Transmission Performance Assessment

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***Abstract*— Transmission availability has become the significant indicator of overall transmission system operational health, due to increased utilization of the transmission system, growth of deregulated energy wholesale markets, and decreased investment in new transmission assets. The industry is increasingly dependent on flow based transactions which are not adequately assessed by traditional distribution load interruption metrics.**

While generation availability assessment has NERC's GADS database, transmission facilities lack a similar repository. Regionalized transmission reliability jurisdictions and energy market operators in North America maintain separate reporting formats. Transmission availability assessment is limited by differences in reporting formats and underlying definitions.

Recent availability trends reflect the increasing dependence upon existing assets to support expanding markets. This paper discusses the differences in transmission availability assessment and the need to increase between system comparability through collaborative development of definitions and data methodology.

***Index Terms*— Transmission availability**

I. Introduction

In 2003 the largest blackout in US history reinforced the nation's understanding of electric reliability as a prerequisite to the quality of life. The electric power transmission industry in the United States faces many challenges in the wake of this event. One of these challenges is mandatory reliability standards under consideration by FERC and for proposal within energy bill legislation. Implicit within the objectives of these regulatory instruments is the concept of monitoring the capability of the transmission system to provide reliable service. However, unlike the power generation sector, the transmission industry has some unique challenges in the area of reliability performance standardization.

The fundamental concepts and definitions of transmission reliability were standardized and documented in standards beginning in the late 1960's with the formation of the North American Reliability Council (NERC), which was an outcome of a 1965 US blackout. Since the 1990's, the industry has embraced deregulation policies to enable continued reliability levels at lower costs through competition.

Recently, the industry has experienced significant consolidation and cost reduction. FERC's Chairman testified in September 2003[i] to a US Senate Subcommittee. "Transmission capital investments and maintenance expenditures have steadily declined in recent years. In the decade spanning 1988 to 1997, transmission investment declined by 0.8 percent annually and maintenance expenditures decreased by 3.3 percent annually. During this same period, demand increased 2.4 percent annually."

Present economic conditions are squeezing existing transmission assets' ability to support an expanding transmission wholesale energy market. This increases the need to establish a baseline of performance yet no major changes in transmission performance assessment have occurred in over twenty years.

II. Standards and Definitions

The IEEE reaffirmed IEEE STD-859, Standard Terms for Reporting and Analyzing Outage Occurrences and Outage States of Electrical Transmission Facilities in 2002 (the original document was approved in 1987). CIGRE's, Power System Analysis and Techniques, CIGRE WG 03 of SC 38 was completed in 1987. The lack of transmission industry standards activity has been somewhat due to the success of its own reliability, however, this is not aligned with recent significant industry changes.

While financial and consumption data are intuitive, reliability data is neither as readily accessible nor as transparent. Although NERC has published definitions for reliability, measurement practices are diverse between systems. NERC definitions leave some room for interpretation.

NERC's Glossary of Terms[ii] defines reliability from a system perspective and addresses the functional capability of the transmission system to transmit electricity from generators to users. Reliability is subdivided into adequacy and security. The adequacy component is system oriented and takes into account the scheduled and reasonably expected unscheduled outages of system elements. Availability's definition on the other hand is element oriented and permits elements that are out of service, but capable, to be considered available.

The definitions are not exclusively complementary, since there is overlap in the states. Reliability metrics quantify the impacts of unreliability, i.e., the frequency, duration, and magnitude of unreliable events. Availability metrics quantify a state of readiness and capability. Reliability connotes "bad times" while availability connotes "good times". However, if reliability is equated to "off", then availability can not be equated to "on"; it is only capable of being "on".

At the inception, availability generally may have been primarily thought of as a generator attribute. High generator availability was desirable in regulated rate environments to prove the usefulness of assets. Mischaracterizing the performance of generation assets, due to lack of demand or economic dispatch order, served no purpose in the comparison of generation asset performance, i.e., by class, size, etc.

