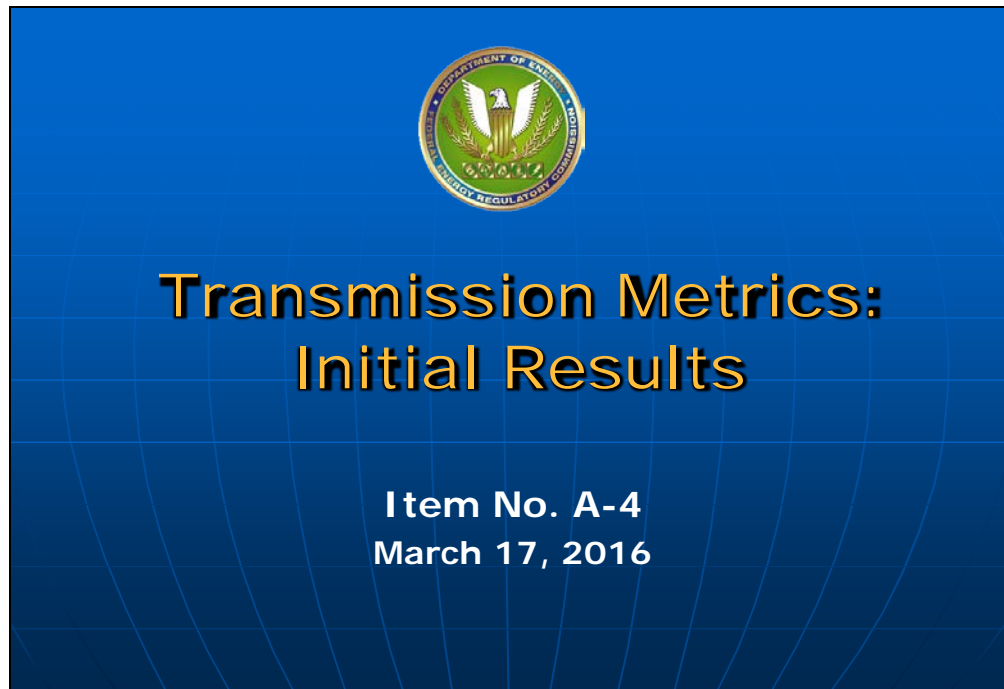


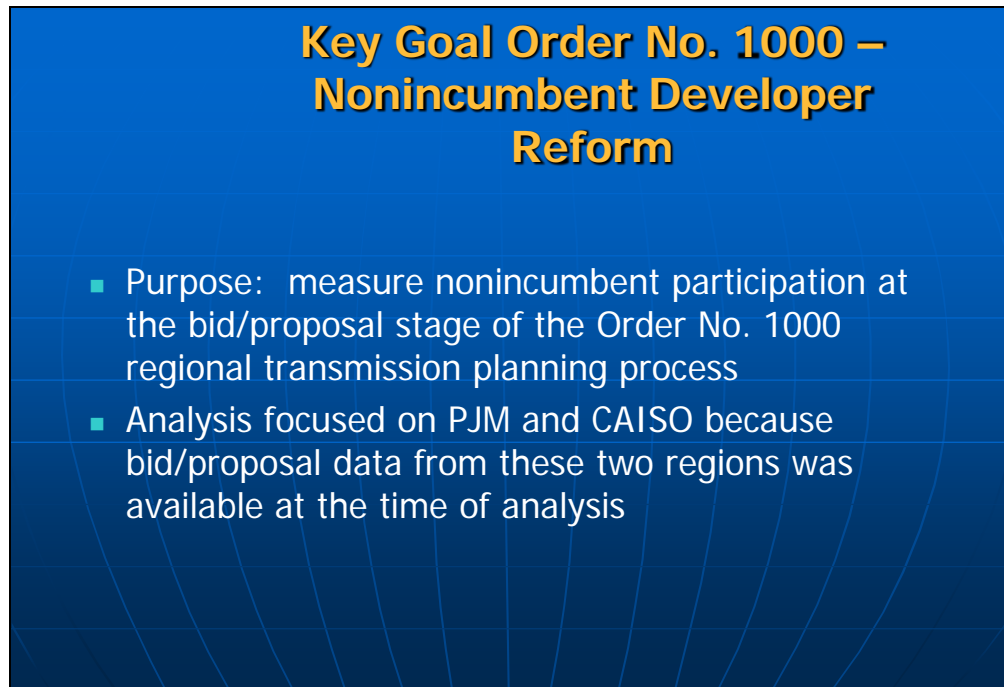
Slide 1



Good morning Mr. Chairman and Commissioners. Office of Energy Policy and Innovation staff has attempted to develop objective and standardized measures of various characteristics of the electric system and its performance to help assess the effectiveness of the Commission's policies 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.

