NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Functional Model Technical Document

Prepared by the Functional Model Working Group

Version 4

This document is a companion to Version 4 of the Functional Model. It provides context, explanations, opinions, and discussions on various aspects of the Functional Model.

to ensure the reliability of the bulk power system

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Table of Contents

Introduction

This document is intended as a companion to Version 4 of the Functional Model that will help the reader better understand the Model's Functions, Responsible Entities and their relationships. It is also intended to explain the changes made to Version 3 of the Model. This document therefore provides context, explanation and opinions. It is a companion to, rather than a formal part of, Version 4 of the Model.

Section I provides details about each of the Responsible Entities. Some entities, such as the Transmission Owner or Purchasing-Selling Entity, are adequately described in the Functional Model document, and there is little detail to add here. Others, such as the Interchange Authority and Balancing Authority, are more complex both unto themselves and in their relationship with other entities, and this document provides additional explanations.

Section II includes technical discussions on related topics and tasks such as managing bilateral Interchange Transactions, Interchange Schedules, task assignment and delegation, the planning functions, and boundary conditions. Many of these topics are mentioned in the Functional Model, but the details may not be obvious.

The discussion of Market Structures illustrates that the Model applies to different market structures.

There is also discussion of the concepts of a scheduling agent, as well as discussion of the relationship of the Market Operator and Balancing Authority, under both bid-based and cost-based dispatch of resources. In addition, certain concepts and conclusions from the 2005 report of the Functional Model Reliability Standards Coordination Task Force (FMRSCTF) are also discussed. This includes the implementation of the Reliability Coordinator and Interchange Coordinator entities in standards; Regional Reliability Plans, and Responsible Entity Areas and boundaries.[1]

[1] Final report is dated March 11, 2005. See ftp://www.nerc.com/pub/sys/all_updl/sac/fmrsctf/FMRSC_TF_Report_3-11-05.pdf

Section I — Entity Responsibilities and Interrelationships

This section describes the responsibilities of the entities in the Functional Model *within the context of the Model itself*. It is important to recognize that the responsibilities that will actually apply to an organization will be determined within NERC's registration, certification and compliance programs, and NERC's Reliability Standards, not by the Functional Model.

The Model describes a somewhat conceptualized state in which responsibility for closely related Tasks are inferred to be assigned to a single organization, avoiding the potential complexity and ambiguity that could result from responsibility for these Tasks being split between two or more organizations.

The situation described in the conceptualized state of the Model will not always be achieved in actuality, because of factors related to particular organizational structures and relationships and regulatory and legal requirements. Addressing how such factors will impact responsibilities is the job of NERC's registration, certification and compliance programs, and reliability standards.

1. Reliability Coordinator

The Reliability Coordinator's purview must be broad enough to enable it to calculate Interconnection Reliability Operating Limits, which will involve system and facility operating parameters beyond its own Area as well as within it. This is in contrast to the Transmission Operator, which also maintains reliability, but is directly concerned with system parameters within its own Area.

The Reliability Coordinator is the highest operating authority; the underlying premise is that reliability of a wide-area takes precedence over reliability of any single local area. Only the Reliability Coordinator has the perspective/vision necessary to act in the interest of wide-area reliability.

The Reliability Coordinator also assists the Transmission Operator in relieving equipment or facility overloads through transmission loading relief measures if market-based dispatch procedures are not effective.

Role in Interchange Transactions. The Reliability Coordinator does not receive tags on Interchange Transactions until they are arranged and ready for implementation as Interchange Schedules. As such, it does not approve or deny tags. However, once the Reliability Coordinator receives the Interchange Schedule information, it will have the necessary information to aid its assessment of the impacts of flowing and impending Transaction Schedules on its area's reliability. As necessary, the Reliability Coordinator may issue transmission loading relief requests (or similar requests for congestion management) which may result in reducing, removing or halting flowing or impending Interchange Transactions. This is viewed by some as "denying" the Interchange Transactions although in this context, the "denial" is not provided during the collection of approval stage.

Day-ahead analysis. The Reliability Coordinator will receive the dispatch plans from the Balancing Authority on a day-ahead basis. The Reliability Coordinator will then analyze the dispatch from a transmission reliability perspective. If the Reliability Coordinator determines that the Balancing Authority's dispatch plans will jeopardize transmission reliability, the Reliability Coordinator will work with the Balancing Authority to determine where the dispatch plans need to be adjusted. The Reliability Coordinator obtains generation and transmission maintenance schedules from Generator Operators and Transmission Operators. The Reliability Coordinator can deny a transmission outage request if a transmission system reliability constraint would be violated.

The Transmission Operator is responsible for the reliability of its "local" transmission system in accordance with maintaining System Operating Limits (SOLs). However, in some circumstances, as noted above for reliability analysis associated with generation dispatch instructions, the Reliability Coordinator may become aware of a potential SOL violation and issue a dispatch adjustment. Therefore, in this context, the Reliability Coordinator also has a role regarding the Transmission Operator's management of SOLs.

Emergency actions. The Reliability Coordinator is responsible for real-time system reliability, which includes calling for the following emergency actions:

- Curtailing Interchange Schedules
- Directing redispatch to alleviate congestion
- Mitigating energy and transmission emergencies
- Ensuring energy balance and Interconnection frequency
- Directing load shedding.

The Reliability Coordinator, in collaboration with the Balancing Authority and Transmission Operator, can invoke public appeals, voltage reductions, demand-side management, and even load shedding if the Balancing Authority cannot achieve resource-demand balance.

System restoration actions. The Reliability Coordinator directs and coordinates system restoration with Transmission Operators and Balancing Authorities.

Authority to perform its reliability functions. The Reliability Coordinator's authority is documented in one or more regional reliability plans, as applicable.

In addition, since the Reliability Coordinator may also have a role regarding the Transmission Operator's management of SOLs, delineation of its authority and that of the Transmission Operator needs to be clearly defined in the reliability plan(s).

2. Planning Coordinator

The Planning Coordinator ensures a long-term (generally one year and beyond) plan is available for adequate resources and transmission within its Planning Coordinator Area. That area, which encompasses the customer demands therein, will not necessarily coincide with a Reliability Coordinator Area.

In providing analyses and reports on the long-term resource and transmission plan(s) for the Planning Coordinator Area, the Planning Coordinator may also:

- Assess and publish system development trends (demands, transmission, and resources) within the Planning Coordinator Area in the time frame of generally one year and beyond
- Provide reports and data, as requested or required, to the Standards Developer, Compliance Enforcement Authority, Reliability Assurers, NERC, and governmental authorities.

Even when the transmission and resource plans developed by the Transmission Planners and Resource Planners comply with Reliability Standards, the Planning Coordinator will monitor the implementation of the transmission and resource plans, including the tracking of generating capacity, demand program, and transmission in-service dates. It will also evaluate the impact of revised transmission and generator in-service dates on transmission and resource adequacy.

In its evaluation of resource plans, the Planning Coordinator will likely review the conversion of various resource adequacy requirements and methodologies into equivalent resource capacity (or reserve) margins (or requirements) for use within the Planning Coordinator Area.

In some areas, there may exist more than one Planning Coordinator, each performing a different role demarcated primarily by the scale (area-wise) of assessment. In these cases, delineation of the role of the various Planning Coordinators needs to be clearly defined in the regional reliability plan(s).

3. Balancing Authority

See "Reliability Areas and Boundaries"

The Balancing Authority operates within the metered boundaries that establish the **Balancing Authority Area**. Every generator, transmission facility, and end-use customer is in a Balancing Authority Area. The Balancing Authority's mission is to maintain the balance between loads and resources in real time within its Balancing Authority Area by keeping its actual interchange equal to its scheduled interchange and meeting its frequency bias obligation. The load-resource balance is measured by the Balancing Authority's Area Control Error (ACE).

NERC's Reliability Standards require that the Balancing Authority maintain its ACE within acceptable limits.

Maintaining resource-demand balance within the Balancing Authority Area requires four types of resources management, all of which are the Balancing Authority's responsibility:

- Frequency control through tie-line bias
- Reliability-related services deployment
- Load-following through generator dispatch and demand-side management
- Interchange implementation.

Frequency control through tie-line bias. To maintain frequency within acceptable limits, the Balancing Authority controls resources within its Balancing Authority Area to meet its frequency bias obligation to the interconnection.

See "Providing and Deploying Ancillary and Reliability-Related Services" 3

Reliability-related services deployment. To maintain its ACE within these acceptable limits, the Balancing Authority controls a set of generators and loads within its Balancing Authority Area that are capable of providing reliability-related services.

Load-following through generator dispatch and demand-side management. The organization that serves as the Balancing Authority will in general also perform the generator commitment and economic dispatch. Included in the commitment and dispatch tasks is the designation of those resources, both load and generation resources, that are available for reliability-related services.

Interchange implementation. The Balancing Authority receives Interchange Schedules from one or more Interchange Authorities, and enters those Interchange Schedules into its energy management system.

Generation commitment and schedules The Balancing Authority receives generation dispatch plans and/or generator commitment and dispatch schedules from any, or a combination of, the following entities: Load-Serving Entities, Purchasing-Selling Entity, Market Operators, Generator Operator, Generator Owner, that have bilateral arrangements for generation within the market or the Balancing Authority Area. The Balancing Authority provides this commitment and dispatch schedule to the Reliability Coordinator.

Role in approving Interchange Transactions. The Balancing Authority approves bilateral Interchange Transactions with respect to the ramping requirements of the generation that must increase or decrease to implement those Interchange Transactions. The Balancing Authority provides its approval or denial to the Interchange Authority. Approvals may be explicit or by exception ("passive").

Energy Emergencies. In the event of an Energy Emergency, the Balancing Authority can implement public appeals, demand-side management programs, and, ultimately load shedding. These actions must be done in concert with the Reliability Coordinator.

4. Resource Planner

The Resource Planner develops a long-term (generally 1 year and beyond) plan for the resource adequacy of loads (customer demand and energy requirements) within a Planning Coordinator Area.

This Resource Planning function may be performed by one or more Resource Planners within the Planning Coordinator Area. The resource plans may include generation capacity from resources outside of the Planning Coordinator Area.

In some markets it may be required that the same entity be the Resource Planner as well as the Planning Coordinator. For example, the Resource Planner may also be the Planning Coordinator in those markets where there are no entities responsible or obligated to serve load. In these cases, the Planning Coordinator identifies the need for additional resources to be provided by the market.

In developing resource plans, the Resource Planner will also collect and develop related resource information for planning purposes from other entities, including:

- Demand and energy end-use customer forecasts from the Load-Serving Entities
- Demand management data and programs
- Generator unit performance characteristics and capabilities from Generator Owners and others
- Information on existing and proposed new capacity (generation or demand management) purchases and sales.

In developing and reporting its resource plans to the Planning Coordinator for assessment and compliance with reliability standards, the Resource Planner will be expected to:

- Identify those resources that may be considered firm resources (e.g., under contract, under construction, or environmental permits in place),
- Verify that resource plans meet adequacy resource requirements, or identify resource deficiencies, and
- Work with the Planning Coordinator to identify potential alternative solutions to meet resource requirements should the resource plans be deficient.

In reporting on resource plan implementation to the Planning Coordinator, the Resource Planner should provide:

- The tracking of capacity and demand program in-service dates, and
- An evaluation of revised transmission and generation in-service dates on resource adequacy.

The term "resource" is to be understood to include supply resources (real and reactive power) and demand resources (such as dispatchable loads).