Standardized tracking of generator performance was ultimately captured (since 1982) in NERC's Generator Availability Data System (GADS). GADS collects, records, and retrieves operating information for improving the performance of electric generating equipment. The information is used to support equipment reliability/availability analyses and decision-making by GADS data users[iii].

In transmission systems, a corollary to generator availability, i.e., the capability to deliver supply, might be the transmission asset's capability to permit flow. Hence a normally-open transmission breaker might be the "normal" configuration, thus an available state in which it is fully capable but not needed to permit flow. If however, a transmission element is incapable of providing function, due to either maintenance (planned or unplanned) or a forced outage, it should be considered unavailable.

Still, the NERC definitions were created upon assumptions which were generally true, i.e., transmission systems had significant margin for element unavailability. Even today, the highest levels of demand are reached during a small percentage of the hours of the year, e.g. the New York ISO exceeds 25,000 MW during <5% of hours.[iv]

The advent of ISO's and RTO's has increased the need for availability assessment in reliability reporting, in order to demonstrate nondiscriminatory behavior to its constituents and to assimilate the market support elements. However, regional ISO organizations have developed independently across the United States with separate models, definitions, and reporting formats.

The California ISO defines reportable unavailability, under its control agreement maintenance standards, when system flow is interrupted. "Forced outages"[v] includes automatic protective operations and planned outages with insufficient schedule notice or those from planned outages that overrun the scheduled period.

The PJM ISO defines availability as a condition of an element that is capable of service whether it is actually in service. PJM has separate definitions for transmission elements such as Forced Transmission Outages and Planned Transmission Outages which contain advanced notice criteria. The definition of installed capacity pertains to system generation. Thus the definition of unavailable capability is the algebraic difference between the installed and available [generation] capability at that time[vi].

New York ISO defines availability as a measure of time that a generating facility, transmission line or other facility is or was capable of providing service whether or not it actually is in service. Yet an outage is defined for periods when a device is not connected and is not fulfilling its design function[vii]. Can a transmission element then be available in an outage state? Or does this only apply to generators?

The concept of availability, as a transmission unit state that requires units to be connected (to permit flow) and fulfilling function, is found in the definitions recommended by CIGRE's 1987 working group, WG03 of 38, and appears consistent with availability needs of integrated transmission markets. Over time, utilities have adopted individualized adaptations that best fit their internal use, market, state regulatory environment, and external application. Vertically integrated utilities generally utilize distribution reliability customer impact metrics, i.e., SAIFI, SAIDI. Transmission-only entities tend to favor delivery point metrics and load indices since customer knowledge may be limited, and distribution metrics may misrepresent the performance of the stand-alone transmission function.

Still, differences in the interpretation of transmission availability & reliability definitions appear to be out of synch with deregulated market operations of today. Most of the interpretive variation results from the treatment of planned outages, i.e., for maintenance, construction, customer request, and operational purposes.

As FERC's Chairman noted, the aggregate margin has been decreasing over the past ten years. And as the blackout illustrated, transmission element unavailability or unreliability can quickly cascade into system-wide reliability concerns. Since the entire power delivery system is only as strong as the weakest link, heavier utilization of the transmission assets is a capability concern. Since transmission unavailability can have economic impacts in the deregulated market, it is also an economic concern.

III. Market Influence

Historically, transmission reliability and availability are very good. However, transmission availability comparisons are not fair if one system is using the forced availability, typically near 99% (about 4 d/y), which includes only forced, automatic outages, yet others are using total availability near 95% which includes forced and planned outages (about 20 d/y). Similarly mixed comparisons to customer availability, i.e. customer interruptions, which is in the range of 99.9% (about 4-9 h/y) would be unfair. Yet due to the proprietary nature of most benchmarking products, the transparency of such comparisons is limited.

While overall service availability of transmission facilities is quite high, during peak periods it is generally higher through normal scheduling oversight. Generation availability traditionally increases in peak periods to ensure adequacy of supply. Generation's availability response to market prices in

RTO environments has been expectedly to maximize profit opportunities.

A June 2001 study prepared for the New England ISO observed that, "In the new market, unavailability tracks seasonal demand better than it did in the past. Power plants seem to be trying to maximize their availability during high demand periods.[viii]" Thus generator availability was marked by longer scheduled outages, at the expense of overall availability, while improving peak period availability.

