Southwest Power Pool

SCHEDULE 1A TASK FORCE MEETING

August 24, 2018

Teleconference

• M I N U T E S •

Administrative Items

Chair John Olsen called the meeting to order at 10:00 AM. The following individuals participated in the meeting:

John Olsen	Evergy
Alfred Busbee	GDS Associates/ETEC
Jason Mazigian	Basin Electric
David Mindham	ITC Holdings
Tim Hall	Southern Power
John Varnell	Tenaska
Robert Tallman	OG&E
Wes Berger	SPS/Xcel Energy
Jim Jacoby	AEP
Greg Garst	OPPD
Joel Dagerman	NPPD
Heather Starnes	Missouri Joint Municipal Elec Utility Commission
Ray Bergmeier	Sunflower Electric
Rob Janssen	Dogwood Energy
David Erkin	AEP
Calvin Daniels	WFEC
Kevin Galke	The Energy Authority for City Utilities of Springfield
Carl Monroe	SPP
Mike Riley	SPP
Scott Smith	SPP
Lee Elliott	SPP
Micha Bailey	SPP
Patti Kelly	SPP
Ty Mitchell	SPP
Zeynep Vural	SPP
Dianne Branch	SPP

Minutes from the August 8, 2018 meeting were reviewed. Heather Starnes motioned to approve the minutes. The motion was seconded by Jason Mazigian. The minutes were unanimously approved by voice vote.

Review of FERC Expense Classification

Dianne Branch provided an overview of SPP's methodology for categorizing the components of its Schedule 1-A administrative fee as required by FERC Order 668. Exhibits detailing the components of each prescribed category were also reviewed. There were various questions regarding the general process and specific components of the allocation that were addressed by SPP staff.

Review of TCR Estimated Cost of Services

Dianne Branch provided a brief overview of the estimated cost to provide the TCR services, highlighting the associated staffing, system maintenance, and debt service cost. Annual costs are estimated at $2.3MM.

Review of RTO Comparisons (Order 668 Fee Allocation)

Dianne Branch provided an overview of other RTO/ISO rate schedules and their allocation to the three expense categories as prescribed by FERC Order 668. There was a general discussion on the varying complexity of the different rate structures employed by the other RTO/ISOs and the related allocation to the FERC expense categories. The task force generally agreed that the methodology ultimately recommended for SPP should not be overly complicated and should minimize any incremental costs to implement and administer.

Fee Structure Development

There was ongoing discussion focused on the various approaches for constructing the cost recovery rate structure. While the general consensus is "simpler is better", there were differing positions on what level of simplicity would be most appropriate. Consistent with discussions from the August 8th meeting, there is general agreement that the current schedule 1A billing methodology should be utilized for costs associated with Scheduling and Planning. In summary, billing for those two areas would be based on demand to transmission customers.

The remainder of the discussion centered on the appropriate mechanism(s) to bill costs associated with Market Facilitation. Specifically, whether it should be based entirely on energy flow and to what level of granularity should market costs be evaluated and potentially allocated to those receiving benefit. Additional analysis was requested of staff to assist the task force in further evaluating market services for purposes of constructing an appropriate rate recovery structure.

There was general agreement that a pre-filing conference with FERC should be considered within the scope of the overall project timeline.

Action Items

Staff to provide clarification on the difference between SPP 12NCP and 12CP.

Staff to accumulate data on nameplate capacity of all generation assets

Staff to provide additional volume data for various market services, with special emphasis on TCR activity

Staff to formulate approach in seeking a pre-filing conference with FERC

Costs of implementing /administering new rate structure to be evaluated and included in the final recommendation

True-up mechanism to be formulated once new rate structure has been solidified

Future Meetings

Thursday, September 6th 10AM -3PM (Face to Face) – DFW Hyatt Regency
Thursday, October 4th 10-Noon – Teleconference

There being no further business, John Olsen adjourned the meeting at 12:10 PM.

Respectfully Submitted,

Dianne Branch
Secretary

Southwest Power Pool, Inc.