5. Transmission Operator

The Transmission Operator operates or directs the operation of transmission facilities, and is responsible for maintaining local-area reliability, that is, the reliability of the system and area for which the Transmission Operator has responsibility. The Transmission Operator achieves this by operating the transmission system within its purview in a manner that maintains proper voltage profiles and System Operating Limits, and honors transmission equipment limits established by the Transmission Owner. The Transmission Operator is under the Reliability Coordinator's direction respecting wide-area reliability considerations, that is, considerations beyond those of the system and area for which the Transmission Operator has responsibility and that include the systems and areas of neighboring Reliability Coordinators. The Transmission Operator, in coordination with the Reliability Coordinator, can take action, such as implementing voltage reductions, to help mitigate an Energy Emergency, and can take action in system restoration.

Note that the Model does not attempt to define what is and isn't a transmission facility, versus a generating facility. As discussed in section 13, this is assumed to be defined elsewhere by NERC or by governmental authorities.

Maintenance. The Transmission Owner provides the overall maintenance plans and requirements for its equipment, specifying, for example, maintenance periods for its transformers, breakers, and the like. The Transmission Operator then develops the detailed maintenance schedules (dates and times) based on the Transmission Owner's maintenance plans and requirements, and provides those schedules to the Reliability Coordinator and others as needed.

The Transmission Operator may also physically provide or arrange for transmission maintenance, but it does this under the direction of the Transmission Owner, which is ultimately responsible for maintaining its transmission facilities.

Bundled with the Reliability Coordinator or Transmission Owner.

A single organization may be the Responsible Entity for multiple Functions. In such a case, the Responsible Entities are said to be "rolled up" or "bundled" into a single organization. An organization may be a Transmission Operator without being a Reliability Coordinator or Transmission Owner. However, in many cases the Transmission Operator is bundled with one of these Responsible Entities.

Bundled with Reliability Coordinator. For example, consider an RTO with several members (**Error! Reference source not found.**). The RTO registers with NERC as a Reliability Coordinator and Transmission Operator and is NERC-certified for both. The RTO then delegates/assigns some of the Transmission Operator Tasks to its members. Regardless of this delegation/assignment, the Model views the RTO as the entity responsible for complying with all Reliability Standards associated with the Reliability Coordinator and Transmission Operator, and being NERC-certified for both.

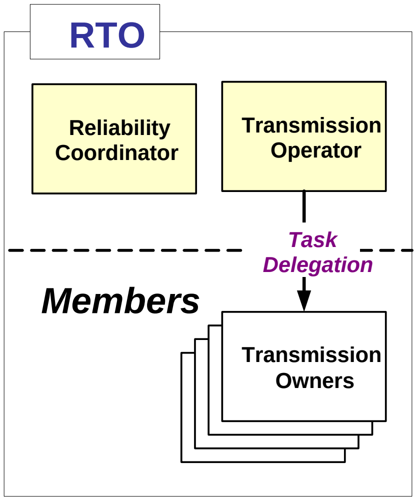


Figure 1 - Transmission Operator bundled with Reliability Coordinator.

Bundled with the Transmission Owner. In other situations, the RTO registers with NERC as the Reliability Coordinator, and its members register as Transmission Owners and Transmission Operators, as shown in **Error! Reference source not found.**. In this case, the Model views the RTO as responsible for complying with all Reliability Standards associated with the Reliability Coordinator and would be NERC-certified as such. The RTO members would be responsible for complying with all Reliability Standards associated with the Transmission Operator, and would be NERC-certified as such.

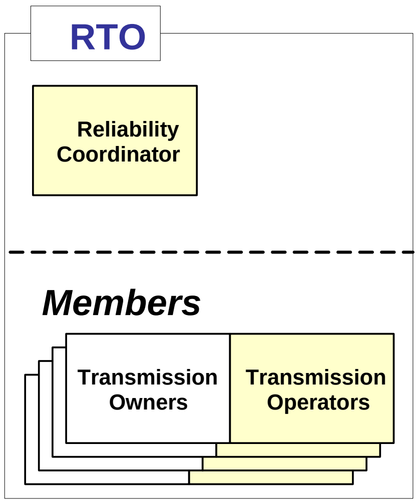


Figure 2 – Transmission Operator bundled with Transmission Owner

6. Interchange Authority

The Interchange Authority provides a service very similar to the Tag Authority that previously had been assigned to the Sink Balancing Authority. That is, it collects approvals or denials from Balancing Authorities, and Transmission Service Providers and verifies the validity of the source and sink.

The Interchange Authority provides the Balancing Authority with the individual bilateral Interchange Schedules. The Balancing Authority must track the individual Interchange Schedules in case one or more of them are curtailed by the Reliability Coordinator or by the Balancing Authority in those cases where a generator or load is interrupted. The Balancing Authorities then create a “net” interchange total for use in their energy management system as well as a “net” interchange for each neighboring Balancing Authority. The net Interchange Schedule for each neighboring Balancing Authority is used by the Receiving Balancing Authority for checkout with the neighboring Balancing Authorities.

All bilateral Interchange Transactions *that cross a Balancing Authority Area boundary* are coordinated through the Interchange Authority.

Authorization may be an explicit, positive approval, or may be implicit on an exception (passive) basis, for example a Transaction is approved unless explicitly denied.

While the approval/denial process may utilize tools (such as computer software and communication protocols), the Model envisages that the Interchange Authority will be assigned to an actual organization. Sanctions for failure to comply with the Interchange Authority standards requirements can only be levied against an organization. A Balancing Authority may serve as its own Interchange Authority or have this service provided by a separate organization.

Assessing ramping capability and connectivity. The Balancing Authority (or Scheduling Agent, for those cases where the Transaction is between resource dispatch areas with multiple Balancing Authority Areas), approves/denies the capability to ramp the Interchange Transactions in or out and notifies the Interchange Authority. The connectivity of adjacent Balancing Authorities is also verified by the Balancing Authorities (or Scheduling Agent) before responding to the Interchange Authority.

Ensuring balanced, valid Interchange Transactions. The Interchange Authority also ensures that the resulting Interchange Transactions are balanced and valid prior to physical delivery. This means:

- The source MW must be equal to the sink MW (plus losses if they are “self-provided”), and
- All reliability entities involved in the arranged Interchange are currently in the NERC registry.

Only when it receives approvals from the Transmission Service Providers and Balancing Authorities, does the Interchange Authority direct the Balancing Authorities to implement the Transaction. If any of these entities — TSPs, or BAs — does not approve the Transaction, then the Interchange Authority does not authorize the Transaction to become an Interchange Schedule.

Curtailments. The Interchange Authority coordinates Interchange Schedule curtailments ordered by the Reliability Coordinator by notifying the Balancing Authorities, Transmission Service Providers, and Purchasing-Selling Entities. The Interchange Authority also communicates and coordinates the resulting modified Interchange Schedules that result from the curtailments.

7. Transmission Planner

In developing plans for transmission service and interconnection requests beyond one year, the Transmission Planner is expected to coordinate and jointly plan with other Transmission Planners, as appropriate, to ensure new facilities do not adversely affect the reliability of neighboring transmission systems.

In reporting its transmission expansion plan to the Planning Coordinator, the Transmission Planner is also expected to verify that its plans for new or reinforced facilities meet reliability standards or identify the transmission deficiencies. The Transmission Planner is to work with the Planning Coordinator to identify potential alternative solutions, including solutions proposed by stakeholders to meet interconnected bulk power system requirements.

The Transmission Planner, in connection with monitoring and reporting its transmission plan implementation to the Planning Coordinator, addresses:

- Transmission facility in-service dates
- Coordination with Transmission Operators on projects requiring transmission outages that can impact reliability and firm transactions
- The impact of revised transmission in-service dates on transmission and resource adequacy.

8. Transmission Service Provider

The Transmission Service Provider authorizes the use of the transmission system under its authority. In most cases, the organization serving as Transmission Service Provider is also the tariff or market rules administrator.

Role in approving Interchange Transactions. The Transmission Service Provider approves Interchange Transactions by comparing the transmission service previously arranged by the transmission customer (Purchasing-Selling Entity, Generator Owner, Load-Serving Entity) with the transmission information supplied by the Interchange Authority. The Transmission Service Provider also ensures that there is a contiguous transmission path and that adjacent TSPs are on the scheduling path. The Transmission Service Provider then provides its approval or denial to the Interchange Authority.

Providing Transmission Service. As its name implies, the Transmission Service Provider is responsible for providing transmission service to transmission customers, such as Generator Owners, Load-Serving Entities, and Purchasing-Selling Entities. The Transmission Service Provider determines Available Transfer Capability based on the established Total Transfer Capabilities, System Operating Limits and Interconnection Reliability Operating Limits (by various entities including the Planning Coordinator, Transmission Planner, Transmission Operator and Reliability Coordinator), and coordinates ATC with other Transmission Service Providers. The Transmission Service Provider manages the requests for transmission service according to the Transmission Owner's tariff, and within the operating reliability limits determined by the Reliability Coordinator. The Transmission Service Provider does not itself have a role in maintaining system reliability in real time — that is the Reliability Coordinator's and Transmission Operator's responsibility.

The Transmission Service Provider arranges for transmission loss compensation with the Balancing Authority.

9. Transmission Owner

The Transmission Owner owns its transmission facilities and provides for the maintenance of those facilities. It also specifies equipment operating limits, and supplies this information to the Transmission Operator, Reliability Coordinator, Transmission Planner, and Planning Coordinator.

In many cases, the Transmission Owner has contracts or interconnection agreements with generators or other transmission customers that would detail the terms of the interconnection between the owner and customer.

Relationship with the Transmission Operator. The organization serving as Transmission Owner may also operate its transmission facilities and register with NERC as a Transmission Operator.

See "Transmission Operator," Section "Bundling with the Reliability Coordinator or Transmission Owner"

On the other hand, the Transmission Owner may arrange for another organization to operate its transmission facilities.

Similarly, the Transmission Owner may arrange for another organization to perform maintenance on the owner's transmission facilities.

10. Distribution Provider

The Distribution Provider provides the physical connection between the end-use customers and the electric system. For those end-use customers that are served at transmission voltages, either the Transmission Owner or the Transmission Operator also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage. One Distribution Provider may be directly connected to another Distribution Provider and not directly connected to the bulk power system.

The Distribution Provider is responsible for "local" safety and reliability. The Distribution Provider provides the switches and reclosers necessary for emergency action. The Distribution Provider may need to demonstrate load-shedding capability to the Balancing Authority and Transmission Operator.

The same organization may serve as the Distribution Provider and Load-Serving Entity, but they may be separate organizations as well. Unlike the Load-Serving Entity, the Distribution Provider has the facilities or assets ("wires") and does not take title to any energy. However, while these functions are distinct, in many cases an organization, such as a vertically integrated utility, bundles these functions together.

11. Generator Operator

The Generator Owner may operate its generating facilities or designate a separate organization to perform the Generator Operations Function.

The Generator Operator operates, or directs the operation of generation facilities. The Generator Operator is responsible for supporting the needs of the bulk power system up to the limits of the generating facilities in his purview. Ultimately the Generator Operator's role is to meet generation schedules, manage fuel supplies, and provide frequency support and reactive resources without jeopardizing equipment.

Relationship with the Generator Owner. The Generator Operator may also be the owner of the generation facilities it operates; or it may be a separate organization designated by the Generator Owner to operate the facilities. The Generator Operator may receive maintenance and performance verification direction from the Generator Owner, and develops operating and unit commitment plans based on this direction.

Relationship with the Transmission Operator. The Generator Operator provides reliability-related services through arrangements, or by direction from the Transmission Operator for support of the bulk power system. The Generator Operator provides maintenance schedules, generator status, and AVR status to the Transmission Operator. The Generator Operator receives notification of transmission system problems affecting its generator from the Transmission Operator or Reliability Coordinator.