In the staff report being released today, staff describes our methodology for calculating each of the three categories of metrics and the results of that analysis. We will now provide a brief overview of the report, which will be available through the www.ferc.gov website.

To begin, my colleague Ben Foster will discuss the first metric, whose development he led, which is intended to help assess a key goal of Order No. 1000 - nonincumbent participation in regional transmission planning processes.



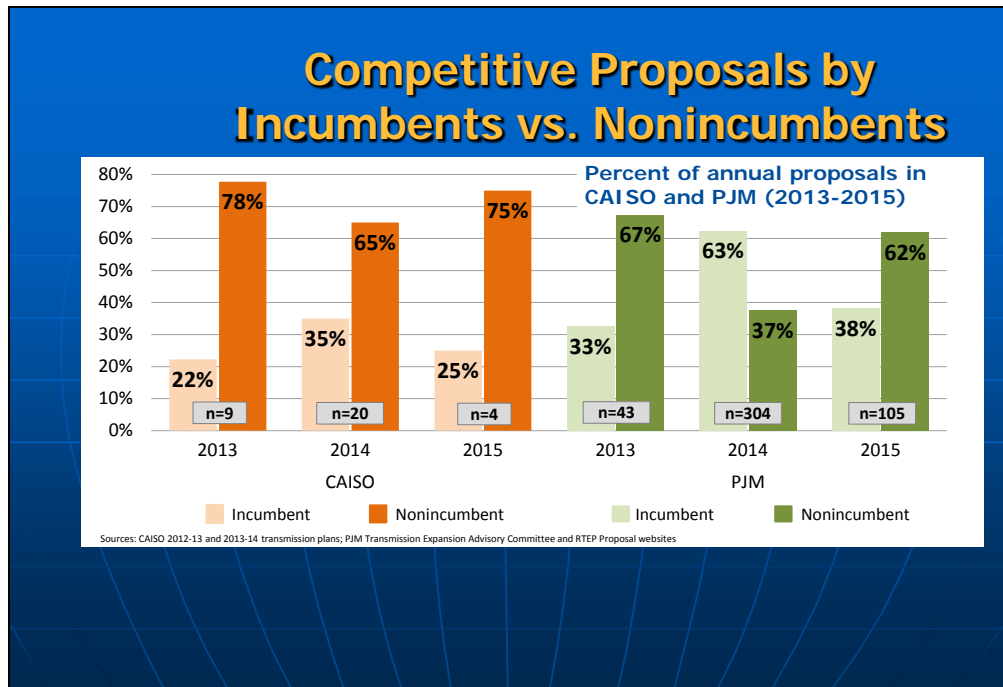
**Key Goal Order No. 1000 –
Nonincumbent Developer
Reform**

- Purpose: measure nonincumbent participation at the bid/proposal stage of the Order No. 1000 regional transmission planning process
- Analysis focused on PJM and CAISO because bid/proposal data from these two regions was available at the time of analysis

This metric measures the percentage of bids or proposals for new transmission projects in the Order No. 1000 regional transmission planning processes that nonincumbent transmission developers submitted.

At the time that staff was preparing the report, relevant data was only available for CAISO and PJM. As explained in more detail in the report, staff gathered data from public documents posted on CAISO's and PJM's websites and elsewhere.

Staff applied Order No. 1000's definition of nonincumbent transmission developer, which turns on whether a transmission developer has a retail distribution service territory or footprint and, if so, whether the project is located there. To determine the incumbency status of developers submitting proposals, which was generally not available on the regions' websites, staff compared the zone in which each proposed project would be built with the developer's retail distribution service territory or footprint, where applicable.



Slide 3 summarizes the results of staff’s analysis of the bids and proposals that developers submitted from 2013 to the period in 2015 when this report was being prepared. The figure shows the percentage of proposals in each RTO that came from incumbent and nonincumbent transmission developers during the studied period, with the associated number of proposals received in each region and year. Overall, of the 485 proposals submitted in the CAISO and PJM regions, 53 percent were from incumbents and 47 percent from nonincumbents.

