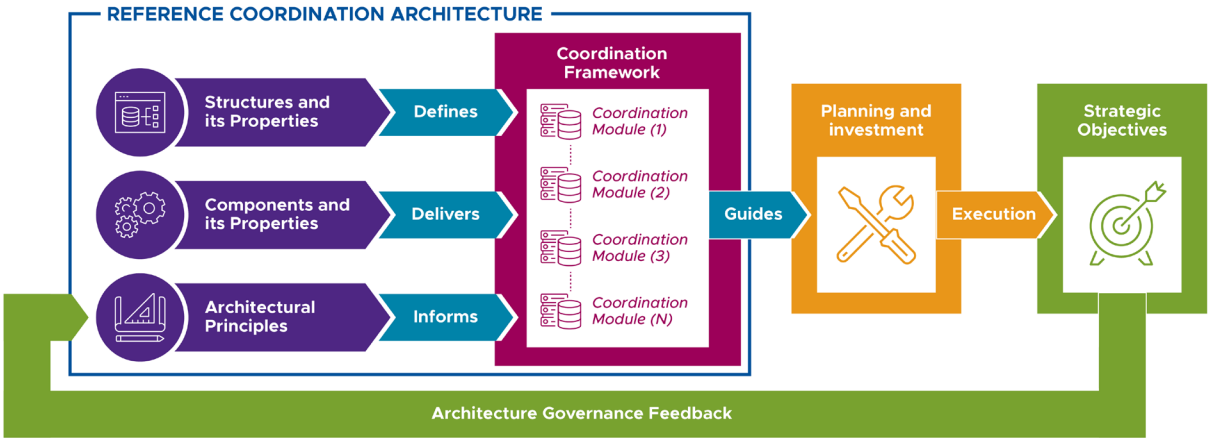


Figure 1. Reference Coordination Architecture Composition

A modular design of the RCA is essential, allowing each module to be adaptable and configurable based on jurisdictional requirements and preferences. Each module includes inputs and outputs to support integration but abstracts from the internal algorithms and techniques which are variable to specific entities, regions, and other jurisdictions. In this context, a modular framework refers to an integrated system of "building blocks" that meet functional requirements. These modules can be grouped and assembled flexibly to satisfy local or jurisdictional coordination needs. It includes standards-based definitions of inputs and outputs and employs a "black box" approach, where customization can occur within modules. These subsystems are then linked or architected via pre-defined, common information flow into a larger system based on varying stakeholder roles. This approach allows for innovation within the black box while ensuring the interoperability of interfacing systems, regardless of their operational and ownership structures. This is illustrated in Figure 1, which is similar to Figure ES-1 but expands the conceptualization to fit the strategic or long-term objectives of stakeholders into the RCA.

Additionally, roles and responsibilities are assigned based on the ownership of system or subsystem (module). This enables portability to a variety of jurisdictions with differing requirements or compositions. This type of Grid Architecture-based framework not only promotes applicability across the industry but also allows decision-makers to develop solutions that address short-term goals without losing sight of long-term objectives. Consequently, it helps reduce system development costs and prevents wasted investment in temporary solutions that would need to be re-engineered to meet future needs.

The RCA allows for the identification of systems and subsystem requirements, including those that need to evolve or are yet to be developed. As mentioned previously, roles and responsibilities are assigned based on the module rather than a specific design, which enables portability across jurisdictions. This approach facilitates coordination between systems and entities, ensuring scalability through hierarchical or fractal structures.

The coordination framework modules are based on the coordination requirements described in FERC Order 2222, as well as various stakeholders' feedback and interpretations. These modules are aligned with prior work from the DOE and the Electric Power Research Institute (EPRI), which provided high-level functional guidance without delving into information exchange requirements or standards involved. They also align with the near-term and long-term objectives based on Integrated Distribution System Planning programs and other planning activities, many

of which are either regulatory requirements of utilities or under development, or part of funding requests to regulatory entities (LBNL n.d.).

The RCA will be validated with case studies, necessitating the development of specific modules tailored to the unique needs of each case study. These modules will be limited in scope to effectively validate the RCA, meaning they will be evaluated as “black boxes” focused on interactions rather than complex and custom algorithms. The case studies will follow a “walk, jog, run” approach, addressing near-term needs while facilitating long-term objectives. Near-term, or “walk” capabilities include the resolution of conflicting objectives between DO, TO, and customers, including issues like tier bypassing and balancing customer preferences. Longer-term, these same capabilities, along with other grid functions, will help address challenges such as distribution congestion and enable capabilities like local energy markets and dynamic grid structure.

With increased visibility at the grid edge, the availability of distribution-level value signals, and distributed compute capabilities, enhancements to reliability and resilience will be enabled while reducing operating costs. In the most advanced scenarios, distributed controls, energy sharing, and multi-level/objective optimization will allow for local challenges to be anticipated and addressed in near real-time. In this report, this is referred as a “run” state, where this highly dynamic and flexible system can leverage high levels of local visibility to reconfigure or self-heal, optimizing generation based on local constraints such as voltage support or increased distribution-level pricing.

2.0 Transmission, Distribution, and Customer Coordination

To address the increasing energy demand and facilitate cost-effective investments, the RCA offers guidance for planning, strategic investment, and the development of applications. The operational coordination framework aims to accommodate DER, markets, and operational concerns and various near-term and long-term grid structures. It is designed to be flexible to support the jurisdictional variability of roles, defining a standard-based, modular framework grounded in Grid Architecture based principles, concepts, and structures (PNNL n.d.). This framework aims to enable a power system that is reliable, flexible, and affordable. The coordination requirements align with the recommendations of FERC Order 2222 and incorporate insights from industry experts, including the DOE, EPRI, utilities, technology developers, and other stakeholders.

Current DER sourcing methods require over-subscription based on uncertainty and risk (DOE 2023a, 2024a). An example of functional risk is service dependability and grid reliability, and how the market participant ensures that the resources will be available at a given time. Complexity risks include aggregators bidding distribution resources into wholesale markets without the DO's system analysis and approval, which could negatively impact the distribution network. As distribution service opportunities and sourcing methods evolve, coordination will not only be desirable for optimization but also required for efficiency and reliability. Based on RCA interdependent structures highlighted in Figure 2, the RCA aims to address these capabilities in a way that can evolve with power system needs and market opportunities.

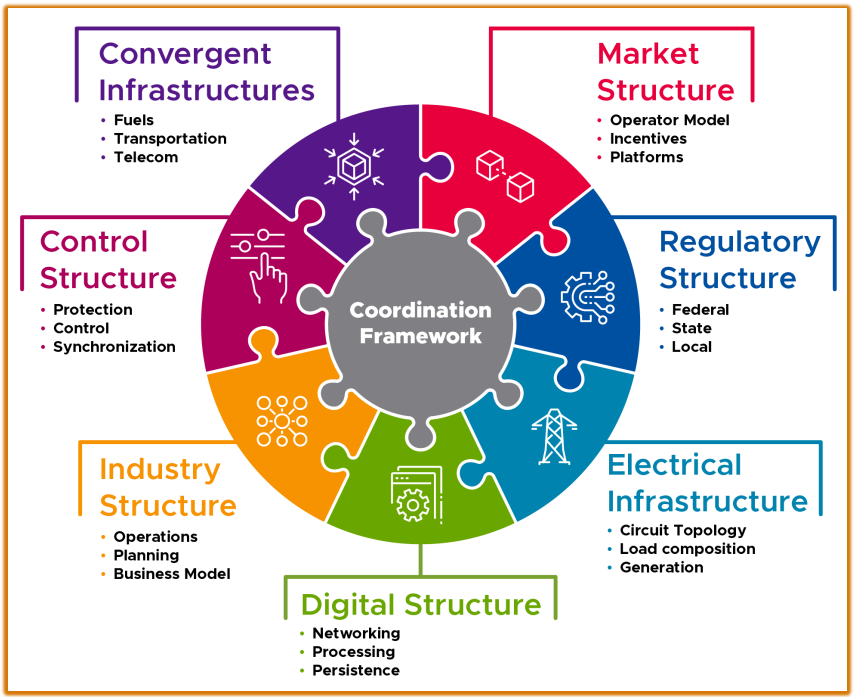


Figure 2. Grid Architecture Structures

The industry model for this RCA assumes the TO and DO are responsible for managing the transmission and distribution systems, respectively. To ensure applicability across different jurisdictions and support capabilities not fully realized in the United States, such as distribution pricing nodes, the MO serves as the market coordinating entity responsible for energy

transactions and their management. Currently, in the United States, this role is primarily fulfilled by Independent System Operators (ISOs) or Regional Transmission Operators (RTOs) to support bulk power system (BPS) services. This is evolving through new policies which allow aggregators to participate in wholesale markets and utilities sourcing non-wire alternatives, e.g., DER and demand response, through programs. Alternative distribution markets are emerging in Europe and Australia and being investigated in the United States. When implemented, the RCA enables effective communication, data exchange, and decision-making among the TOs, DOs, MOs, and customers or their designated agents (e.g., aggregators) to support a more reliable, resilient, flexible, affordable, and sustainable energy system.

Additionally, there are recent and ongoing investigations in the UK into the use of a Distribution System Operator (DSO) model where the DSO may facilitate prosumer energy-related transactions (De Martini et al. 2015). This model is gaining traction in Europe, where similar guidance relating to coordination is needed. The MO role would cover market-related activities of the Independent System Operator and Regional Transmission Operator and would provide a flexible way to describe similar activities where a DSO exists or some other future state where customers can directly provide services.

In order to meet near-term energy service requirements, this RCA document references aggregators and market participants. These actors can be synonymous, and, in this context, the “aggregator” refers to a customer's agent that combines, or groups, DERs to meet capacity requirements for market participation. This role can be undertaken by a large customer system fulfilling jurisdictional requirements as a direct grid service market participant, or when small-capacity customers are allowed to meet grid service obligations independently (e.g., through aggregator programs).

2.1 Architectural Principles

The RCA presented here follows principles that provide a basis for making informed decisions throughout the user’s design process, ensuring consistency and achieving desired outcomes. These principles are influential in design requirements and ensure that the reference design broadly aligns with energy stakeholder goals and can meet regulatory requirements across jurisdictions. Therefore, these architectural principles address essential structural elements for safe, reliable and resilient operation through the transition to the future grid while meeting near- and long-term business objectives. In this context, these architectural principles represent a level of consensus among various stakeholders and are foundational to building a coordination framework. The interactions among TO, DO, resource aggregators, and individual customers are complex and evolving, and industry-wide standards are lacking. This makes integrated system planning based on flexible and adaptable system architecture critical to ensuring efficient and strategic investment. Key architectural principles are defined in Table 1 (PNNL 2019).