Relationship with the Balancing Authority. The Generator Operator provides unit commitment schedules, generator status, annual maintenance plans, operating and availability status of generating units to the Balancing Authority.

Relationship with the Reliability Coordinator. The Generator Operator provides annual maintenance plans, and operational data to the Reliability Coordinator. The Generator Operator takes actions based on directives from the Reliability Coordinator for the needs of the bulk power system.

Relationship with Purchasing-Selling-Entity. The Generator Operator receives notice of Interchange Schedules approved by the Purchasing-Selling-Entity.

12. Generator Owner

The Generator Owner owns its generation facilities and provides for the maintenance of those facilities. It also is responsible for providing verified equipment operating limits and for supplying this information to the Generator Operator, Reliability Coordinator, Transmission Planner, and Planning Coordinator.

In many cases, the Generator Owner has contracts or interconnection agreements with Transmission Owners or Distribution Providers that detail the terms of the interconnection between these parties.

Relationship with the Generator Operator. The Generator Owner provides direction to the Generator Operator to perform maintenance and verification. The Generator Owner may arrange for another organization to operate, perform maintenance and verification on the owner’s generation facilities.

13. Purchasing-Selling Entity

The Purchasing-Selling Entity (PSE) arranges for and takes title to energy products (capacity, energy and reliability-related services) that it secures from a resource for delivery to a Load-Serving Entity (LSE). The PSE also arranges for transmission service with the Transmission Service Provider that provides transmission service to the LSE under a tariff or market rule.

The Purchasing-Selling Entity implements a bilateral Interchange Transaction between Balancing Authority Areas by submitting the Interchange Transaction information to the Interchange Authority.

14. Load-Serving Entity

The Load-Serving Entity (LSE) arranges for the provision of energy to its end-use customers, but does not include distribution services ("wires"). The LSE defined in the Model is not to be confused with or equated to the LSE as defined in any tariff or market rule.

Today, organizations serving as Load-Serving Entities may also be Generation Owners and can self-provide or have contracts with other Generator Owners for capacity and energy to serve the LSE's customers, or purchase capacity and energy from non-affiliated Generator Owners through a Purchasing-Selling Entity (or Market Operator), or employ a combination of these three options.

The Load-Serving Entity reports its generation (affiliated and non-affiliated) arrangements to serve load to the Balancing Authority, which forwards this information to the Reliability Coordinator for day-ahead analysis.

The LSE may contract for reliability-related services through the Market Operator (if the LSE is part of a market or pool) or directly from Generator Owners or loads.

The same organization may serve as the Distribution Provider and Load-Serving Entity, but they may be separate organizations as well. Unlike the Distribution Provider, the Load-Serving Entity, does not have bulk power system assets ("wires") and does take title to energy. However, while these functions are distinct, in many cases an organization, such as a vertically integrated utility, bundles these functions together.

The Functional Model assigns to the LSE the identification of loads for curtailment (such as loads subject to voluntary curtailment, and loads that are critical and should be excluded from non-voluntary curtailment where possible) and the development of load profiles and load forecasts.

The LSE communicates requests for voluntary curtailment to the appropriate end-use customer loads, thereby ensuring that these loads will in fact be curtailed.

15. Compliance Enforcement Authority

NERC has overall responsibility for monitoring compliance with Reliability Standards, with Regional Entities having the major role in the actual performance of the monitoring, under delegated authority from NERC.

16. Standards Developer

The Standards Developer is written to be NERC. The Reliability Standards referenced in the Model consist of standards developed by either NERC or a Regional Entity and that are approved by NERC and subsequently by governmental authorities. This would therefore not include regional reliability criteria that are not submitted to NERC for approval. This is discussed further in Section 2

17. Market Operator (Resource Integrator)

Market Operations is not a reliability Function. It is included in the Model to provide a linkage between reliability Functions and commercial functions.

The associated Responsible Entity is the Market Operator (Resource Integrator). The term Resource Integrator replaces Resource Dispatcher used in Version 3. This recognizes that integration of resources is the essential feature, not resource dispatch, which is the responsibility of the Balancing Authority.

Market Operator alone was used in Version 2, to apply to all jurisdictions. However, this led to some in the industry commenting that "market" should not be used in those areas not having a full-service commercial market for electricity. Accordingly, the additional term Resource Dispatcher was provided in Version 3.

The Market Operator is described further in Section II, Technical Discussions.

18. Reliability Assurer

Version 4’s Reliability Assurer for the Reliability Assurance Function replaces Version 3’s Regional Reliability Organization for the Regional Reliability Assurance Function.

The change to Reliability Assurer reflects the fact that a name specific to the Model is preferable to a name already in use in another context.

Similarly, the change to Reliability Assurance reflects the view that responsibility for reliability performance will not necessarily be on a regional basis.

The changes therefore provide NERC with flexibility in assigning the Responsible Entity for Reliability Assurance.

The role of the Reliability Assurer may be considered to involve "defense-in-depth". That is, the Reliability Assurer provides an independent assessment of Tasks performed by other Responsible Entities, or facilitates or coordinates such Tasks. While the specific role of the Reliability Assurer is not fully developed at the present time, the following are representative of the Tasks that might be performed:

- Perform high level evaluations, such as at a regional or Interconnection level, of transmission and resource adequacy. These evaluations may be based on a review of the plans of Transmission Planners.
- Perform readiness evaluations of Responsible Entities, to provide assurance that a Responsible Entity will be able to meet assigned requirements in Reliability Standards.
- Develop regional reliability plans, to ensure there are no reliability gaps, or no missing or ambiguous responsibilities or relationships.
- Perform high-level evaluations, such as at a regional or Interconnection level, of protection systems as they relate to the reliability of the bulk power system.
- Perform disturbance analysis evaluations.

The selection of particular Tasks for the Reliability Assurer will reflect NERC's judgment on which Tasks merit such a “defense-in-depth” approach.

Section II — Technical Discussions

1. General Clarifications of the Functional Model

The general features of the Functional Model are described in the Introduction, Purpose and Guiding Principles sections of the Model. In brief:

The NERC Reliability Functional Model ("the Model") provides the framework for NERC's Reliability Standards, as follows:

- *The Model describes a set of Functions that are performed to ensure the reliability of the bulk power system. Each Function consists of a set of related reliability Tasks. The Model assigns each Function to a Responsible Entity, that is, the entity responsible for ensuring the Function is performed. The Model also describes the interrelationships between that Responsible Entity and other Responsible Entities (that perform other Functions).*
- *NERC's Standard Drafting Teams develop Reliability Standards that assign each reliability requirement within a standard to a Responsible Entity, as defined in the Model. This is possible because a given standards requirement will be logically related to a Task within a Function. A standards requirement will be very specific whereas a Task will be more general in nature.*
- *NERC registers individual organizations as Responsible Entities for Functions they perform.*
- *NERC, through its compliance monitoring and enforcement programs, holds each organization accountable for complying with all reliability requirements in standards assigned to the Responsible Entities that the organization has registered for.*
- *The Model's Functions and Responsible Entities also provide for consistency and compatibility among different Reliability Standards.*

The NERC Reliability Functional Model ("the Model") does NOT address:

- *Entity Certification*
- *Registration*
- *Compliance*
- *Sanctions*

There are a number of clarifications that are important for those involved in developing standards and monitoring compliance with them. These clarifications are generally made in the Model itself, but because of their importance and potential for mis-interpretation, they warrant being repeated.

The Model is a guideline, it is not prescriptive. The Model is not a standard, and does not have compliance requirements. An organization that is a Responsible Entity for a particular Function is not accountable to NERC for the performance of the Function's Tasks, per se. Moreover, a standard drafting team is not precluded from developing Reliability Standards requirements that conflict with the Model's Function's Tasks or relationships among Responsible Entities. However, the Model is an approved NERC guideline, and as such, it is intended and expected that the Task definitions and interrelationships contained in the Model will guide the development of Reliability Standards and their applicability -- but, if it comes down to a choice, the needs of the Reliability Standards themselves take precedence over the Model.

A Responsible Entity is not an actual organization. The Model describes Tasks performed by Responsible Entities, which are in effect generic *classes or categories* of organizations – the Model itself does not address *specific* organizations. The Model, for example, describes the Reliability Coordinator, a Responsible Entity; the Model does not reference PJM and MISO, which are specific organizations. It is through NERC's registration process that the PJM and MISO organizations become a member of the category of organization called Reliability Coordinator, and thereby responsible for meeting standards requirements specified for the Reliability Coordinator.

The "Responsible" of Responsible Entity ultimately refers to responsibility for meeting standards requirements. An organization that is a Responsible Entity is "responsible" or accountable to NERC for meeting the standards requirements assigned to that Responsible Entity. The organization is not responsible to NERC for the performance of the Model's Function's Tasks *per se*.

The Model describes a conceptualized state that is not always achievable in actuality. The Model, which attempts to reflect all reliability-related activities, envisions that an organization that becomes a Responsible Entity is responsible to NERC for the performance of <u>all</u> standards requirements assigned to that Responsible Entity -- even if the organization delegates or shares the performance of some of the Tasks related to the standards requirements. Responsibility for closely-related standards requirements would be assigned to a single organization, avoiding potential complexity and ambiguity when two or more organizations are assigned responsibility. For example, there would be one, and only one, Transmission Operator for a given bulk power system facility.

However, in actuality, the conceptualized state described in the Model cannot always be achieved, because of factors related to particular organizational structures and relationships and regulatory and legal requirements. Addressing how such factors will impact responsibilities is the job of NERC's registration, certification and compliance process, and reliability standards (not the Model).

Every Function has an associated Responsible Entity. A Function is a set of related reliability Tasks; whereas the Responsible Entity is the name given to the category of organization that performs these Tasks. The diagram (Figure 3) of the Model includes two names within each Function box as shown in**Error! Reference source not found.** . The Function is shown in a larger typeface with the associated Responsible Entity underneath.

