Wholesale Transmission Rates: Impact of Emerging Issues

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AGENDA

- Brief Background on Wholesale Transmission Rates and Recent Developments

- Deeper Dive Into Emerging Issues and Developments Related to:

  - Order 1000 Cost Allocation Methodologies
  - Increased Penetration of Distributed Energy Resources
  - Return on Equity
  - Conclusions and Take Aways

- Questions and Comments

Brief Background on Wholesale Transmission Rates and Recent Developments

General Concepts of FERC Rate Making and Rate Design

- Establish just and reasonable rates for public utilities via:
  - **rate making**, which determines the cost of service or revenue requirement (how many $ to collect through rates); and
  - **rate design**, which determines the actual rates to be charged (e.g., cost allocation - how to collect $ from various customer groups)

General Concepts of FERC Rate Making

- **Rate making:**
  - FERC has flexibility in exercising its ratemaking authority
  - FERC may set rates anywhere within a range of reasonableness
  - Basic methodology used is cost-of-service ratemaking
    - A cost of service is a measure of a utility's annual "revenue requirement"
  - **Revenue Requirement** – allows the utility the opportunity to recover its prudently incurred costs of providing service and a reasonable return on investment
  - Cost of service formula = $E + d + T + (V-D) * R$

General Concepts of FERC Rate Design

- **Cost Allocation and Rate design:**
  - Involves balancing investor and consumer interests
  - One set of ratepayers should not subsidize other ratepayers
  - No undue discrimination among similarly situated customers
  - Cost causation/beneficiary pays (those who cause costs to be incurred should pay; those that benefit can be said to have caused a part of the costs)
  - Billing determinants are the detailed customer usage data needed to bill customers
- **Regional transmission cost allocation and rate design**
  - Postage stamp, license plate, volumetric, demand, etc.

Regional Order 1000
Cost Allocation Methodologies

- Regions had the flexibility to design their own Order 1000 cost allocation methodologies
- Various regions chose to fashion their cost allocation methodologies based on project type (e.g., reliability, economic, policy, MVP, etc.) and/or by voltage
- Examples of approved cost allocation methods:
  - Load ratio share across entire region
  - Costs assigned to zones based on load-flow analysis
  - Hybrid combinations
  - Proportional share based on individual share of quantified benefits
- Some issues have arisen as a result of the application of the methodologies and underlying beneficiary determinations

Rate Designs used by RTOs for Transmission Cost Recovery

- To assign cost responsibility for the total revenue requirement
- FERC chose demand as the *pro forma* billing determinant in Order 888, and specifically the 12 monthly coincident peak (12 CP) allocation method because FERC believed the majority of utilities plan their systems to meet their twelve monthly peaks; but welcomed alternatives.

	VOLUMETRIC	DEMAND		
BASIS	MWh/Gross Load	Monthly Peak	Annual Peak	Variable
EXAMPLES	CAISO NYISO MISO MVPs	SPP NITS ISO-NE NITS MISO NITS	ERCOT (4 Summer months)	PJM NITS

FERC Staff Report on 2017 Transmission Metrics

- FERC is actively monitoring effectiveness of its Order 1000 policies to determine if additional FERC action is needed.
- FERC Staff October 6, 2017 Report discussed three primary metrics:
  - First Metric: assess **non-incumbent participation** in transmission planning processes, and found it to be generally robust. It will consider joint ventures in future reports. Staff also considered **stakeholder participation** and found stakeholder attendance dropped off slightly in most transmission planning regions from FY 2015 to FY 2016, but that NTTG, ISO-NE, FRCC, SERTP, and SCRTP showed increases.
  - Second Metric: assess whether appropriate levels of transmission infrastructure exist, and found **at least in certain areas of U.S., transmission investment is reducing persistent congestion**. Staff caveated limitations to this analysis, which may suggest that new transmission may not be needed in certain situations or may not be the cost-effective solution.
  - Third Metric: determine how much transmission infrastructure developed and the relative cost of that investment, and found: (a) **Increase in load-weighted transmission investment from last report** ($2.43/MWh v. $2.19/MWh); (b) **Load-weighted circuit-miles unchanged** from 2016 report across all NERC regions between 2018 and 2015; and (3) Average **load-weighted circuit-miles per million dollars of investment decreased slightly** (by 0.1) between the 2016 report and 2017 report.
- Staff caveated that more investment in transmission is not necessarily better in all cases; cost of constructing facilities varies by region, such that higher cost does not mean more transmission infrastructure was constructed.

https://www.ferc.gov/legal/staff-reports/2017/transmission-investment-metrics.pdf

