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Transmission Metrics: Initial Results

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Executive Summary

Office of Energy Policy and Innovation (OEPI) staff developed several metrics that assess transmission investment patterns to inform whether additional Commission action is necessary to facilitate more efficient or cost-effective transmission development in the U.S that is sufficient to satisfy the nation's transmission needs. This report explains the data and methods staff used. Then, the report presents the results of each metric calculation together with staff's inferences based on the calculated metrics. As discussed in the section on next steps and further research, these metrics could be refined, revisited periodically, or used to select regions or issues for further study.

Key findings include:

Metric	Finding
Percentage of nonincumbent[1] transmission project bids or proposals	Nonincumbent proposals accounted for 48% of all competitive transmission project proposals submitted in California Independent System Operator Corporation's (CAISO's) and PJM Interconnection, L.L.C.'s (PJM's) regional planning processes from 2013 to 2015 (excluding the 2015 RTEP 2 window in PJM). In CAISO, nonincumbent proposals accounted for the majority of proposals in all three years; in PJM, nonincumbents submitted more proposals than incumbents in 2013 and 2015, but not in 2014, when PJM received the majority of proposals from incumbents.
Load-weighted curtailment frequency	Southwest Power Pool, Inc. (SPP) consistently experienced more Transmission Loading Relief (TLR) events per gigawatt-hour load than other regions during the analyzed period, but significant operational changes appear to be reducing its TLR use in subsequent periods.
RTO/ISO Price Differential	Relatively high or low real-time Locational Marginal Prices (LMP) (relative to high or low prices prevailing in the Commission-jurisdictional Regional Transmission Organization/Independent System Operator (RTO/ISO) market) occurred in 2012, 2013, and 2014 at 1,986 generator or load points.

[1] Order No. 1000 defines a "nonincumbent transmission developer" as either: (1) a transmission developer that does not have a retail distribution service territory or footprint; or (2) a public utility transmission provider that proposes a transmission project outside of its existing retail distribution service territory or footprint, where it is not the incumbent for purposes of that project. By contrast, an "incumbent transmission developer/provider" is defined as an entity that develops a transmission project within its own retail distribution service territory or footprint. *See Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 225 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g and clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth.* v. *FERC*, 762 F.3d 41 (D.C. Cir. 2014).

Metric	Finding
Load-weighted transmission investment (incremental)	Load-weighted transmission investment averaged over all regions for all years is over two dollars per MWh of retail load, although investments are "lumpy" for most regions, as is typical for large infrastructure projects. The largest load-weighted investments were in the reliability region covering most of Texas, exceeding four dollars per MWh across all years. The smallest load-weighted investments were in the reliability regions of the southeast (SERC Reliability Corporation (SERC) and Florida Reliability Coordinating Council (FRCC)).
Load-weighted circuit-miles (incremental)	Findings are similar to the load-weighted transmission investment metric.
Circuit-miles per million dollars of investment (incremental)	The Midwest Reliability Organization (MRO) region has the highest circuit-miles per million dollars of transmission investment across all years (1.7), compared to an average of 1.1 circuit-miles per million dollars for all regions. PJM's reliability region (Reliability First Corporation or RFC) has the lowest circuit-miles per million dollars of transmission across all years, of less than one circuit-mile for every million dollars invested.

Introduction

The Commission has long had the goal of ensuring that its policies help achieve appropriate levels of transmission investment to address current and emerging reliability needs, economic considerations, and needs driven by public policy requirements, while maintaining just and reasonable rates as required under the Federal Power Act. Most recently, the Commission reformed its policies regarding transmission planning and cost allocation in Order No. 1000, through which it sought to promote more efficient or cost-effective transmission development by requiring each public utility to, among other things, (1) participate in regional transmission planning processes, (2) provide opportunities for nonincumbent transmission developers to propose and develop regional transmission facilities, and (3) establish a regional cost allocation method to allocate the costs of transmission facilities selected in the regional transmission plan for purposes of cost allocation (i.e., regional transmission facilities). Earlier efforts also sought to achieve this goal. For example, Order No. 679 provides the opportunity for transmission developers to apply for transmission incentives, while Order No. 890 requires an open and transparent local transmission planning process. Even earlier, the Commission held in Order No. 2000 that an RTO must have ultimate responsibility for both transmission planning and expansion within its region that will enable it to provide efficient, reliable, and non-discriminatory service and coordinate such efforts with the appropriate state authorities.[2] In reviewing individual Order No. 2000 compliance filings, the Commission provided further guidance on this planning and expansion function, sometimes in ways that presaged related aspects of later efforts including Order No. 1000. For example, in the order conditionally approving PJM's Order No. 2000 compliance filing, the Commission, among other things, required PJM to revise its tariff to permit third parties (i.e., nonincumbents in the parlance of the later

[2] *See Regional Transmission Organizations, Order No. 2000*, 89 FERC ¶ 61,285 *slip op.* at p.485 (1999).

Order No. 1000) to participate in constructing and owning new transmission facilities identified by the transmission plan.[3]

It is difficult to assess whether the industry is investing in sufficient transmission infrastructure to meet the nation's needs and whether the investments made are more efficient or cost-effective.[4] Nevertheless, staff has attempted to develop a range of objective and standardized measures of various characteristics of the electric system and its performance to help assess the effectiveness of the Commission's policies in achieving its goals regarding transmission investment and to inform potential policy revisions going forward. As the team described in its presentation at the April 2015 open meeting, staff considered a range of potentially relevant metrics in three broad categories: (1) metrics designed to evaluate key goals of Order No. 1000; (2) metrics designed to indicate whether appropriate levels of transmission infrastructure exist in a particular region; and (3) metrics designed to permit analysis of the impact of Commission policy changes by comparing key values before and after changes take place.

Below, staff describes our methodology for applying each of the three categories of metrics, the results of that analysis, and the further research that staff believes would be needed to help ensure that each metric provides useful insight as to whether transmission investment in the United States (U.S.) is both cost-effective and sufficient to meet the nation's needs.

I. Key Goal of Order No. 1000 - Participation of Nonincumbent Transmission Developers in the Transmission Planning Processes (Metric: Percentage of Nonincumbent Transmission Project Bids or Proposals)

Background

This metric seeks to measure the percentage of bids or proposals for new projects in the Order No. 1000 regional planning processes that are submitted by nonincumbent transmission developers. For purposes of this report and consistent with Order No. 1000, staff includes as nonincumbents new consortia formed by incumbents in the region in which the project will be located and developers from outside that region, as long as the project will be located outside of the incumbent's zone within the region. Staff notes that

[3] *See PJM Interconnection, L.L.C., Allegheny Electric Cooperative, Inc., Atlantic City Electric Company, Baltimore Gas and Electric Company, Delmarva Power and Light Company, Jersey Central Power & Light Company, Metropolitan Edison Company, PECO Energy Company, Pennsylvania Electric Company, PPL Electric Utilities Corporation, Potomac Electric Power Company and Public Service Electric & Gas Company, UGI Utilities Inc.*, 96 FERC ¶ 61,061 at 61,240-1 (2001).

[4] Potential reasons for this difficulty include, but may not be limited to:

- ***Stakeholders cannot agree on what would constitute an appropriate amount of transmission investment.*** For example, some stakeholders may prefer a system that prioritizes public policy concerns, while others may prefer a system that prioritizes reliability. Similarly, some may expect strong load growth or the development of distributed generation, while others may not.
- ***There are alternatives to transmission in some circumstances***. Some transmission issues can be addressed using alternatives to transmission investments, such as generation or demand-side resources, while other issues can only be addressed with transmission investment.

this metric addresses only regional transmission projects; it does not reflect projects proposed outside of the regional transmission planning process, or any interregional projects. This metric is intended to measure nonincumbent participation in regional transmission planning processes, which the Commission concluded in Order No. 1000 was necessary in order to eliminate practices that have the potential to undermine the identification and evaluation of more efficient or cost-effective alternatives to regional transmission needs, helping to ensure just and reasonable rates for transmission customers.[5]

Methodology

Staff gathered data on the proposals submitted by developers in each of the competitive proposal windows recently opened in CAISO and PJM, the two transmission planning regions that have held competitive requests for proposals since the implementation of Order No. 1000. In the future, it should be possible to perform a similar analysis for other planning regions.

Staff gathered data from public documents posted on CAISO's and PJM's websites. For CAISO, proposal data are from documents submitted during Phase 3 (the project sponsor selection phase) of the 2012-2013 and 2013-2014 transmission planning processes, under which CAISO opened nine proposal windows from 2013-2015.[6] For PJM, staff gathered information on proposals from PJM's Regional Transmission Expansion Planning (RTEP) Proposal website[7] and from documents posted by the Transmission Expansion Advisory Committee.[8] PJM opened nine proposal windows from 2013-2015 , but this analysis only includes data from eight of these. In some cases, information about the transmission zone(s) of the proposed projects was not available from CAISO or PJM; staff undertook additional research, based on public data, to determine the transmission zone for each project.

Staff applied the definition of nonincumbent from Order No. 1000. To determine the incumbency status of developers submitting proposals, staff compared the zone in which each proposed project would be built with the developer's retail distribution service territory, where applicable.[9] This was necessary because the publicly available data does not generally list whether a particular developer is an incumbent or not; it merely lists the names of the entities submitting proposals, and transmission owners frequently create subsidiaries, sometimes with unique names, for the sole purpose of submitting proposals in one or more particular transmission planning region. Nevertheless, staff was able to identify the incumbency status of developers with a high degree of confidence.

[5] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities,* Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 226.

[6] *See* https://www.caiso.com/planning/Pages/TransmissionPlanning/2012-2013TransmissionPlanningProcess.aspx and http://www.caiso.com/planning/Pages/TransmissionPlanning/2013-2014TransmissionPlanningProcess.aspx. On compliance with Order No. 1000, the Commission approved CAISO's request for an effective date for their filing of October 1, 2013 to allow the compliance tariff provisions to be applied to the 2013-14 transmission planning cycle rather than the 2012-2013 cycle, which was almost complete. *See Order on Compliance Filing,* 143 FERC ¶ 61,057 at P 28.