SCHEDULE 1A TASK FORCE MEETING

August 24, 2018

Teleconference

• A G E N D A •

10am – Noon CST

1. Administrative Items (10 minutes)
    a. Call to Order…………………………………………………………………………...John Olsen
    b. Attendance…………………………………………………………………………...Dianne Branch
    c. Review of Agenda………………………………………………………………….John Olsen
    d. Approve Meeting Minutes………………………..……………………………….John Olsen
2. FERC Expense Classification (15 minutes) .... Dianne Branch
3. RTO Comparison - Order 668 Cost Allocation (15 minutes) .... Dianne Branch
4. Fee Structure Development (70 minutes)……………………………………………………..John Olsen
5. Closing Items (10 minutes)…………………………………………… ……………………Dianne Branch
    a. Summary of Action Items
    b. Future meetings

Southwest Power Pool

SCHEDULE 1A TASK FORCE MEETING

August 8, 2018

DFW Hyatt Regency – Dallas, Texas

• M I N U T E S •

Administrative Items

Chair John Olsen called the meeting to order at 12:00 PM. The following individuals participated in the meeting:

John Olsen	Evergy
Alfred Busbee	GDS Associates/ETEC
Jason Mazigian	Basin Electric
David Mindham	ITC Holdings
Tim Hall	Southern Power
John Varnell	Tenaska
Robert Tallman	OG&E
Wes Berger	SPS/Excel Energy
Jim Jacoby	AEP
Greg Garst	OPPD
Joel Dagerman	NPPD
Don Frerking	Evergy
David Erkin	AEP
Dwayne Stradford	AEP
Tom Dunn	SPP
Dianne Branch	SPP

Those participating by phone were as follows:

Heather Starnes	Missouri Joint Municipal Electric Utility Commission
Ray Bergmeier	Sunflower Electric
Rob Janssen	Dogwood Energy
Shawn Geil	Kansas Electric Power Corp
Brian Rounds	AESL Consulting
Sam Loudenslager	SPP
Tom Kleckner	RTO Insider

Finalize Charter

John Olsen led a brief discussion of the draft charter for the Schedule 1A Task Force. There were no proposed changes to the charter as presented in the meeting materials. Jim Jacoby made a motion to approve the charter and Jason Mazigian seconded. The charter was unanimously approved without amendment.

Review of FERC Cost Recovery

Dianne Branch provided an overview of the FERC Order 668 memo provided in the materials. It is staff's position that Order 668 does not contemplate the manner in which RTO fees are collected from its customers. Therefore, regardless of the methodology selected for billing Schedule 1-A fees, staff believes the reporting requirements for SPP under Order 668 would remain unchanged from current practices. There was a brief discussion on the potential impacts to respective utilities who are billed Schedule 1-A fees that could result from changes to the Schedule 1-A billing methodology. The task force wants to remain mindful of this issue as it goes thru this process of proposing a new administrative fee structure and that respective regulatory staff should be engaged to ensure any potential issues are identified in a timely manner.

MOPC Background Material

Tom Dunn provided an overview of SPP's current cost recovery mechanism through Schedule 1-A based on a presentation previously provided to the MOPC. In the presentation, Tom walked thru the current process, identifying the issues that are associated with the current methodology, highlighting the direction that SPP staff has proposed in their whitepaper, and the overarching guiding principles staff believes are important in crafting a new methodology. The principles outlined were for a simple rate design, charges based on market transactions, and an annual rate setting process. Tom closed the presentation with an overview of the projected timeline for completing changes to the Schedule 1A fees. The timeline projects an estimated go live date of June 2020.

RTO Cost Recovery

The task force reviewed the meeting materials relative to the cost recovery mechanisms utilized by other RTO/ISOs. There was a general discussion on the varying complexity of the different structures employed by the other RTO/ISOs. The task force generally agreed that the methodology ultimately recommended for SPP should not be overly complicated.