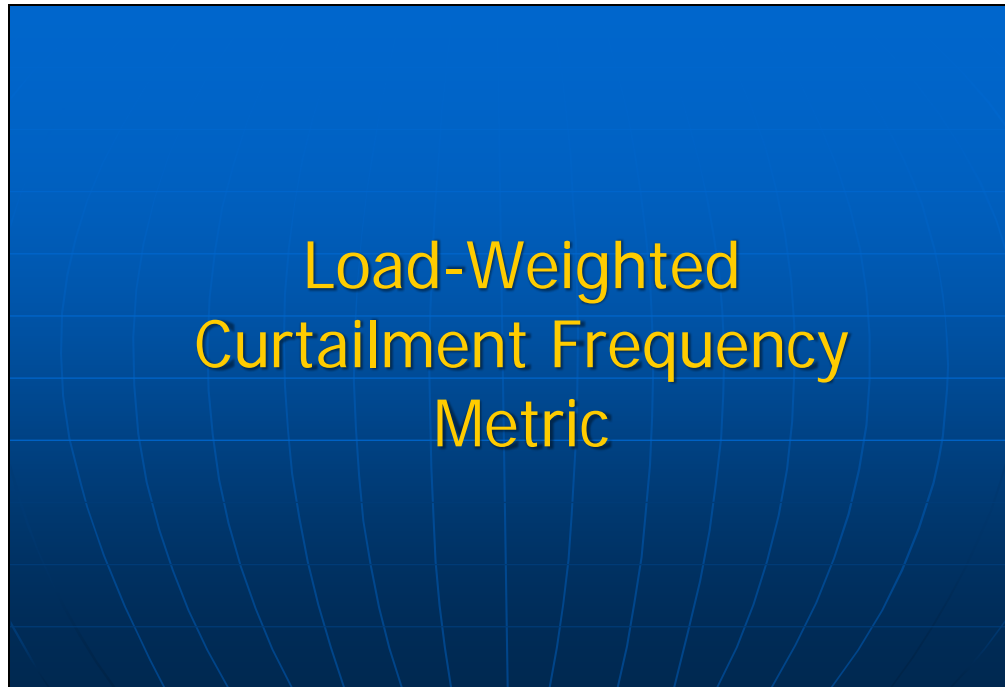
On a regional basis, the percentage of proposals from nonincumbents accounted for two-thirds to three-quarters of proposals in each of the three years in CAISO. In PJM, the percentage of proposals from nonincumbents accounted for more than 60 percent of all proposals in 2013 and the studied portion of 2015, but less than 40 percent of proposals in 2014, the year in which PJM received the majority of its proposals.

Metrics to Help Assess Need for Transmission Investment

- Assumption: Persistent and costly congestion may indicate need for additional transmission capacity
- Different approaches for bilateral markets and RTO/ISO markets
 - Bilateral Markets – based on number of interchange-curtailing Transmission Loading Relief (TLR) events
 - RTO/ISO markets – based on Locational Marginal Price data

Thank you, Ben. Next we will turn to metrics designed to help indicate whether appropriate levels of transmission infrastructure exist in a region.

Here, 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. RTO/ISO markets generate pricing data directly applicable to this purpose, and as such, staff used this data to calculate the metric for RTO/ISO market regions. For non-RTO/ISO market regions, staff used a more indirect metric based on historical NERC Transmission Loading Relief (TLR) data.



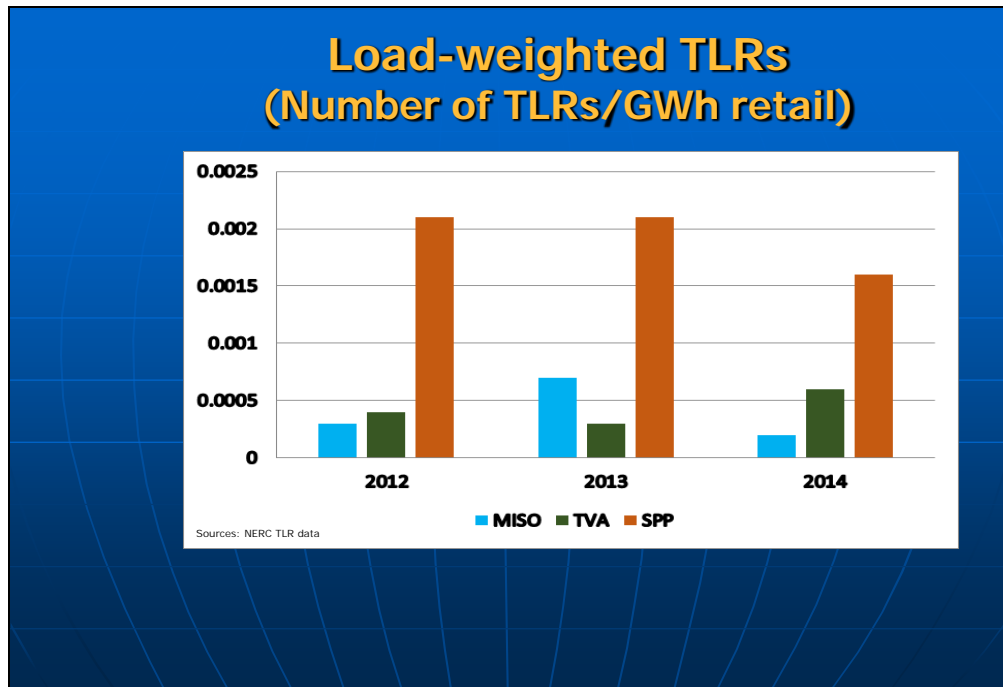
Load-Weighted Curtailment Frequency Metric