[7] *See* http://pjm.com/planning/rtep-development/expansion-plan-process/ferc-order-1000/rtep-proposal-windows.aspx.

[8] *See* http://pjm.com/committees-and-groups/committees/teac.aspx.

[9] Proposals from transmission developers without a retail distribution service territory (e.g., Northeast Transmission Development (LS Power)) were classified in all cases as nonincumbent proposals. In the case of a joint venture or consortium of developers, if a proposed project is in a zone or zones in which one or more of the developers in a group is the incumbent, then that particular proposal is classified as an incumbent proposal. If the joint venture or consortium proposed a project outside of the service territories of all of its members, the proposal is classified as a nonincumbent proposal.

As discussed further in the analysis section, for purposes of comparison, staff grouped proposals by region and year in which the proposal window was opened.

On compliance with Order No. 1000, CAISO and PJM developed regional transmission planning processes along two distinct models. CAISO adopted a competitive solicitation model, pursuant to which CAISO identifies regional transmission projects to meet the region's needs and then allows developers to bid on the right to build and own facilities that are eligible for competitive solicitation. CAISO then makes its selection of the developer based on criteria identified in its tariff.[10] As a result of the 2012-2013 and 2013-2014 transmission planning processes, CAISO opened nine solicitations.[11]

In contrast, under PJM's sponsorship model, once PJM has identified the region's transmission needs, it opens proposal windows to provide an opportunity for transmission developers to submit project proposals and be considered to construct, own, and operate projects they sponsor. PJM then evaluates, selects, and includes in its transmission plan projects that address the identified needs.[12] PJM opened nine proposal windows from 2013-2015, but our analysis only considers the eight for which PJM had publicly posted the proposals it received in response as of the time this report was being prepared.[13]

Results and Analysis

Figure 1 summarizes the results of staff's analysis of the bids and proposals that developers submitted from 2013-2015 in CAISO's and PJM's proposal windows. For the purposes of this metric, staff analyzed the number of proposals in each window and the incumbency status of the entities proposing projects. Staff did not gather data on or analyze any costs associated with bids and proposals.

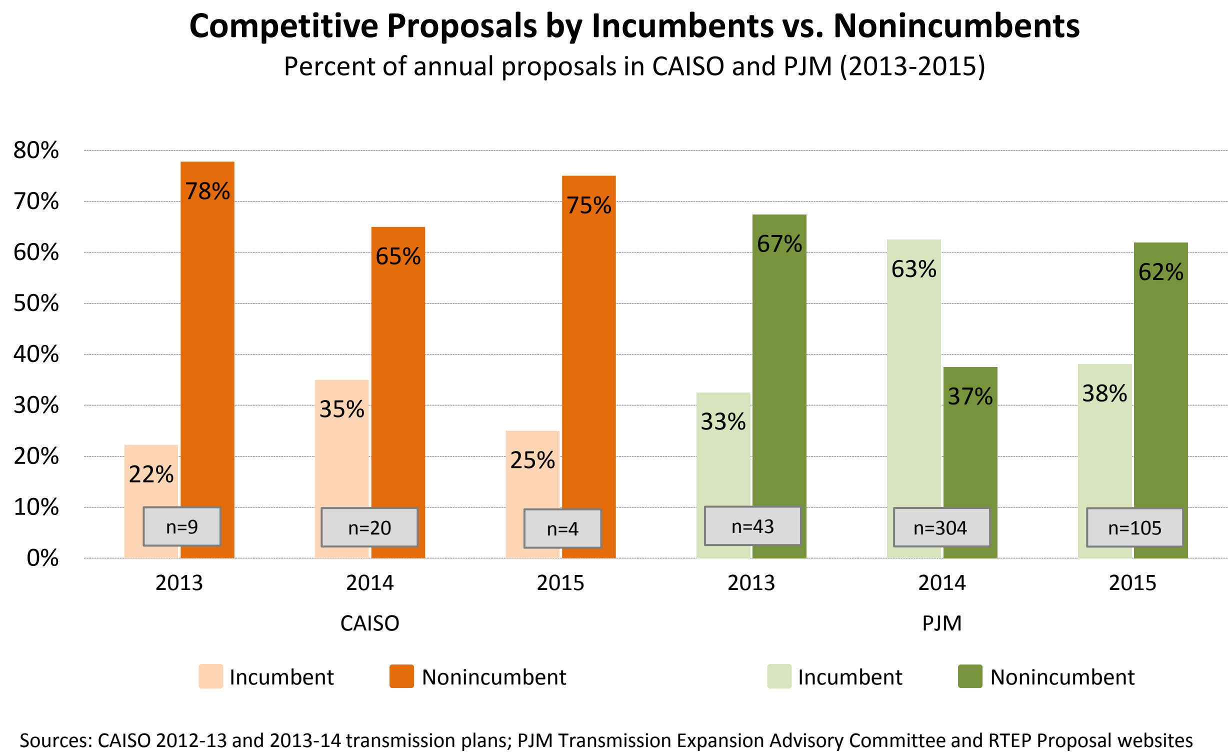
[10] CAISO, *2013-2014 ISO Transmission Plan*, at 16-21, http://www.caiso.com/Documents/Board-Approved2013-2014TransmissionPlan_July162014.pdf.

[11] The nine solicitations are: Gates-Gregg 230kV, Sycamore-Penasquitos 230 kV, Delaney-Colorado River 500 kV, Estrella Substation, Harry Allen-Eldorado 500kV, Miguel 500 kV 375 MVAr, Spring Substation, Subcrest 230 kV 300 MVAr, and Wheeler Ridge Junction Substation.

[12] PJM, *2014 Regional Transmission Expansion Plan: Book 2 (Input Data and Process Scope)*, at 2-4, http://pjm.com/~/media/documents/reports/2014-rtep/2014-rtep-book-2.ashx.

[13] Artificial Island, Market Efficiency, 2014 RTEP 1, 2014 RTEP 2, 2014/15 Long Term RTEP, 2014 RTEP 2 Addendum, 2014 RTEP 2 Addendum 2, 2015 RTEP 1, and 2015 RTEP 2. The 2015 RTEP 2 window closed on September 4, 2015, but, as of the time this report was being prepared, PJM had not yet posted the proposals it received in response.

Figure 1:



The figure shows the percentage of all proposals in each RTO that came from incumbents and nonincumbents from 2013 to 2015, with the associated number of proposals received in each region and year. Overall, of the 485 proposals submitted in both regions, 53 percent were from incumbents and 47 percent from nonincumbents. This result is largely influenced by the number of proposals received in PJM (452 across all three years, more than half of which were from incumbents in 2014).

On a regional basis, the percentage of proposals from nonincumbents accounted for two-thirds to three-quarters of proposals in each of the three years in CAISO, based on nine proposals from seven developers in 2013, 20 proposals from ten developers in 2014, and four proposals from four developers in 2015. Overall, there were 33 proposals from 21 unique developers over the three years. Of these, five proposals were submitted by five unique joint ventures or consortia. Two developers (TransCanyon DCR[14] and PG&E/MidAmerican) were classified as incumbents based on the location of the projects, while three developers were classified as nonincumbents (DCR Transmission,[15] Duke/ATC, and Pattern Energy/City of Pittsburg, CA).

In PJM, the percentage of proposals from nonincumbents accounted for more than 60 percent of all proposals in 2013 and 2015, but fell to less than 40 percent of proposals in 2014, the year in which PJM received the majority of its proposals. That year, the 2014 RTEP 1 window garnered 106 proposals from

[14] TransCanyon DCR is a joint venture between subsidiaries of Pinnacle West Capital Corp, the parent company of Arizona Public Service Co., and Berkshire Hathaway, parent company of PacifiCorp, NV Energy and MidAmerican Energy.

[15] DCR Transmission is a joint venture between subsidiaries or affiliates of Abengoa, South America and Starwood Energy Group Global, LLC.

15 developers, the 2014 RTEP 2 window 79 proposals from 14 developers, and the 2014/15 Long Term RTEP window 119 proposals from 22 developers, for a total of 304 proposals from 30 unique developers. Of this total, 50 proposals (27 incumbent, 23 nonincumbent) were submitted by six unique joint ventures or consortia. Transource—a joint venture between AEP and Great Plains Energy, formed to pursue new competitive transmission projects—submitted 35 proposals, 23 classified as a nonincumbent and twelve as an incumbent. Of the remaining proposals from joint ventures or consortia, Transource/Dominion submitted six as an incumbent, Transource/Dominion High Voltage MidAtlantic submitted one as an incumbent, Dominion/First Energy submitted four as an incumbent, PPL/First Energy submitted three as an incumbent, and Duke/ATC submitted a single proposal as an incumbent.

While it is too early in the Order No. 1000 process to describe a "typical" year, it appears that PJM may open more and larger proposal windows in even-numbered years than in odd-numbered years because of the nature of its 24-month planning cycle.[16] In 2014, PJM opened two short-term windows and one long-term window, while in 2015 it opened only two short-term windows (2015 RTEP 1 and 2).[17] While this difference may explain the higher overall number of proposals in 2014 as compared with the other years, it is not immediately clear why this difference would cause such a significant reversal in the incumbent-to-nonincumbent ratio otherwise observed in the region. One might hypothesize that the proportion of responses from incumbents to a particularly large proposal window like the 2014/15 Long Term RTEP could account for the different result in that year compared to 2013 and 2015. However, that is not the case—proposals from incumbents constituted the majority of proposals submitted during each of the three windows opened in 2014. More years of data appear necessary to understand the results more fully.

These results also raise other questions and potential areas for further research. For example, is the more than 10-fold difference in the number of proposals received by PJM and CAISO due to the regions' respective regional transmission planning model (sponsorship vs. competitive solicitation), specific requirements for submitting proposals (such as different proposal submission fees), the specific nature and magnitude of the transmission needs in each region, or some other factor?