Brain Storming/Structure Development

The task force approached the discussion utilizing the framework provided by FERCs reporting requirement under Order 668. In summary, all operating costs would be evaluated in the "buckets" required to be reported under Order 668 which include 575.7 - Market Facilitation, Monitoring & Compliance, 561.4 - Scheduling, System Control & Dispatch, and 561.8 – Reliability Planning & Standards Development.

General assumptions made during the discussion for the functions included within each category are summarized as follows –

- Scheduling, System Control & Dispatch – Tariff Administration, Scheduling, Reliability Coordination
- Market Facilitation, Monitoring & Compliance – Energy market, Transmission Congestion Rights (TCR), Ancillary Services, Market Monitoring Unit (MMU), virtual transactions
- Reliability Planning & Standards Development – Order 1000, Integrated Transmission Planning (ITP), LOLE/SAWG

There was a general discussion on whether there should be one methodology utilized across all buckets or a varied approach be employed. There was strong support that a mixed approach should be utilized. With respect to those costs include in 561.8 and 561.4, the task force agreed that a billing methodology similar to current schedule 1-A billing would be more appropriate. In summary, billing would be billed to transmission customers based on demand utilizing prior year coincident peak (PY12CP). In the discussion this was termed as "Fixed" billing method.

For the costs that are included in 575.7 (Markets), the task force discussed at length, the various functions that are included in this category and potential approaches for recovering those costs. The discussion was wrapped up with the determination that additional detailed cost analysis would be needed for these various functions before any definitive decisions could be made. Of special interest to the task force members was the cost surrounding the TCR services.

Future Meetings

Friday, August 24th 10-Noon (Teleconference)
Thursday, September 6th 10AM -3PM (Face to Face) – DFW Hyatt Regency
Thursday, October 4th 10-Noon – Teleconference

There being no further business, John Olsen adjourned the meeting at 4PM.

Respectfully Submitted,

Dianne Branch
Secretary

SPP Southwest Power Pool

Memorandum

To: **1A Task Force**

From: **Zeynep Vural/Dianne Branch**

CC: **Tom Dunn**

Date: **August 16, 2018**

Re: **SPP Administrative Fee Breakdown**

Objective

The purpose of this memo is to provide an overview of SPP's process for categorizing the components of its Schedule 1-A administrative fee as required by FERC Order 668. Exhibits detailing the components of each FERC prescribed category are also provided. The process described below is representative of the one followed in preparation of the Order 668 disclosure for the 2018 Schedule 1-A administrative fee. Amounts and percentages utilized in the exhibits were taken directly from the final work papers that support the official Order 668 disclosure as posted on SPP's OASIS site.

Allocation Methodology

FERC Order 668 requires RTOs to provide a breakdown of the allocation of their operating costs into three specific functional categories (Market Facilitation, Monitoring, and Compliance; Scheduling, Systems Control and Dispatch; Reliability Planning and Standards Development). SPP does not utilize a company-wide function-based time tracking system. The breakdown of operating costs into the FERC-required specific accounts is based on the analysis of each department's costs to determine which of the three categories departmental costs should be allocated.

As documented on the following pages, a number of departments are solely dedicated to a specific function. For example, Market Design Department is only involved in market facilitation type of activities or the Engineering Planning Department's sole function is within the Reliability Planning category. The entire cost of such departments is directly assigned to a specific functional category.

Certain departments provide services or staff that are utilized across the three functional categories. For example, Credit Department staff provides services related to SPP customers across all three categories. Costs of such departments are allocated based on estimated percentage weights for each category or number of staff dedicated to a specific function, as applicable.

SPP has a large amount of costs and a number of departments that are considered corporate overhead or corporate support, such as IT, Corporate Services, Legal and Regulatory, and Accounting. To the extent that certain costs or staff from these departments directly benefit any or all of the three functional categories, allocations are calculated based on estimated percentage weights for each category. The remaining corporate support costs are allocated to the three categories based on the total direct costs of each category, as shown on the previous page.