For non-RTO/ISO market regions, my colleague Abdur Masood led staff's investigation of whether NERC TLR procedures used to manage congestion can serve as an indirect measure of the level of transmission infrastructure in the region. Specifically, all other things being equal, 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 a need for additional transmission infrastructure.

At this point, I need to note that instead of TLRs, the Western Interconnection manages unscheduled flows using a coordinated combination of controllable devices, such as phase shifting transformers, and schedule curtailments that staff believes are similar to TLRs but are not recorded in the NERC TLR logs. Thus, staff did not calculate this metric for the Western Interconnection.

For the Eastern Interconnection, TLR data is publicly available from NERC, but reliable price information for non-RTO/ISO market areas is less readily available for the types of price indices or retail rate data that staff initially hoped to use. However, in the future staff intends to explore whether it could use FERC Electric Quarterly Report (EQR) wholesale pricing data to calculate this metric for non-RTO/ISO markets. All jurisdictional and some non-jurisdictional wholesale sellers of electricity submit EQR pricing data to FERC, 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.

For this report, the basis of this metric is the number of interchange-curtailing TLRs that the transmission operators of the region reported to NERC. In order to provide a basis for comparing between regions of different sizes, staff normalized this metric based on the retail load associated with the region in question.



This slide shows the load-weighted TLR metric for Southwest Power Pool, Midcontinent Independent System Operator, Inc., and Tennessee Valley Authority, which were the areas with the highest numbers of TLRs. While MISO and SPP operate organized markets that optimize dispatch based on congestion, greatly reducing their internal use of TLRs, it is still possible for RTOs to require TLRs to address unscheduled loop flow originating from outside their footprints. 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. However, it should be noted that 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 and capability than the Integrated Marketplace. The TLR logs show a significant decrease in the rate of SPP's 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 report notes certain potential concerns with reliance on a TLR-based metric, such as the fact that TLRs only represent transmission limitations between Balancing Authority Areas, and the fact that it is theoretically possible for a system to experience costly congestion but not have a significant number of TLRs. However, on balance, staff believes that a TLR-based metric can provide one useful data point in analyzing non-RTO/ISO bilateral markets.

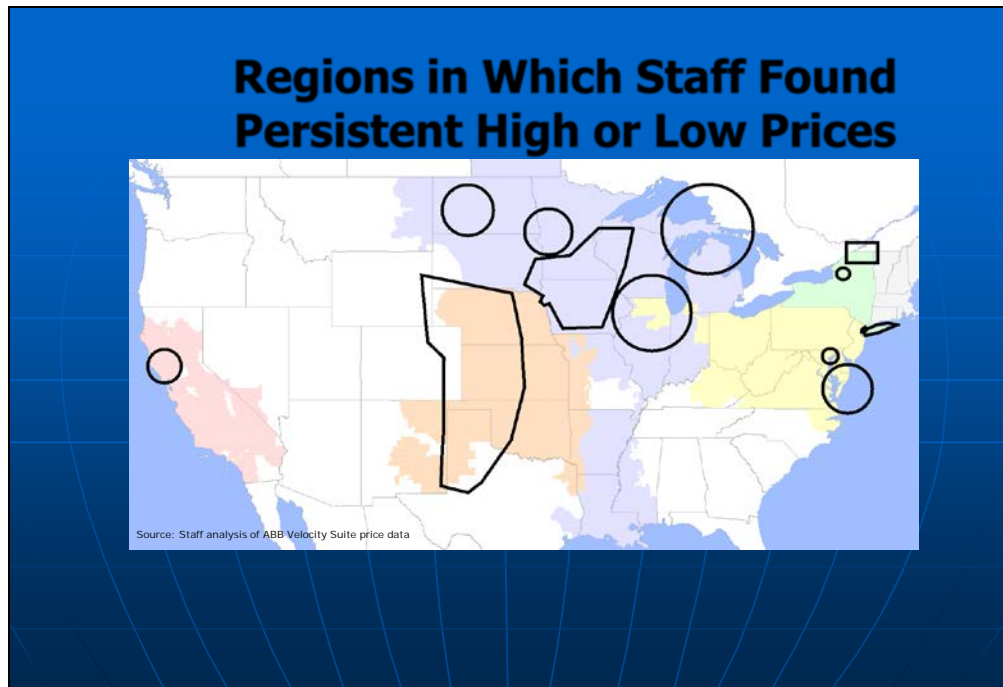
James Nachbaur will now discuss the price differential metric he developed for RTO/ISO market regions.

