Emerging Regional Electricity Market Issues

Wholesale Energy Markets in the United States that Are Managed by Regional Transmission Organizations (RTOs) Face a Number of Challenges

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INTRODUCTION

This white paper published by ScottMadden provides our perspective of the challenges facing wholesale energy markets in the United States that are managed by Regional Transmission Organizations (RTOs). These challenges are being driven by current economic pressures coupled with emergent public policy, including federal legislative and regulatory initiatives. ScottMadden will describe the broad level of responsibilities that RTO market administrators must exercise on a daily basis and examine the following challenges that they will likely encounter over the next several years:

- Credit issues and cash flow constraints
- Emergency operations planning
- Grid security
- Transmission siting and renewables development

For more information on this and other efficient energy topics, please visit ScottMadden on the web at www.scottmadden.com, or contact us:

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MARKET STRUCTURES

Much of the generation in United States is managed in competitive markets through RTOs, as illustrated by the shaded areas in Figure 1 below.

Figure 1 – North American Regional Transmission Organizations

The southeast United States is dominated by investor-owned utility control area operations and the western United States is dominated by public power and investor-owned utility control areas. In these regions, the utilities or public authorities manage generation supply and demand within their own jurisdictional boundaries and interchange power with adjacent utilities as needed.

Within the competitive markets, RTOs control the generation resource on behalf of multiple entities and ensure that regional reliability under their jurisdictional control is maintained.

Individual competitive markets have their distinct set of bylaws and operational protocols, but they all perform similar functions, as shown in Figure 2.

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1 Source: Federal Energy Regulatory Commission web site (ferc.gov)
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RTO ISSUES

Although individual RTOs have experienced their own set of challenges, their external environment has been relatively stable until recently. The economic challenges and public policy issues currently at the forefront for the United States have the potential to exacerbate competitive energy market issues. These issues pose the most significant threats to RTO operations:

- Credit issues and cash flow constraints
- Emergency operations planning
- Grid security
- Transmission siting and renewables development

The remainder of this article will explore these issues. (RTO market functions upon which the issue has the greatest impact are highlighted at the beginning of each section.)
CREDIT ISSUES AND CASH FLOW CONSTRAINTS

RTO market structures in the United States all have processes and procedures for establishing creditworthiness of market participants. The current financial crisis highlights the need for continuously updating market participants and counterparties. The robustness of the market settlements process is a key enabler for the RTO or market manager to assure accurate transactional accounting. This process, in turn, depends on credit quality and information about credit quality.

There are two types of settlements within a competitive RTO market structure: transmission settlements and market settlements.

A **transmission settlements process** financially settles (provides for billing and payment) the participant’s use of the RTO transmission system for both transmission and ancillary services. Ancillary services are mandated support services necessary to operate the grid and maintain reliability, such as scheduling and voltage support. Charges to market participants for transmission and ancillary services are based on tariffs approved by the Federal Energy Regulatory Commission (FERC). The funds collected are distributed to the transmission owners and the providers of the ancillary services.

A **market settlements process** financially settles generation transactions for market participants (e.g., generators of electricity and purchasers of energy) within an RTO-managed market operations footprint. Depending on the specific market structure for an RTO, there may be multiple market settlement processes that assign financial charges and credits to market participants and asset owners based upon their participation in the markets. Markets can include day-ahead energy, real-time energy, Financial Transmission Rights (FTR), and those ancillary services not covered under the RTO’s transmission settlements process (e.g., operating reserve services to handle load in the event of an emergency).

Historically, there have been settlements dispute backlogs in several of the U.S. RTO markets. Many disputes prove to be not valid, but nevertheless take time and effort to resolve. Some disputes settled by the RTO are later litigated through FERC and the tariff process. This can be very time consuming, since the litigant typically will not only cite the time duration for the original event prompting the dispute, but will claim the dispute conditions were also in effect for days (or perhaps months) preceding the dispute date. All must be analyzed by the RTO staff.

The potential for financial default among market participants could dramatically increase the size of a settlements dispute backlog and create much more work for the RTO staffs. RTOs are in the process of reducing the interval between settlements to ensure they manage their cash flow risks. If the current ratio of disputes to settlements stays the same, there will be more disputes; and increasing the frequency of disputes should put pressure on counterparties to dispute more often in order to more carefully manage their cash inventories.
Attention to settlements process details, reducing the interval between settlements, reducing any residual dispute backlogs, as well as creditworthiness re-certification should be considered to help manage this issue.