Following are specific allocation methodologies used for a variety of specific cost items that represent significant costs:

Principal and interest on debt: SPP's capital projects are funded through borrowings from financial institutions and/or institutional investors. Annual principal repayments and interest expense on such borrowings are recovered through SPP's admin fee. Such borrowings are generally used to fund a variety of capital projects for different purposes therefore the majority of debt and interest cost is assigned as corporate support which is then allocated to functional categories as explained above. However, SPP did obtain separate borrowing to fund the Integrated Marketplace, the principal and interest for which is shown as a direct charge in the Market Facilitation category.

Maintenance: SPP has significant investments in hardware, software, and equipment that require maintenance contracts. Maintenance expenses for systems and software that are identifiable as being utilized for a specific functional category are directly charged to that category. Remaining maintenance, including all hardware maintenance, is charged to corporate support.

Communications: SPP has a significant and complex communications infrastructure throughout its footprint for data transfer and information exchange related to various services provided to its customers. Each of the functional categories is allocated a portion of total communications expense based on estimated utilization needed for each category.

Exhibit 1 – Summary by Category

Admin Fee Allocation Summary (in $000)					
	2018 Budget	**Allocation**	**Total Budget**	**%**	**Admin Fee**
Market Facilitation	$48,851	$45,956	$94,807	57.8%	24.8¢
Scheduling and Dispatch	$23,602	$22,203	$45,804	27.9%	11.98¢
Planning	$12,052	$11,337	$23,389	14.3%	6.12¢
Corporate Support	$79,496	($79,496)	-	-	-
Total	**$164,001**	**-**	**$164,001**	**100.0%**	**42.9¢**

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Exhibit 2 - Market Facilitation, Monitoring & Compliance (575.7)

575.7 - Market Facilitation, Monitoring & Compliance (in $000)			
	2018 Budget	**%**	**Cost Type**
Markets Department in Operations	$4,012	4.2%	Staffing
Market Monitoring Unit	$3,035	3.2%	Staffing
Dedicated IT resources (22 FTEs - allocation)	$2,737	2.9%	Staffing
Network Communications Infrastructure (allocation)	$2,505	2.6%	IT Infrastructure
Settlements Department Resources (allocation)	$2,260	2.4%	Staffing
Software Maintenance Expenses	$1,919	2.0%	SW Maintenance
Market Support and Analysis Department in Ops Support	$1,772	1.9%	Staffing
Operators (two per desk, total 12 FTEs - allocation)	$1,763	1.9%	Staffing
Customer Relations resources (allocation)	$890	0.9%	Staffing
Market Design Department	$789	0.8%	Staffing
Congestion Hedging Department	$776	0.8%	Staffing
Credit Department resources (allocation)	$599	0.6%	Staffing
Customer Training Resources (allocation)	$391	0.4%	Staffing
OATI Wrap Agreement Charges (allocation)	$379	0.4%	Services
SOC 1 Controls Audit	$362	0.4%	Services
Debt and Interest	$24,661	26.0%	Debt and Interest
Corporate Support Allocation	$45,956	48.5%	Overhead Allocation
Total	**$94,807**	**100.0%**	

Exhibit 3 – Scheduling, Systems Control, & Dispatch (561.4)

561.4 - Scheduling, Sys Control & Dispatch (in $000)				
	2018 Budget	%	Cost Type	
Systems Operations Department	$9,931	21.7%	Staffing	
Operations Support Department	$4,663	10.2%	Staffing	
Dedicated IT resources (18 FTEs - allocation)	$2,142	4.7%	Staffing	
Software Maintenance Expenses	$1,436	3.1%	SW Maintenance	
OATI Wrap Agreement Charges (allocation)	$1,136	2.5%	Services	
Wind forecasting services and IDC Fee	$1,055	2.3%	Services	(a)
Outside Services related to IT/CIP Security	$1,040	2.3%	Services	
Ops Analysis & Performance Support Department	$992	2.2%	Staffing	
Network Communications Infrastructure (allocation)	$582	1.3%	IT Infrastructure	
Interregional Affairs Department	$515	1.1%	Staffing	
Customer Relations resources (allocation)	$111	0.2%	Staffing	
Corporate Support Allocation	$22,203	48.5%	Overhead Allocation	
Total	**$45,804**	**100.0%**		

(a) Interchange Distribution Calculator, a secure information management system, operated by OATI in the Eastern Interconnection.