The trend is similar in transmission systems as well, despite differences between transmission and generation business models. Transmission planned maintenance effectively could be constrained to certain times of the year or day by economics of the industry. The East Central Area Reliability Coordination Agreement (ECAR) *2002 Transmission Line Outages Summary Report* indicates fewer but longer scheduled Extra High Voltage (EHV) outages[ix] in the last five years and continuing through 2002. The data is based upon twenty years of member experience.

Average service availability can be calculated for an element or unit and aggregated at various levels, i.e. equipment class, voltage class, systems, etc. Regulatory usage of transmission availability has some precedent here and abroad. Peak system availability provides a way to assess the system performance during periods of maximum demand and generally high cost supply conditions. These periods are more critical from system reliability, socio-economic and overall market perspectives.

The California ISO has tracked line availability in order to assess maintenance effectiveness. Forced availability has recently gained some state regulatory usage in Delaware with a requirement to monitor transmission equipment (lines and transformer) forced availability[x].

Transmission asset management uses retrospective availability as a way to track maintenance effectiveness and as input to asset replacement decisions. In planning and operational studies, where prospective reliability analysis is performed based upon a system model, transmission availability conditions are needed to establish baseline conditions for deterministic models or unit availability probabilities for probabilistic models. Retrospective availability analysis is necessary an appropriate check of actual operating conditions against planning assumptions and criteria, i.e., N-1, LOLP = one/ten year, etc.

Since the relative location of generation, network facilities, and load have an effect on pricing in regional markets, network unavailability has the potential for economic impact even in low demand periods for specific providers. ISO market monitoring functions must be able to discern the difference between market power and responsible grid maintenance & operations under all demand conditions. Transmission availability assessment is needed that provides an independent indication of the transmission network capability and management, and that is not influenced by spatial changes in generation and load, unlike congestion metrics.

IV. International Assessment

Deregulation has developed independently across the globe. World markets provide suggest similar challenges with transmission availability assessment yet offer several improvement alternatives.

UK's Office of Gas and Electric Markets (Ofgem) reviews annual transmission system performance from transmission owners. System availability is defined as the sum for all circuits of hours available divided by the number of circuits times the number of hours in the period. Availability is reduced whenever a circuit is taken out of operation, either for planned purposes i.e., for construction work, or as a result of a fault[xi]. Peak (winter) system availability is also reported in addition to overall system availability.

Australia's National Electricity Code Administrator (NECA) Reliability Panel publishes, as part of their annual reliability assessment of the Australian transmission market, an assessment of all transmission outages submitted to NEMMCO, (the independent Australian market operator), and their overall effect upon network reliability and market efficiency. Australia's NECA defines unavailability, as it impacts load capability, which could include de-rated conditions or limitations. Code changes in the previous reporting year, required NEMMCO to publish an assessment of network outages on intra and inter-regional power transfer capabilities[xii]. Reserve generation is reported versus demand for each region to assess adequacy at peak demand periods.

In addition, NECA reports the price sensitivity of trading intervals of the day-ahead market to changes in supply and demand commodities, including network outages. In the past reporting period, network outages accounted for approximately 2% of the overall annual price variation in 2002-3 (Demand, generator availability, or combinations of those two accounted for ~98% of the variation.)[xiii].

Canadian Electric Association has conducted power system benchmarking on a proprietary basis for its members for over twenty years. The data is organized into generation, transmission, and distribution sections within the Equipment Reliability Information System (ERIS). Power system analysis is organized under the Electric Power System Reliability Assessment (EPSRA) into transmission reliability assessment of the bulk electric system (BES) and distribution reliability assessment of service continuity.

The BES delivery point (DP) database reports on delivery point interruptions[xiv]. The ERIS database reports on forced outages of major components of transmission on a national scale[xv]. Within ERIS a Component Forced Outage is defined to include automatic or emergency removal of Major Components, and those manual removals which cannot be delayed for thirty minutes or less. It does not include healthy

Major Component removals as a result of an outage of some other Major Component or from cascading system events[xvi].