RTO/ISO Market Price Differential Metric

Staff developed a transmission investment metric that reflects persistent differences in RTO/ISO market nodal prices. This metric is expressed in years and it captures how long RTO/ISO market nodal price differentials have occurred persistently, though not necessarily at all times throughout a year. Staff reasons that consecutive years of significant price differentials could indicate insufficient transmission infrastructure because, for example, lower cost energy at lower-priced nodes is not being delivered to the node with higher prices. Staff, however, notes that available transfer capability between places—and the transmission investment that maintains that capability—may not be the only variables relevant to persistent price differences.

To calculate this metric, staff used real-time prices at load and generator points. Staff gathered these prices 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 in each year. Staff then calculated market-wide average high and low generator and load prices in each year. Using this information, staff identified points whose high or low prices were at least one standard deviation higher or lower than the market-wide averages in each year.

Staff identified high-priced and low-priced points in 2012, 2013, and 2014 to determine where price separation occurred persistently and had not yet been resolved, based on data available as of the time this report was being prepared. To focus on the *persistence* of price separations, staff then calculated how long ago the current run of high or low prices began. There are many high-priced and low-priced points.



As shown on this slide staff identified *areas* within each RTO that contain multiple points with persistent price separations in the same direction. Finally, staff identified for each region the longest period of price separation experienced by a point in that region. That number is the RTO/ISO Price Differential metric for that region.

RTO/ISO Market Price Differential Metric for Select Regions																
Region identified by staff	Baltimore, Maryland	Upper Peninsula	Delmarva Peninsula	Long Island, New York	Northwestern New Jersey	North-central MISO	Western SPP	Greater Chicago	North Dakota-South Dakota-Minnesota border	New York-Canada border	Northern New York	West-central North Dakota	The Geysers, California			
Direction	High	High	High	High	High	High	Low	High	Low	High	Low	High	Low	Low	Low	Low
Start of price differential	'05	'05	'06	'07	'07	'05	'05	'08	'07	'10	'06	'12	'10	'06	'06	'10
Years of persistence through 2014	10	10	9	8	8	10	10	7	8	5	9	3	5	9	9	5

This slide summarizes these results. As you can see, there are several regions that experienced significant price differentials for up to 10 years, at least through 2014. At this point, I would like to emphasize a few important caveats. By themselves, these metric results do not *prove* that transmission capacity should necessarily be added in any of these areas. These data merely provide one indication that it could be useful to explore the economics of adding new transmission capacity in these regions. Furthermore, significant changes in underlying fundamental inputs to electricity prices, like the types of large-scale changes in relative fuel prices that we've seen in recent years, could greatly impact price trends going forward. Accordingly, it would likely be very useful to continue updating this type of analysis as more recent data become available.

Baseline Transmission Investment Metrics

- Basic measures of transmission investment
- Investment dollars and circuit-miles were normalized based on associated retail load
- Main use is to permit before-and-after comparison following relevant changes in policy