Caveats

While this metric provides information about the degree of nonincumbent participation in Order No. 1000 regional transmission planning processes, its usefulness is extremely limited at this time due to the small number of regions (two out of twelve planning regions) for which data was available. Moreover, it is too early to tell whether the experience in CAISO and PJM will prove representative of other Order No. 1000 planning regions. It is not clear that nonincumbent participation will be as robust in the other planning

[16] PJM has a 24-month transmission planning process consisting of two 12-month cycles to examine immediate needs (fewer than 3 years in the future) and short-term needs (3-5 years in the future), and a 24-month cycle to examine long-term needs (15 years in the future). Projects needed in fewer than 3 years are not competitively bid through a proposal window, and are therefore not included in this analysis. *See* http://pjm.com/planning/rtep-development/expansion-plan-process/ferc-order-1000/rtep-proposal-windows.aspx, and PJM, *2014 Regional Transmission Expansion Plan: Book 2 (Input Data and Process Scope)*, at 15, http://pjm.com/~/media/documents/reports/2014-rtep/2014-rtep-book-2.ashx.

[17] PJM also opened two windows in 2015 that were addenda to the 2014 RTEP proposals; both received relatively few proposals.

regions. Finally, while both CAISO and PJM have awarded projects to nonincumbents,[18] the likelihood of nonincumbents being selected in other regions is unknown.

II. Metrics to Indicate Whether Appropriate Levels of Transmission Infrastructure Exist

In evaluating the following two metrics, staff relied on the assumption that persistent costly congestion in an area may indicate insufficient transmission investment because it may suggest that there is not enough available transfer capability on the transmission system to support the delivery of less costly energy. Ideally, persistent costly congestion would be identified directly from historical energy price information by looking for significantly large price differentials that persist for extended periods of time. As discussed further below, while RTO/ISO markets generate pricing data directly applicable to this purpose, staff initially assumed that other more indirect means would be needed in non-RTO/ISO market regions. The first metric below, therefore, is intended to help identify persistent congestion in non-RTO/ISO market regions by relying on historical NERC Transmission Load Relief (TLR) data. Meanwhile, the second metric below is intended to help identify persistent costly congestion in RTO/ISO market regions by relying directly on historical pricing data.

Load-weighted Curtailment Frequency

Background

For areas outside of RTOs and ISOs, staff proposed to investigate whether NERC TLR procedures used to manage congestion can serve as an indirect measure of the level of transmission infrastructure in the region. Specifically, more TLR events might indicate a need for more transmission infrastructure and fewer events might indicate less need for additional transmission infrastructure. In practice, staff assumed that such a TLR-based metric would need to be used in conjunction with publicly available sources of pricing data, such as price indices or retail rate information, in order to incorporate the concept of costly congestion. In other words, even if a region experiences large numbers of TLR events, in the absence of any significant and persistent price differentials in that region, the TLR events might not indicate any particular need for additional transmission infrastructure.

TLR data for the Eastern Interconnection is easily and publicly available from NERC,[19] but reliable price information for these non-RTO/ISO market areas is less readily available from the types of price indices or retail rate data that staff initially hoped to use. However, staff intends to explore whether Electric

[18] Information on proposals submitted to PJM is available at http://pjm.com/planning/rtep-development/expansion-plan-process/ferc-order-1000/rtep-proposal-windows.aspx; proposals submitted to CAISO are available at http://www.caiso.com/planning/Pages/TransmissionPlanning/2013-2014TransmissionPlanningProcess.aspx.

[19] *See* http://www.nerc.com/pa/rrm/TLR/Pages/TLR-Logs.aspx. Instead of TLRs, the Western Interconnection manages unscheduled flows using a coordinated combination of controllable devices (e.g., phase shifting transformers) and schedule curtailments that would be similar to TLRs. This Western Interconnection-wide policy is called the Unscheduled Flow Reduction Guideline and is managed through a system called webSAS developed by Open Access Technology International, Inc. (OATI). The NERC TLR logs do not include schedule curtailment data from the Western Interconnection, and the fact that schedule curtailment plays a secondary role to controllable device control in managing unscheduled flows in the Western Interconnection makes it unclear how useful a metric based on TLR-like schedule curtailments would be in the Western Interconnection.

Quarterly Report (EQR) wholesale pricing data could fill this role instead. EQR pricing data is submitted by all jurisdictional and some non-jurisdictional wholesale sellers of electricity, and staff believes that the approximate location of associated transactions can be gleaned from the data. Accordingly, EQR data may provide a comprehensive view of pricing trends in bilateral market regions comparable to what RTO/ISO pricing data provides for organized markets. Thus, staff believes that eventually this EQR data may also be used to help assess whether appropriate levels of transmission infrastructure exist in non-RTO/ISO market regions.

Methodology

The basis of this measurement is the number of interchange-curtailing TLRs at and above Level 3[20] that the transmission operators of that region reported to NERC. In order to provide a basis for comparing between regions of different sizes, rather than only focusing on the number of TLRs for each region, staff proposed to normalize this metric based on the retail load associated with the region in question. After studying available sources of retail load data, staff chose to rely on "net energy for load" data available from NERC.[21] Thus, to determine the metric of load-weighted curtailment frequency, staff divided the number of TLRs in the planning regions reviewed for each NERC region for each year by that region's "net energy for load" in each year, as reported in NERC's 2014 Electricity Supply & Demand (ES&D) database.[22]

Results and Analysis:

Table 1 shows TLRs at Level 3 and above reported to NERC in 2014, the majority of which were from SPP, Midcontinent Independent System Operator, Inc. (MISO), and Tennessee Valley Authority (TVA).[23]

Table 1: Interchange Curtailing TLRs

Region	2014	2013	2012
MISO	139	367	155
TVA	131	67	107
SPP	428	555	529

Source: NERC TLR Logs, http://www.nerc.com/pa/rrm/TLR/Pages/TLR-Logs.aspx.

[20] There are six levels of NERC TLRs. Starting at TLR Level 3, interchanges are curtailed to prevent System Operating Limit (SOL) or Interconnection Reliability Limit (IROL) violations. All TLR events at Level 2 and above must be reported to NERC.

[21] "Net energy for load" is defined as "Net Balancing Authority Area generation, plus energy received from other Balancing Authority Areas, less energy delivered to Balancing Authority Areas through interchange. It includes Balancing Authority Area losses but excludes energy required for storage at energy storage facilities." *See Glossary of Terms Used in NERC Reliability Standards*, September 29, 2015, http://www.nerc.com/files/glossary_of_terms.pdf.

[22] From 2008-2012, figures are actual GWh; 2013 and 2014 figures are NERC estimates. *See* http://www.nerc.com/pa/RAPA/ESD/Documents/2014_ESD.zip.

[23] Though most of the reported TLR events are from MISO, SPP, and TVA, a small number were reported from PJM and the Virginia-Carolinas (VACAR South) subregion of SERC. For purposes of Table 1 and this analysis, staff chose to focus only on the areas with large amounts of TLR activity.

Table 2 below shows the associated load data for MISO, SPP and TVA, and Table 3 shows the resulting metric.

Table 2: Net Energy for Load (GWh)

Region	2014 (projected)	2013 (projected)	2012 (actual)
MISO	678,759	548,976	497,906
TVA	158,057	161,925	165,255
SPP	249,560	263,605	258,590

Source: 2014 NERC ES&D, http://www.nerc.com/pa/RAPA/ESD/Pages/default.aspx .

Table 3: Load-weighted TLRs (TLR/GWh)

Region	2014	2013	2012
MISO	0.0002	0.0007	0.0003
TVA	0.0008	0.0004	0.0006
SPP	0.0017	0.0021	0.0020

While MISO and SPP operate organized markets that optimize dispatch based on congestion, and thus should greatly reduce their internal use of TLRs, it is still possible for RTOs to require TLRs to address unscheduled loop flow originating from outside their footprints. Staff notes that both MISO and SPP have extensive borders with non-organized market areas, which may help explain their continuing use of TLRs.

Overall, it appears that SPP consistently experienced more TLR events per gigawatt-hour of retail load than other regions during the analyzed period, which may point to the presence of persistent congestion and a need for additional investments to improve the transmission system, or may be related to other issues such as issues associated with being interconnected with multiple Balancing Authority Areas, some of which are inside organized market areas and some of which are not.

To make the most meaningful use of this metric, it would be necessary to test whether recurring TLR events may be associated with costly congestion rather than other unknown factors. As noted earlier, staff believes that EQR data may ultimately serve this purpose, either in conjunction with TLR data or by itself.

Before moving on, staff has two observations. First, staff has observed one interesting, though not surprising, correlation in the SPP TLR data. SPP formed its Consolidated Balancing Authority and launched its Integrated Marketplace in March of 2014. Prior to that, SPP was acting as the reliability coordinator for multiple Balancing Authority Areas and operated an imbalance market that was more limited in scope than the Integrated Marketplace. The TLR logs show that SPP called 126 interchange-curtailing TLRs in the first quarter of 2014, when the Balancing Authority Area consolidation and Integrated Marketplace switchover was wrapping up. In the remaining quarters of 2014 the number of TLRs dropped to 101, 97, and 104. This decline continued into 2015, where 87 interchange-curtailing

TLRs were called in the first quarter and 32 were called in the second.[24] This appears to demonstrate a significant decrease in the rate of TLR use after the consolidation and market start-up took place. While correlation is not necessarily causation, this is what we would expect to happen; consolidating Balancing Authority Areas and moving to a more comprehensive market structure should lead to more efficient use of the associated existing transmission facilities, which should result in a decrease in the need for TLRs.

The second observation is that, as proposed in the April 2015 presentation, the results reported above are based only on pure numbers of interchange-curtailing TLRs. As a side investigation, staff also explored the possibility of basing a TLR metric on the actual amount of interchange that was curtailed. While these results were not studied in great detail, and thus are not included here, it was clear that they may indicate different congestion trends than what is reported above based on pure numbers of TLRs.

Caveats

Staff has identified a significant potential issue with attempting to use TLR data to measure congestion. Specifically, TLRs represent a fairly narrow view of transmission congestion. That is, TLRs only represent transmission limitations between Balancing Authority Areas. Accordingly, the TLR data above attributed to MISO and SPP does not reflect internal congestion within those RTOs, which is addressed through centralized dispatch. Rather, it most likely reflects congestion, including unscheduled loop flow, arising at their borders. In addition, some neighboring RTOs have entered into market-to-market coordination arrangements that reduce the need for TLRs at their mutual borders. Of course, this metric was mainly intended to be applied in non-RTO/ISO regions.