Exhibit 4 – Reliability Planning and Standards Development (561.8)

561.8 - Reliability Planning & Standards Dev (in $000)				
	2018 Budget	%	Cost Type	
Engineering Planning Department	$5,235	22.4%	Staffing	
Engineering R&D and Tariff Services Department	$5,227	22.3%	Staffing	
Engineering Support Department	$2,435	10.4%	Staffing	
Network Communications Infrastructure (allocation)	$582	2.5%	IT Infrastructure	
Interregional Relations Department	$518	2.2%	Staffing	
Software Maintenance Expenses	$453	1.9%	SW Maintenance	
Regional State Committee	$381	1.6%	Services	
Dedicated IT resources (2 FTEs - allocation)	$238	1.0%	Staffing	
Customer Relations resources (allocation)	$111	0.5%	Staffing	
Credit Department resources (allocation)	$67	0.3%	Staffing	
Corporate Support Allocation	$11,337	48.5%	Overhead Allocation	
Less: Engineering Studies Revenues	($3,194)	-13.7%	Revenue	(a)
Total	**$23,389**	**100.0%**		

(a) Billable staff time and pass-thru charges associated with engineering planning studies, such as generator interconnection or transmission service request studies.

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Exhibit 5 – Corporate Support

Corporate Support (in $000)				
	2018 Budget	**%**	**Cost Type**	
Information Technology Department	$31,409	39.5%	Staffing, IT Infrastructure, Services, Maintenance	
Officers Department	$9,216	11.6%	Staffing and Services	
Administration Department	$8,285	10.4%	Retirement Benefits	
Corporate Services Department	$8,060	10.1%	Staffing, Services, Maintenance	
Legal, Regulatory, and Market Policy Departments	$6,394	8.0%	Staffing and Services	
Compliance Department	$2,843	3.6%	Staffing	
Project Management Office	$1,953	2.5%	Staffing	
Accounting Department	$1,578	2.0%	Staffing	
Customer Training Department	$1,381	1.7%	Staffing	
Internal Audit Department	$871	1.1%	Staffing	
Network Communications Infrastructure (allocation)	$805	1.0%	IT Infrastructure	
Settlements Department	$597	0.8%	Staffing	
Communications Department	$573	0.7%	Staffing	
Government Affairs Department	$331	0.4%	Staffing	
Credit Department	$102	0.1%	Staffing	
Customer Service Department	$21	0.0%	Staffing	
Debt and Interest	$7,903	9.9%	Debt and Interest	
Less: Revenues other than Admin Fees	($2,824)	-3.6%	Revenue	(a)
Total	**$79,496**	**100.0%**		

(a) Revenues other than SPP's annual admin fee and engineering studies (shown as a direct reduction of costs allocated to the Reliability Planning category), such as annual member fees and contract services revenues.

TCR
Cost Overview

August 24, 2018

1A Task Force Teleconference

Transmission Congestion Right (TCR) Estimated Cost of Services

(in $0,000s)

Staff Expense			
Dedicated Staff w/i Engineering Dept	$	810	(includes 1 manager and 5 staff)
IT Staff Support		280	(estimated at 2 FTEs)
Total Staff Expense		**1,090**	
Maintenance Expense			
Annual Maintenance on I-Hedge System		730	(Nexant)
Annual Maintenance on TCR Transfer Tool		15	(GE/Alstom)
Total Maintenance Expense		**745**	
Estimated Annual Operating Cost for TCR Services		**1,835**	
Approximate Cost of Annual Debt Service		450	
(Based on Original Asset plus Major Enhancements)			
Projected Total Annual Cost of TCR Services	**$**	**2,285**	