AD16-18 Comments on Interregional Coordination

- In response to the question on what factors have contributed to the lack of development of interregional transmission facilities, and if FERC should take any action to facilitate development:
  - 16 sets of comments (including PJM, MISO, CAISO, NEISO, NYISO) disagreed with the concern or said it is too early to conclude that interregional processes are not working; 8 sets of comments (including OMS, WIRES, GridLiance, LS Power, ITC, and NRDC) said improvements are needed
    - APPA/NRECA said too early to conclude there is a lack of development; FERC should require regions to monitor and report on status of their processes; then FERC could ask regions to conduct stakeholder processes to address any concerns

Some Recent Developments on Transmission Cost Allocation and Rate Design

- New Order 1000 Cost Allocation Developments
  - PJM Cost Allocation for Stability Projects (Docket EL15-95)
  - CAISO Regionalization Transmission Cost Allocation Options (Currently inactive)

- Proposals Related to DER
  - FERC Consideration of Storage Resources as Transmission Assets (Docket AD16-25)
  - Proposal to Reconsider CAISO Transmission Access Charge Billing Determinants to Account for DG

DIVING IN TO SOME ORDER 1000 COST ALLOCATION DEVELOPMENTS

Artificial Island Project and PJM's Cost Allocation Methodology

- In 2015, PJM approved AIP to address transmission system stability limitations and generation operation issues associated with certain NJ nuclear generating plants.
- Complaint filed at FERC noting SBDFAX unreasonable for such projects where 93% of costs allocated to Delmarva zone, although it receives only 10% of benefits.
- FERC denied the complaint:
  - "no cost allocation method can perfectly assign costs to the beneficiaries. . . ."
  - SBDFAX focuses on benefits over time through the use of a project, not the reliability violation that drove the immediate need for the project; said Delmarva zone will receive significant benefits based on results of the SBDFAX.
  - Market efficiency analyses are not the appropriate metric for measuring the benefits of reliability projects in the PJM region, because they do not capture all of the broad regional benefits.
  - Found no basis to allocate a portion of costs to generators that are directly benefiting from the increased output of the new facility; it is reasonable to allocate costs of transmission facility to load.
- Commissioner LaFleur dissent:
  - Supports *ex ante* cost allocation in general but record clearly establishes that in discrete cases, the methodology produces an anomalous result and does not allocate costs in a manner commensurate with benefits.
  - SBDFAX relies solely on use of the facility and not on entities that benefit from underlying reliability issues that triggered the development and selection of these projects.
  - Similar to PJM's existing hybrid methodology for high voltage transmission, a hybrid that recognizes (1) benefits accruing from resolution of the underlying short circuit or stability issue; and (2) benefits accruing from use of facility over time, would reflect a fairer cost allocation.
- Rehearing filed and pending.

FERC Docket EL15-95, 155 FERC ¶ 61,090 (Apr. 22, 2016), *dissent* (LaFleur), *reh'g pending*; *PJM Interconnection*, Docket ER17-1420, 161 ¶ 61,024 (Oct. 5, 2017), *concur* (LaFleur).

PJM Comparison of Different Methods for Artificial Island Project

ZONE	EXISTING SBDFAX METHOD	STABILITY INTERFACE DFAX METHOD	STABILITY DEVIATION METHOD
AEC	0.12%	7.31%	7.24%
AEP	0.97%	0.00%	0.00%
APS	0.38%	0.00%	1.11%
ATSI	0.55%	0.00%	0.00%
BGE	0.28%	2.61%	3.93%
COMED	0.91%	0.00%	0.00%
DAYTON	0.14%	0.00%	0.00%
DEOK	0.23%	0.00%	0.00%
DL	0.12%	0.00%	0.00%
DPL	93.37%	6.94%	10.36%
DVP	0.84%	0.00%	0.00%
ECP	0.01%	1.20%	1.32%
EKPC	0.12%	0.00%	0.00%
HTP	0.01%	1.09%	1.22%
JCPL	0.27%	13.00%	12.38%
ME	0.13%	0.00%	4.78%
NEPTUNE	0.03%	1.50%	3.11%
PECO	0.36%	19.94%	15.17%
PENELEC	0.12%	0.00%	1.09%
PEPCO	0.28%	0.00%	3.91%
POSEIDON	0.00%	2.66%	2.41%
PPL	0.30%	0.00%	12.53%
PSEG	0.42%	42.06%	18.86%
RE	0.02%	1.69%	0.58%
TOTAL	100.0%	100.0%	100.0%

: PJM Whitepaper Alternative Approaches to Identification of Artificial Island Project Beneficiaries at 11 (June 9, 2017)