Additionally, it is possible for a system to experience costly congestion, but not have a significant number of TLRs. If transmission operators in a region use very conservative available transfer capability assumptions in deciding whether or not to approve transmission service requests, then they may be able to avoid the need to call TLRs in most circumstances. However, customers may stop requesting transmission service in this situation, despite any persistent price differentials that might otherwise lead them to seek, for example, the transmission of less expensive supplies to their load. Accordingly, as with RTO/ISO markets, staff believes that a direct transmission infrastructure metric based on pricing data might provide useful information on existing transmission infrastructure, and staff believes that EQR data will eventually provide a comprehensive view of pricing trends in bilateral market regions comparable to what RTO/ISO pricing data provides for organized markets.

RTO/ISO Market Price Differential Metric

Background

Staff proposed a metric, expressed in years, to find places where RTO/ISO market nodal price differentials have occurred persistently, though not necessarily at all times throughout a year. Staff reasons that more consecutive years of price differences could indicate insufficient transmission infrastructure, while bearing in mind that available transfer capability between places—and the

[24] The Commission's April 2015 acceptance (Docket No. ER13-1864-001) of enhanced market-to-market coordination arrangements between SPP and MISO likely contributed to these continued reductions in TLR activity as well.

transmission investment that maintains that capability—may not be the only variables relevant to persistent price differences.

Methodology

While staff initially proposed in its April 2015 presentation to the Commission to base this metric on the differential between LMPs for defined zonal or nodal pairs, staff has since realized that, in RTO/ISO markets, there is no advantage to only looking at defined pairs of zonal or nodal LMPs. As explained below, staff now believes that it should focus on individual points or regions where the LMPs are significantly different from the average of the LMPs in the surrounding regions.

In RTO/ISO markets, where prices reflect congestion costs, a point where anomalous LMPs occur persistently should indicate congestion on the transmission interfaces linking the point with other parts of the transmission system. In contrast, in an area without congestion, LMPs should all be essentially the same, differing perhaps only by virtue of the varying marginal losses at each point. Thus, the persistent occurrence of high or low prices at a point relative to the rest of the market suggests transmission investment could be needed, at least where such investment is economic (i.e., the costs associated with the additional transmission infrastructure needed to relieve the congestion do not outweigh the benefits associated with moderating prices at that point).

To calculate this metric, staff used real-time prices at load and generator points from ABB Velocity Suite. To avoid placing excessive weight on highly unusual prices, staff used the 95th and 5th percentiles of prices, rather than maximum or minimum prices, at each load and generator point. Staff then calculated the average 95th and 5th percentiles of prices at all points in the market to identify a market-wide average 95th percentile price and a market-wide average 5th percentile price. Using this information, staff identified those points whose 95th or 5th percentile price were, compared to the market-wide averages, either relatively high or relatively low.

To determine whether a price was relatively high or low compared to the market-wide averages, staff relied on a common statistical concept, the standard deviation. Staff considers a location "high-priced" ("low-priced") in a year if the 95th percentile (5th percentile) of prices at that point is more than one standard deviation above (below) the average of the 95th percentiles (5th percentiles) of all points in the market. This approach finds points where the high prices in a year were high relative to the average of the high prices in the same year for the entire market the points are in, as well as points where the low prices in a year were low relative to the average of the low prices in the same year for the entire market the points are in. For example, if the average of the 95th percentile of real-time LMPs is \$150/MWh in an RTO (for generator price points) and the standard deviation of the 95th percentile of real-time LMPs is \$300/MWh, the threshold for counting generator price points as high-priced would be \$450/MWh. Thus, the 95th percentile of the real-time LMPs at a point would have to be at least \$450/MWh for the point to be characterized as high-priced.

Staff identified points with high or low prices in 2012, 2013, and 2014 to determine the points at which price separation occurred persistently and likely has not yet been resolved. To focus on the persistence of price separations, staff then calculated the number of years in which the current run of high or low prices began. Finally, staff identified regions within each RTO that encompass multiple neighboring points with persistent price separations in the same direction, identified for each region the longest period of price separation experienced by a pricing point included in that region, and used that number of years as the RTO/ISO Price Differential metric for that region.

Results and Analysis

Starting with ABB Velocity Suite data through 2014, staff found 1,986 generator or load points in Commission-jurisdictional RTOs/ISOs where relatively high or low real-time LMPs occurred persistently.

The figures below show regions with more than one high-priced or low-priced point, as defined, and the points themselves. To focus on the persistence of price separations, staff shows the number of years in which the current run of high or low prices began through the use of color. Table 4 lists staff's findings for each region with persistent price differentials. Figures on the following pages show maps of the regions and associated pricing data.

Table 4: Summary of RTO Market Price Differential Metric for Select Regions

Region identified by staff	Price Direction	Start of region's longest occurrence of ongoing price differentials[25]	Metric (Years of persistence through 2014)
Baltimore, Maryland	High	2005	10
Upper Peninsula region	High	2005	10
Delmarva Peninsula	High	2006	9
Long Island, New York	High	2007	8
Northwestern New Jersey	High	2007	8
North-central MISO	High	2005	10
	Low	2005	10
Western SPP	High	2008	7
	Low	2007	8
Greater Chicago	High	2010	5
	Low	2006	9
North Dakota-South Dakota-Minnesota border region	High	2012	3
	Low	2010	5
New York-Canada border region	Low	2006	9
Northern New York	Low	2006	9
West-central North Dakota	Low	2010	5
The Geysers, California	Low	2011	4

Source: Staff analysis of ABB Velocity Suite price data through 2014

Figure 2 shows the 13 regions in which staff found instances of persistent high or low prices.

Figure 3 shows low-price points in these regions. Generator points are represented by solid squares and load points by hollow squares; colors represent the number of years that prices have persisted. As the figure shows, there are a large number of low-priced points in the middle of the country, particularly western SPP, north-central MISO, and the Greater Chicago area, with a few instances of persistent low prices in the Northeast and California.

[25] Not all points in each region have experienced the persistent occurrence of high or low prices for the same period of time; this column shows the initial years of persistent price differences based on the longest-standing, persistent occurrence of high or low prices in the region.

Similarly, Figure 4 shows high-priced points, with generator points represented by solid stars and load points by hollow stars. The colors again represent the number of years prices have persisted. As shown in the figure, the Delmarva Peninsula, Long Island, Baltimore, north-central MISO, the Upper Peninsula, and ND-SD-MN border region have a large number of persistent high price points, with a few instances in other regions.

Figure 5 combines the low and high price maps.

Figure 6 shows the Delmarva Peninsula, a cluster with numerous high price points.