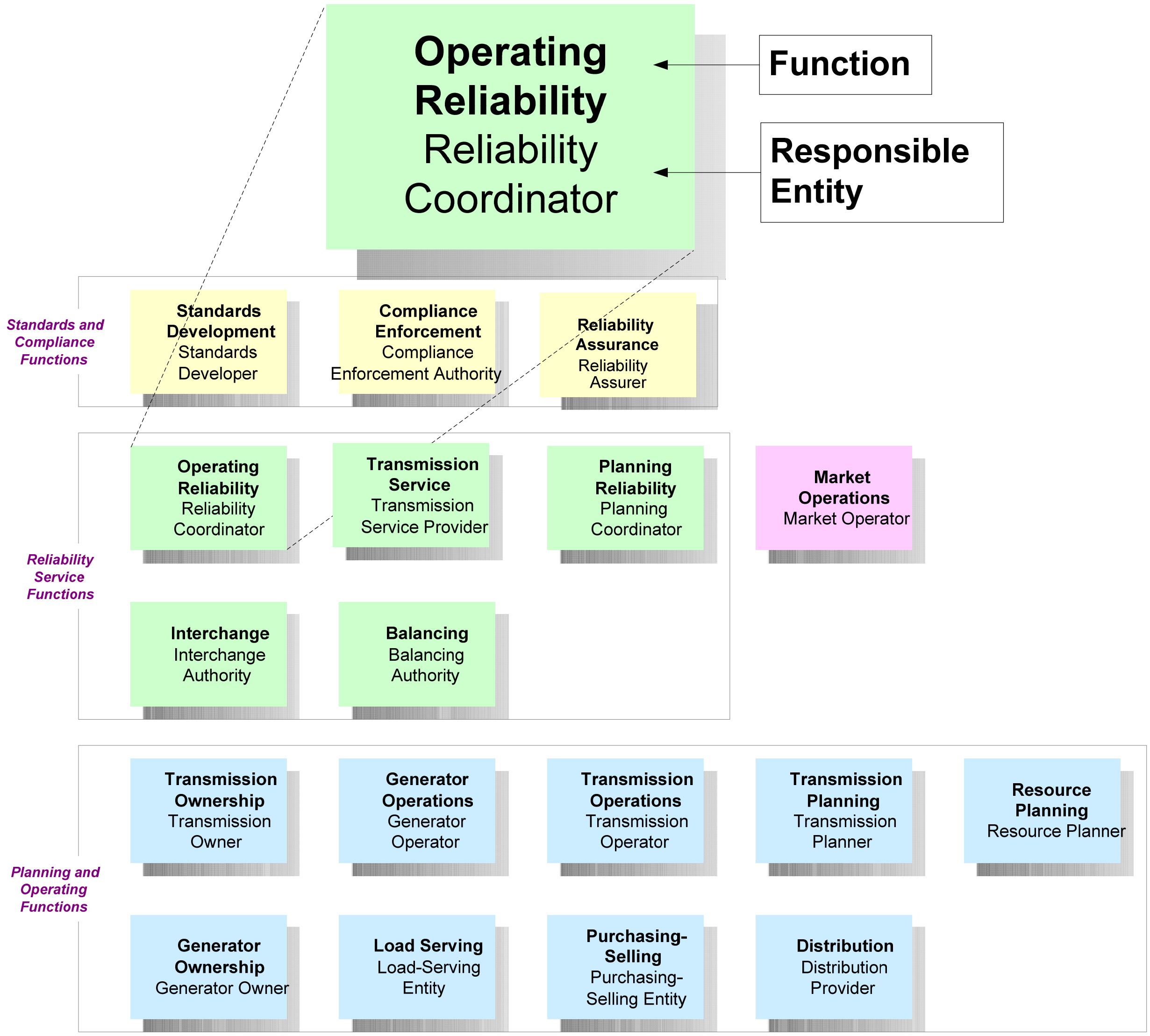


Figure 3 – Function and Responsible Entity

Organizations, such as Regional Transmission Organizations or integrated utilities, are expected to register with NERC as Responsible Entities by identifying which Functions they perform.

For example, as shown in Figure 4 an RTO (organization) may register with NERC to be a Reliability Coordinator, Balancing Authority, and a Transmission Service Provider. In this case we say that the RTO is the **Responsible Entity** for the Operating Reliability, Balancing, and Transmission Service Functions. We also use the expression that the RTO has “rolled up” these three Functions and is responsible for ensuring that the Tasks within each of those Functions are performed and all applicable standards requirements met.

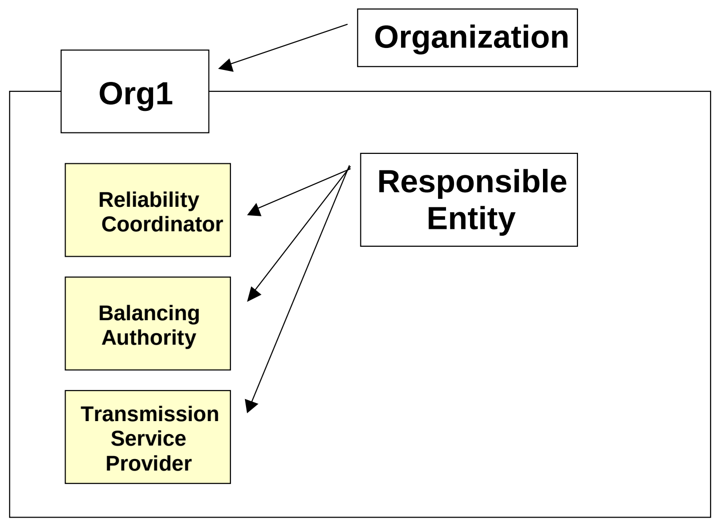


Figure 4 - Organizations are responsible for the Functions they "roll up".

2. Reliability Standards

The Functional Model describes the Standard Development Function and the Standards Developer as responsible entity and how these are related to "Reliability Standards".

Reliability Standards can be developed at the North American level as well as at the regional level and can therefore be placed in two categories:

1. **Reliability Standards Developed at the North American Level**

   NERC, develops and maintains Reliability Standards using the NERC Reliability Standards development process. They are applicable across North America upon approval by governmental authorities, unless specifically stated otherwise within the standard, and enable NERC and Regional Entities to monitor and enforce compliance with the standards requirements.

   NERC can use the standards development process to approve a variance from a NERC Reliability Standard; the variance then becomes part of the standard. The three categories of variance are:

   - Entity Variance that applies to an area less than a NERC Region
   - Regional Variance that applies to a NERC Region but less than an Interconnection
   - Regional Variance that applies to a NERC Region on an Interconnection-wide basis.

2. **Reliability Standards Developed by a Regional Entity**

   Regional Entities may develop and propose to NERC regional reliability standards that:

   - Set more stringent reliability requirements than the NERC Reliability Standard
   - Cover matters not covered by an existing NERC Reliability Standard.

   Alternatively, NERC may direct Regional Entities to develop a regional reliability standard in order to implement a NERC Reliability Standard.

   Regional Entities must use a NERC-approved development process to develop these regional reliability standards. Such regional reliability standards, upon approval by NERC, become NERC Reliability Standards. As appropriate, NERC will approve the regional reliability standard as an:

   - Interconnection-wide regional standard, or
   - Non-Interconnection-wide regional standard.

Regional Criteria. Regional Entities may develop regional reliability criteria that are necessary to implement, to augment or to comply with Reliability Standards, or to address issues not within the scope of Reliability Standards. Such criteria are not approved by NERC and are not (NERC) Reliability Standards. As such, regional criteria, while clearly serving a reliability purpose, are best considered to be outside of the (NERC) Functional Model.

3. Market Operations (Resource Integrator)

Market Operations is not a reliability Function. NERC does not assign standards requirements to the Market Operator.

Nevertheless, Market Operations, a commercial or market function, is included in the Functional Model, in order to provide an interface point between reliability and commercial functions.

Market functions differ in design and responsibilities, depending on the nature of the market, as discussed below.

The role of the Market Operator also varies in design and responsibilities, but all perform a resource integration task of one form or another under a set of market rules that are recognized by a state, federal, or provincial regulator. Resource integration is discussed further in the following section 4, Functional Model and Market Structures.

Version 4 of the Model refers to the Responsible Entity as "Market Operator (Resource Integrator)", where Resource Integrator may be a better term in areas not having a full-service market. Version 3 used the term "Resource Dispatcher"; however, Version 4 replaces this term, because in the Model, dispatch is performed by the Balancing Authority, not the Market Operator. For simplicity, the discussion below uses only the term Market Operator, to apply even where there is not a full-service market.

1. **The Market Operator in a Full-Service Market**.

A full-service market is one which offers both the commercial services such as integrating resources ahead of real-time and settlement after completion of Interchange Transactions and dispatch cycles, and implement the resource plan in real-time, making adjustment as necessary to meet other reliability requirements not envisaged during the resource integration process (for example, reliability constraints). In a full service market, the Market Operator tasks involve integrating resources in accordance with established market rules. Following its market rules and using available market mechanisms, the Market Operator integrates market resources by establishing a generation dispatch plan to meet the load forecast for the upcoming dispatch cycle (typically five minutes or longer).

This generation dispatch plan is usually a function of the generators' incremental bids ("merit order"). The established generation dispatch plan is submitted to the Balancing Authority for implementation. When the plan is tested for implementation, and limitations caused by transmission congestion are identified, the Balancing Authority will adjust the dispatch schedules accordingly. This constitutes a "security-constrained" dispatch.

Relationship between the Market Operator and Balancing Authority. In a full-service market, there is a close relationship between the Market Operator and the Balancing Authority. A full-service Market Operator performs resource integration tasks and is assigned the tasks of:

- Determining the generation dispatch plan (unit commitment) ahead of time

- Integrating scheduled interchange into that generation plan
- Designating which generators are available for regulation service
- Providing the generation dispatch plan to the Balancing Authority ahead of real time.

The Balancing Authority receives the plan, and implements it in real time.

2. The Market Operator Where There is not a Full-Service Market.

In jurisdictions not having a full-service market there will often be a traditional, vertically-integrated utility that may be both the Market Operator and the Balancing Authority, and most or all of the associated tasks will be performed internal to the utility. The generation dispatch plan will typically be cost-based, in contrast to bid-based dispatch in a full-service market.

4. The Functional Model and Market Structures

This section explains how the Functional Model can accommodate different market structures by examining these structures from the perspective of resource integration protocol.

Resource Integration Protocol. A resource integration protocol is the method used to determine the merit order of the generation to be dispatched. Generally, resource integration protocols are either cost-based or bid-based, depending on the market rules established by the regulatory authority, as described in section 3, Market Operations. The basis and the results for the resource integration algorithms are generally the same for cost-based and bid-based dispatch, which is why the Functional Model can accommodate either type of protocol.

Bid-Based Resource Integration. In those areas of the U.S. and Canada having a full-service market, market protocols provide Generator Owners the ability to bid into the market. In those cases, Generator Owners will direct the submission of bids via the Generator Operators to the Market Operator. The market protocols are established by the governmental authority, such as the Federal Energy Regulatory Commission in the U.S. and provincial regulators in Canada. The Market Operator, in turn, provides the Balancing Authority with the generator dispatch plan, so that the generators within the market footprint would be instructed to operate at the same incremental bid. Transmission constraints may cause the actual dispatch to deviate from the dispatch plan. Redispatch methods used to relieve the congestion may use: direct resource assignments, area / zonal dispatch signals, or bus-signals. The zonal and bus methodologies are often referred to as “Locational Marginal Pricing,” or LMP.

Cost-based Resource Integration. Where there is not a full-service market, the Market Operator may be a traditional, vertically-integrated utility that acts also as Balancing Authority. The utility will dispatch its resources based on its incremental costs (fuel and operations and maintenance) and losses. The regulatory authority, such as the state public utility commission, might specify the accounting rules for calculating these costs. In this case, the “market” is cost-based, and the utility determines the resource plan according to the same incremental cost (“lambda”). Transmission constraints can cause the incremental costs to be different on the two sides of the constraint. Thus, the lambda can vary by location.

Multiple Balancing Authorities Within a Market Area. If the Market Area includes more than one Balancing Authority Area, then the Market Operator will also provide each Balancing Authority with the net “interchange” schedule that results from the resource plan (“Resource Dispatch Interchange Schedule”, or RDIS). Each Balancing Authority’s RDIS will be an import or export to the Balancing Area, and the sum of all RDISs within the Market Area must add to zero at each dispatch cycle.

The table below describes how the current operating tasks may be performed by both the vertically-integrated utility and the unbundled, full-service market operator.