Concepts Stemming From CAISO 2016 Regionalization Options

- CAISO's Draft Regional Framework for Cost Allocation Under an Expanded Region included:
  - New sub-region will not pay for existing facilities of the other sub-regions, unless deemed integrated
  - No recalculation of benefits of projects or cost allocation revisions as new sub-regions join
  - For new projects selected in an integrated region:
    - Different cost allocation methods based on type of project and if project intended to meet reliability, economic, or policy need within the sub-region or if multiple sub-regions would benefit, and also based on whether project would be located in or out of the sub-region driving the project, with 10 different scenarios considered for the framework, e.g.,
      - policy project entirely within a sub-region allocated to that sub-region which drove the policy;
      - an enhancement or replacement of a reliability or policy driven project with higher costs than original solution and for which economic benefits exceed the incremental cost of the original reliability or policy project to be cost allocated first based on avoided cost to sub-region that drove the need and remainder to sub-regions in proportion to their economic benefits
- Cost Causation concerns raised during the initiative, including:
  - Various CA munis concerned with proposal to deem "integrated" entities as part of a zone
  - CPUC concerned with rate disparity between existing and new PTOs; ORA said cost of existing facilities should be spread to all sub-regions within the expanded region
  - Stakeholders split on various of the cost allocation methods by project type
- CAISO recognized that some elements of proposal were complicated and some added late during process, stated, "[i]f and when the regional TAC options initiative is reopened the ISO will conduct additional discussions on several topics."

Questions for Consideration on Cost Allocation

- Does the pre-approved cost allocation methodology always result in cost causative and beneficiary pays cost allocation?
  - Are there exceptions that can be identified in your region?
- Should immediate needs or future benefits be weighted more in the cost allocation?
- How should a zone or sub-region be defined? Is the entire footprint of an existing region a reasonable division?
  - If FERC mandated interregional planning and cost allocation, how should sub-regions or zones be defined?
- Is postage-stamp allocation for all new high-voltage projects irrespective of type reasonable or is more granular allocation more consistent with cost causation?
  - Would the answer depend on the characteristics of your zone?
  - Should lower voltage facilities ever be subject to postage-stamp allocation?
- Should new entrants to a region have to bear costs of a facility they did not have the opportunity to vet?
- Should new entrants benefit from facilities approved before they joined without paying a share of the costs of that facility?

PROPOSAL RELATING TO INCREASED PENETRATION OF DISTRIBUTED ENERGY RESOURCES

AD16-25 Comments on Electric Storage Resources as Transmission Assets

November 2016 FERC technical conference on utilization in the organized markets of ESRs as transmission assets compensated through transmission rates.

- Utilities generally: (1) see value in ESRs being used as transmission assets or providing market-based products, but want to be sure that if resource is receiving cost-based recovery through transmission rates, that the resource goes through the market's transmission planning process; if so, storage owner should prioritize transmission service over any market participation; (2) say market revenues should be credited against cost-based revenues; and (3) ISOs/RTOs should be permitted to design frameworks to enable storage resources to participate in both transmission planning process and in markets.
- ISOs/RTOs generally concerned with the availability of an electric storage resource if it is used in place of transmission; if used as transmission, it should abstain from market participation and remain fully charged to be able to meet contingency.
- Energy storage developers want FERC to ensure that all options are open – to be able to provide transmission service and receive cost-based rates, and to be able to offer market services at market-based rates.
- AMP noted that if an ESR was selected in a TPP as the least-cost solution, traditional cost of service ratemaking would apply, where the storage device recovered its costs, including a cost-based ROE. However, storage would have to have same level of availability and reliability as other traditional transmission assets. AMP also noted that wholesale market rules should not interfere with the ability of state and local authorities in accordance with Order 719 to regulate storage assets that function as distribution or retail sale facilities.

Transmission Rate Design Changes Considered in CAISO Relating to DERs

- CAISO stakeholder process to consider revisions to Transmission Access Charge ("TAC") structure:
  - Current Structure: volumetric TAC established to align with CAISO's market-based approach for scheduling transmission use on hourly MWh volumes
  - Now at Issue:
    - Whether to modify the current volumetric TAC structure to incorporate other approaches such as demand-based or time-of-use structure to align with drivers of upgrades
    - Whether/how to modify TAC to reduce charges in Participating Transmission Owner areas for load offset by "DG Output."
    - "DG Output" includes energy injections from (1) distribution-grid connected resources, and (2) behind-the-meter resources that exceeds consumption at the same site during the same hour