Figure 2: Regions with high priced or low priced points

Source: Staff analysis of ABB Velocity Suite price data

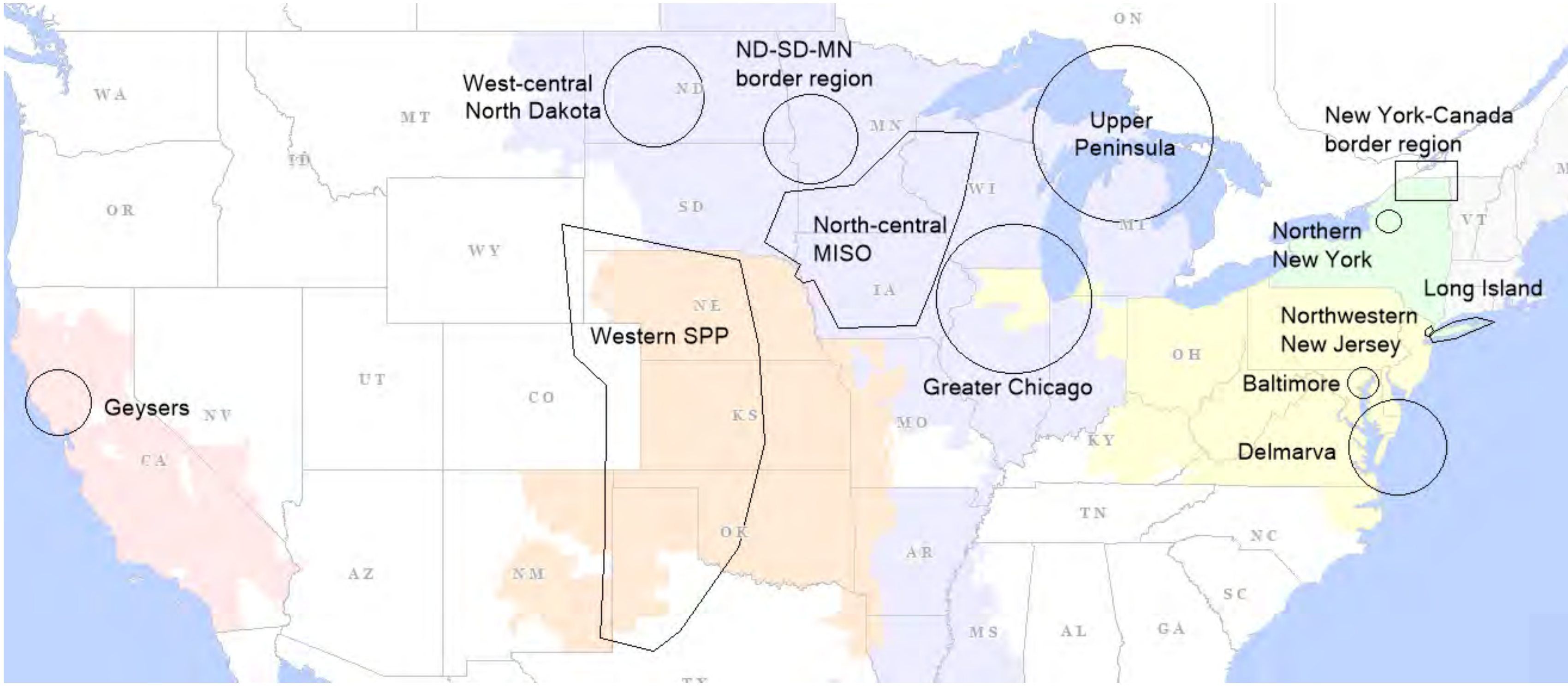


Figure 3: Low priced points

Source: Staff analysis of ABB Velocity Suite price data

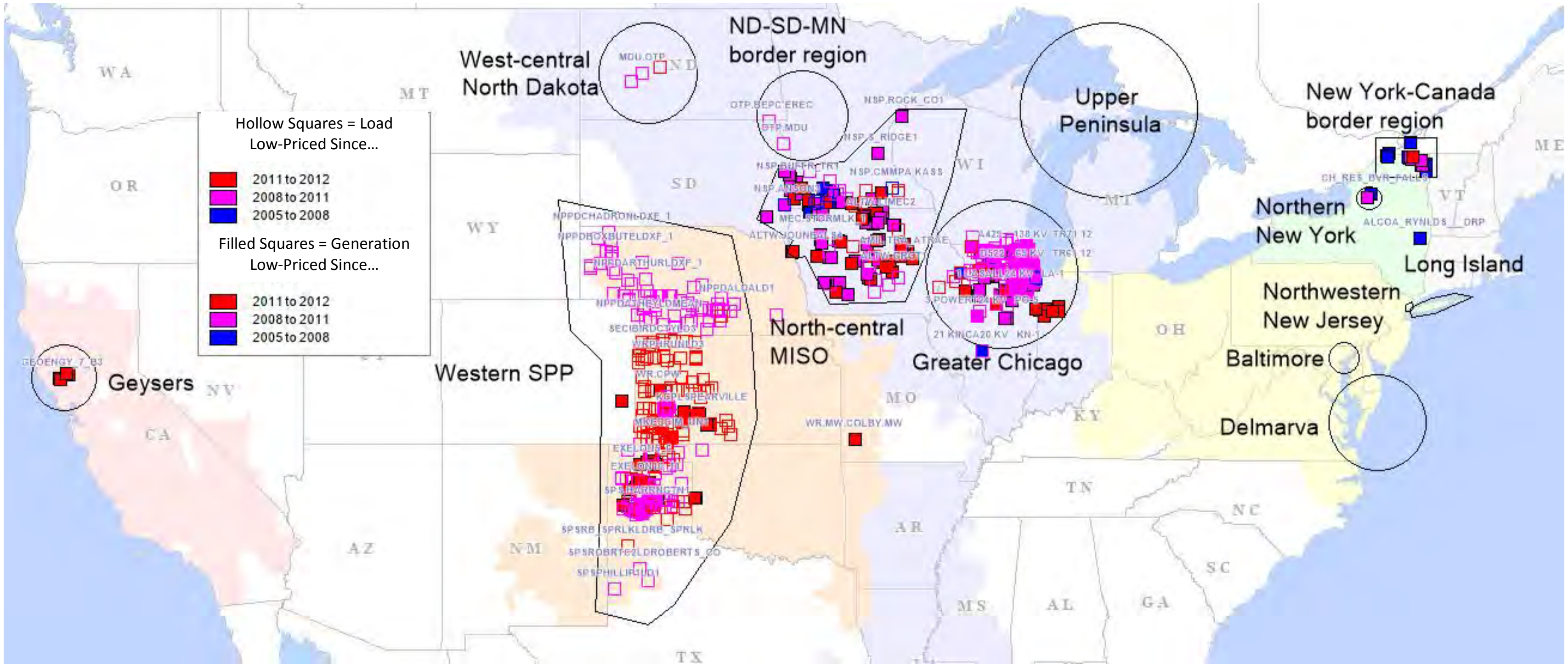


Figure 4: High priced points

Source: Staff analysis of ABB Velocity Suite price data

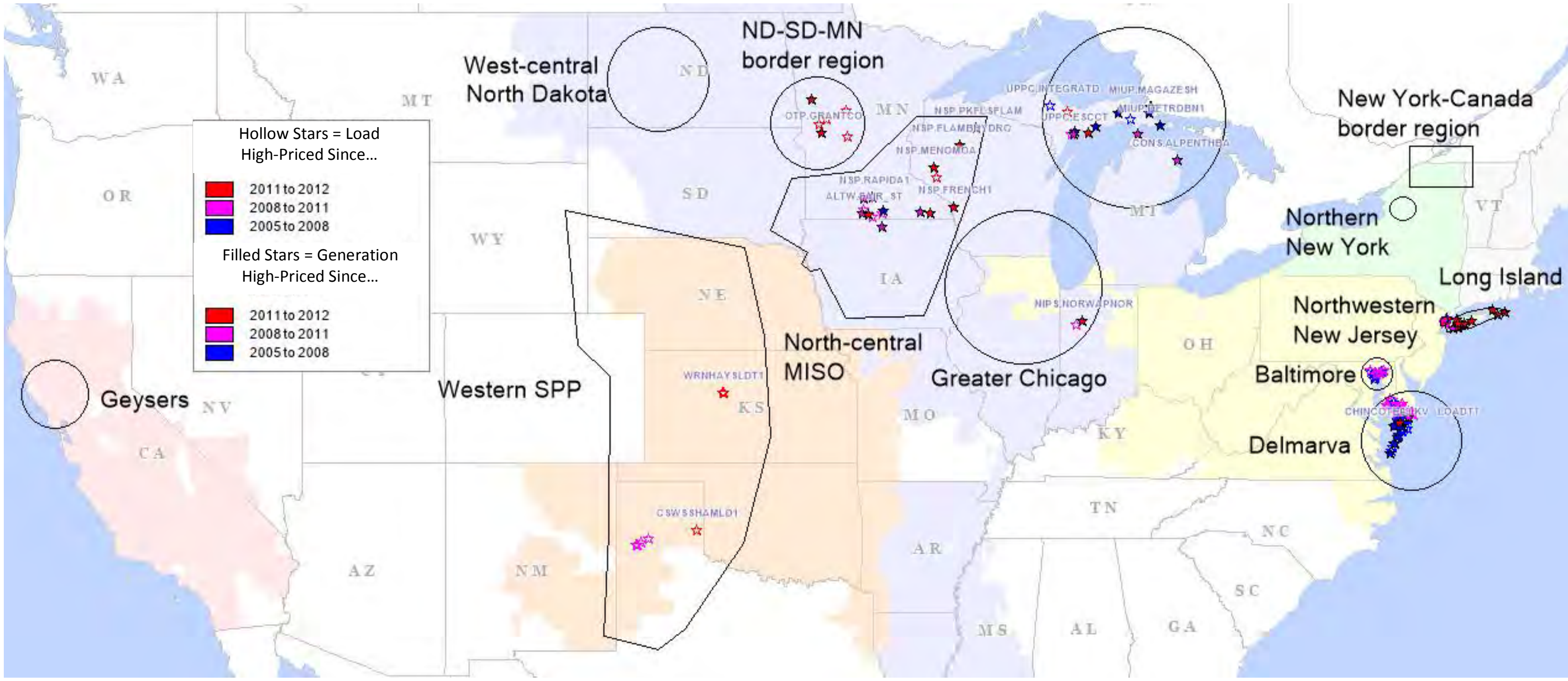


Figure 5: High priced and low priced points

Source: Staff analysis of ABB Velocity Suite price data

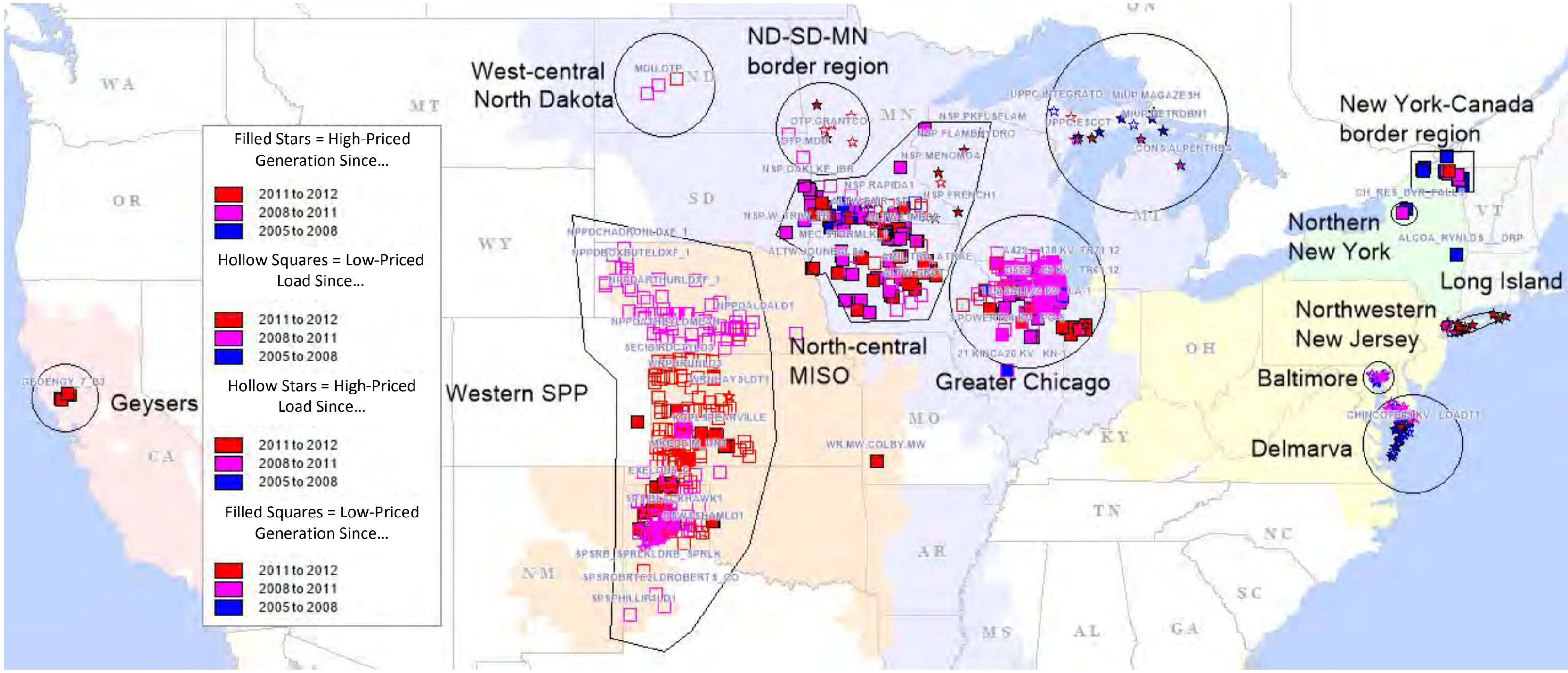
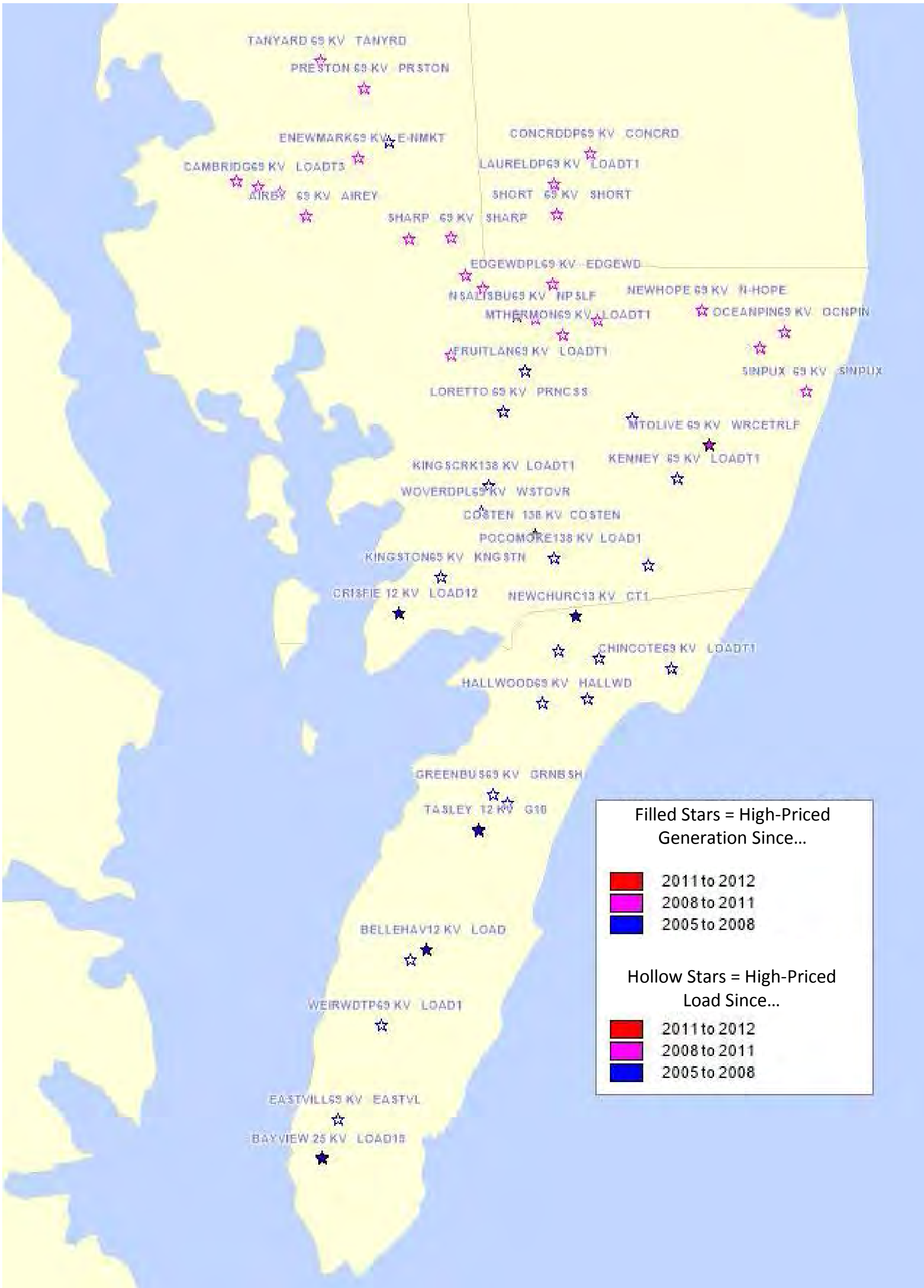


Figure 6: Cluster of high priced generator and load points on the Delmarva Peninsula (PJM)

Source: Staff analysis of ABB Velocity Suite price data



As shown in Table 4 at the beginning of this analysis, the RTO/ISO Price Differential Metric for the Delmarva Peninsula is 9 through 2014, close to the highest result in the current analysis. Figure 6 above provides more geographic detail and shows that the lower Delmarva Peninsula is the main location for these persistent high prices compared to the PJM average.

Caveats

While staff found its analysis of persistent price differentials informative, there are limitations to this analysis. First, there may be reasons other than insufficient transmission capacity why high or low prices persistently occur in a particular case. For example, a state may have a renewable portfolio standard that only counts in-state resources toward compliance, thus requiring the use of potentially more expensive local resources no matter how much transmission capacity may be available to access lower cost resources elsewhere. Second, even if more transmission capacity could reduce the deviation of price from the market average in a particular case, if the cost of the needed transmission upgrade would exceed this benefit, it might not be beneficial to undertake such an upgrade. Finally, lines connecting points where high prices occurred to points where low prices occurred might not help equilibrate prices as much as might be expected based only on this analysis. For example, the high prices and the low prices may not occur at the same time of the year.

III. Metrics to Permit Baseline Analysis of the Impact of Policy Changes

The third category of metrics includes three interrelated metrics: (1) Load-weighted Transmission Investment; (2) Load-weighted Circuit-miles; and (3) Circuit-miles per Million Dollars of Investment. Given the caveats associated with each metric, as discussed below, they are best analyzed as a group to provide an indication of whether transmission investment is both sufficient and cost-effective. In combination, these three metrics allow for a comparison of how much transmission infrastructure has been developed in each region and the relative cost of that investment.

Load-weighted Transmission Investment (incremental)

Background

This metric describes the load-weighted dollar value of transmission facilities added (i.e., that went into operation) each year from 2008-2014 in the eight NERC regions of the contiguous U.S.[26] Weighting transmission investment dollars by associated retail load allows for comparisons between entities of different sizes (as measured by the amount of retail load).[27] While more load-weighted investment may not always be better than less investment, tracking how these values change following changes in Commission policy may be informative.