Table 1. Architectural Principles for the RCA

Architectural Principle	Description
Flexibility for distribution network infrastructure, equipment, and controls	Future-proof distribution system infrastructure with the following attributes: distribution network equipment designed for bidirectional power flows; reclosers and protection equipment for future scenarios, enabling microgrids and capable of multiple settings groups; voltage regulation and volt-ampere reactive control considering future topologies; communication networks developed to enable high-volume data sharing; current and voltage sensor deployment with adequate accuracy and connected to distribution Supervisory Control and Data Acquisition (dSCADA), Advanced Distribution Management System (ADMS), and Distributed Energy Resource Management System (DERMS).
Stabilize-by-design	The architectural design must enable evolution of operation through advanced, distributed, and redundant controls. This means the design must be flexible, considering current, primarily centralized, utility-operated systems while also considering how grid-edge resources and increasing levels of sensors and computational power, both centrally and distributed, will be able to enhance the reliability and resilience of the electricity supply for all customers, necessitating coordinated planning.
Tier bypassing awareness	With multiple actors involved in the control of edge resources, the creation of information flow or instruction/dispatch/control paths that skip a tier of the power system hierarchy (e.g., aggregators responding to TO service opportunities without having their bid-participating DER assessed by the DO for power quality possible problems) creates risk, thus opening the possibility for creating operational problems. Any interactions that may impact operations across multiple regions or jurisdictions must be coordinated to mitigate or eliminate such risk.
Latency optimization	Due to the integration of multiple systems and organizational layers, the serial data/information flow creates bottlenecks, leading to extended latencies that hinder real-time and near-real-time monitoring, protection, and control capabilities in the electric distribution system. Data pipelines should be designed to provide the right information to the right location in the timeframe necessary. Distributed sensor networks and computational capabilities must be leveraged to implement data management strategies to reduce or eliminate latency challenges.
Scalability	The ability of a system's processes and technology design will need to support very large quantities of DER resources and controllable loads. The coordination framework will need to support an increasing number of DER and interactions between owners, operators, and third parties as well as their assets.
Observability	Functions related to operational visibility of the transmission/distribution interface, distribution network, and DERs (and their owners/operators) to enable control action decision-making will enable coordination between stakeholders. Sensing and data management can provide insights into system behavior for control and grid management purposes, enabling decision-making based on grid state. The data can also be utilized to validate planning models. Observability needs of the DSO and the transmission system operator (TSO) depend on how roles within the RCA are specified, and on aggregated amounts. Observability extends beyond power flows to include market monitoring along with DER capabilities, locational attributes, and operational states.
Cybersecurity robustness	While this topic has many dimensions, the principle here is to reduce cyber vulnerability risks through architectural structure. Structure can expose bulk

Architectural Principle	Description
	power systems to more or less vulnerability depending on the data flow structure, which depends on the coordination framework. Access and information should be constrained to an as-needed basis. The RCA risk assessment for cybersecurity will be addressed on a continuous process and a subject of another volume.

2.2 Architectural Concepts of the Coordination Framework

The RCA enables effective communication, data exchange, and decision-making among the TOs, DOs, MOs, and customers or their designated agents (e.g., aggregators) to support a more reliable, flexible, affordable, and sustainable energy system. The intent of the RCA is to accommodate a wide variety of ownership models, business objectives, and requirements that will likely necessitate a combination of systems that are integrated to enable coordination. This RCA supports the structures and multitude of functionalities that are tied to the DER coordination, operational coordination, and market coordination based on Grid Architecture concepts, including layered decomposition and laminar coordination (Chiang et al. 2007; Taft 2016a). These techniques provide scalability and adaptability through a system of systems engineering design. From the technological standpoint, the proposed coordination framework is modular, technology-neutral, and consists of multiple coordination blocks based on integration requirements. The functional coordination modules can be specialized based on jurisdiction, ownership, and roles. This methodology is adaptable, connecting multiple systems to exchange information between them seamlessly and securely. The coordination modules that make up the coordination framework should have well-defined interfaces that support the interoperability requirements of different entities and adopt recognized and widely adopted standards and protocols. This section describes key architectural structures of the coordination framework.

2.2.1 Coordination Platform Concept

The conceptual coordination platform shown in Figure 3 outlines the various systems, typical entities that manage them, and an abstract view of the functionality required for the operational and market coordination to enable the benefits of DER utilization among aggregators, MOs, TOs, and DOs. While this diagram provides insight into a complex system involving multiple stakeholders with business and critical operational roles and various subsystems that require coordination, the RCA elaborates on the characteristics and functions of the Shared Coordination Platform (blue coordination boxes).

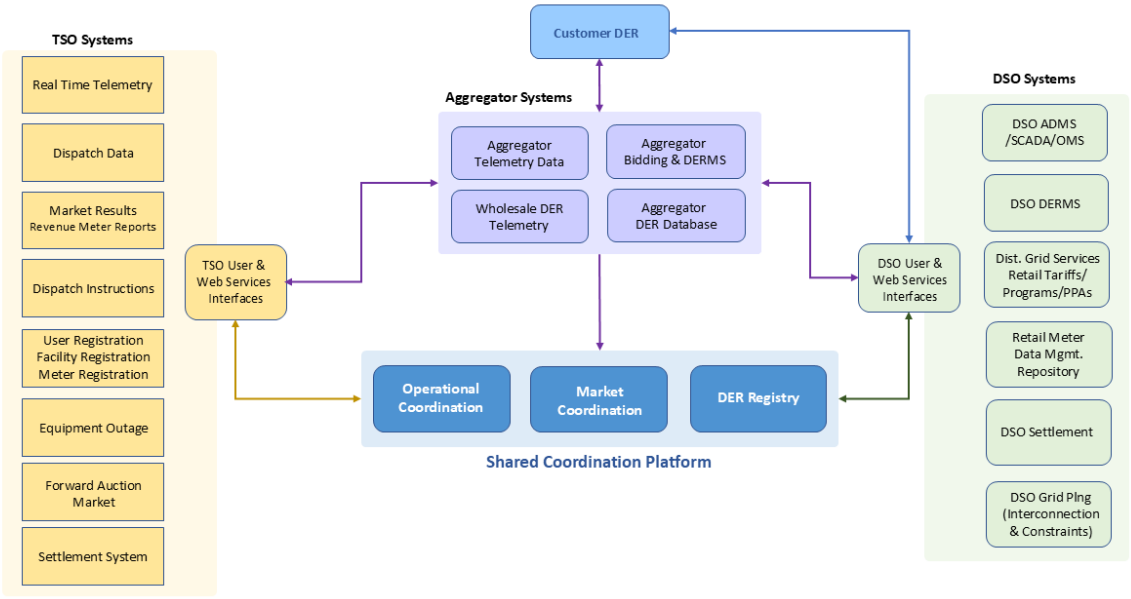


Figure 3. Conceptual Coordination Platform (Source: DOE. 2024. *TSO-DSO-Aggregator Market and Operational Coordination Requirements*)

2.2.2 Coordination Architecture Layers Concept

Knowledge graphs aid in the identification of interdependent functions or concepts. By visualizing and then evaluating the dependencies, system designers can identify the data inputs that must be provided between modules and domain layers. For example, an asset registration module must be able to capture sufficient information to facilitate both market and operational coordination; information such as locational attributes is necessary to avoid issues such as tier bypassing.[1]

Figure 4 shows the knowledge graph articulating the proposed reference conceptual RCA attributes. It maps the functional modules (ovals) that support coordination while also capturing the relationships, exchanges, and dependencies that exist among them (e.g., *manages, constrains, informs*). An example is *Asset registration Manages* the *DER registry*. The solid arrow lines are for intra-layer relationships while the dashed arrow lines are for inter-layer relationships.

This knowledge graph provides decomposed conceptual guidance that helps coordination application developers and stakeholders identify requirements and interactions between modules to achieve various Transmission-Distribution-Customer (or Customer Agent) coordination objectives, which are referred to as transmission, distribution, and customer objectives in this document.

[1] Tier bypassing occurs when a DER aggregator attempts to offer services to a wholesale market (a higher tier) without properly coordinating with the local utility distribution system (a lower tier).

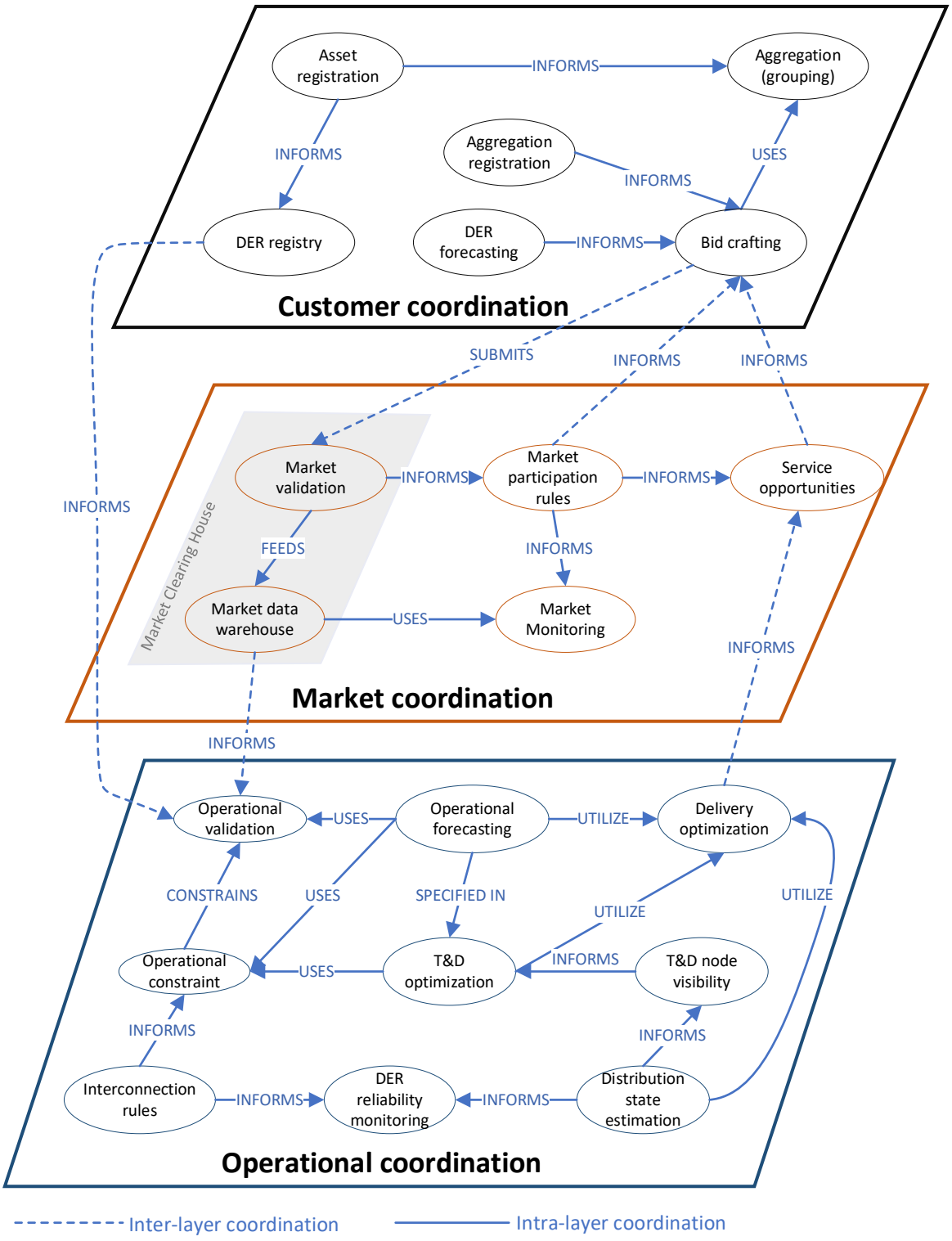


Figure 4. Reference Coordination Architecture Knowledge Graph

The RCA adopts a layered coordination framework, shown in Figure 4 where system components are organized into functional layers based on domain. Each layer encapsulates a set of modules aligned with a specific coordination domain, with each module being assigned a

unique goal. As part of this approach, a module's internal mechanisms do not need to be known, and instead the focus is set on defining the interfaces and functional goals that must be satisfied. By abstracting specific details within each functional application, this design strategy is expected to reduce the complexity of the coordination modules while also enabling system flexibility as well as future extensibility and specialization through a modular framework.

This approach also defines interaction requirements between different functionalities, meaning clear boundaries exist between different functions or modules. The roles and responsibilities are associated with the module, and therefore the actor who owns or otherwise manages that capability also carries the associated roles and responsibilities.

To cost-effectively engage grid-edge resources such as DER, which were procured for the benefit of their owner, they will likely require compensation through value-based mechanisms, including price signals. Thus, the coordination framework places the market coordination layer between the operational and DER coordination layers. Though near-term case studies will be based primarily on wholesale market participation and FERC orders, similar value-based mechanisms evolving in the distribution system and microgrids (Mengelkamp et al. 2018; Triolo et al. n.d.). Registered DERs may provide grid services for bulk system and distribution needs while simultaneously ensuring operational coordination requirements are met through this coordination layer (Kolln et al. 2023).