Task	**No Full-Service Market:** **Vertically Integrated Structure**	**Full-Service Market:** **Unbundled Structure**
Unit Commitment	Utility (performing as the Generator Owner) decides which units to run.	Generator Owners decides which units to make available.
Economic Dispatch	Utility (as Market Operator or Resource Integrator) performs economic dispatch calculation based on incremental costs or other requirements. Utility must consider generator operating limits, which units are providing regulation service, and any commitments for bilateral arrangements.	Market Operator collects bids from Generator Owners and develops integrated resource plans based on market rules (e.g., bids). Market Operator must consider generator operating limits, which units are providing regulation service, and any commitments for bilateral arrangements.
Congestion Management	Results in different incremental costs (“lambdas”).	Depending on the market structure, results in Different locational marginal prices (LMP), or Different marginal costs
Regulation Service	Utility (serving as the Balancing Authority, Load-Serving Entity, and Generator Owner) in concert with the Reliability Coordinator, determines the amount of regulation service required. and designates those units that provide the regulation service Utility (as Balancing Authority) uses this information in its economic dispatch.	Balancing Authority, along with Reliability Coordinator, determines the amount of regulation service required. Generator Owners decide which units to bid in for regulation service. Market Operator runs bid pool for regulation service. Load-Serving Entity arranges for regulation services.
Generator Control	Utility (as Balancing Authority) pulses units that are designated by the Market Operator for regulation service. As regulating ability declines, the part of the utility that acts as Balancing Authority directs the part of the utility that acts as Market Operator to develop a new dispatch plan.	Balancing Authority pulses units that are designated by the Market Operator for meeting energy and regulation service requirements. As regulating ability declines, the Balancing Authority asks the Market Operator for a new dispatch plan.

5. Providing and Deploying Ancillary and Reliability-Related Services

Tariff Domain – Requirement for Ancillary Services. The FERC open access (pro forma) tariff requires the (U.S.) Transmission Provider to provide the following Ancillary Services to all customers taking basic transmission service (Figure 5):

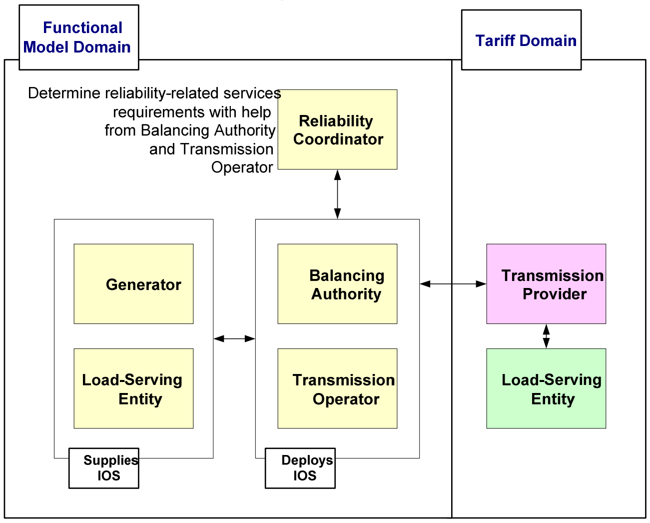


Figure 5 - Supply and Deployment of Ancillary Services and Reliability-Related Services.

1. Scheduling, system control, and dispatch
2. Reactive supply and voltage control from generation.

The FERC pro-forma tariff requires that the Transmission Provider offer to provide the following services to customers serving loads within the Transmission Provider's own area which do not purchase or self-provide:

3. Energy imbalance
4. Regulation and frequency response
5. Operating reserve – spinning
6. Operating reserve – supplemental
7. Generator Imbalance

Functional Model Domain – Reliability-related services. Version 2 of the Model used the term Interconnected Operations Services (IOS) to describe reliability services that may be considered building blocks of Ancillary Services. In Version 4, it is recognized that IOS as a defined term is not in use in Reliability Standards, and hence it has been replaced by the term "reliability-related services" to mean those services other than the supply of energy that are physically provided by generators, transmitters and loads, in order to maintain reliability.

Reliability-related services include voltage control and reactive power resources from generators, transmitters and loads. Certain transmission facilities can provide reactive support, but are not considered an Ancillary Service in the open access tariff, rather, they are considered part of basic transmission service. In addition, loads may provide reserves through load-shedding or demand-side management, and may also provide frequency response.

Figure 5 shows how Ancillary Services in the “tariff domain” could be served by reliability-related services in the "reliability domain". The Functional Model explains that the Balancing Authority, alone or in coordination with the Reliability Coordinator, determines the amount required and arranges for reliability-related services to ensure balance:

- The Balancing Authority determines regulation, load following, frequency response, and contingency reserves, etc., and deploys these as reliability-related services.
- The Transmission Operator determines the reliability-related services necessary to meet its reactive power requirements to maintain transmission voltage within operating limits, and deploys these as its set of reliability-related services.
- The Reliability Coordinator, working with the Transmission Operator, determines the need for Black Start capacity. The Transmission Operator cannot do this alone, because it may not have a wide enough picture of the transmission system.

Through its Reliability Standards, NERC holds Responsible Entities (the Reliability Coordinators, Balancing Authorities, Transmission Operators and Transmission Service Providers) responsible to comply with applicable standards requirements, including those requirements that depend on reliability-related services. The quantity of and processes used to deploy those reliability-related services depend on the Regional and local system characteristics and regulatory requirements. The Responsible Entities establish the quality and quantity of their own reliability-related services, using these processes and procedures in a manner that ensures compliance with the standards requirements.

6. Managing Bilateral Interchange Transactions – Basic Concepts

Interchange Transactions that cross multiple Balancing Authority (BA) Areas can be broken down daisy-chain fashion into individual Balancing Authority-to-Balancing Authority Interchange Transactions, with the sink Balancing Authority designated as the "manager" (the "Tag Authority").

Version 3 of the Functional Model recognizes this Interchange process as the current Industry practice and includes BA-to-BA "after hour" checkout for net Interchange between adjacent Balancing Authorities. Also, the Interchange Authority function "coordinates" and "communicates Interchange Transactions ("deals") that are ready for physical implementation between Balancing Authorities. The IA receives approvals that recognize ramping capability rather than verifying it as prescribed in Version 2. The IA also communicates the Interchange transaction information to all involved parties (Figure 6).

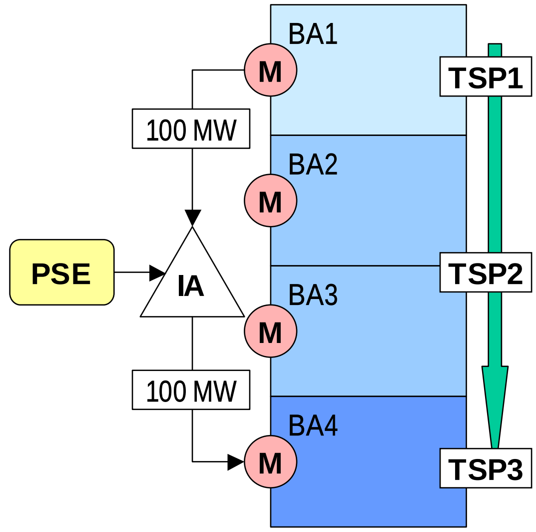


Figure 6 - The Interchange Authority manages transactions between the source and sink Balancing Authorities.

Managing Bilateral Interchange Transactions- Allowable Concept

Version 3 of the Functional Model does not prevent Balancing Authorities from scheduling Interchange with Interchange Authorities (IA). The IAs would ensure that the schedules are balanced (equal and opposite) between the Source and Sink BAs. In the example in Figure 6, the IA manages a transaction from BA1 to BA4. The schedule is

BA1 → IA → BA4

and the transmission service path is

TSP1 → TSP2 → TSP3.

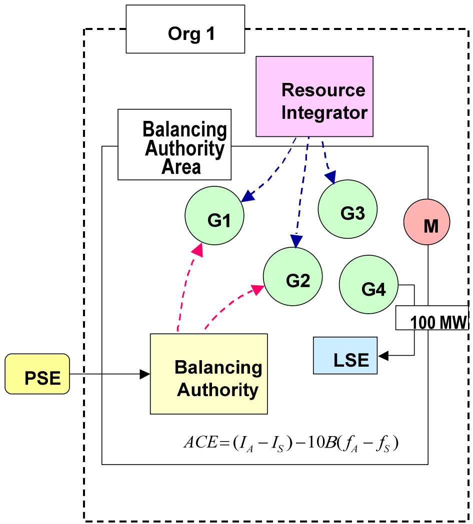


Figure 7 – The Purchasing-Selling Entity submits the bilateral transaction to the Balancing Authority for intra-BA transactions.

Interchange Transactions within a Balancing Authority Area. A bilateral Interchange Transaction within a Balancing Authority Area does not require Interchange Authority authorization. In the example in Figure 7, the Purchasing-Selling Entity submits the 100 MW Interchange Transaction to the Balancing Authority who will inform the Resource Integrator (or Market Operator) if the Resource Integrator needs to know which generators are committed to the Transaction, and to the Reliability Coordinator for reliability assessment.

The following tables compare the Interchange checkout procedures that the Balancing Authorities use today with the procedures that the Balancing Authorities would use if this type of Interchange concept were applied.

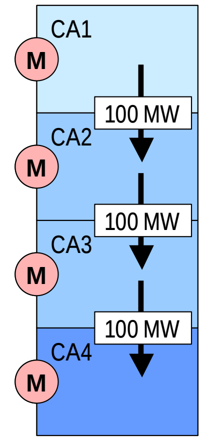
Checkout under Existing NERC Practice Figure 8

Control Area	Actual from Tie Meters	Schedule with CA	Inadvertent
CA1	+100 to CA2	+100 to CA2	0
CA2	-100 from CA1 +100 to CA3	-100 from CA1 +100 to CA3	0
CA3	-100 from CA2 +100 to CA4	-100 from CA2 +100 to CA4	0
CA4	-100 from CA3	-100 from CA3	0

Potential Future Checkout Figure 9

Balancing Authority	Actual from Tie Meters	Schedule with IA	Inadvertent
BA1	+100 to BA2	+100 to IA	0
BA2	-100 from BA1 +100 to BA3	0	0
BA3	-100 from BA2 +100 to BA4	0	0
BA4	-100 from BA3	-100 from IA	0

Figure 8



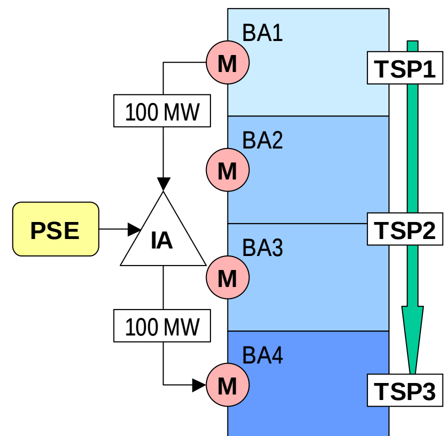


Figure 9

7. Managing Bilateral Interchange Transactions – Scheduling Agents

Some Transmission Providers provide a Scheduling Agent service for their Balancing Authority members. The Scheduling Agent provides a single point of contact for all Interchange Schedules into or out of those Balancing Authorities. For example, the Southwest Power Pool serves as a Scheduling Agent for its members, and any Balancing Authority external to SPP will schedule to any SPP Balancing Authority by way of the SPP as the Scheduling Agent. This simplifies Interchange scheduling for parties both internal and external to SPP.

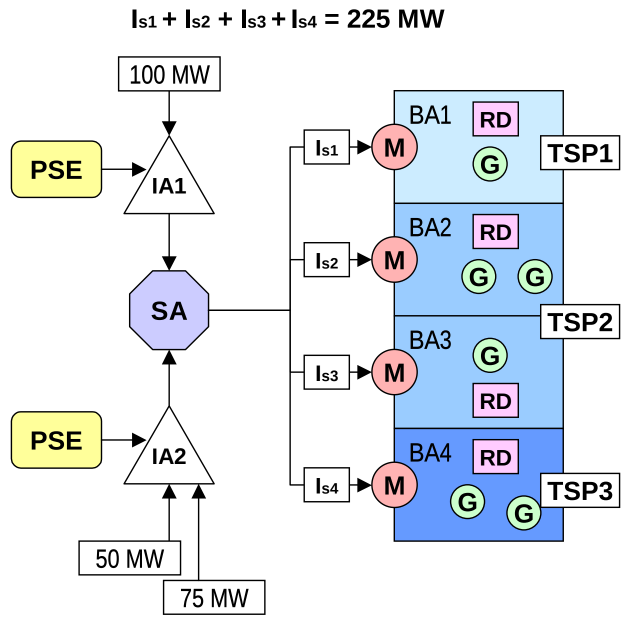


Figure 10 - The Scheduling Agent divides a 100 MW transaction among a group of Balancing Authorities.