SPP

RTO/ISO Order 668 Fee Allocation

August 24, 2018

1A Task Force Teleconference

PJM Fee Breakout

Rate Schedule	Description	Billing Metric	MARKET Account 575.7	SCHEDULING Account 561.4	RELIABILITY Account 561.8	2018 Stated rate
9-1	Control Area Admin on Service	per MWh	0%	89%	11%	0.2100
9-2	FTR Service Rate Component 1	per FTR MWh	99%	0%	1%	0.0028
9-2	FTR Service Rate Component 2	per FTR bid hour	99%	0%	1%	0.0019
9-3	Market Support Svc Rate Component 1	per MWh	99%	0%	1%	0.0463
9-3	Market Support Svc Rate Component 2	per bid/offer segment	99%	0%	1%	0.0693
9-4	Regulation & Frequency Response Admin Svc	per MWh	0%	96%	4%	0.2819
9-5	Capacity Resource & Obligation Mgmt Svc	per MW Day	97%	0%	3%	0.1073

PJM Service Fee Structure and Rates

Schedule	Market Participants	Rates - Monthly
Schedule 9 -1 Control Area Administration Service Comprises all the activities of PJM associated with preserving the reliability of the PJM region and administering Point-to –Point Transmission Service and Network Integration Transmission Service. Fee applies to users of the Control Area Administrative Service	• Electric Utilities • Regional Transmission Owners • Power Marketers • Federal power marketing agencies • Entities generating electricity for resale • Retail customers taking unbundled transmission service	***Commencing January 1, 2017*** $0.2100 per MWh of energy delivered by each of user during the month(including losses) ***Commencing January 1, 2019*** $0.2153 per MWh of energy delivered by each of user during the month(including losses) ***Commencing January 1, 2020*** $0.2207 per MWh of energy delivered by each of user during the month(including losses)
Schedule 9 -2 Financial Transmission Rights Administration Service Includes all activities of PJM associated with administering FTRs including; bilateral trading, administration of FTR auctions, support of PJM's on line internet based FTR tool, and analyses to determine what total combination of FTRs can be outstanding and accommodated by the PJM system at a give time. The service applies to entities that hold FTRs or that submit offers to sell or bids to by FTRs	• Same as above	***Commencing January 1, 2017*** ($0.0028 per MWh of holding FTR by each user) + ($0.00019 per hour*) ***Commencing January 1, 2019*** ($0.0029 per MWh of holding FTR by each user) + ($0.00019 per hour*) ***Commencing January 1, 2020*** ($0.0029 per MWh of holding FTR by each user) + ($0.00020 per hour*) *(# of hours in all bids to buy FTR Obligations submitted by each user during the month) + (5 x # of hours in all bids to buy FTW Options submitted by each user during the month) This applies to the Annual and Monthly Auctions

PJM Service Fee Structure and Rates

Schedule	Market Participants	Rates - Monthly
Schedule 9 -3 Market Support Service Comprises all the activities of PJM associated with supporting the operation of the PJM Interchange Energy Market and related functions including: market modeling and scheduling functions, locational marginal pricing support and support of PJM's Internet-based customer transaction tool. This service applies to customers using Point-to-Point or Network Integration Transmission Service to Generation Providers, and to entities that submit offers to sell or bids to buy energy in the PJM Interchange Energy Market.	• Electric Utilities • Regional Transmission Owners • Power Marketers • Federal power marketing agencies • Entities generating electricity for resale • Retail customers taking unbundled transmission service	***Commencing January 1, 2017*** ($0.0463 per MWh*) + ($0.0693 per Bid/Offer Segment) ***Commencing January 1, 2019*** ($0.0475 per MWh*) + ($0.0710 per Bid/Offer Segment) ***Commencing January 1, 2020*** ($0.0487 per MWh*) + ($0.0728 per Bid/Offer Segment) * [MWh = Total quantity in MWhs of energy delivered to load (including losses and net of operating Behind the Meter Generation, but not to be less than zero) in the PJM region or for export from such region during the month by each user as a customer under Point-to-Point transmission Service(other than Wheeling-Through Service) or NIT + Total]
Schedule 9 -4 Regulation and Frequency Response Administration Service This service is used to ensure continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at 60Hz. PJM provides this service to Load Serving Entities and to generators that provide such regulation.	• Same as above	***Commencing January 1, 2017*** $0.2819 per MWh* ***Commencing January 1, 2019*** $0.2889 per MWh* ***Commencing January 1, 2020*** $0.2961 per MWh* * MWh = (MWh of each user's hourly regulation objective as a Load Serving Entity) + (MWhs of regulation scheduled, including self-scheduling, from generating units owned by such user)