Methodology

Transmission project data are from the C Three Group's North American Electric Transmission Projects database.[28] Investment dollars represent nominal cost or reported budget for each project. To aid comparison across years, staff converted these figures to 2014 dollars using the annual average of the

[26] These eight regions include FRCC, Midwest Reliability Organization (MRO), Northeast Power Coordinating Council (NPCC), ReliabilityFirst Corporation (RFC), SERC, SPP, Texas Regional Entity (TRE), and Western Electricity Coordinating Council (WECC).
[27] As with other load-weighted metrics in this paper, staff uses NERC "net energy for load" data for retail load.
[28] *See* https://www.cthree.net/transmission/database/default.aspx

consumer price index for all urban consumers (CPI-U).[29] To calculate the final, load-weighted metric, staff divided the normalized investment figures for each NERC region for each year by the net energy for load in each year, as reported in NERC's 2014 Electricity Supply & Demand (ES&D) database.

Staff chose 2008 as the first year of the analysis due to a lack of robust project data across all NERC regions prior to that year. A limited number of projects without a NERC region designation, or with multiple designations, were excluded.

Results and Analysis

The results are based on 8,169 projects that went into operation from 2008-2014, representing approximately $61 billion (in 2014 dollars) of incremental transmission investment. Approximately three-quarters of this total ($47 billion) was invested in projects primarily involving new and upgraded transmission lines, with the remaining quarter ($14 billion) invested in projects involving substations and other non-line facilities.[30]

Figure 7 shows load-weighted incremental transmission investment (in dollars per MWh) in the eight NERC regions of the contiguous U.S. from 2008 to 2014. The figures in red represent the load-weighted investment across all seven years, while figures in black refer to the highest load-weighted dollar figure in each region.

Overall, the average load-weighted transmission investment for all regions for all years is over two dollars per MWh of load, although investments are "lumpy" for most regions, as is typical for large infrastructure projects. Due to a major spike in transmission investment in 2013, the average load-weighted investment for TRE over all years exceeds four dollars per MWh. Five of the eight NERC regions (SPP, NPCC, WECC, RFC, and MRO) are in the range of approximately $1-3/MWh on average over the period, while two regions without organized markets (SERC and FRCC) fall below one dollar per MWh on average over the period. The metric shows a generally increasing trend of load-weighted investment over the period, with all regions except FRCC and MRO reporting the greatest load-weighted investment in 2013 or 2014.

The highest all-year average investment over the period, of $4.72/MWh, and highest single-year metric ($19.70/MWh in 2013) was in TRE. This was due to the approximately $6.5 billion of projects—the largest single-year investment of any region—that went into operation in 2013, of which approximately $5.7 billion was under Texas' Competitive Renewable Energy Zone (CREZ) initiative, which aimed to alleviate congestion and integrate wind capacity into the electric grid.[31] Excluding this large CREZ