2.2.3 Sensor and Data Exchange Architecture Concept

To achieve the various operational, market, and DER coordination requirements grid sensors residing within or at the boundaries of the various actor domains must provide the information required by the actors for exchange information across the domains and throughout the coordination modules. This is a key factor in meeting the "observability" principle mentioned previously. The use of diverse standards and (sometimes proprietary) protocols depending on the actors and technologies involved creates challenges to integration, including a lack of flexibility, service fragmentation, and data silos. All of these create unnecessary financial burden, and consideration should be given to align information and data models, with as few custom interfaces as possible.

FERC Order 901 directs North American Electric Reliability Corporation (NERC) to develop new or modified existing reliability standards that address reliability gaps to inverter-based resources (IBRs) (18 CFR Part 40). The order mandates that generator owners, TOs, and DOs to share accurate modeling, planning, operations, and disturbance monitoring data for all IBRs (registered, unregistered, and aggregated distributed energy resources - DERs). Any coordination framework data-sharing architecture should comply with FERC Order 901, as it indirectly supports improved coordination between transmission and distribution systems by emphasizing data sharing and modeling for IBRs.

Coordination modules rely on both computing and communication capabilities (see Figure 5). To address the computational needs, processing capabilities must be provisioned throughout the grid to enable decision-making closer to edge resources, while also helping to increase system resilience. Similarly, communications must continue to provide reliable connectivity among all participants, essentially becoming ubiquitous. By leveraging the evolving capabilities of modern communication networks, sensing devices, and distributed computing systems, the necessary infrastructure to support the coordination framework can be gradually achieved.

Below are some key architectural considerations for the coordination framework from a sensor and measurement perspective:

- Have standards-based interfaces that enables actors to exchange data while abstracting hardware and software differences, thereby offering a system-agnostic approach to data exchanges.
- Leverage the use of uniform data models to support DER coordination, while providing key constructs to support future data needs. For example, registry data could complement the data exchange requirements required by FERC Order 901 thereby supporting interoperability . Access to uniform data models can also help fulfil the needs of NERC's Reliability Standard MOD-032-2, which seeks to increase visibility into retail-scale (behind the meter) resources
- Provide a scalable, flexible architecture that borrows from the internet's decentralized operational model—enabling system participants to dynamically participate ŧusing well-defined procedures, further facilitating interactions among distinct participants/systems, and have provision to accommodate current and future structure variability.
- Leverage the use of decentralized controls (distributed computing) and ubiquitous network communication infrastructure to provide data exchange capabilities among all system participants, enabling coordination among them.
- Employ a hybrid communication approach in which real-time operational needs continue to rely on session-based communication, while near-real-time coordination leverages an asynchronous messaging model. In this model, messages are exchanged and delivered independently of receiver availability and requirements, using mechanisms such as fault tolerance, message persistence, and assured delivery to prevent the loss of coordination data and enhance overall system availability.-This hybrid communication approach has achieved a common virtualized information sharing layer on top of the sensor network.
- Data access can be authorized using role access mechanisms to ensure information access is provided on a need-to-know basis and that the privacy of involved stakeholders is maintained. Such a requirement can enable participants to maintain business competitiveness while also facilitating coordination with other stakeholders.

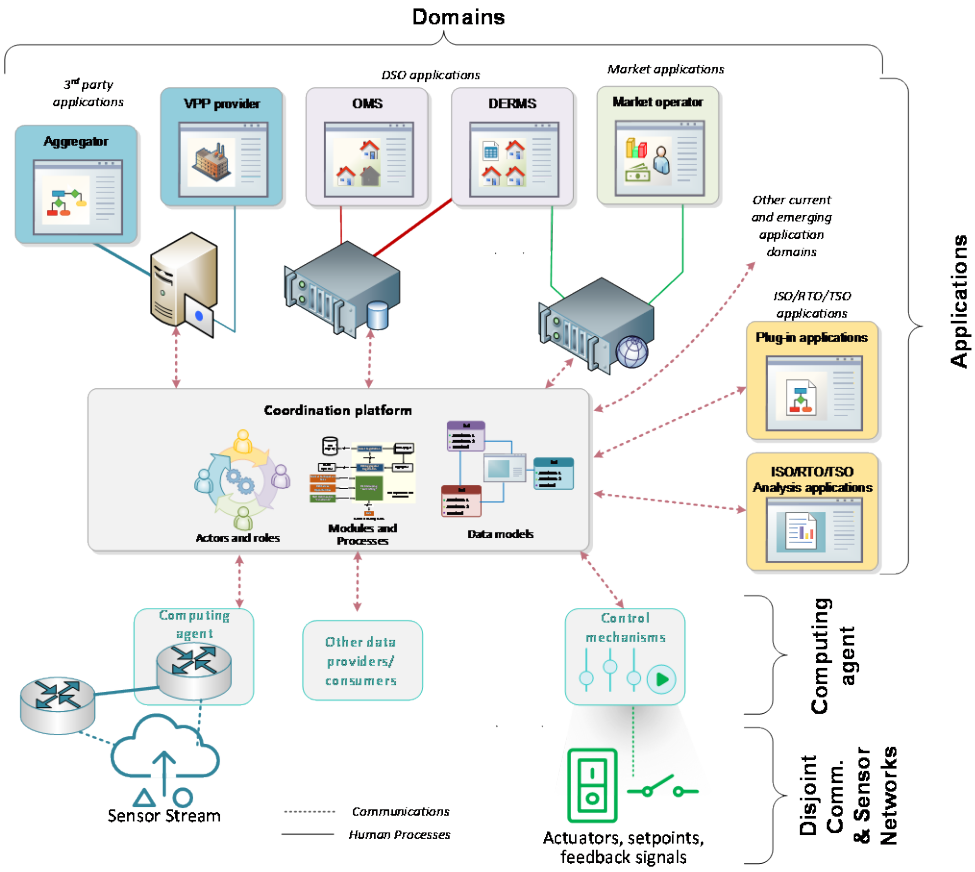


Figure 5. Underlying Applications, Sensor and Communication Network

2.3 Coordination Framework Cybersecurity Requirements

To protect sensitive data and ensure operational integrity while coordinating between multiple entities, the coordination framework should have robust cybersecurity measures in place. From inception, the framework should adopt secure-by-design and cyber-informed engineering concepts to ensure that the coordination modules provide the necessary cybersecurity features to meet the reliability and resilience goals while enabling secure information exchange among participants. The framework should implement a zero-trust architecture, ensuring that all actors are continuously authenticated and authorized before accessing system resources. By incorporating basic cybersecurity constructs into the modules, market participants using them have control over their data through mechanisms like role-based access control (RBAC) and reducing data misuse.

From a coordination framework perspective, this means that mechanisms must be in place to ensure system participants with competing interests maintain business competitiveness. This, for example, may include limiting the amount of information that an aggregator must share to ensure their business model operates as a free market or that the customer's Personally Identifiable Information (PII) remains private (from the perspective of TOs, MOs, and other customers). Typical examples may include: (a) developing modules to secure the DER registration and DER discovery process while maintaining ownership and operational boundaries, (b) securing end-to-end configurations (e.g., securing routing and Quality of Service

settings), and (c) providing configurable data in transit and data at-rest security guarantees. Additionally, to ensure the reliability and integrity of coordination operations, interacting systems should use secure communication channels and protocols. For example, communication paths must be protected against well-known cyber threats, such as unauthorized access, data tampering, and denial-of-service attacks.

In addition to the aforementioned advantages, by integrating strong cybersecurity features as a fundamental block of the coordination framework, trust among different system participants can be strengthened. For example, by embracing non-repudiation features, system participants can be held accountable for their actions by ensuring any coordinated actions can be traced back to the agents involved in the decision process. Furthermore, by providing security as a fundamental capability, participating entities may be able to fulfill or justify adherence to security mandates. This might be particularly relevant toward fulfilling well-known industry requirements, such as the Critical Infrastructure Protection (CIP) family of standards published by the NERC (the so-called “NERC CIP” standards) (NERC n.d.), the International Electrotechnical Commission (IEC) 62443 family of standards (IEC 2026),[2] and the CISA Secure by Design best practices (CISA 2024). In particular, standards such as NERC CIP require qualified entities (e.g., TSOs) to establish effective cybersecurity practices to secure relevant data objects, application programming interfaces (APIs), and computing resources.

By providing key cybersecurity features and certification, the use of RCA should be addressed at the module level. However, if the capabilities of multiple modules exist within one system, compliance certifications can be grouped together for simplification. This is particularly true in the current environment, where certification procedures often require that collaborating entities operate within the same set of security baselines. To reduce the cyberattack surface, the certification processes should leverage digital certificates that allow for the issuance, revocation, and renewal of security evaluations to indicate if individual systems conform to the agreed security baselines through the coordination modules.

Below is a list of the required security features that should be applied across modules. The modular approach of distributing security features across different functional blocks addresses cyber risk while contributing to the overall resilience of the entire ecosystem.

- Authentication service capabilities—provides the means to verify the identity of the application and/or actor that invokes (or executes) functions within the coordination framework. Includes mechanisms to perform mutual authentication between participants and establish a shared secret.
- Access control service capabilities—provides the means to enforce policy decisions on what an authenticated user/system can perform within the coordination framework. This coordination framework also facilitates secure collaboration by defining roles that allow controlled data sharing (e.g., DER registration data) while maintaining the separation of duties between entities. For example, by assigning a role, the coordination framework ensures that the TO has access only to the required DO data without gaining full access to the local grid operation.
- Cryptographic service capabilities—during information sharing, the framework should provide access to appropriate cryptographic operations such as encryption, decryption,

[2] The IEC 62443 series was developed to secure industrial automation and control systems (IACS) throughout their lifecycle. It currently includes nine standards, technical reports (TR) and technical specifications (TS).

hashing, and digital signatures to protect data in transit and at rest. This includes the ways to derive keys from a shared secret.

- Logging, monitoring, and auditing service capabilities—supports log capture, auditing of security-relevant events and Timely Product Vulnerability Disclosure Reporting.

3.0 Coordination Modules

The RCA framework is decomposed into modules, which interact with corresponding functional requirements. The interactions between modules follow the architectural concepts as described in Section 2.2.2 and shown in Figure 4. That description of how coordination occurs across three layers is further described based on the processes expected and how the functional modules will be applied. These coordination modules are designed to be sets of inputs and outputs that provide the interface requirements among them and perform functionalities therein. Further, the information requirements are associated with roles and responsibilities based on ownership and/or management of the respective module.

3.1 DER Coordination

As mentioned in Chapter 2, coordination between multiple stakeholders requires varying levels of information exchange among shared functions and data providers (subject to role-based access). The coordination framework requires several steps of verification of capabilities and roles, many of which have contractual terms associated with them. Registration processes shown in Figure 6 ensure that actors have been approved to participate in market processes and have unique identifiers associated with them. This registration process will be explained later. Additionally, physical capabilities, locational attributes, certifications, and other qualifications can also be validated, as will be explained in the next sub-sections. All of these enable the engagement of DER to provide grid services.