In the example in Figure 10, two Interchange Authorities schedule a total of 225 MW with the Scheduling Agent for a group of four Balancing Authorities as follows:

IS1 = 100 MW into BA1

IS3 = 50 MW into BA3

IS4 = 75 MW into BA4

IS2 = 0

The Scheduling Agent must ensure that the sum of the Interchange Schedules from all Interchange Authorities is exactly equal to the sum of the Interchange Schedules from the Scheduling Agent to its Balancing Authorities:

ISA1 + ISA2 = IS1 + IS2 + IS3 + IS4

If the Balancing Authority(ies) use a Scheduling Agent, then the Interchange Authority will request approvals from the Scheduling Agent — not the Balancing Authority(ies) — during the Interchange Transactions authorization process. The Interchange Authority will also notify the Scheduling Agent of any Interchange Transaction curtailments.

Because Interchange scheduling is an integral function of the Balancing Authority, the Functional Model Working Group defines that the Scheduling Agent is actually an agent of the Balancing Authorities. The Balancing Authorities would still be the Responsible Entities for ensuring that the Interchange schedules from the Scheduling Agent were incorporated into the BAs' energy management systems. Some have argued that the Scheduling Agent would need to be certified and monitored to ensure that it handled the interchange schedules properly.

8. Non-coincident Resource Integrator and Balancing Authority Areas

Bilaterals between Market Areas. In the examples above, each Balancing Authority Area was the same as the Market or Resource Integrator Area. When generation is dispatched (either cost-based or bid-based) over several Balancing Authority Areas, we may be faced with a bilateral Interchange Transaction whose source or sink is the entire Market Area, and cannot be identified with any particular Balancing Authority within that area. In this situation, the Interchange Authority schedules with the Scheduling Agent for the Market Area. Then the Scheduling Agent, working with the Market Operator, will determine how the bilateral Interchange Transaction is allocated among the Balancing Authority Areas.

As was explained in the technical discussion on reliability-related services, the Scheduling Agent ensures that the RDIS are properly allocated to the Balancing Authorities.

Now we can combine the Scheduling Agent's management of RDIS with bilateral Interchange Transactions as shown in Figure 11.

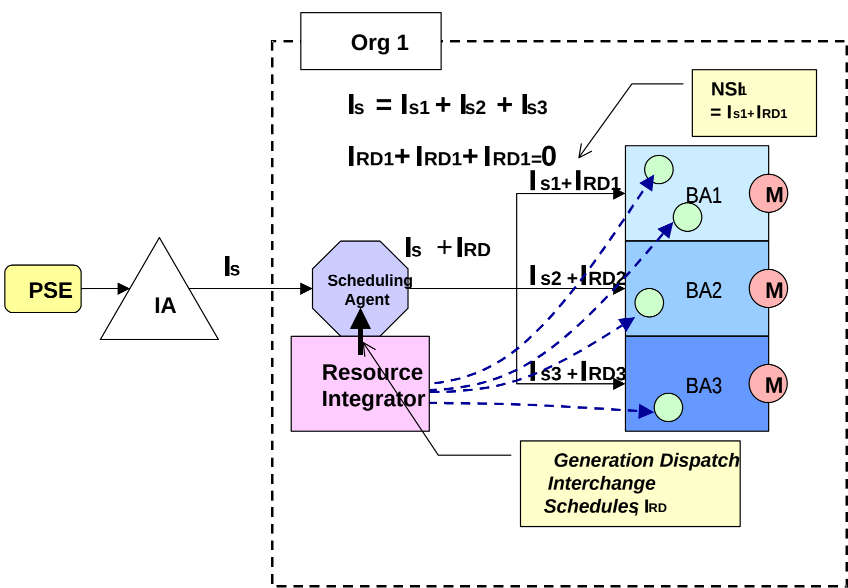


Figure 11 - The Scheduling Agent manages bilateral Interchange Transactions in to or out of the Market Area as well as the Interchange Schedules that result from the economic dispatch or market operations.

Bilaterals between Balancing Authorities within the same Market Area. A bilateral Interchange Transaction between two Balancing Authorities within the same Market Area does not require Interchange Authority management because the Market Area is under a common tariff, and the Market Operator would have a close relationship with the Reliability Authority. In the example in Figure 12, the Purchasing-Selling Entity has submitted a 100 MW bilateral Transaction from BA1 to BA3 directly to the Scheduling Agent, who would then coordinate the transaction between the source and sink Balancing Authorities. The Scheduling Agent then submits the resulting interchange schedule to the Source and Sink Balancing Authorities, and informs the Market Operator if the Market Operator needs to know which generators are committed to the transaction.

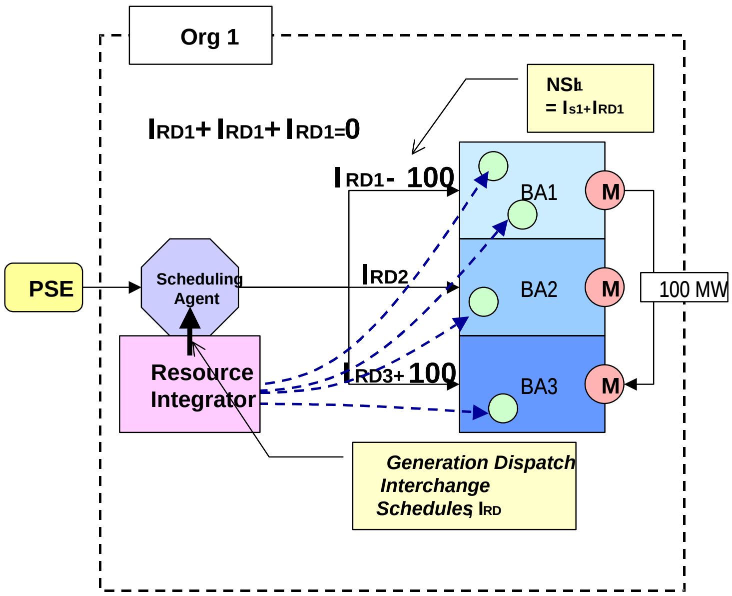


Figure 12 - The PSE submits its Interchange Transaction information directly to the Scheduling Agent when the bilateral transaction is within the same Market Area.

9. Implementing the Interchange Authority

Questions have arisen within the industry concerning the implementation of the Interchange Authority (IA).

From the perspective of the Functional Model there are no implementation issues. That is, the IA functional Tasks are currently being performed and the associated entity relationships exist. Specifically, the IA Tasks are being performed by the organization registered as BAs, specifically the "sink BA"[2] for a particular interchange transaction. It has been noted that the Functional Model could in principle have assigned the IA Tasks to the BA and avoided the need for a separate Interchange function. This approach was not followed because it was envisioned in the future that the IA Tasks could be performed by entities other than a BA, a possibility that is allowed for by defining the IA separate from the BA. Therefore, the Functional Model *accommodates* the sink BA as the IA, but does not *require* it.

The implementation of the IA extends also to the NERC INT standards that exist today, which impose data collecting and interchange-information distribution requirements on an IA.

To date there has been a gap in the implementation of the IA regarding registration and compliance processes. There are relatively few organizations presently registered as an IA. There are therefore many interchange transactions where no entity is being monitored and held accountable for compliance with the INT standards.

However, on July 14, 2008 NERC:

> "… added Interchange Authority (IA) to the list of functional entities that are required to be included on the NERC Compliance Registry (NCR) in accordance with the NERC *Statement of Compliance Registry Criteria (Revision 4.0)* approved by the U.S. Federal Energy Regulatory Commission (FERC) on February 5, 2008. NERC has delegated the responsibility to the eight Regional Entities for identifying the organizations to be registered in the NCR".

Further clarification was provided, as follows: "To assist in registration of entities as IAs, NERC is providing the following guidelines:

1. As a starting point, all entities performing functions as an IA shall be registered as an IA. If an IA registrant cannot be identified in a given footprint and the BA(s) for that footprint is performing the IA tasks or is using a software program to perform the IA tasks, that BA(s) shall be registered as the Interchange Authority.
2. If the BA has assigned responsibility to another entity (*e.g.*, a Regional Transmission Organization), upon written agreement by both parties involved, NERC will register the entity to whom the responsibilities have been assigned. If an entity states that it is

[2] That is, the BA in whose area the bilateral interchange transaction terminates.

not responsible for all the IA requirements, and that some other entity also is responsible for certain of the applicable IA standard requirements, then both entities shall be registered using the Joint Registration Organization process from the Rules of Procedure, section 507.

3. A third party or vendor company that develops software that is used as a tool to enable an entity to perform the IA function shall not be eligible for registration as an IA unless the software company is an owner, operator, or user of the bulk power system. The entity that is using the software tool to perform the IA function is responsible for compliance with the NERC Reliability Standards applicable to IA and shall be registered as the IA. While a centralized computerized system may make the handling of these reliability responsibilities more efficient, the entity actually responsible to perform the responsibilities must be identified and registered. To recognize the relationship with software and system vendors, those vendors may be audited by an nationally recognized independent auditor for the tasks they perform on behalf of the entity."

This NERC direction regarding registering of IAs is therefore compatible with the approach taken in the Model:

- There is a need for a separate Interchange Function
- Allowance is made for BAs to register as IAs, but non-BA entities are not precluded from doing so.
- The IA is an entity, not a software tool.

The remainder of this section clarifies the context and need for an IA from the perspective of the Model, by describing the associated reliability tasks and their implications. As such, it may be of use to those involved in registration processes.

INTERCHANGE PRACTICE

Background

To help ensure reliability, *"requests" for interchange transactions* must be approved before that request is allowed to be become an "implemented" Interchange Schedule. Without approvals, it is possible that the sum of all Interchange schedules in an interconnection will not sum to zero. That, in turn, would lead to the condition that even if every BA were controlling to zero Area Control Error, there could still be off-generation occurring because of the Net schedule being in error.

Historically, approvals were handled on a control area to control area basis. Net Interchange schedules between neighbors were checked and approved prior to implementation. Only if there were disagreements, did individual requests get checked. This pragmatic practice served the industry well – but not perfectly. When given control areas did not take the time to compute their own Net Schedule interchange (and instead merely accepted the numbers from its individual neighbors) – what can and did happen was that individual schedules were active on one side of the control area, but not on the other side. Not until serious operational symptoms arose (e.g., unexplained parallel flows, or unusual number of time error corrections) was there an investigation.

Current Practice

The Functional Model's inclusion of an IA recognizes a reliability concern regarding responsibility for approving a request for interchange, and the distribution of the information for the approved request for interchange. Each and every transaction that a PSE desires to implement must have approvals from all parties involved, and must have approval by each of them regarding the characteristics of each of those transactions.

Today, the approval and communication are implemented in a two-step process – each step focusing on different quantities. One step focuses on the individual transactions and their respective characteristics. This step is carried out by a tagging authority. The other step focuses on implementing Net schedules (i.e., the net of the transactions that were approved). This step is carried out by neighboring BAs. This two-step process can and does work. The problem is that when there is a breakdown in the process, there is no compliance process in place.