The examples above provide alternatives that have developed abroad. All of the cited models utilize objective criteria to establish consistent and meaningful availability data for network performance analysis that supports interconnected transmission system reliability and market efficiency objectives.

V. Conclusion

Given the developmental nature of the US markets, and the opportunity for change precipitated by the 2003 blackout, transmission reliability reporting should be examined for adoption within the current national discussion for reliability standards. Worldwide examples provide alternatives for consideration, toward the establishment of routine reporting of network performance, as it impacts reliability and market efficiency.

This serves as a necessary prerequisite to effective transmission regulation and competitive transmission open-access markets. The strategic goals of deregulation policies would be served by enabling accountability and transparency for the marketplace, improving the system reliability, and providing objective criteria for reliability investment in the transmission system.

The industry needs updated assessment tools for transmission network performance since transmission is no longer coupled with generation by integrated ownership and/or control. The industry needs metrics that are simple yet capable of supporting impact analysis.

Availability metrics provide an independent indication of the network reliability and management, i.e. maintenance, operation, planning, and investment. Availability metrics are independent from the transactional market and congestion mechanisms that may reflect issues beyond the transmission owner's control, i.e. load and generation location and availability.

The time for revisiting underlying definitions and reliability metrics to support a broadly held methodology for assessing the transmission system reliability is upon the industry. This is consistent with FERC's desire to set meaningful reliability standards and baseline performance benchmarks, for transmission monitoring and system augmentation, to preclude future blackouts.

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[i] Testimony of Pat Wood, III, Chairman, Federal Energy Regulatory Commission Before the Subcommittee on Oversight of Government Management, the Federal Workforce, and the District of Columbia, Committee on Governmental Affairs United States Senate, September 10, 2003.

[ii] NERC website, NERC Glossary of Terms, www.nerc.com/glossary/glossary-body.html

[iii] GADs Services, Source: NERC Website; http://www.nerc.com/~gads/

[iv] United States General Accounting Office, GAO-04-204, *2003 Blackout Identifies Crisis and Opportunity for the Electricity Sector*, November 2003, Appendix I, page 21

[v] *California Independent System Operator Transmission Control Agreement, Appendix C*, Issued March23, 2001. *Maintenance Procedure 5, Classifying Forced Outages*, 9/7/00, page 5-3.

[vi] http://www.pjm.com/documents/downloads/glossary/pjm101-glossary.pdf, *PJM Glossary of Terms*, #113687v1 Glossary,01/10/01

[vii] http://www.nyiso.com/services/training/glossary/defs2.html#O, New York Independent System Operator Market Training Services Definitions/Glossary

[viii] *How Availability Changed in a Competitive Market*, H.M. Merrill, J.A. Natour, C. P. Sedlacek, IEEE Power Engineering Review, January 2002, page 14

[ix] *2002 Transmission Line Outages Summary Report, 03-TFP-46*, August 2003, http://www.ecar.org/publications/TFP/2003-TFP-46.pdf

[x] *Electric Distribution Company Electric Service Reliability and Quality Standards*, Delaware PSC Docket No. 50, Order 6298, November 4, 2003, page 10

[xi] National Grid, *UK, Report to the Director of the Office of Gas & Electricity Markets 2002>2003*,April 2003, page 5, http://www.nationalgrid.com/uk/library/documents/pdfs/System_performance_%20Report_2002-2003.pdf

[xii] National Electricity Code Administrator Limited, *Reliability Panel Draft annual report 2002-2003*, September 2003, page 20

[xiii] *Ibid*, page 22

[xiv] Canadian Electric Association, *About EPSRA*, http://www.canelect.ca/english/aboutcea_prod_serv_reliability_BES.html,

[xv] Canadian Electric Association, *About ERIS*, http://www.canelect.ca/english/aboutcea_prod_serv_reliability_transmission.html

[xvi] Canadian Electric Association, *2001 Forced Outage Performance of Transmission Equipment*, issued May 2003, Section 3 Definitions, page 13