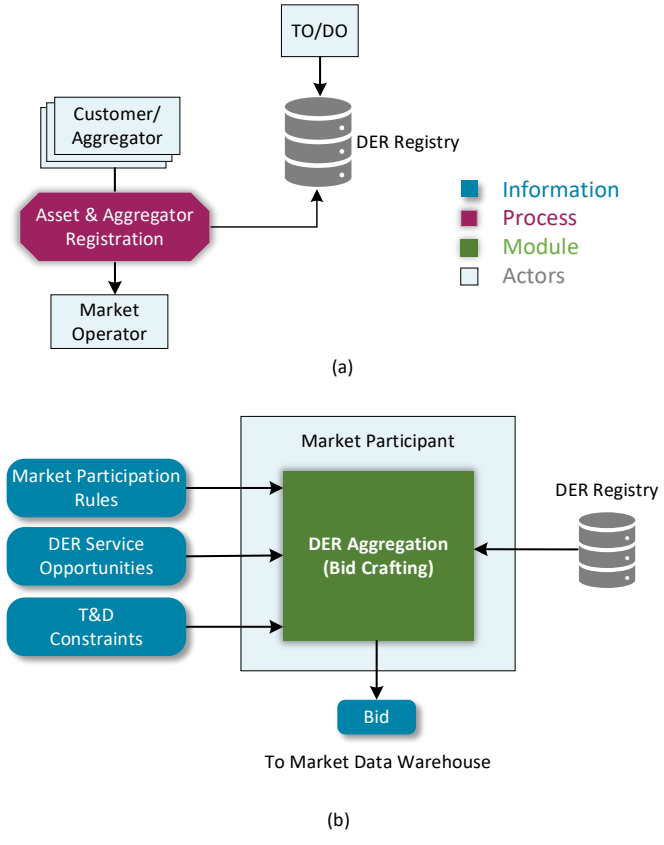
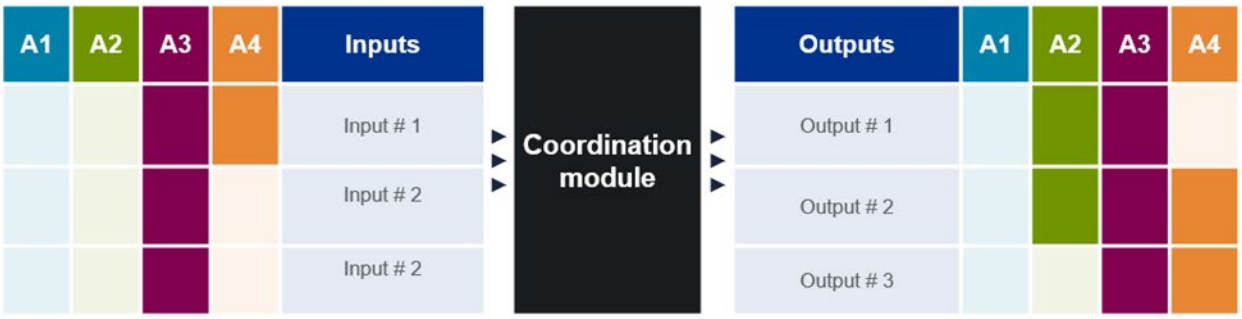


Figure 6. Modules, Processes, and Information Exchange for (a) DER Registration and (b) Bid Crafting

Aggregators will register and go through an approval process to participate in market activities or programs on behalf of DER owners as their agent. Individual DERs must be registered (*Asset Registration*) in a collaborative/shared *DER Registry* (local, regional, or national database) to enable aggregation and market participation. The DO will use this registry to associate the DER with network models and analysis to conduct any required reviews, including safety and reliability assessments. The operational parameters and other characteristics can either be automatically or manually submitted to the *DER Registry* by the DER owner or their agent, e.g., an aggregator or installer. In some instances, the DO may also submit verified DER data into the registry as part of their interconnection process. The *DER Registry* is a key component in coordination, enabling grouping of DER and their provision of services to be validated prior to market award. Based on the roles of the actors accessing the registry, the entities will have specific access, i.e., role-based access, including read or read/write authority. The individual modules and processes involved as part of the DER/Aggregator registration will be explained in the next sections. Each coordination module will be accompanied by a table outlining the *potential* actors involved—identifying those who might be responsible for providing inputs and those that might consume the outputs of the coordination module (see Table 2). These actor roles may vary based on ownership and management structure between jurisdictions.

Table 2. Sample Table Representing a Module and Associated Input/Output (I/O)



At the center, the black-colored block represents a module, while the colored blocks adjacent to the inputs and outputs represent different actors (e.g., MO, TO, DO, aggregator) interacting with that module. Specifically, colored blocks on the left indicate which actors contribute to each input (e.g., A3 and A4 contribute to Input #1), and those on the right show which actors utilize or respond to the outputs (e.g., A2 and A3 respond to Output #1). While the module's structure remains consistent, the specific actors involved in providing inputs or consuming outputs may shift as the grid evolves from its current state (“walk”) to more advanced operational states (“jog” and “run”), reflecting system complication, increased distribution of decision-making, and more flexible grid operations. These may also vary depending on jurisdictional context and ownership or governance of the module.

3.1.1 DER Aggregator Registration Process

For aggregators to submit bids and otherwise participate in markets, they must be registered as market participants with the MO, providing relevant information and agreeing to terms and conditions of service. The information provided may include company information, accounting information, and required regulatory certifications. Once aggregators have completed their registration, they can become eligible to participate in the markets. This arrangement includes modules that enable visibility into market opportunities where access to this and other systems is likely restricted until registration is approved. The aggregator will need a unique ID assigned

to them for any sort of automated processes. Once authorized, they can participate in available DER service opportunities, based on service qualifications, strategically forming optimal DER groups based on service requirements, and initiating the bidding process. It is likely that this registration is an infrequent process and only between two parties; therefore, the function will not have an ongoing role in the coordination framework, but the relevant information from this activity will be referenced, e.g., aggregator unique ID.

3.1.1 Asset Registration Process

Asset registration begins when an owner or their agent seeks to register its assets (or DERs) with an *Aggregator*. An asset can be a DER, controllable load, or a facility containing one or more of these. The *DER Registry* houses detailed information about the asset(s), including its capabilities, location, operational characteristics, and qualifications. Much of this information can be provided by the owner's agent, such as an installer or aggregator. Security and/or other certificates may also be part of the *DER Registry* if it serves as the certificate authority entity. Other information, such as geospatial position or feeder location, may require associated topological information, such as feeder or zone, which will be provided or associated by the DO. Based on this data, the various actors can validate eligibility and capability to participate in programs and align with the types of grid services it is targeting. This *DER Registry* could also aid in group formulation. In particular, the *DER Registry* provides a way for the DO to associate which resources are participating in markets to avoid inadvertent negative impacts to the distribution network. This information might also be used to optimize dispatch between the TO and DO. This assessment will be informed by service opportunities, i.e., operational needs and operational constraints. If the criteria are met, the DO will validate and approve the bid to be submitted to the MO.

Asset registration and group formation may be a dynamic process, as DERs such as electric vehicles may relocate, change aggregators, or enter and exit programs over time. To uphold the integrity of the registry and ensure compliance with business practices, certifications or approvals may be required and housed in the registry, and periodic audits, such as capability validations, may be conducted to identify and remove stale or non-conformant entries. Capability validations could include certificates (such as UL1741SB), inspections, or field validations, which may occur routinely in cases where resources may have variable levels of performance, e.g., energy storage degradation.

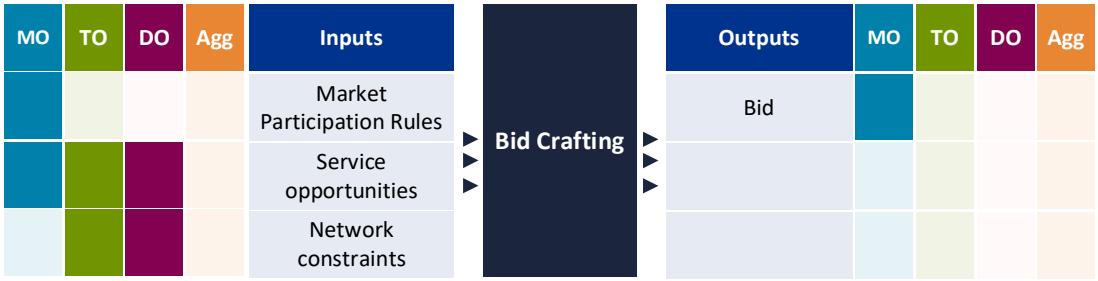
3.1.2 DER Aggregation (Bid Crafting) Module

The *DER Aggregation* module allows an Aggregator to form and manage groups of DERs tailored for market participation based on capability and/or locational attributes. This involves associating key information such as the DER capability, capacity, location, and other operational characteristics. By leveraging this information, the aggregator can identify and select suitable candidate assets or groups that can meet the requirements of a specific service or market opportunity. In parallel, the aggregator can optimize these assets based on the *DER Service Opportunities*,[3] such as frequency regulation and reserve, along with specific requirements for participation in specific services, including minimum aggregation thresholds, flexibility margins, timing attributes, and response characteristics. This is shown as "*Market Participation Rules*" in

[3] DER service opportunities are shaped by the specific needs and operational objectives of the DSO or ISO—whether related to energy, capacity, reliability, or other grid services. Based on these priorities, the DSO/ISO can provide aggregators with a detailed list or map outlining available opportunities to participate in wholesale and distribution-level services.

Figure 6. Additionally, the *Aggregator* may receive grid constraint information from the DO or TO, which can support the formation of suitable DER groups. Although each DER has undergone the interconnection process, it is essential to ensure that group formation and associated dispatch actions uphold grid reliability. The DO and TO can also identify optimal geographic areas for service provision and share this information with the *Aggregator*, allowing them to enhance the value of their service offerings through strategically formed groups.

Table 3. Sample I/O and Actors Involved in the *DER Aggregation* Module



A key output of the *DER Aggregation* module is the generation of offers. Bids are complex objects that must capture large amounts of information (see Table 4). First, a bid must specify the offer itself, including the quantity and offered price. Second, it must clearly identify both the market participant, e.g., aggregator, and the set of DERs represented within the bid, typically through a mapping function such as a list of DER's IDs or an aggregation ID that resolves to a grouping set. Additionally, the bid must include sufficient information to accurately identify the entity initiating the bid.

The crafting of competitive bids follows a similar approach. Any bid placement must be informed by the service opportunity announcements and must leverage DER performance forecasts, known network constraints, and other techno-economic evaluations to identify entities that will be able to satisfy the announcement. In addition, the bid must adhere to market participation regulations. This process will ensure that *Aggregators*—or, more broadly, DER market agents—maximize their opportunities for competitive engagement in energy markets. Table 3 illustrates the information exchanges necessary to facilitate the *DER Aggregation* module, highlighting both the potential actors responsible for providing the required inputs and those who utilize the resulting outputs.

Table 4. Attributes That May Be Present Within a Bid

Bid Elements	Description
Event/Market Instance ID	Facilitates the identification of the specific context in which the bid is evaluated by the market clearinghouse.
Participant ID	Connects the bid with its originating entity, serving as a reference for tracking performance, verifying qualifications, and other relevant assessments.
Life-Cycle Stage	Used to track bid events and transitions, such as submission, evaluation, or clearance. By exposing common attributes across life-cycle stages, coordination processes can be simplified.

Bid Elements	Description
Product Versus Value Offer	Specifies the proposed quantity of a product and service in relation to a proposed value (e.g., its cost). For energy services, this may be a curve describing quantity versus price or a proposed service mileage versus price.
Timing information	Allows tying service delivery to specific time intervals, which is particularly relevant for scenarios involving extended timeframes where services may only be made available during a subset of the market period.
Service terms	Enables bidders to define specific conditions for the offered product or service, such as limiting voltage support to within specified range bands or limiting participation to a finite number of events or total service mileage.
Service Guarantees	Allows bidders to define fines for instances where they fail to deliver the agreed service, thereby strengthening the competitiveness of their proposal.
DER/DER Group IDs	Identifies the DER or aggregated DER groups involved in the bid, enabling participants to determine geographic location, historical performance metrics, and other relevant properties held by system participants.
Verification/Approvals	Tracks endorsements or certifications applied to a bid as it progresses through life-cycle stages, enhancing coordination by enabling validation by different stakeholders.

3.2 Market Coordination

To support effective market operations for DER participation and coordination across multiple actors, we envision a market-clearing process (pink box in Figure 7) that includes a Market Data Warehouse as a key component, enabling robust validation and monitoring functions. The *Market Data Warehouse* provides a shared database where bids, approvals, and any other related market interactions can be logged for reference by other actors based on their role. The *Market Validation* module includes subfunctions for dual participation validation, market participation rules validation, and identifying other market conflicts such as multiple offerings of mutually exclusive services. As part of the *Operational Validation*, bids will be confirmed to meet aggregation and service requirements. Conflict and validation messages pass through the *Market Data Warehouse* to be logged and can be sent onto or monitored by the market participant to inform potential bid updates. The *Market Data Warehouse* can additionally be used to perform market and participation analytics for the MO or any other authorized actor.