**EMERGENCY OPERATIONS PLANNING**

As of June 18, 2007, compliance with transmission reliability standards became mandatory and enforceable (FERC Order No. 693). There are more than 80 approved standards, each containing multiple requirements. FERC certified the North American Electric Reliability Corporation (NERC) as the Electric Reliability Organization (ERO) and stated that NERC will administer and enforce standards and delegate compliance responsibilities to regional reliability councils.

Requirements specific to transmission operator and balancing authority participants are for developing, maintaining, and implementing a set of plans to mitigate operating emergencies. These plans need to be coordinated with adjacent transmission operators and balancing authorities and the reliability coordinators, as well as be compliant with ERO guidelines.

RTOs, by virtue of their central position in the transmission and generation markets, have a specific set of requirements that must be maintained and coordinated among members to ensure that reliability standards are developed and maintained. This includes adherence to NERC Emergency Operations Planning Standard EOP-001 as well as the development and adherence to individual RTO procedures for operating under abnormal conditions. Although these issues are operational in nature, as Figure 2 makes evident, operational and reliability functions are closely related.

As a transmission operator, the RTO must have an emergency load reduction plan for all identified NERC Interconnection Reliability Operating Limit (IROL) violations. IROL violations are potential contingencies (unexpected events) in which a grid operational limit, monitored in real time, would be exceeded, were the contingency to occur. The emergency load reduction plan must detail how the transmission operator will implement sufficient, timely load reduction. This load reduction must mitigate the IROL violation before system instability, uncontrolled separation, or cascading outages would occur. (Separation is when a portion of the grid remains operational in a blacked-out area.) The transmission operator must be capable of implementing the emergency load reduction plan within 30 minutes.

The RTO must develop, maintain, and implement a set of operating plans to: mitigate operating emergencies for insufficient generating capacity, mitigate operating emergencies on the transmission system, perform load-shedding operations when needed, restore the system after emergencies, and communicate to all system stakeholders during any emergency or abnormal event. Furthermore, the RTO must have backup facilities that can be used in the event of loss of main system functionality and must have all personnel thoroughly trained in emergency and off-normal operating conditions.
These requirements are not new, but the increased enforcement authority and potential for fines and punitive assessment have increased the importance of RTO readiness in all facets of emergency procedures and supporting protocols and documentation.

**GRID SECURITY**

Computer systems used in generation and transmission infrastructure have always been vulnerable to cyber attack, whether internal or external; however, concerns about that threat have increased substantially in recent years (for obvious reasons, including increased terrorism and cyber crime). This vulnerability is increased as legacy stovepipe (isolated) systems are converted from legacy systems into modern, more integrated information technology (IT) systems.

Many conversions address obvious security issues on a static basis without dynamically stress testing the integrated system to determine if heavy system or transient volumes are error free. Additionally, there are increasingly more communications among RTOs and external parties over the internet, which provides additional challenges to RTO system administrators. The problems must be addressed so that security is effective and sustainable throughout the entire system lifecycle, including design, installation, operation, maintenance, and retirement.

There are several types of computer systems commonly used to manage the electric grid, including energy/transmission management systems, billing meter systems, and supervisory control and data acquisition (SCADA) systems. SCADA systems are the eyes and ears of the RTO for monitoring and controlling real-time transmission operations and are also an important component in gathering and developing information needed for accurate transmission and market settlements.

According to the Sandia National Laboratory, “The present state of security for SCADA is not commensurate with the threat or potential consequences. The industry has generated a large base of relatively insecure systems, with chronic and pervasive vulnerabilities that have been observed during security assessments. Arbitrary applications of technology, informal security, and the fluid vulnerability environment lead to unacceptable risk.”

Additionally, in an April 10, 2009 *Wall Street Journal* article, it was reported that cyber spies have penetrated the U.S. electrical grid and left behind software programs that could be used to disrupt the system, according to current and former national security officials. The Director of National Intelligence recently told lawmakers that “Over the past several years, we have seen cyber attacks against critical infrastructures abroad, and many of our own infrastructures are as vulnerable as their

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2 “Sustainable Security for Infrastructure SCADA,” May, 2004; Jason Stamp, Phil Campbell, Jennifer DePoy, John Dillinger, William Young; Sandia National Laboratories, Albuquerque, NM
foreign counterparts. A number of nations, including Russia and China, can disrupt elements of the U.S. information infrastructure.”

Security for SCADA typically lags that for most IT systems by years because of SCADA’s historically isolated stovepipe architecture, which can lead to redundant and overlapping solutions and significantly higher costs. Upgrading SCADA to cyber-safe standards is expensive and time consuming; however, prudent and systematic investment in system security can reduce risk immediately and in the future. Prudent companies will deter threats to their SCADA systems by identifying and managing risks with an effective, programmatic approach to security.