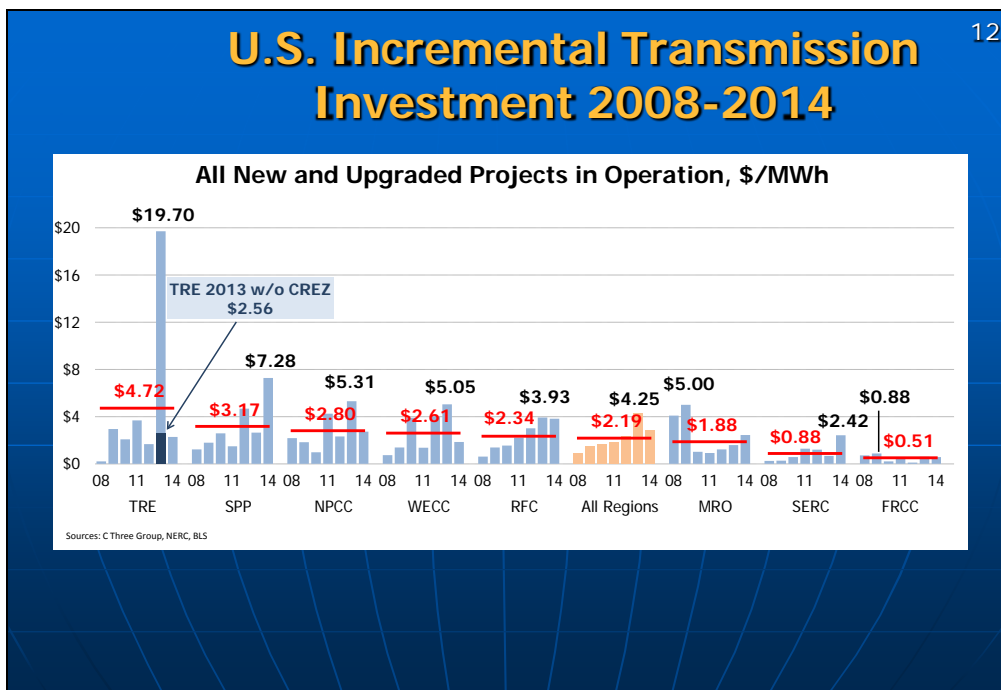
Thank you, James. The third category of metrics is designed to permit analysis of the impact of Commission policy changes by allowing the comparison of key values before and after policy changes take place. This category includes three interrelated metrics: (1) Load-weighted Transmission Investment; (2) Load-weighted Circuit-miles; and (3) Circuit-miles per Million Dollars of Investment. 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. Ben, who also led the development of these metrics, will now discuss each metric in turn.



Load-Weighted Transmission Investment Metric

This metric describes the load-weighted dollar value of transmission facilities that went into operation each year from 2008-2014 in the eight NERC regions of the contiguous U.S. Weighting transmission investment dollars by associated retail load allows for comparisons between regions of different sizes. 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.

Transmission project data are from the CThree Group's North American Electric Transmission Projects database, and load data are from NERC's 2014 Electricity Supply & Demand database. Staff converted nominal cost or budget figures to 2014 dollars using the annual average of the consumer price index for all urban consumers. To calculate the final, load-weighted metric, staff divided the normalized investment figures for each NERC region for each year by the retail load in each year.

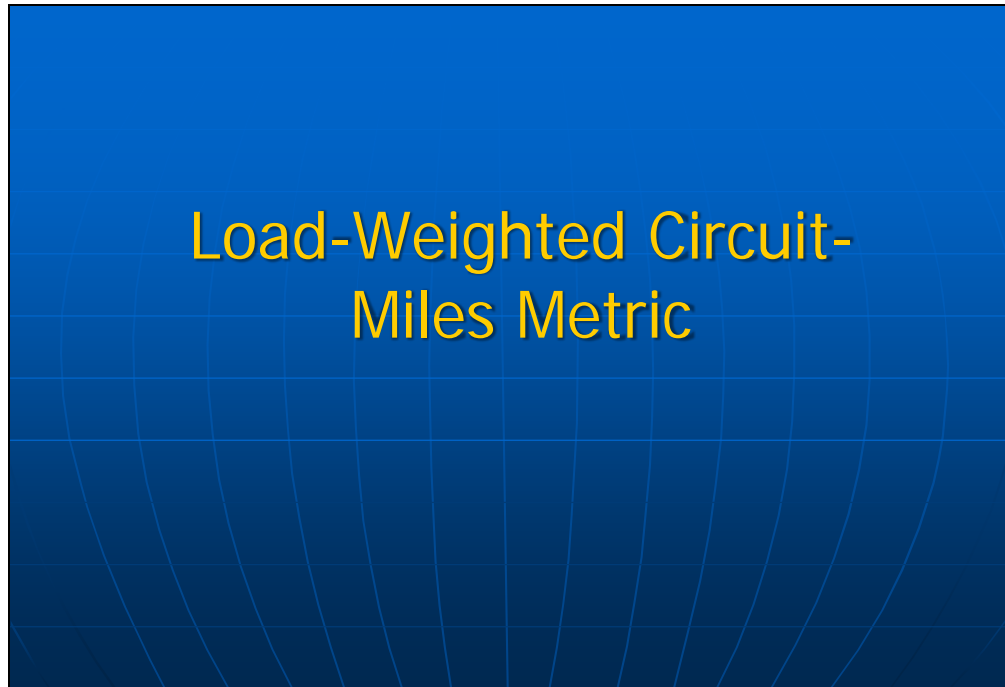


Slide 12 shows load-weighted incremental transmission investment in dollars per MWh in the eight NERC regions of the contiguous U.S. from 2008 to 2014. The figures in red represent the load-weighted investment across all seven years, while figures in black refer to the highest load-weighted dollar figure 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 (the Texas Regional Entity) 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 (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. Excluding this large CREZ 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.