For example, if the tagging authority were the root cause of non-compliance (such as a computer error that caused transaction information to elude analysis of a participant in the transaction, and that error resulted in a blackout), then no one would be held non-compliant, if no entity is registered as IA for the transaction. If a BA_{left} accepts a Net Schedule from BA_{center} but the transactions within that Net do not agree with the complementary transactions of the accepted Net Schedule between BA_{center} and BA_{right}, then again no one can be held non-compliant if no one is registered as IA.

What is in place today is the NERC Tagging Specification, under which each sink BA is responsible for providing Tagging Services, either directly or by arranging with a third party to provide this service as its agent.[3] However, the Tagging Specification is not a standard and therefore not a sufficient basis for compliance enforcement.

[3]Electronic Tagging Functional Specification, ver 1.8.0, approved Nov 7, 2007, http://reg.tsin.com/Tagging/e-tag/e-tag-spec-v-18-20071107.doc)

10. Task Assignment Options

The Tasks of the Functional Model are high level and are not to be confused with requirements of the standards. This section describes the concept of Task assignment *within the context of the Model* -- this is therefore not to be confused with the assignment to organizations of their responsibilities for meeting standards requirements.

Delegation

Within the context of the Model, an organization, such as an RTO, can delegate/assign Tasks to one or more organizations. In this example (Figure 13), the organization (RTO) is the NERC-certified Transmission Operator, but has delegated/assigned some of the Transmission Operator Tasks to its members. In the context of the Model, the RTO would be the Responsible Entity, and that its members would carry out certain Tasks under the RTO's direction.

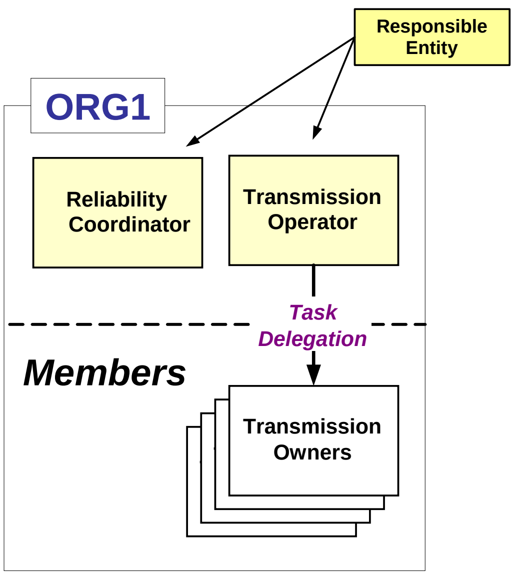


Figure 13 - In this example, Organization 1 has delegated certain Transmission Operations Tasks to its members.

The concept of delegation can be generalized to include any arrangement in which a second party is obligated to perform one or more of a Responsible Entity's Tasks. Such an arrangement may be in the nature of sharing.

11. Planning Functions

In Version 2 of the NERC Functional Model was expanded to include three planning functions . The Operating Committee's Control Area Criteria Task Force had previously developed the operational portion of the Functional Model (Version 1), which was approved by the NERC Board of Trustees in June 2001. Adding the planning functions completed the NERC Functional Model, and allows it to serve as the framework for the Reliability Standards that cover resource planning and transmission planning.

The three Version 3 (and hence version 4) planning functions are: Planning Reliability, Transmission Planning, and Resource Planning. The Planning Coordinator, who is the responsible entity for the Planning Reliability Function, resides at the "highest" planning level, with the Transmission Planners and Resource Planners within their respective Planning Coordinator Area reporting to the Planning Coordinator.

Planning Reliability Function

The Planning Coordinator, who is responsible for the Planning Reliability Function, integrates and assesses the plans from the Transmission Planners and Resource Planners within its Planning Coordinator Area to ensure that their plans comply with Reliability Standards and meet future needs, or develops and recommends revisions to plans that do not meet Reliability Standards or future needs. The Planning Coordinator also ensures that a long-term (generally one year and beyond) plan is available for adequate resources and transmission within its Planning Coordinator Area. The Planning Coordinator is not responsible for implementing the transmission and resource plans. However, it helps to ensure that adequate resources and transmission facilities are placed into service in a timely manner through the Resource Planners, Transmission Planners, and possibly others through open solicitations for facilities.

Like the Resource Planners and Transmission Planners at the "local" level, the Planning Coordinator maintains system models and performs the necessary studies to evaluate whether the composite resource and transmission plans of its Resource Planners and Transmission Planners are in compliance with reliability standards.

Calculates transfer capabilities. The Planning Coordinator reviews the transmission transfer capability determined by Transmission Planners and also determines future (generally one year and beyond) transfer capabilities between and among the Transmission Planners and other Planning Coordinators based on the transmission and resource plans. These longer-term transfer capabilities are used in determining long-term ATCs and assessing requests for long-term transmission service. These values are provided to the Reliability Coordinator and Transmission Operator(s) for their use as a reference in developing operating limits.

Evaluates plans for customer requests. The Planning Coordinator evaluates responses for long-term (generally one year and beyond) transmission service requests developed by its Transmission Planners and provides the resulting plans to the Transmission Service Providers, Transmission Owners, and Transmission Customers. The Planning Coordinator also reports on system development trends for customer demand, transmission expansion, and resources within its Planning Coordinator Area. It also provides, as appropriate, plan assessments and reports to regulatory authorities and government agencies, and tracks capacity, demand programs, and transmission in-service dates. Finally, the Planning Coordinator evaluates the impact of revised generation and transmission in-service dates on the long-term reliability of the bulk transmission systems.

Resource Planning Function

The Resource Planners, who are the responsible entities for the Resource Planning Function, develop long-term (generally one year and beyond) resource adequacy plans necessary to supply specific customer demands within the Planning Coordinator Area. These plans can also be provided by the Load-Serving Entities or Generator Owners, or both, within the Planning Coordinator Area.

Develops resource plans. The Resource Planners maintain resource models to develop and evaluate resource plans in conjunction with Reliability Standards. These models also are coordinated with the Resource Planner’s related Planning Coordinator. The Resource Planners also identify areas of resource deficiency and provide potential alternative solutions to meet resource requirements.

The Resource Planners also evaluate, in conjunction with the Transmission Planners and Transmission Owners, the deliverability of the planned resources to the customer demands.

Provides resource plans to Planning Coordinator. The Resource Planners provide their resource plans to the Planning Coordinator for assessment and review for compliance with Reliability Standards. They also track capacity and demand program in-service dates, and evaluate the impact of revised generation and transmission in-service dates on resource adequacy.

Transmission Planning Function

The Transmission Planners, who are the responsible entities for the Transmission Planning Function, provide long-term (generally 1 year and beyond) transmission plans for the areas under their purview, called the Transmission Planner Areas. A Transmission Planner Area may be smaller than or equal to the Area of its related Planning Coordinator. Every existing and proposed transmission line, or portion thereof, must be within the boundary of a Transmission Planner Area.

The Transmission Planners coordinate with other Transmission Planners to include the impacts of transmission plans on both on an intra- and inter-area basis. The Transmission Planners also maintain the system models and perform the necessary steady-state, dynamic, and short-circuit studies to ensure that their transmission plans meet Reliability Standards. These models are also coordinated with the Transmission Planner’s related Planning Coordinator.

Evaluates customer requests for transmission service. The Transmission Planner evaluates long-term (typically longer than one year) requests for transmission service (as compared to the Transmission Service Provider who evaluates and provides transmission service for the shorter term (generally less than one year)), and identifies the facilities that will be needed to integrate new generation, transmission, and end-use customers into the bulk power system). Requests for transmission service will usually come from Transmission Owners, Generator Owners, Load-Serving Entities, and Transmission Service Providers.

Develops planning procedures and protocols. The Transmission Planners develop the planning procedures and protocols that are necessary to ensure that a reliable transmission system is developed within their respective Transmission Planner Areas. These procedures and protocols include specifications for transmission data, system protection and control and special protection systems as needed, and voltage and stability limits to meet reliability standards. They also coordinate these procedures and protocols with neighboring Transmission Planners and their related Planning Coordinator.

Develops transmission expansion plans. Based on customer requests for transmission service, the planning procedures and protocols established for their Transmission Planner Areas, plus the reliability standards, the Transmission Planners will develop transmission plans to accommodate long-term firm transmission service requests. While developing these plans, they may provide alternate solutions and evaluate alternatives suggested by the transmission customers.

Provides transmission plans to Planning Coordinator. The Transmission Planners provide their transmission plans for their respective Transmission Planner Areas to their Planning Coordinator for assessment and review for compliance with Reliability Standards.

12. Reliability Areas and Boundaries

Assets versus Geography as the Basis for Defining Areas and Boundaries

It is useful for organizations that are Responsible Entities to specify an associated Area, which defines the portion of the bulk power system within which their Responsible Entity status applies. Moreover, by reviewing all of the Areas for a particular Responsible Entity, it is possible to establish whether there are overlapping responsibilities or gaps, which can then be eliminated. The concept of Areas and boundaries (the interfaces between adjacent Areas) is therefore important in establishing clear responsibilities for compliance with Reliability Standards.

The previous version of the Technical Document referenced boundaries and Areas as being both geographic and electrical in nature. However, the FMRSCTF review of the Model conducted in 2005 concluded that the most logical building block for defining boundaries and Areas, and ultimately responsibility for compliance with reliability standards, is electrical, namely the individual bulk power system asset. That is, the building blocks are the individual transmission, generation and customer equipment assets that collectively constitute the bulk power system . Accordingly, the FMRSCTF report recommended that assignment of Responsible Entities should be on the basis of particular bulk power system assets, not geography.

This will enable any given bulk power system asset to be associated with a single organization, with respect to the Responsible Entity for a given function. This will therefore provide the basis for clear assignment of responsibility for managing the potential reliability impacts of the asset, where the specific responsibility is to be established in NERC's registration, certification and compliance processes.

It is noted that a geographic definition is not adequate in a situation where there are, for example, two Transmission Operators in a given geographic footprint, differentiated by the voltage level of the assets under their respective control. In such a situation, the use of the specific bulk power system assets provides an adequate basis for defining Areas/boundaries.

Boundaries for Operations and Planning

The previous version of the Technical Document examined boundary conditions and reached certain conclusions, including:

- Each Balancing Authority Area should be within a Reliability Coordinator Area
- There should not be gaps between adjacent Areas of the same type.
- There should not be overlaps in adjacent Areas for Operations, but there may be overlaps for Planning.

Boundary conditions are intrinsic to effective standards, and therefore any specification of boundary conditions should arise in the standards development process, i.e., in response to a perceived reliability need, not in response to the needs of the Model. Specifically:

> *Mandatory boundary constraints between responsible entities should be set at the minimum threshold necessary for the reliability of the interconnections. Otherwise there should be no restrictions on boundary conditions between responsible entities. These criteria should be set through an open process and adopted into organization certification standards*[4].

This is the recommended approach of Version 4. It does not refute the broad and intuitively reasonable conclusions on matters such as the need to avoid gaps and overlaps, but leaves this as a matter to be addressed in the NERC compliance process and Reliability Standards, not in the Model.

Boundaries for Operations

NERC requires that every generator, load (customer), and transmission facility be within an area having a metered boundary. This ensures that within the area:

- All resources are balanced with demand, including transmission system losses, and
- All transmission facilities are operated within their operating limits.

The Functional Model groups the reliability Tasks into Functions, but we must still ensure that all generation, load, and transmission facilities are located within certain boundaries to ensure generation-load balance and reliable transmission operations. This creates a need to incorporate these boundary conditions into the Reliability Standards.