In parallel, the *Market Monitoring* module provides real-time and historical data monitoring to the party responsible that oversees bid award activities to ensure that rules and regulatory requirements have been met. The *Market Data Warehouse* also facilitates information exchange between the DO for operational validation, then bids can continue to the MO, followed by MO awards or other notifications to market participants, as shown in Figure 7. The figure shows messages that require logging being issued by the *Market Data Warehouse*. These could alternatively be issued simultaneously while also being sent to the *Market Data Warehouse*. Note that this process for operational validation, from an architectural perspective, greatly depends on T&D Coordination (section 3.3). That activity is complex and depends on information contained by the *DER Registry* (mentioned in section 3.2), accurate forecasts, and operational constraints covered in section 3.3.

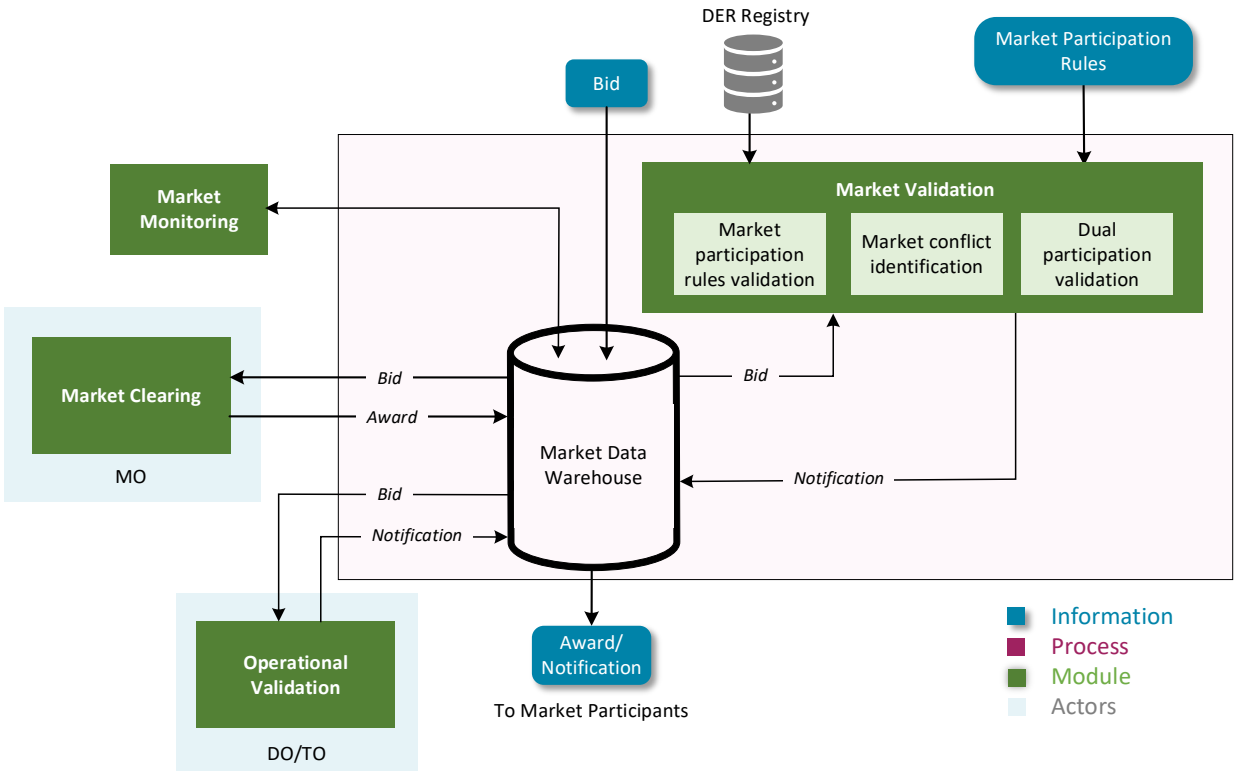


Figure 7. Module, Process, and Information Exchange for Market Coordination

Market coordination requires that market participation rules have been established and are well understood by the entities involved. This coordination relies on data, such as service enrollment details and operational constraints from existing DO programs. Standardized data models and digital contracts are necessary to efficiently share this type of information. These may vary or not exist between these stakeholder ecosystems; therefore, it is recommended that these actors comply with appropriate standards that will support coordination and exchange of common information.

3.2.1 Market Validation Module

To participate in an energy service market, the DER or aggregation bid is required to comply with the electricity market participation rules and regulations while not conflicting with the distribution grid operational requirements and constraints. Market validations use an *a priori* (i.e., before the service takes place) evaluation model and are approved through a multi-faceted evaluation. The *Market Validation* functional subprocesses include compliance with regulatory standards and constraints, as well as wholesale market and retail participation rules based on jurisdictional information. The *Market Validation* module ensures that the bid meets the performance, operational, and regulatory requirements of the service opportunity and also ensures that resources do not have any conflicting service commitments.

The *Market participant* sends all the required bid information discussed in section 3.1.2, *DER Aggregation (Bid Crafting)*. This bid includes DER group information, participant registration information, and service opportunity being bid into. The coordination framework's modular design enables the *Market Validation* module to be executed flexibly by different entities based on their role. For example, if there is a wholesale and distribution MO/manager, they could each

have the required modules for their own activities and use the market clearing process to coordinate with each other.

The *Market Validation* scope is broad, encompassing market and service participation requirements, bidding and scheduling, and regulatory compliance. Three subfunctions have been identified as being priorities based on FERC 2222 and industry experts. They are:

- ***Market participation rules validation*** ensures DER/Asset or Aggregator participation is compliant with the Market Participation Rules.
- ***Market conflict identification*** is the process of identifying procedural conflicts, such as when a *Market participant*/Asset *(DER* or *Aggregator)* intends to participate in two or more mutually exclusive markets at the same time.
- ***Dual participation validation*** is a specific type of conflict identification that focuses on ensuring that a *DER* or *Aggregator* does not engage in multiple market activities, e.g., retail and wholesale, and that their participation does not lead to "double counting" or service delivery conflicts.

The *Market Validation* module uses these subfunctions internally to perform specific validation tasks. This module can be under the purview of the MO, a DSO, or another agreed-upon organization to coordinate between entities, which is why it is included in a Market clearing process that includes the *Market Data Warehouse*. Figure 7 shows the relationship between these capabilities and the general information exchange of the *Market Validation* module. After the initial market validation process is complete, this module sends a Validated BIC, Conflict Status, or DER dual service notification to the *Market Data Warehouse* to be accessible to the DO, MO, and *Market participant*.

3.2.2 Market Participation Rules Validation Subfunction

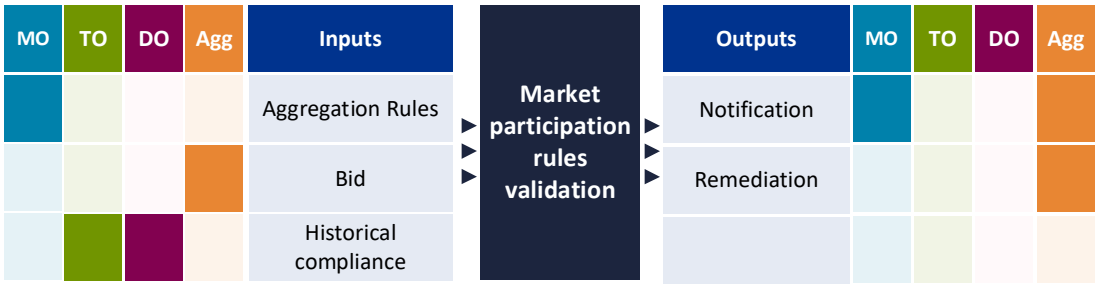
The *Market Participation Rules Validation* subfunction verifies that the *Market participant* meets participation eligibility criteria, such as predetermined constraints (e.g., aggregating a minimum of 100 kW per FERC Order 2222), registration processes, participation rules (bidding, scheduling, dispatch), compliance, and technical standards (e.g., voltage, frequency regulation requirements for ancillary services) for market participation.

Market participation rules are generally based on predetermined regulatory and contractual requirements, such as minimum size thresholds for aggregation, DER and aggregator information, and service capabilities. These rules are created and made available to the validation modules before the validation process begins.

This subfunction involves verifying contractual agreements for participation, metering, and telemetry requirements and coordinating with distribution utilities through the *Market Validation* module to ensure that *Aggregator* operations align with market rules. For example, in California Independent System Operator (CAISO), the DERs enrolled with an *Aggregator* must be analyzed by the utility to ensure that no reliability concerns arise from the *Aggregator's* participation (Gridworks 2017).

As an output, this subfunction communicates a valid bid to the Market Data Warehouse that meets the compliance of the market participant and the bid in compliance with market rules. Table 5 shows how this subprocess might be accomplished from the actor, inputs, and outputs to the module.

Table 5. Sample I/O and Actors Involved in *Market Participation Rules Validation* Subfunction



3.2.2.1 Market Conflict Identification Subfunction

A market conflict arises when an *Asset's* commitments across multiple markets lead to a service execution conflict, even if it may technically comply with individual market rules. Typical examples include overlapping operational regimes (offering to absorb/supply load at the same time) or operating under a physically unfeasible condition (e.g., providing the same service at the same time from different locations). Different markets operate on varying timescales (day-ahead, intraday, hour-ahead, real-time), potentially creating temporal conflicts where an *Asset* is committed to conflicting operations during overlapping time periods. Accurate and timely identification of market conflicts is a critical task when managing market validations. The *Market conflict identification* subfunction detects and flags operational conflicts, financial conflicts, and rule violations arising from the *DER* or *Aggregators'* simultaneous participation in more than one market, even when it operates within defined market rules.

The *Market conflict identification* subfunction must track whether *Assets* are registered in multiple markets and monitor commitments, schedules, and dispatch instructions across all participating venues, using information from the *Market Data Warehouse*. Additionally, when new bids, schedules, or dispatch instructions are issued, this subfunction performs cross-market validation and checks compatibility with existing requirements. When conflicts are detected, the *Market conflict identification* subfunction alerts relevant users to the issue, either directly or through the *Market Data Warehouse*, where any notifications are logged. Alerts can be directed to the *Asset* owner/operator, relevant MOs, and system operators with jurisdiction over the affected *Asset*.

This subfunction should classify alerts based on the type of conflict (e.g., resource allocation, temporal). Also, this subfunction should address two fundamental questions in multi-market participation and also may provide a recommendation strategy or a resolution based on—

- When will the *Assets* be allowed to participate in each market?
- How will the *Asset* be allowed to participate in the market functionalities, e.g., capacity allocation?

Table 6 shows an example of how a set of actors may interact with the *Market conflict identification* subfunction.

Table 6. Sample I/O and Actors Involved in the *Market Conflict Identification* Subfunction



3.2.3 Dual Participation Validation Subfunction

FERC Order 2222 allows market participation in one or more services in multiple wholesale markets or retail programs. This creates a dual participation risk of double-counting services provided by resources. For example, those resources might offer the same capacity or service to both retail and wholesale markets. The *Dual participation validation* subfunction ensures that DERs participating in both wholesale and retail markets are not double compensated for the same service. Market rules (through availability, performance, and penalty calculations) discourage *DER* and *Aggregators* from committing the same capability and capacity to multiple entities for any particular time interval.

As a first step, an Aggregator is required to notify the MO of its intention to participate in a dual capacity upon registration. Then the *Dual participation validation* subfunction uses verification mechanisms to compare information from the *Market Data Warehouse* and constraints from other validation subfunctions to ensure the dispatch or operation of a DER for one market activity does not interfere with its commitments or contributions in another market, or to the distribution system. As markets evolve, the *Dual participation validation* subfunction may increase in complexity, depending on the regulatory requirements. For instance, CAISO and Southwest Power Pool rely on Distributed Energy Resource Aggregators to self-attest that they are not participating in both retail and wholesale markets for the same service (e.g., demand response) (Chowdhury n.d.). A *Market Data Warehouse* could extend this capability, further enabling cross-jurisdiction visibility. Additionally, this *Dual participation validation* module input may vary based on regulatory requirements—some MOs allow dual participation for DER (New York Independent System Operator) (Lavillotti n.d.), while others prohibit dual participation in similar products across retail and wholesale markets (CAISO). This dual participation validation subfunction supports—

- Dynamically managing and validating real-time expectations from the participant DER or DER Aggregator when service restrictions prioritize one service (e.g., grid reliability over market trading) or reduce service levels to multiple entities.
- Reducing double compensation risk.
- Removing the barrier of fragmented or conflicting rules that arise from jurisdictional restrictions in the wholesale and retail market.