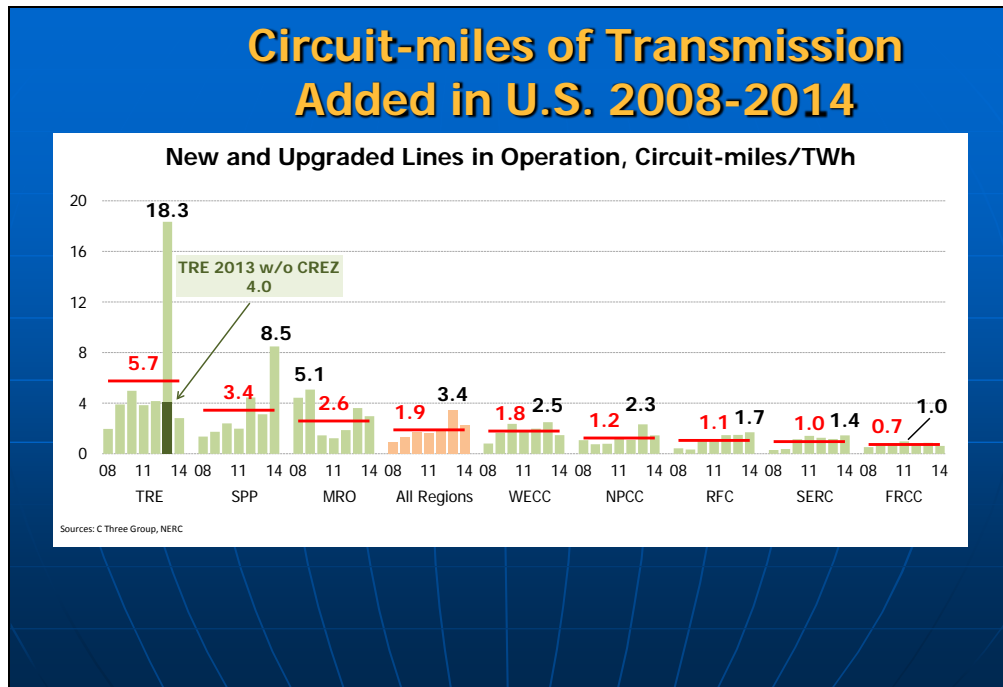
Load-Weighted Circuit-Miles Metric

The next metric describes the load-weighted circuit-miles of transmission line added from 2008 to 2014. As with the previous metric, weighting transmission circuit-miles by associated retail load allows for comparisons between regions of different sizes.

For this metric, staff filtered the data in the C Three Group database, removing the data associated with those projects that do not include a line component and a limited number of projects without a NERC region designation, or with multiple designations.

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 conservatively assumed that the line has only one circuit.

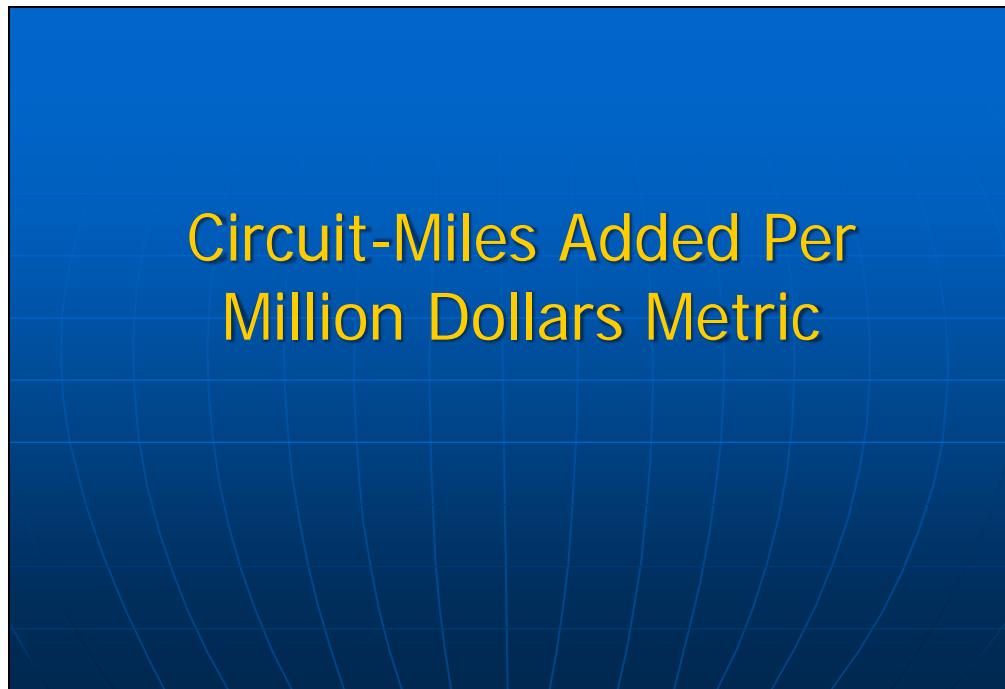
To arrive at the final metric of load-weighted circuit miles, staff divided the circuit-mile figure for each NERC region for each year by that region's retail load.