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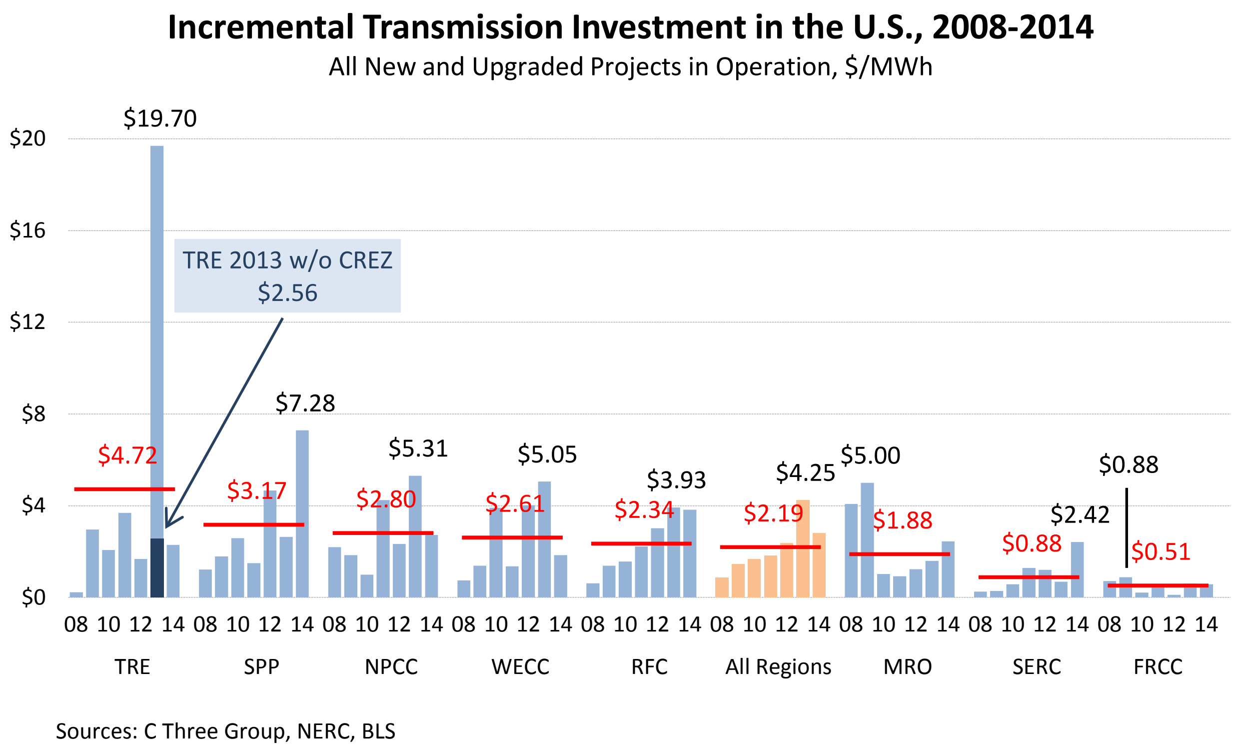
[29] In the absence of an industry standard for calculating changes in the prices of goods associated with transmission investment, CPI-U was chosen as a broad measure of changes in prices over time. *See* Bureau of Labor Statistics, *CPI Detailed Report – August 2015*, Table 24 (annual average), http://www.bls.gov/cpi/cpid1508.pdf.

[30] The project types in the C Three Group database are not completely binary (i.e., line vs. non-line projects); some projects involve both new or upgraded lines and associated new or upgraded substations. For the purposes of this paper, where the project involves a line component, it has been categorized as a line project; this includes upgrades to address sag, clearance, or thermal issues. If there is no line-related component, the project has been categorized as a non-line project.

[31] The Competitive Renewable Energy Zone initiative was established by state legislation in 2005. All initiative projects were complete by January 30, 2014, at a total cost of $6.9 billion. *See* Lasher (ERCOT), "The Competitive Renewable Energy Zone Process," presentation to DOE's Quadrennial Energy Task Force, August 11, 2014, http://energy.gov/sites/prod/files/2014/08/f18/c_lasher_qer_santafe_presentation.pdf.

investment in 2013, investment in that year would be $2.56/MWh and the TRE regional average investment would be $2.22/MWh, much closer to the all-region average. Thus the changes in this metric over the period perfectly illustrate the powerful impact of one particular policy initiative –Texas' CREZ initiative.

Figure 7:



For the other NERC regions within the Commission's jurisdiction, it is difficult to identify the particular Commission policies that may have resulted in the observed metric pattern, because several Commission initiatives were underway simultaneously. These include the transmission planning initiatives launched first in Order No. 890 and later expanded in Order No. 1000 and the Commission's evolving transmission incentives policies. Nevertheless, below staff summarizes our observations to date.

In SPP, the relatively large investment in 2014 represents the completion of several balanced portfolio projects and priority projects proposed under the region's highway/byway initiative. Meant to facilitate upgrades to existing transmission infrastructure and new transmission facilities to satisfy expanding demands on the region's transmission system, the highway/byway initiative proposed a new method for allocating costs of transmission projects regionally and/or locally depending on project voltage. The Commission accepted the proposal in 2010, finding that it would foster improvements in SPP's transmission system by consolidating and simplifying the cost allocation process and by providing greater certainty for cost recovery.[32] The first phase of priority projects under this initiative was estimated to cost

[32] Southwest Power Pool, Inc., 131 FERC ¶ 61,252, at PP1-4, 10.

$1.14 billion; several of the projects went into operation in 2014,[33] as did several of the balanced portfolio projects.[34]

In NPCC and WECC, investments in 2013 reflect completion of several large projects. In NPCC, the Greater Springfield Reliability Project and Rhode Island Reliability Projects—both portions of the New England East-West Solution group of projects[35]—began operating. In WECC, portions of the Tehachapi Renewable Transmission Project and Energy Gateway Transmission Expansion Project were completed in 2013, and the Sunrise Powerlink—a $1.9 billion project designed to, among other things, deliver renewable energy from the Imperial Valley to maintain reliability and meet state and federal energy policy goals[36]—was completed in 2012.

RFC had large absolute and load-weighted investments in 2013 and 2014—a total of approximately $6.5 billion over the two years—due to several large projects coming into operation. These include the merchant-owned Hudson Transmission Project, an underground and underwater HVDC line from New Jersey to Manhattan,[37] and a number of projects in PSEG's service territory.

MRO had its largest absolute transmission investment of $1.7 billion in 2014, when several portions of the CAPX2020 projects[38] came into operation. Unlike other regions, MRO had higher load-weighted investments in 2008 and 2009.

Load-weighted transmission investment in SERC and FRCC was consistently below that of other regions. Absolute investment in SERC has increased for most years since 2008, reaching a peak of $1.7 billion in 2014, while load has been gradually falling since 2008. These two factors lead to a general increase in load-weighted transmission investment in the region from 2008-2014, but still well below that of other regions. FRCC has had relatively consistent levels of investment since 2008, but has the lowest average load-weighted investment of any region over the period.

Caveats

Staff notes that there are important caveats with respect to its analysis of this metric. First, as mentioned above, more investment in transmission is not necessarily better in all cases. For example, entities whose loads are located near their generation resources may be able to serve load with less transmission investment than similarly sized entities with more dispersed loads. Second, the costs of constructing transmission facilities may vary by region such that a project meant to address an identified need may cost more in one region than it would in another. In such case, the total transmission investment in the higher-cost region will be higher, but not because that region has constructed more transmission infrastructure.

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[33] SPP, "SPP Approves Construction of New Electric Transmission Infrastructure to Bring $3.7 Billion in Regional Benefits," (April 27, 2010 Press Release), http://www.spp.org/publications/Priority_Projects_Approved_4-27-10.pdf.
[34] SPP, "Balanced Portfolio," http://www.spp.org/engineering/transmission-planning/balanced-portfolio/.
[35] Northeast Utilities, "New England East-West Solution (NEEWS)," http://www.transmission-nu.com/residential/projects/neews/.
[36] CPUC, *Decision Granting A Certificate of Public Convenience and Necessity for the Sunrise Powerlink Transmission Project*, Application 06-08-010, http://docs.cpuc.ca.gov/PUBLISHED/AGENDA_DECISION/95357.htm.
[37] *See* http://hudsonproject.com/project/.
[38] *See* http://www.capx2020.com/index.html.

Load-weighted Circuit-miles (incremental)

Background

This metric describes the load-weighted circuit-miles of transmission line added from 2008 to 2014 in the eight NERC regions of the contiguous U.S. As with the earlier metric, weighting transmission circuit-miles by associated retail load allows for comparisons between entities of different sizes.

Methodology

For this metric, staff filtered the C Three Group database by project type and status, removing those projects that do not include a line component (e.g., that involve only a substation upgrade) and those that were not operating during the seven-year period from 2008-2014.[39] A limited number of projects without a NERC region designation, or with multiple designations, were excluded.

To determine the number of circuit miles for each project, staff multiplied reported line miles by the number of reported circuits. In cases where the number of circuits was not reported, staff assumed that the line has only one circuit. While this may underestimate the number of actual circuit-miles for these projects, staff believes this is an appropriately conservative assumption. Staff then summed all of the projects reported in each NERC region to determine the total number of circuit-miles added in each region in the years in question.

To arrive at the final metric of load-weighted circuit miles, staff divided the circuit-mile figure for each NERC region for each year by that region's net energy for load.

Results and Analysis

Figure 8 shows load-weighted transmission line additions (in circuit-miles/TWh) in the eight NERC regions of the contiguous U.S. from 2008 to 2014. The figures in red represent the seven-year regional average, while figures in black refer to the highest load-weighted circuit-mile figure in each region. The 4,083 projects in the sample represent a total of 52,688 circuit-miles of transmission facilities added over the period from 2008-2014.

Overall, the results for this metric are similar to those for the previous metric. TRE and SPP lead, and SERC and FRCC lag, the other regions in terms of load-weighted circuit-miles added, with five regions (WECC, NPCC, RFC, SERC, and FRCC) below the all-region all-year average of approximately two circuit-miles/TWh.