Table 7 shows an example of how a set of actors may interact with the *Dual participation validation* subfunction.

Table 7. Sample I/O and Actors Involved in the *Dual Participation Validation* Subfunction



3.2.4 Market Monitoring Module

The purpose of the *Market Monitoring* module is to enable the monitoring of transactions based on policies and requirements laid out in the respective jurisdictions. This information is most likely to be used near term to ensure regulatory compliance but ultimately could be extended to understand performance metrics and other actor and technology characteristics to inform planning and the evolution of market policy and practices.

This module may be managed by an independent organization or become delegated to an independent unit within the MO or DSO. This module will use information primarily stored in the *Market Data Warehouse* (a component of the market clearinghouse), which includes bid information, the *Market Validation* records, and any other interaction information, including measurement and verification data if available. There could exist multiple versions of this module based on jurisdiction and agreements between parties. Therefore, role-based access control to the market clearinghouse data will be a key consideration when integrating the *Market Monitoring* module.

While market monitoring activities may occur at any point in time, their oversight and analytical nature benefit from long-term pattern analysis, which helps provide insight into potential instances of market manipulation or the exertion of market power and, more generally, market flaws or policy gaps. For instance, in a short-term scenario, it is hard to determine whether discrepancies between approved bids and actual delivery are due to an unforeseen circumstance or if a market participant is making strategic decisions to increase profitability. This may occur, for example, when a market participant willingly withdraws from a scheduled day-ahead bid to participate in a more profitable real-time market.

Although *Market Monitoring* is a passive techno-economical based module, it has a critical impact on system operations and reliability. A non-functioning market can disrupt system operations by violating system constraints or reducing operating reserves or mis-representing reserve capacity, potentially compromising reliability metrics and resilience goals. Market gaming can also have impacts on performance when economic benefits are not completely aligned with performance requirements. An infamous example of this is the market manipulation by Enron in the early 2000s when they were able to create false congestion in the CAISO-managed system by routing power out of state to collect congestion payments (FERC 2003). This activity also demonstrated a previously unappreciated and unconsidered coupling of natural gas and electricity market pricing. Therefore, the *Market Monitoring* module must not only be designed to capture the information from market data warehouse but also likely have

comparative cross-sector capabilities for pattern analysis in a continuous manner[4] while being continually updated to ensure market analysts have the tools necessary to identify emerging issues.

In summary, the *Market Monitoring* module enables assessing if market participants are following the intent (or "spirit") of the market regulations as well as the rules and that their actions do not adversely impact the grid. Prompt issue identification can be facilitated using an open coordination framework where detailed market participant data is readily available and actors are held accountable for their actions. This provides transparency and accountability by leveraging inherent features such as non-repudiation and access to event records, such as those stored in the *Market Data Warehouse*.

Table 8 shows an example of how a set of actors may interact with the *Market Monitoring* module.

Table 8. Sample I/O and Actors Involved in Market Monitoring Activities

MO	TO	DO	Agg	Inputs
■	■	■	■	Historical market participation data (Market registry)
■	■	■		Market clearance house data (settlement, price, cleared quantities)
■				Regulatory market rules
			■	Control status
		■	■	Demand/generation forecast
		■	■	Meter data (DER)

Market Monitoring

Outputs	MO	TO	DO	Agg
Market analytics (e.g., market power)	■			
Assessment of market impact on grid operation		■	■	■
Dispatch vs market commitment mismatch	■	■	■	■

3.3 T&D Coordination

Operational coordination serves the obvious role of aligning power system operations but is additionally critical to aligning market opportunities, i.e., grid services, with those operational requirements. Additionally, operational cost reduction through utilization of least-cost resources can increasingly be achieved through the various programs of customer-sited resources. As load increases, more locationally distributed opportunities will exist at the grid edge and can further be exploited to reduce the cost of capital infrastructure investments.

[4] For example, real-time market monitoring can allow distribution utilities to identify reliability and safety issues that require modifying already issued DER dispatch orders under an emergency provision of FERC Order 2222.

As noted previously, prior to a final bid going to market, the DO or TO, depending on the location of the resource, will have two important interactions where these interactions depend on operational coordination occurring in advance.

To coordinate with the *DER Aggregation (Bid Crafting)* module covered in section 3.1.2, there may be jurisdictional variability and optionality to address. In the concept diagram, information from the delivery optimization is shown to be passed into the service opportunity. Alternatively, information that would inform group formation could be provided directly or through the *Market Data Warehouse*. Regardless of post optimization, the Bid Crafting module provides information that can be used to craft service requirements, and the same or a subset of that information can be used to group resources based on locational and performance attributes to provide said service where the power system needs it. Figure 8 suggests the coordination between transmission and distribution and how constraints and the T&D Coordination module inform the delivery optimization. In the current state of DER applications for grid services, a high level of DO-Aggregator coordination isn't tightly coupled or important but as load growth increases, this capability will increase in benefit, and it has been identified as a critical requirement for near-term utilization.

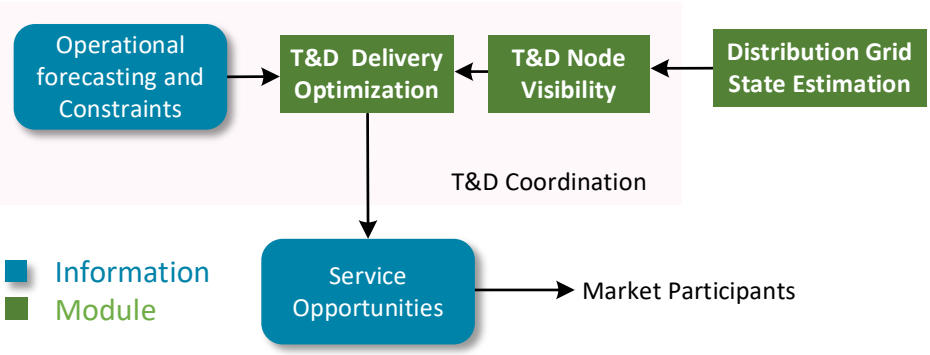


Figure 8. Transmission and Distribution (T&D) Coordination

Another critical challenge that the coordination framework addresses is tier bypassing. This occurs when distribution resources provide transmission-level (wholesale) services without validating the fact that these activities will not have a negative or even less than optimal impact on the distribution system. Without this coordination, the reliability of distribution operations could be compromised and cost impacted if the DO then must operate inefficiently using distribution equipment to counter these DER-related activities. Operational validation, explained in Section 3.2, is therefore one of the most beneficial modules within the operational coordination layer.

3.3.1 Distribution Grid State Estimation Module

The distribution grid state estimation module helps the actors to determine the real-time operational state of the distribution grid, including identifying outages, curtailments, or other events that impact the deliverability of DERs. Since this is a DO function, it is likely that only a limited set or an interpretation of this information is passed on to other actors through other modules. This module leverages DER and sensor network data that is location-specific and includes the duration of events. The objective is to ensure that the system operates as expected, uses measurements to estimate the system state, then verifies the estimate with the

next set of measurements. When necessary, the aggregators, TO and MO, are informed in a timely and accurate manner so they can adjust dispatch plans and maintain system reliability.

The DO collects data from field sensors, SCADA systems, and Advanced Metering Infrastructure (AMI) meters to monitor grid conditions. Using this data, the DO will run distribution-level grid state estimation algorithms (hybrid or linear), including the identification of abnormal conditions, such as voltage violations, equipment outages, or thermal overloads. Upon detection, the DO can determine the specific DER nodes affected, quantify the impact on their deliverability, estimate the expected duration of the issue, and share this information with the market data warehouse and/or service notification module to enable appropriate response (see Table 9). In addition to state estimation results, the DO can also share information on planned outages and network reconfigurations that may affect other actors, for example, by influencing an aggregator's ability to dispatch resources. If the state estimation outcomes or any planned actions are expected to affect transmission-level operations (e.g., inability to meet scheduled injections or large reverse flows), the DO also communicates the relevant details to the TO. It should be considered that data rates may vary, and data synchronization and interpolation may be required.

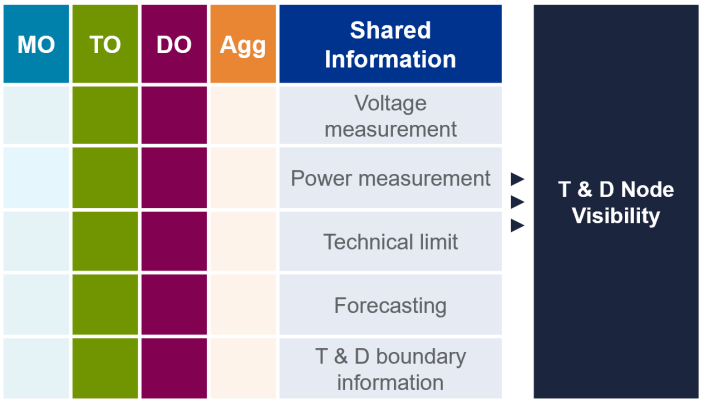
Table 9. Sample I/O and Actors Involved for Distribution Grid State Estimation

MO	TO	DO	Agg	Inputs		Outputs	MO	TO	DO	Agg
		■		SCADA, AMI and sensor data	▶ Distribution grid state estimation ▶	Impacted DER location ID		■		■
		■		Equipment status (breaker, switches)		Event type	■	■		■
	■			TD boundary condition		Expected duration	■	■		■
						Updated delivery (KW)	■	■		■

3.3.2 T&D Node Visibility Module

To achieve operational real-time visibility into the state, deliverability of power, and other services at the interchange points between transmission and distribution networks, it is imperative to have a well-defined mechanism for information exchange. Role-based access control of this module enables visibility into corresponding power networks without exposing what could be considered "private" or otherwise out-of-purview information. The T&D Node Visibility module is responsible for the automated, low-latency, timely exchange of information between the TO and DO that consists at a minimum of voltage and power measurements as well as messages about current or upcoming limits on power flow at the interface between their respective jurisdictions. This may also include forecast information related to the node(s). This module may also include a shared operational network model or similar representation of the transfer capability between transmission and distribution networks and the respective grid state information. Since this module is used to coordinate between entities, limited visibility might also be preferred and should be agreed upon by both parties. Since this is an information exchange or database capability, Table 10 shows only inputs and no functionality that would require outputs.