Arguments in ongoing CAISO TAC discussion

- Supportive arguments include:
  - DG does not require any or much transmission, so load consuming DG should not have to pay for transmission
  - There is no current price signal for the development of DG on distribution
  - Increased DG will reduce future transmission needs
  - Certain municipal utilities are already excused from paying TAC on DG resources in their systems
  - Transmission owner will recover TRR; only change is where energy is measured
- Opposing arguments include:
  - DG connected to distribution grid receives reliability benefits from transmission, as power can be received from anywhere on the grid
  - DG may offset some of the total energy that would otherwise come from transmission grid, but may not reduce the peak load on the grid
  - Installation of DG at a later time to serve some load does not reduce any costs of existing transmission facilities that were built to serve that load
  - Removing local DG in billing would result in cost increases to everyone else
  - Properly accounting for DG on distribution grid would require new metering infrastructure
  - Why should DG receive special treatment as opposed to other resources, excusing it from common socialized costs

Questions for Consideration Related to DER Developments

- To what extent can distribution-connected resources (such as electric storage or other distributed generation) offset the need for transmission investment?
- To what extent can distribution-connected resources reduce the operating and maintenance costs of the existing transmission system?
- What is the most appropriate way to measure each end-use customer's or load-serving entity's benefits or usage of the grid?

Conclusions and Takeaways

- Participate
  - Participation in local and regional planning processes and in FERC proceedings, including to:
    - Ensure transparency, and cost/benefit of proposed cost allocations.
    - Meet FERC's transmission metric, which gauges stakeholder participation in determining whether changes to its transmission policies are warranted.
    - Advocate for changes deemed needed or to prevent adverse proposals at the stakeholder level, before the RTO/ISO/public utility makes a FPA Section 205 filing at FERC.
    - Gauge if transmission solutions or non-transmission alternatives (such as DERs) provide the more efficient or cost-effective solution in the immediate or long term.
    - Educate FERC about regional differences to avoid one-size-fits-all policies where they may be inappropriate.
- Prepare
  - Take a long-term view and anticipate how various changes may impact your position, e.g.,
    - If FERC moves towards mandatory interregional transmission planning and cost allocation, what cost allocation methods and rate designs would work best for your region?
    - If your region expands or as entities join or leave particular regions, what changes would be needed to mitigate any adverse consequences?
    - Will further penetration of DER or other non-transmission alternatives facilitate your utility's economic or policy goals or will they lead to unjust cost-shifts in the immediate or long term?

ADDENDUM

Definition of Distributed Energy Resource (DER)

- FERC's November 17, 2016 NOPR in Docket Nos. RM16-23 and AD16-20 defined a distributed energy resource as "a source or sink of power that is located on the distribution system, any subsystem thereof, or behind a customer meter. These resources may include, but are not limited to, electric storage resources, distributed generation, thermal storage, and electric vehicles and their supply equipment." *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators,* 157 FERC ¶ 61,121 (Nov. 17, 2016) at fn. 2, *available at https://www.ferc.gov/whats-new/comm-meet/2016/111716/E-1.pdf*

- National Association of Regulatory Utility Commissioners' 2016 Manual on Distributed Energy Resources Rate Design and Compensation defined DER as "a resource cited close to customers that can provide all or some of their immediate electric and power needs and can also be used by the system to either reduce demand (such as energy efficiency) or provide supply to satisfy the energy, capacity, or ancillary service needs of the distribution grid. The resources, if providing electricity or thermal energy, are small in scale, connected to the distribution system, and close to load. Examples of different types of DER include solar photovoltaic (PV), wind, combined heat and power (CHP), energy storage, demand response (DR), electric vehicles (EVs), microgrids, and energy efficiency (EE)." NARUC's Manual at 44-45, *available at*: http://bit.ly/2fFHH34

Revenue Requirement Formula

Revenue Requirement = E + d + T + (V-D) * R

- V = Gross value of property
- D = Accrued depreciation
- R = Overall rate of return
- E = Operating expenses
- d = Depreciation expense
- T = Taxes

Transmission Revenue Requirement

- Revenue Requirement recovers
  - Operating & Maintenance ("O&M") expenses
  - Depreciation
  - Taxes
  - Rate of Return (equity and debt service) on rate base
- Rate Base (V-D)
  - Regulatory concept that represents the used and useful set of assets upon which the utility is able to recover a return
  - Typically based on net plant plus allowances for working capital, general plant, and other items; ADIT and customer contributions principal offsets
- Case stated on a test year basis (base period) that is adjusted for known and measureable changes (adjustment period)

COST ALLOCATION AND RATE DESIGN

- Various Methods of Allocating Costs to Services:
  - To service/customer
  - By individual Transmission Owners' rate zones
  - Region-Wide Allocation of Certain Costs
  - Based on Cost-Causation Principles

- Rates are determined by:

$$\frac{\text{Cost of Service (by service)}}{\text{Billing Units } (\textit{e.g.}\text{, 12 CP})}$$