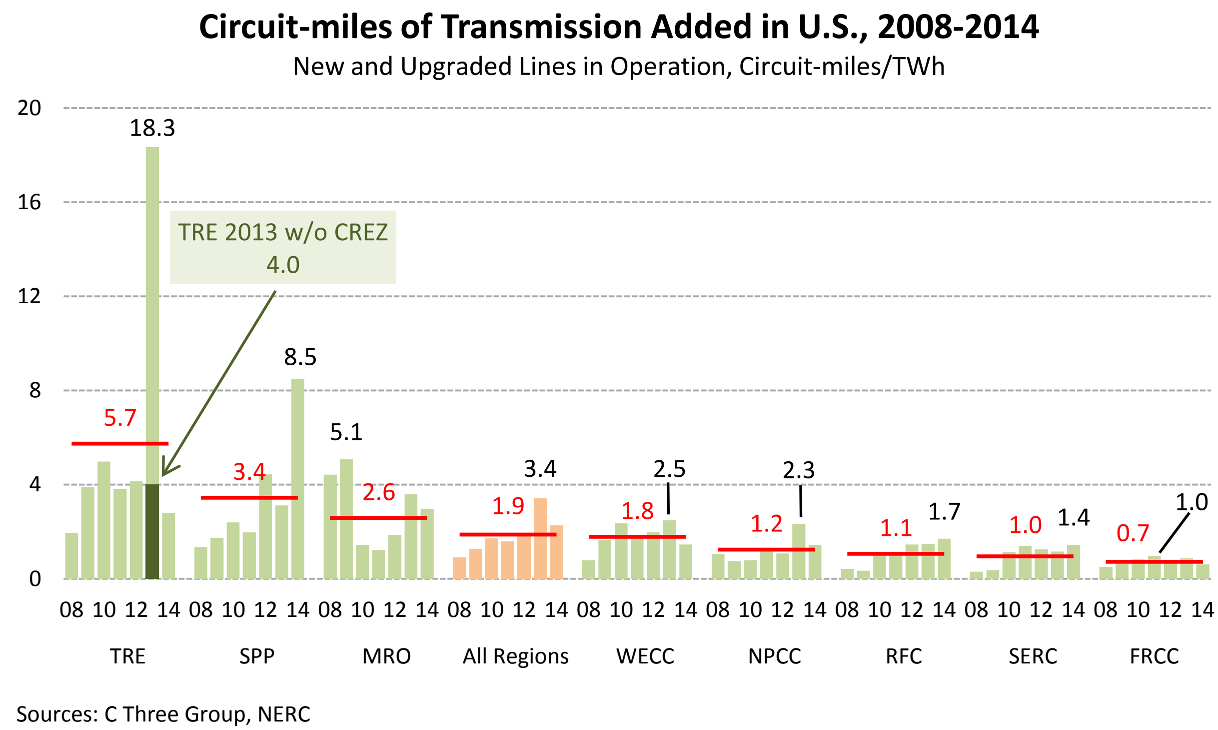
The relative position of some regions differs from the overall investment metric because of regional differences in investments in projects with a long line component versus shorter line projects or projects without a line component. This may reflect recent build-outs in some regions of transmission lines meant to access distant wind resources.

TRE added the most circuit-miles on a load-weighted basis. As noted above, this is mainly due to the CREZ projects, most of which included a relatively long line component. Only WECC built longer lines

[39] Based on projects in the C Three Group North American Electric Transmission Project Database as of August 20, 2015.

on average than TRE, but it added fewer circuit-miles on an absolute basis and, because its load is almost twice that of TRE, on a load-weighted basis as well.

Figure 8:



Although approximately 70 percent of FRCC's projects from 2008-2014 involved a line component, the lines were relatively short and it had the fewest total projects compared to other regions, which may account for its relatively low levels of load-weighted circuit-miles added.

Caveats

This metric helps to address some of the concerns with the Load-weighted Transmission Investment metric because it does not consider the costs of transmission infrastructure, which, as explained above, may differ by region. However, the usefulness of this metric is also limited in that it does not account for geographic variation between regions. For example, in regions where loads are located far from generation, there may be a greater need for transmission investment than in those regions where loads are located relatively close to generation.

Circuit-miles per Million Dollars of Investment (incremental)

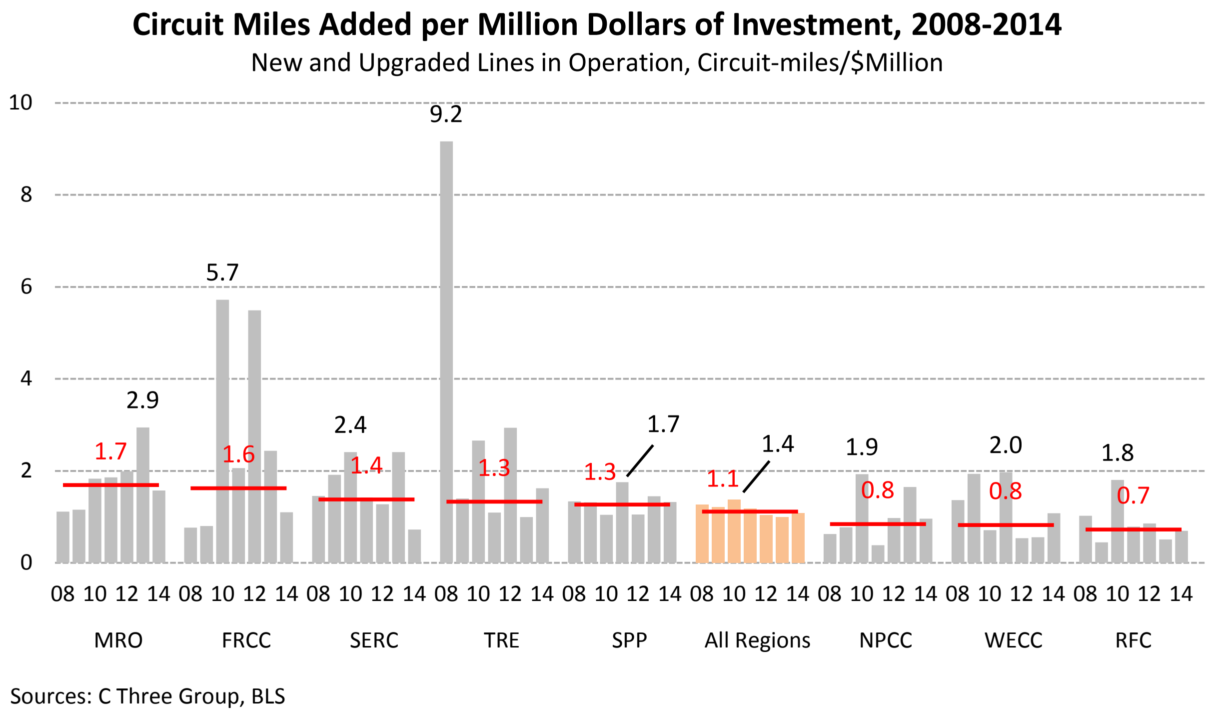
Methodology

This metric is designed to provide a basis for assessing the cost impact of different policy choices or factual circumstances on transmission investment. Specifically, this metric divides the circuit-miles of transmission line added in the U.S. from 2008-2014 by the amount of money invested over the same period (in million dollars of investment). Data for this metric are also taken from the C Three Group's transmission database. Staff used the sample of 4,083 projects that have a line component, and filtered the data as described earlier.

Results and Analysis

Figure 9 shows circuit-miles per million dollars of transmission investment in the eight NERC regions of the contiguous U.S. from 2008 to 2014. The figures in red represent the seven-year regional average, while figures in black refer to the highest circuit-mile per million dollars figure in each region.

Figure 9:



Regions with higher figures represent a greater number of circuit-miles added per million dollars invested. By this measure, MRO built the most circuit-miles per million dollars on average across all years (1.7 circuit-miles per million dollars), compared to a total of 1.1 circuit-miles per million dollars for all regions. RFC, NPCC, and WECC built the fewest circuit-miles per million dollars across all years, of less than one circuit-mile for every million dollars invested. The difference in circuit-miles per million dollars invested may be due to a range of factors, including terrain, population density, and state policy choices, among others.

TRE and FRCC appear to have the most variability in their figures for circuit-miles per million dollars, although several projects that went into operation in TRE in 2008, and FRCC in 2010 and 2012, have circuit-mile data but no associated dollar figure, which causes those years to appear as outliers in the figure above. SPP appears to have the least variability in this metric across the years. From a developers' perspective, less variability in costs would likely be desirable, but more research is necessary to determine what may be driving differences in the number of circuit-miles built per million dollars among these regions.

Caveats

As outlined in the staff presentation at the April 2015 open meeting, gauging the cost-effectiveness of different transmission investments may be difficult because much of the cost of a project is driven by the highly variable physical and regulatory challenges particular to each region, project, or developer. For example, an upgrade to an existing transmission facility is likely to cost less than a greenfield facility. Likewise, a transmission facility that is to be located in a population-dense or environmentally-sensitive area may involve higher costs per circuit-mile. To the extent that these challenges are more prevalent in some regions than others, they are likely to affect the cost-effectiveness analysis.

To at least partially address these concerns while aiding comparison, staff grouped the seven years of data by region and calculated an average across the years. Staff grouped by NERC region under the assumption that most of these regions are large enough to encompass both areas where transmission investment would be expensive on a per-mile basis, and areas where such investment would be relatively cheaper on a per-mile basis.

IV. Next Steps / Further Research

Next steps for this project can be divided into three categories: 1) steps related to current metrics; 2) steps related to new metrics; and 3) further study of any issues raised by the metrics results so far.

With respect to current metrics, staff would:

- **Expand the data gathering and analysis to more regions of the country.** In this preliminary analysis, staff restricted analysis of some metrics to regions that had available data. Over time, further work could be done to expand the scope of this analysis. For example, as Order No. 1000 is further implemented, other transmission planning regions may open competitive proposal windows for regional transmission projects. Expanding the analysis to include more years of data across more regions may yield further insights into the impact of Commission policies and the various means of implementing those policies.

- **Research applicability of EQR pricing data to the Load-Weighted Curtailment Frequency metric or alternative bilateral market costly-congestion metrics.** OEPI staff may be able to use EQR data for purposes of assessing the persistence of costly congestion in non-RTO/ISO markets.

With respect to new metrics, staff would:

- **As appropriate given data and other potential limitations, begin calculating additional metrics identified by staff.** Additional metrics could include, among others: Percentage of Nonincumbent Transmission Project Awards; Regional vs. Local Approved Project Percentage; and Successful Regional Proposal Percentage.

- **Consider a new Load-Weighted TLR-Based Congestion Metric using the amount of curtailed interchange.** As noted in body of this report, staff's preliminary investigation of this concept showed that it may provide additional insight into congestion trends.

With respect to further study of any issues raised by the metrics results so far, staff would:

- **Research the reasons behind differences in preliminary results of the competitive transmission investment metric and monitor the ultimate outcomes of the planning processes in question** (i.e., the percentage of nonincumbent transmission project bids/proposals and awards). Staff hypothesizes that differences in the number of proposals overall and percentage of proposals from incumbents and nonincumbents in CAISO and PJM may be due to differences in the regions' respective transmission planning models, proposal submission requirements, and other related factor(s). The final outcome of these two solicitations could also be monitored.