Table 10. Sample Inputs and Actors Involved in T&D Node Visibility



3.3.3 T&D Delivery Optimization Module

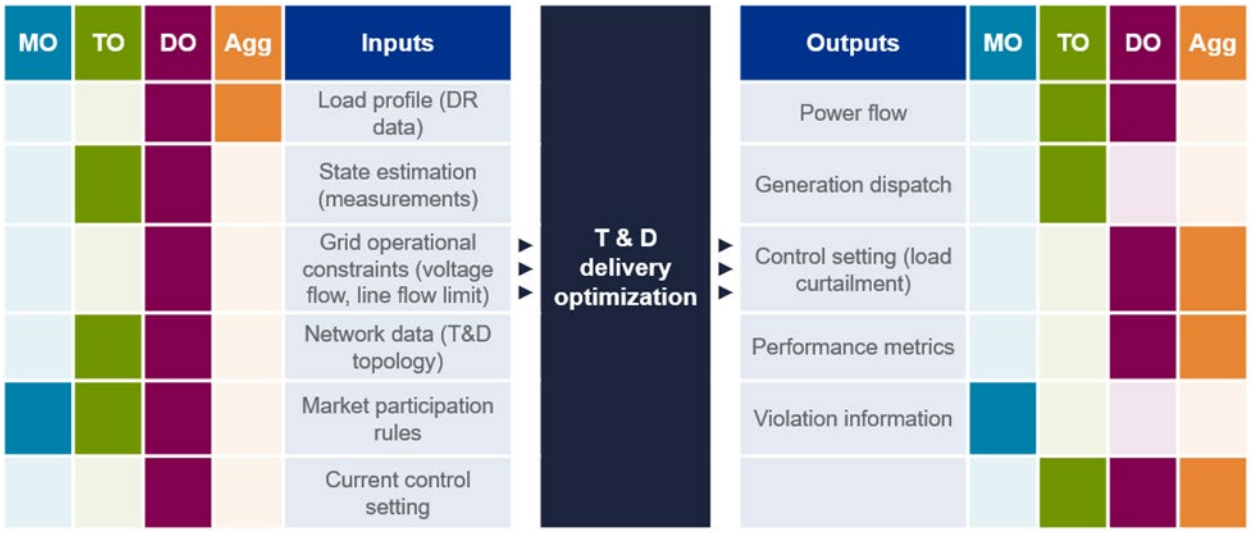
The DO is responsible for overseeing and managing distribution assets. At the same time, MOs and TOs have limited or no visibility of operations at the distribution level. The TO and DO share relevant information about the T&D node through the T&D Node Visibility module, which includes forecasting and state information. This enables the TO and DO to develop a delivery strategy to utilize DER grid services for enhanced grid resilience or supply flexibility. In contrast, the DO must ensure the reliability of the distribution system, the TO must ensure safe and reliable operation of the transmission system, and the MO (or market function for vertically integrated utilities) is responsible for ensuring firm capacity.

FERC Order 2222 requires TOs/MOs to develop participation models that account for the physical and operational characteristics of DERs, ensuring their output can be reliably delivered to the wholesale market while respecting transmission and distribution system constraints (e.g., frequency control, voltage control, thermal limits). Optimizing supply and demand in the entire spectrum of grid systems is necessary, as DERs are often located on distribution systems but participate in transmission-level wholesale markets.

The T&D optimization module manages and balances supply and demand across both the transmission and distribution systems to enable DER to participate effectively in wholesale markets. MO, TO, or DO can use this optimization module independently to coordinate the optimization of their grid objectives. This module utilizes forecasting and real-time grid operational constraints of both the distribution and transmission systems from the distribution grid state estimation module. It also uses the grid state, readiness, and constraints functions. The general interaction between modules is shown in Figure 8 Transmission and Distribution (T&D) Coordination, above. Market rules and regulatory requirements are also considered as optimization constraints in this function to ensure that all market participants operate on a level playing field and maintain the day-ahead, real-time, and other market structures. Aligning with market regulatory requirements establishes a transparent procedure for scheduling and dispatch, which is essential for efficiently optimizing T&D delivery. In summary, this module manages constraints (e.g., voltage limits, thermal limits, congestion) across both T&D networks to prevent operational issues, optimize resource dispatch, and support DER to participate in wholesale and retail markets by ensuring regulatory requirements are satisfied.

The coordination framework enables optimization by interpreting both T&D constraints (e.g., T&D node limits), capabilities (e.g. available capacity,), operational requirements and sharing the necessary resource requirements with TO and DO so that they can optimize for their needs while resolving potential conflicts (e.g., a DER needed for local voltage support vs. wholesale market dispatch) and make sure the most effective and least-cost resources are used system-wide.

Table 11. Sample I/O and Actors Involved for T&D Delivery Optimization



3.3.4 Operational Validation (DO) Module

The Operational Validation module supports distribution power system operators in validating the bids submitted by market participants (aggregators). To perform this validation, the operator utilizes information from the DER Registry, such as location and nameplate capacity, and schedules submitted by aggregators as a part of their bidding process. Using this information along with forecasted loads and generation, constraints such as those based on capacity and interconnection rules, the operator could perform a forecasted power flow analysis to assess the feasibility of the bids submitted by aggregators. The module and data associations are shown in Figure 9.

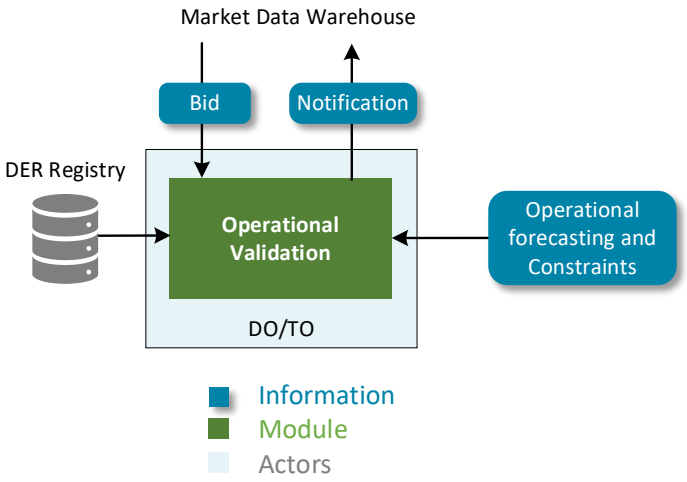


Figure 9. Operational Validation

The bid information mentioned in Section 3.1.2 includes DER group information. These groupings should be mapped to individual DERs and their location to determine device-level dispatch and assess the impact on the grid. This can be achieved using the DER Registry, which can either have pre-defined groups or include the list of participating DER in the bid. The output of this module is a validation signal, or a constraint identified that informs the aggregator about the reason for rejection of a proposed bid. This could also be a recommendation or other information that offers contextual guidance to help market participants correct their bids. This is likely to be provided to the DER Aggregation (Bid Crafting) module to update the bid strategy. The input, output, and potential actors involved in this module are shown in Table 12.

Table 12. Sample I/O and Actors Involved for Operational Validation

MO	TO	DO	Agg	Inputs		Outputs	MO	TO	DO	Agg
	■	■		Operational constraints	Operational Validation	Notification	■			■
■				Bid		Locational Impact				■

3.3.5 DER Reliability Monitoring Module

The primary objective of this module is to ensure the safe and reliable operation of the power grid by systematically evaluating the performance of DER interconnections and to identify emerging reliability challenges. This module is designed to uphold the short-term and long-term grid reliability requirements while mitigating potential system disruptions by ensuring alignment with regulatory standards and local grid codes (DOE 2023b). While real-time reliability monitoring provides immediate insights into system health, long-term reliability assessments necessitate the use of post-event data derived from historical records or operational metrics, which typically become available after measurement and verification processes are completed. Responsibility for DER reliability monitoring can be undertaken by any entity with visibility into

asset/system performance, such as the DO. The general relationships between modules are shown in Figure 10.

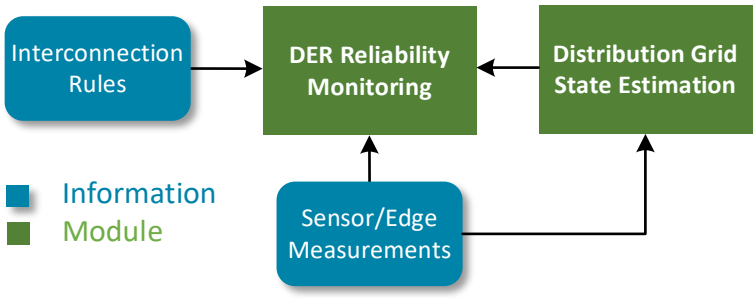


Figure 10. Reliability Monitoring

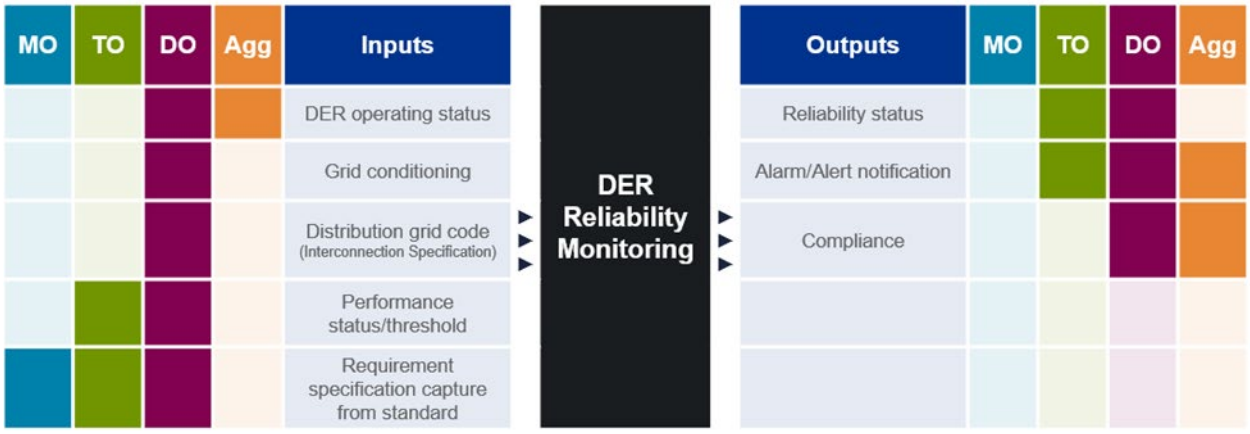
Reporting requirements may provide guidance on who is ultimately responsible for this task. Reliability evaluations are typically framed using index-based metrics that can be used to measure progress toward a desired goal. These indices may assess:

- DER availability: Evaluating whether DERs are or will be online and capable of providing any contracted/agreed services when invoked. This could also include planned outages.
- DER performance: Evaluating whether DER service observed performance aligns with forecasted values or contractual obligations or that the output aligns with nameplate capacity (i.e., capacity factors).
- DER Response: Assessing DER behavior during frequency or voltage events and ensuring that this response adheres to regulatory standards (e.g., IEEE 1547).
- Grid impacts: Analyzing the influence of bulk-sized or aggregated DERs on grid operations, with particular emphasis on their effects on voltage and frequency stability.
- Assessing traditional reliability metrics (i.e., IEEE 1366): Examining the reliability of DER tripping operations in accordance with the NERC recommendations, considering their capabilities guided by standards such as IEEE 1547-18, and local grid codes, particularly in scenarios involving voltage and frequency disturbances.

The DER reliability monitoring module is expected to leverage the information provided by state estimation and sensor measurements and actual vs. committed performance records. The collection of such records should incorporate privacy considerations to ensure fairness and market competitiveness are maintained. Any observed patterns will then need to be reflected in the corresponding grid state and evaluated against any applicable reliability requirements, such as NERC's reliability requirements or interconnection rules. Such assessments will generally output reliability indices that quickly inform on reliability status, notify participants of potential issues, and emit compliance reports. Furthermore, these outputs can inform participants on resource adequacy, inform strategies to enhance future reliability, and support the refinement of contingency planning efforts.

A robust RCA such as the one envisioned within this document can provide the necessary requirements to inform interoperability and streamlined data access mechanisms to enable improved integration, reduce operational inefficiencies, and facilitate a more comprehensive understanding of DER impacts on the grid.

Table 13. Sample I/O and Actors Involved in DER Reliability Monitoring



4.0 Case Studies

The RCA is intended to have broad application across and between jurisdictions and at various levels of maturity. The case studies outlined in Appendix A and presented in detail in a companion document (Touhiduzzaman et al. 2026) are intended to provide a multiphase ("walk," "jog," "run") assessment, where initially, the case studies will be used to validate the architectural structure and interaction requirements that have been developed. This includes ensuring that market and operational data, functions, and interaction requirements have been satisfied. The next phases implement "generic" functions within the black box to meet basic application needs. This basic coordination is referred to as the "walk" phase of the coordination, where coordination is used but decision-making is centralized within the responsible entities system.

As the "jog" and "run" phases of the coordination framework are implemented, the case studies and the coordination functions will evolve. For example, the jog phase will apply coordination at multiple layers within the network. This includes enabling the use of advanced sensor networks, distributed computational capability, and a data management pipeline that considers what data at what level of granularity needs to exist throughout the system. This scenario could also be described as flexible.