Boundaries for Planning

The Reliability Planning, Transmission Planning and Resource Planning Functions apply to specific defined Areas that may or may not have a direct correlation with the corresponding operating areas (Reliability Coordinator Area or a Balancing Authority Area). Again, planned generation, load and transmission facilities must be located within specified boundaries, with the specification of such boundaries given in standards, not in the Model.

As described previously, there is in practice often "layering" of the areas of the plans. That is, a specific generation or transmission facility may be included in more than one plan. Again, there should be no gaps.

Size Considerations Relating to Area

The Functional Model does not specify a minimum or maximum size for a reliability area. From the perspective of the Model, an organization qualifies to be the Responsible Entity for a particular Function by virtue of performing the Function's Tasks.

Size is not a consideration in the distinction between local-area versus wide-area reliability. Local-area reliability is the responsibility of the Transmission Operator in the sense of

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[4] The March 11, 2005 report of the Functional Model Reliability Standards Coordination Task Force (FMRSCTF). See ftp://www.nerc.com/pub/sys/all_updl/sac/fmrsctf/FMRSC_TF_Report_3-11-05.pdf

considerations relating to the Transmission Operator's local system or area, regardless of how large that area may be. Similarly, wide-area reliability is the responsibility of the Reliability Coordinator in the sense of considerations relating as well to the systems and areas of neighboring Reliability Coordinators, regardless of how small the Reliability Coordinator's own area may be.

13. Generating versus Transmission Assets

The Model does not attempt to define the boundary between generating and transmission facilities, in particular regarding facilities such as protective relays and lines that are within or in proximity to a generating plant perimeter. Such boundaries may be defined by NERC, Regional Entities or governmental authorities.

From the perspective of the Model, for a facility that is determined to be a generating facility, its owner will be a Generator Owner, and its operator a Generator Operator. Correspondingly, for a facility that is determined to be a transmission facility, its owner will be a Transmission Owner, and its operator a Transmission Operator.

It is recognized that an owner may not be the operator of its facility, as a result of delegating the operating of the facility to another party through an agreement, and that in all cases it is NERC's registration process, not the Model, that determines assignment as a Responsible Entity.

14. Roles in Load Curtailment

This section discusses the roles of the various Responsible Entities that may be involved in load curtailment. These entities include: Reliability Coordinator, Balancing Authority, Transmission Operator, Distribution Provider and Load-Serving Entity.

Types of Load Curtailment

There are two general types of load curtailment – voluntary and non-voluntary.

A. Voluntary Load Curtailment

Voluntary load curtailments are usually arranged ahead of real time under some form of agreements – market price trigger, compensation, etc., or on a totally voluntary basis with or without any compensation. Implementation of voluntary load curtailment is intended to provide a relief to the market price in some established markets, or a relief to system demand to aid the Balancing Authority in a tight capacity/energy situation, or a relief to loading on a Distribution Provider system.

Voluntary load curtailment based on pricing structure need not to be requested since it is governed by pre-arranged agreement and mechanism. Voluntary curtailments that have not been pre-arranged may need to be communicated. Since the end-use customers is involved in the decision making process and must respond to the request, and the Load-Serving Entity holds the contractual obligation to serve these customers, such requests are usually communicated to the end-use customers through the Load Serving Entity as directed by the initiating entities, which include the Balancing Authority and the Distribution Provider, to address potential capacity/energy shortfall in the Balancing Authority area or potential overload on the Distribution Provider system.

B. Non-Voluntary Load Curtailment (Shedding)

Non-voluntary load curtailments are usually implemented in real time to address imminent or existing capacity/energy shortfalls or transmission reliability concerns such as exceedence of an IROL or SOL, or a low voltage problem. Some pre-arrangements may be made ahead of time such as identifying the amount and location of load to be shed, and specific critical loads that may be excluded from curtailment by feeder configuration. However, since implementation is often of urgent nature, a decision process involving the end-use customers and communication via the Load-Serving Entity is usually bypassed.

Depending on the need to implement this type of curtailment, load is either curtailed automatically (such as in the case of Underfrequency or Undervoltage load shedding), or a curtailment directive is made by the Reliability Coordinator, Balancing Authority, or Transmission Operator directly to the Distribution Provider for physical implementation (except when this can be accomplished directly by the Transmission Operator). The Distribution Provider may also have a need to curtail load to address overload problems on its system. In this case, the Distribution Provider may implement load shedding directly.

Role of Responsible Entities in Load Curtailment

Reliability Coordinator

The Reliability Coordinator is responsible for real-time system reliability, which includes implementing a number of emergency actions which include directing load shedding to preserve system reliability. In addition, the Reliability Coordinator, in collaboration with the Balancing Authority and Transmission Operator, may also participate in invoking public appeals, voltage reductions, demand-side management, and even load shedding if the Balancing Authority cannot achieve resource-demand balance.

When a Reliability Coordinator has a need to direct non-voluntary load curtailment, it issues a directive to the Distribution Provider or the Transmission Operator to implement the curtailment.

Balancing Authority

When a Balancing Authority anticipates or experiences a capacity or energy shortfall, it will take actions such as public appeals, demand-side management programs, and load curtailment, as necessary to maintain a resource/demand/interchange balance. As time permits, the Balancing Authority may seek voluntary load curtailment to reduce demand in its area. In this case, the Balancing Authority will communicate such a request to the Load-Serving Entity. In the event of an Energy Emergency, the Balancing Authority may direct non-voluntary load curtailment by issuing a directive to the Distribution Provider or the Transmission Operator for implementation.

Transmission Operator

The Transmission Operator, in coordination with the Reliability Coordinator, can take actions such as implementing voltage reductions and implement load shedding to mitigate a transmission emergency. When a Transmission Operator sees a need for non-voluntary load curtailment to relieve transmission constraints, such as an actual or expected exceedence of an operating limit, it implements load shedding that is under its control, or directs a Distribution Provider to physically implement the curtailment.

Distribution Provider

The Distribution Provider provides the facilities that could be used to shed load for emergency action. It is that entity that has the capability to physically shed load, but it is generally not responsible for directing load shedding. Loading shedding is generally directed by the Reliability Coordinator, Balancing Authority and Transmission Operator.

However, the Distribution Provide may itself initiate voluntary and non-voluntary load curtailments for its own reasons, for example to reduce its area's demand or to mitigate overload on its system. When a Distribution Provider sees a need for voluntary load curtailment, it directs the Load-Serving Entity to communicate a request for curtailment to the end-use customers. When it sees a need to implement non-voluntary load curtailment to address a loading or voltage concern, it implements the curtailment on its own.

Load Serving Entity

The Load Serving Entity identifies the loads for voluntary as well as non-voluntary curtailments. For voluntary load shedding, the LSE is responsible for making contractual arrangements with end-use customers who participate in such a program, and identifying to the Balancing Authorities and Distribution Providers of such arrangements so that these customers, once committed, would be put on curtailment list if and when needed to address potential capacity shortage and/or system constraints.

For voluntary load curtailment that has not been pre-arranged, the Load-Serving Entity may be directed by the Balancing Authority or Distribution Provider to communicate its curtailment requests to the end-use customers.

For non-voluntary curtailment, such as automatic underfrequency and undervoltage load shedding and manual load shedding, the Load-Serving Entity identifies which critical customer loads should be excluded from curtailment for safety and/or security reasons. Once identified and necessary contractual arrangements are made, the Distribution Provider (or the Transmission Operator as appropriate) will make (feeder) connection arrangement such that these critical loads will not be curtailed by the load shedding facilities until other options have been exhausted.

The Load-Serving Entity is responsible for communicating requests for voluntary curtailment to the appropriate end-use customers, thereby ensuring that these loads will in fact be curtailed. In some jurisdictions, it appears that the “wires” entity, i.e., the Distribution Provider, that performs these Tasks. However, from a functional model viewpoint, it is the Load-Serving Entity function within that Distribution Provider organization that performs this task.

15. History of Revisions

Version 1

Version 1 of the Model was approved in February 2002.

Version 2

Version 2 of the Model[5] was approved Feb. 10, 2004.

Version 2 responded to confusion between a Function and the organization responsibility for its performance, by separately identifying the Responsible Entity associated with each Function. For example, whereas Version 1 used the single term Transmission Operator for both the Function and responsible entity, Version 2 introduced Transmission Operations as the Function (the Tasks), and Transmission Operator as the Responsible Entity for those Tasks. Corresponding changes were made for all Functions. This distinction has been maintained in subsequent versions.

The Market Operation Function and Market Operator were added to the Model to provide an interface point with commercial functions.

Version 1 contained only operating Functions. Version 2 introduced three planning Functions (Planning Reliability, Transmission Planning, Resource Planning) and three associated Responsible Entities (Planning Authority, Transmission Planner and Resource Planner).

Version 3

Version 3 of the Model was approved February 13, 2007.[6] It addressed a number of issues that arose as NERC transitioned to new, mandatory and enforceable reliability standards. Several of these issues were outlined in a final report issued by the Functional Model-Reliability Standards Coordination Task Force (FMRSCTF) in March 2005.[7] The FMRSCTF was established to ensure alignment between the Model and the new NERC standards being developed.

The changes introduced in Version 3 included:

- The Reliability Authority entity name was changed to Reliability Coordinator, for consistency with terminology used in reliability standards.

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[5] See ftp://www.nerc.com/pub/sys/all_updl/oc/fmrtg/Functional_Model_Version_2.pdf.

[6] See ftp://www.nerc.com/pub/sys/all_updl/oc/fmrtg/Function_Model_Version3_Board_Approved_13Feb07.pdf.

[7] Final Report of the Functional Model – Reliability Standards Coordination Task Force **("** FMRSCTF"), approved March 11, 2005. See ftp://www.nerc.com/pub/sys/all_updl/sac/fmrsctf/FMRSC_TF_Report_3-11-05.pdf.

- Changes were made to more clearly define the Transmission Operations Tasks and the relationship of the Transmission Operator with the Reliability Coordinator
- Changes were made to the Interchange Authority to accommodate the practice of Balancing Authority-to-Balancing Authority interchange scheduling
- The Planning Authority was renamed the Planning Coordinator
- The Regional Reliability Assurance Function and the Regional Reliability Organization Responsible Entity were added.
- It was clarified that "area" of responsibility for a particular Responsible Entity's applied to the collection bulk power system assets associated with the entity, that is, that area was defined electrically, not geographically.

Version 4

Version 4 is an update of the Reliability Functional Model ("the Model" or "Functional Model") that includes the following changes from Version 3:

- The names Regional Reliability Assurance / Regional Reliability Organization / were changed to Reliability Assurance / Reliability Assurer.

  The changes reflect the view that reliability assurance could be performed on other than a regional basis. Moreover, the Responsible Entity need not be a Regional Entity..

- The names Compliance Monitoring / Compliance Monitor were changed to Compliance Enforcement / Compliance Enforcement Authority.

  The changes are judged to better reflect the strong role of compliance in the ERO regime.

- The wording was changed in a number of instances to ensure that the Model's Tasks and relationships between Responsible Entities do not specify prescriptive requirements. Prescriptive requirements are specified in reliability standards and NERC processes, not in the Model.
- For example, references in Version 2 that a Responsible Entity "must ensure" or "is required to ensure" are changed in Version 4 to simply "ensures".
- It was clarified that the Generator Owner and Transmission Owner *provide for the maintenance* of their respective assets.

  This recognizes that the performance of the maintenance may be assigned by the owner to another party, for example, to a Generator Operator or Transmission Operator, respectively.