Slide 14 shows load-weighted transmission line additions in circuit-miles/TWh from 2008 to 2014.

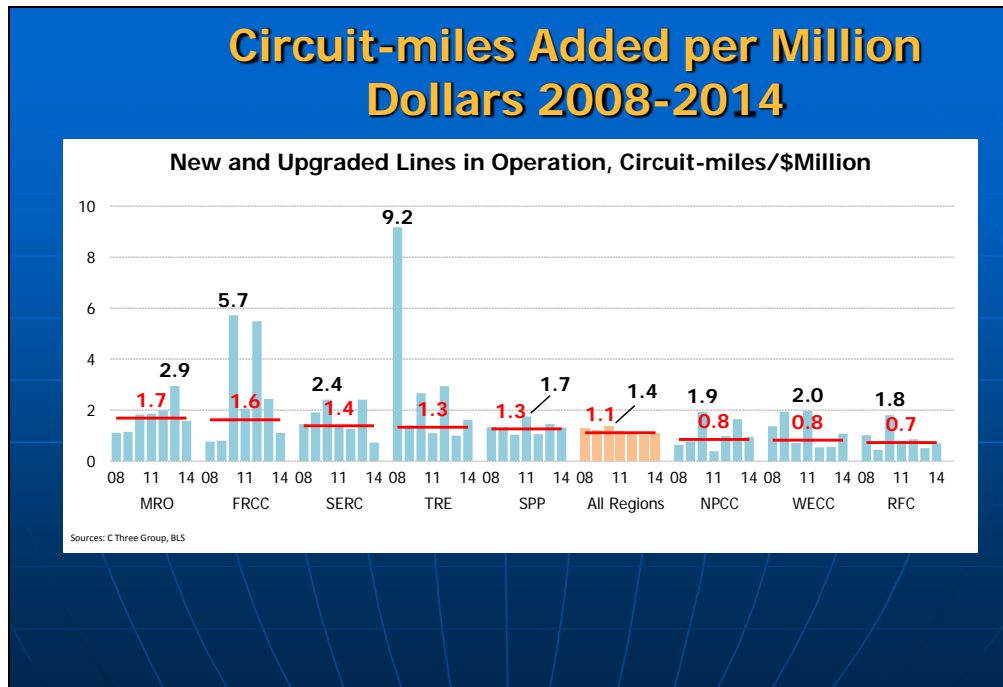
Overall, the results for this metric are similar to those for the previous metric. TRE and SPP lead, and SERC and FRCC lag, the other regions in terms of load-weighted circuit-miles added, with five regions (WECC, NPCC, RFC, SERC and FRCC) below the all-region all-year average of approximately two circuit-miles/TWh.

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 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.



Circuit-Miles Added Per Million Dollars Metric

This last 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 contiguous 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 filtered the data as described earlier.



Slide 16 shows circuit-miles per million dollars of transmission investment from 2008 to 2014.

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), compared to a total of 1.1 for all regions. RFC, NPCC, and WECC built the fewest circuit-miles per million dollars across all years, of less than one. 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 results, 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.

I would like to emphasize that care should be taken in attempting to use the results of this metric to gauge the “cost-effectiveness” of different regions’ transmission investments 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. Nevertheless, staff believes that this metric, in combination with the other two I’ve just discussed, can provide useful insights into the impact of Commission policy changes, particularly when considered over time.

Slide 17



Transmission Metrics: Initial Results

Item No. A-4
March 17, 2016

Thank you, Mr. Chairman and Commissioners. This concludes our presentation and we welcome any questions you may have.