In the run phase, even more advanced coordination enables calculations to inform decisions so that the system can respond to highly localized needs and constraints, considering distribution system level pricing nodes, energy transactions between edge assets and facilities, and autonomous distribution reconfiguration to support complex optimization.

Each case study phases will aim to meet ever-increasing affordability and resilience objectives. The modules and their functionalities described in the previous section will serve as building blocks for each case study. General characteristics of the various phases of the case study scenarios that the coordination framework will be evaluated against are described in Table 14, Sample characteristics of walk, jog, run phases.

Table 14. Sample Characteristics of Walk, Jog, Run Phases

	Walk	Jog (Flexible)	Run (Dynamic)
High-Level Capability	• Centralized with coordination including Operational, Market, and DER. DER has limited certifications	• Some decentralized control as visibility increases and hierarchical controls are deployed at substations. DER is enabled to provide a variety of grid services (e.g., energy, voltage, frequency, etc.)	• Highly decentralized systems allow self-configuring distribution networks and multi-objective optimization, e.g., resilient self-aware distribution islands and distribution Locational Marginal Prices. DER certified and contracted to provide services
Power Flow Management	• Substation-level control • SCADA • Limited ADMS • DERMS • DER managed by aggregators providing energy services	• Feeder segment coordination centrally optimized (static) • Advanced ADMS • DER providing voltage and other grid services • DERMS incorporates aggregator functions • Limited distributed control	• Sub-feeder coordination nodes (dynamic) • Distribution network optimization within feeder and between neighboring branches • Locally aware distributed controllers • Autonomous segmenting to enhance resilience
Market Structure	• Aggregators participate in wholesale markets and DER in programs	• DER in programs and responding to value signals • Distribution market signals (e.g., Distribution LMP) • Local grouping for targeted response	• Localized energy market, e.g., Peer-to-peer • Local system value included in local Distribution LMP calculations • Local market signals (coordination/participation) Local system value included in local Locational Marginal Price calculations
Aggregator Platform	• Required to participate in markets • Signals broadcast rather than targeted, “shotgun” approach to the substation level	• Highly coordinated with distribution operations (locational attributes, etc.) • Feeder-level precision	• Targeted and/or coordinated with distributed computation • Feeder segment precision • Variable/adaptive coordination node, based on topology (e.g., a re-segmented feeder)
Certificate Authority	• Many, fragmented certificate authorities	• Initial adoption of grid service (capability) certification	• Centralized/Federated certifications to provide various grid services
Visibility	• Substations with some feeder segment visibility	• Feeder segment and some grid-edge sensors (e.g., distribution transformer, DER) • Hierarchical visibility	• DER visibility • AMI and distribution sensors used in real-time operations • Distributed control situational awareness
AMI Data	• AMI data for billing and planning	• AMI data for analytics	• AMI data for electrical load comp • Load forecasting behavior • Near real-time

	Walk	Jog (Flexible)	Run (Dynamic)
Grid-edge structure	Limited functionality • Distributed storage reducing DER curtailment • Self-management (microgrid) • “Old school” microgrid— continuous resource optimization; separation when needed	Distributed control introduced • Storage strategically placed for minimal curtailment • Coordinated by ADMS/DERMS • Responds to market signals • Situational awareness at the edge informs decisions	Highly decentralized computation • Coordination between distribution network segments • Auto formation/ Self-healing/ Scalable • May operate as a distributed system Auto formation/ Self-healing/ Scalable

5.0 Conclusion

The anticipated growth of the DER market in the U.S. highlights the critical need for an evolved coordination framework that seamlessly integrates DER capabilities into existing energy systems. By implementing advanced coordination strategies, stakeholders can better harness the expected growth of behind-the-meter capacity, enhance system reliability and reduce energy costs. Additionally, DER owners, aggregators, and system operators can adapt to increasing or fluctuating regional pricing while also benefiting from participation in wholesale markets.

The RCA, rooted in Grid Architecture principles, provides a modular, standards-based approach that accommodates jurisdictional variability and supports cost-effective and informed planning. It facilitates a flexible, scalable, and resilient energy system catering to short-term and long-term objectives across various market structures, addressing interoperability and reducing integration challenges.

Through strategically structured coordination modules, robust cybersecurity measures, and adaptable functionalities, the proposed framework offers a pathway to streamline operations among TO, DO, MO, and DER aggregators and owners. It not only resolves long-standing challenges related to market participation, operational efficiency, and resource optimization but also opens avenues for innovation and increased collaboration at various jurisdictional levels.

The RCA offers guidance for strategic investment and application development in the DER market, addressing evolving market conditions and operational challenges. In the near-term, the coordination framework facilitates rapid and scalable integration of diverse resources, enabling utilities to defer capital investments and recover DER costs more efficiently. In the long-term, the application of coordination modules and layered coordination strategies for DER registration, bid crafting, market validation, and operational delivery optimization ensures localized, flexible, and secure interactions that improve system reliability. The benefits extend to both the stakeholders, providing them with tools to achieve significant operational cost savings, reliability enhancement, and future grid adaptability.

Finally, case studies employing a phased “walk, jog, run” methodology are provided to validate and refine the RCA, optimizing DER utilization, enhancing grid resilience, and paving the way for innovative solutions to emerging energy challenges. These case studies demonstrate that as stakeholder roles evolve and coordination capabilities mature, the RCA promises substantial efficiencies and cost savings while enhancing grid performance and customer satisfaction.

Developing the RCA has exposed that the current system construct imposes scaling challenges that prevent immediate implementation utilizing existing actors’ abilities. For example, while a functioning framework has been articulated and validated, realizing the requirements prescribed in FERC 2222 requires registration and market clearing capabilities that must be translated into standards and equipment. A gap analysis is underway, which will support a subsequent implementation guide.

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Appendix A – Case Study Scenarios

This appendix describes the case studies scenarios of the standalone RCA Case Studies companion document. The companion document highlights leveraging the RCA to manage:

1. The integration of Large Dynamic Digital Loads (LDDLs), which exposes the grid to the impact of their dynamic behavior, potentially resulting in poor quality on the transmission system and that can propagate into distribution customers.

2. Extreme cold weather events that create energy scarcity scenarios and require load management. The February 2021 event recorded in ERCOT is leveraged

3. Cascading Blackouts, illustrated by the 2003 northeastern US blackout event, which necessitates enhanced blackstart features.

The RCA framework is used to improve grid reliability, resiliency, and market integration. Across all cases, the framework is assessed through three maturity phases: Walk, Jog, and Run, which progressively enhance situational awareness, coordination, data exchange, DER participation, and automated response capabilities. Across all scenarios, the RCA framework's modular architecture (e.g., T&D Node Visibility, Delivery Optimization, Bid Crafting, Operational Validation) is shown to enhance coordination across operators, aggregators, and large customers. The document demonstrates how progressively advanced technologies, visibility, and distributed control can reduce risk, improve affordability, and support future grid modernization.

A.1 Case Study Description and Maturity Levels

A.1.1 Large Dynamic Digital Loads

There has been an explosive growth in interconnection requests for AI data centers. The challenges observed are extreme ramp rates, unpredictable demand spikes, and rapid disconnection. These characteristics impose stress on both transmission and distribution systems, including congestion, voltage problems, and system-wide frequency impacts.

This case study evaluates how better coordination between Market Operators (MO), Transmission Operators (TO), Distribution Operators (DO), aggregators, and LDDLs themselves can mitigate these impacts through staged maturity levels:

- **Walk**: Basic coordination, day-ahead scheduling, reserve services, limited visibility, and initial DER participation.
- **Jog**: Greater feeder-level observability (SCADA + AMI), five-minute markets, coordinated T&D optimization, expanded DER-based flexibility.
- **Run**: High-resolution sensing, distributed control, sub-minute markets, feeder-level islanding, and real-time distribution pricing.

This case study demonstrates that increased coordination enables ramp mitigation, improved reliability, congestion relief, and new revenue opportunities at both transmission and distribution levels.

A.1.2 Extreme Cold Weather Event Case Study

This case study addressed the February 2021 ERCOT/MISO/SPP cold weather event to analyze how improved coordination could mitigate widespread outages. The event caused massive generator failures, gas supply disruptions, and 23 GW of manual load shedding. Identified gaps included limited SCADA visibility, fragmented coordination, minimal DER aggregation capabilities, and inadequate reliability assessments.

The case study applies the RCA framework through three phases:

- **Walk**: Improve situational awareness, demand forecasting, and emergency planning; establish many-to-many data exchange; onboard aggregators for emergency reserve roles.
- **Jog**: Introduce real-time coordination (5-30 min), activate distribution-level services, leverage feeder-level data, and deploy DERs with dynamic grouping and graceful aggregation strategies.
- **Run**: Enable autonomous, blackstart capable feeder segments, distributed computation, and near-real-time market responses; support microgrid-like operations during system stress.

This case study shows how better coordination could reduce load shed, accelerate response, and maintain critical load during prolonged extreme events.

A.1.3 Cascading Blackout of 2003

This case study analyzes how the coordination framework could enhance system restoration following a large-scale blackout, using the 2003 Northeast US blackout as a reference. The blackout originated from inadequate situational awareness, voltage collapse, and cascading line trips, resulting in 50 million customers losing power. The study reviews the traditional blackstart process, which restores power from central generation outward, identifying limitations such as slow restoration, lack of visibility into distribution systems, and inability to leverage local DERs.

The framework's phased progression:

- **Walk**: Improve TO-DO data sharing, enhance load visibility, reduce cold load pickup via DER-based demand reduction, and strengthen cranking path planning.
- **Jog**: Introduce DER-assisted blackstart, distribution-level service markets, coordinated island formation, and feeder segmentation with enhanced validation and monitoring.
- **Run**: Enable automated blackstart at the grid edge using DERs with grid-forming capability, decentralized control, autonomous islanding, and fast T&D re-integration.

The case study demonstrates how enhanced visibility, modular coordination tools, and DER participation can accelerate restoration, reduce risk of re-collapse, and improve resilience during high-impact outages.

A.2 Case Studies Modeling and Validation

The RCA establishes the coordination framework through which TOs, DOs, MOs, and customers or their designated agents, such as aggregators, exchange information, validate decisions, and coordinate market and operational activities. The architecture defines a set of coordination modules, such as bid crafting, market validation, operational validation, that govern how information, models, and decisions are exchanged among actors. These modules establish

the interfaces through which market and operational processes are coordinated to ensure that awarded services remain feasible and reliable from both transmission and distribution perspectives. To evaluate the architecture, representative case studies, including LDDL, extreme cold weather, and cascading blackout scenarios, were implemented using actor-specific system models (such as PSS/E, OpenDSS) and Python-based coordination modules. Validation was conducted using a walk–jog–run progression, where successive stages introduced greater operational maturity through enhanced visibility, richer market interactions, expanded DER participation, and more distributed operational control, as summarized in Table 14. A key aspect of the validation was the recognition that each actor owns different models, datasets, and decision-making authority. The modeling and validation (Yip et al. 2026) focused on determining whether

a) the information specified by the architecture was sufficient for each coordination module to execute and produce meaningful outputs,

b) data and models could be communicated to the appropriate actors while respecting ownership, visibility, and confidentiality constraints, ensuring that only the information necessary for coordination was exchanged,

c) the sequence of information exchanges and decision-making steps defined by the architecture could be executed as intended, ensuring that dependencies among coordination modules were properly maintained, and

d) market coordination processes and operational coordination processes could interact effectively to support reliable service delivery.

The primary purpose of this exercise was not only to validate the architecture but also to develop an implementation path and provide feedback for its refinement. The implementation revealed additional information requirements, coordination sequence, and actor interactions that were not fully captured in earlier versions of the framework. As a result, the architecture evolved iteratively throughout the modeling and validation process. The updated architecture presented in the main body of this report reflects the lessons learned from these case studies and the resulting refinements. Detailed descriptions of the modeling procedures, implementation methodology, and validation results are documented in a separate report.



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