Just as the RTO must develop operational procedures to adhere to the aforementioned NERC Emergency Operating Planning Standard EOP-001, the RTO must also develop, implement, and maintain a series of cyber security procedures to comply with NERC Critical Infrastructure Protection (CIP) requirements, including:

- Sabotage Reporting
- Critical Cyber Asset Identification
- Security Management Controls
- Personnel and Training
- Electronic Security Perimeters
- Physical Security of Critical Cyber Assets
- Systems Security Management
- Incident Reporting and Response Planning
- Recovery Plans for Critical Cyber Assets

For RTOs, market functions depend on operations and reliability. Security is a critical element of reliability. Unlike the emergency operating procedures, these security requirements are relatively new and are made more difficult by the very modernizations required to improve operations and day-to-day grid reliability. With increased enforcement authority and potential for fines and punitive assessment, NERC has effectively elevated the importance of RTO readiness in all facets of emergency planning and infrastructure protection, including procedures and supporting protocols and documentation.

TRANSMISSION SITING AND RENEWABLES DEVELOPMENT

The U.S. electrical grid was designed to bring the lowest possible cost power to the largest possible number of people. Over the past century, regional utilities and government agencies have built many large, central station generation plants as close to population centers as practical. This minimized the cost of generating power and both the construction and maintenance cost of the transmission system. A patchwork system has developed, organized around large plants and loads, and

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connections between local networks have been designed primarily for reliability and grid stability. This system was not designed for transporting power from generation in one region to electricity consumers in another. While the size and complexity of the transmission grid have grown immensely, the grid’s basic architecture has changed little over the past 100 years.

This structure has served its purpose well, but it is not well suited to support remote or intermittent power sources, such as concentrated solar power or wind. The transmission lines are not where they need to be to connect such renewable sources, the grid lacks the storage capacity to handle the inherent variability of wind and solar power generators, and the grid is, for the most part, a “dumb,” one-way system. To address the latter two issues, there is the promise of a “Smart Grid” that, when fully evolved, would be better equipped to manage the intricacies of renewable energy. However, that may be years away.

Notwithstanding the inadequacy of the transmission infrastructure for renewable generation, many states have enacted aggressive Renewable Portfolio Standards (RPS), requiring, for example, as much as 25% of power in a state to be obtained from renewable energy sources by the year 2025. The United States is also on the cusp of having a federal RPS which would create a national RPS mandate. Because the transmission grid is not capable of absorbing this amount of intermittent generation, and because thousands of miles of transmission lines would need to be built to connect renewable energy sources to consumers, it is estimated that billions of dollars would be necessary to enable the transmission infrastructure to support the renewables that would be required.

Even if the funding were available, the regulatory framework in the United States does not support such a build out in transmission infrastructure. While FERC can approve utilities' requests for electricity rates and license transmission across state lines, individual states retain control over where, and whether or not, major transmission lines get built. In the 1990s, many states revised their regulations in an attempt to introduce competition into the energy marketplace. Federal legislation required utilities to provide open access to all power producers. These regulatory changes came with unintended consequences, namely that companies had less incentive to invest in the grid (investing instead in new power plants) and that no single entity had a clear responsibility for expanding the transmission infrastructure.

As a result, the national transmission grid needs significant investment today to comply with reliability requirements. This is required before the system can absorb the dramatic expansion required to facilitate a renewable build out, whether mandated by individual states or the federal government.

The multi-faceted nature of RTOs places them squarely in the center of this issue. RTOs not only manage the competitive market and operate the transmission system, they are responsible for reliability and planning within their footprints. Most RTOs prepare a detailed expansion plan annually or bi-annually. Transmission owners that are members of RTOs also prepare expansion plans that pertain to their particular jurisdictions. Therefore, the expansion of any transmission system within an RTO footprint will require a coordinated effort to both improve the existing system for reliability purposes and expand it to accommodate the virtual flood of renewable generation connections to the grid.
There is a question as to whether existing RTO planning processes and protocols are sufficient to meet these increased challenges arising from grid build out and accommodation of renewables, while continuing to ensure grid reliability.

SUMMARY

Since their inception, RTOs have been at the center of transmission and wholesale electricity market issues both within their footprint and in concert with adjacent transmission markets or networks. Emerging forces make the role of the RTO that much more critical. They face increasing demands (and costs) at a time when their members are asking for reduced RTO costs. There is no shortage of quick-fix solutions suggested by bystanders and critics of the U.S. transmission grid. Nonetheless, the fact is that entities that manage the breadth of issues and inherent complexity of regional markets do a very good job. Their involvement as the coordinator and gatekeeper of critical transmission and market issues will continue well into the future.