SPP

PJM Service Fee Structure and Rates

Schedule	Market Participants	Rates - Monthly
Schedule 9 -5 Capacity Resource and Obligation Management Service Comprises the activities of PJM associated with (a) assuring that customers have arranged for sufficient generating capacity to meet their unforced capacity obligations under the Reliability Assurance Agreement ("RAA"); (b) processing Network Integration Transmission Service; (c) administering the Reliability Pricing Model auctions for the PJM Region; and (d) administering or providing technical support for the RAA (as delegated to PJM under the RAA), including, but not limited to, long-term load forecasting, studies to establish reserve requirements, and the determination of each Load-Serving Entity's capacity obligations. PJM provides this service to Load-Serving Entities and to owners of Capacity Resources.	• Electric Utilities • Regional Transmission Owners • Power Marketers • Federal power marketing agencies • Entities generating electricity for resale • Retail customers taking unbundled transmission service	***Commencing January 1, 2017*** $0.1073 per MW -day ***Commencing January 1, 2019*** $0.1100 per MW –day ***Commencing January 1, 2020*** $0.1128 per MW –day In addition to this charge, PJM will charge each month, each entity that included in an FRR Capacity Plan, self-scheduled, or sold and cleared, in a Reliability Pricing Model Auction, a Capacity Resource committed to serve load for such month, a charge equal to the Capacity Resource and Obligation Management Service Rate state above time such entity's total share, in MWs, of the Unforced Capacity of all Capacity Resources cleared or self-scheduled (including through an FRR Capacity plan) by such entity, for commitment to service load during such month.

SPP

ISO-New England Breakout

Rate Schedule	Description	Billing Metric	MARKET Account 575.7	SCHEDULING Account 561.4	RELIABILITY Account 561.8	2018 Stated rate
1	**Scheduling, System Control & Dispatch**					
	Regional Network Service	kW-month	0%	100%	0%	$ 0.17886
	Through and Out Service	kWh	0%	100%	0%	$ 0.00025
2	**Energy Administration Service**	multi (see detail)	100%	0%	0%	multi (see detail)
3	**Reliability Administration Service**					
	Mkt Participant Real Time Non-CP Load	kW-month	65%	0%	35%	$ 0.22461
	Mkt Participant Export	MWh	65%	0%	35%	$ 0.48
	Non-Mkt Participant Through and Out	Reservation-hr	65%	0%	35%	$ 3.50

SPP

ISO – NE Service Fee Structure and Rates

Schedule	Market Participants	Rates - Monthly
Schedule 1 - Scheduling, System Control, and Dispatch Service required to schedule at the regional level the movement of power through, out of, within, or into the New England Control Area. • For regional transmission service, Scheduling Service is an Ancillary Service that can be provided only by the ISO. • All Transmission Customers must be Customers for Scheduling Service and purchase this Service from the ISO	• Generators • Transmission owners • Suppliers • Municipal utilities • Alternative resources • End-user customers	***Regional Network Service Customer*** ($0.19093 per kilowatt month)x (its regional Monthly Network Load for that month). ***Transmission Customer receiving Through or Out Service*** [Transmission Customer's highest amount of Reserved Capacity (expressed in kilowatts) for an hour for each transaction scheduled to occur during the month as Through or Out Service] x ($0.00026 per kilowatt for each hour of service).
Schedule 2 – Energy Administration Service Service provided by ISO to administer the Energy Market. Each MP that has an account for Energy that is settled by the ISO for the current month shall pay each month an amount based on Energy Transaction Units (TUs), Increment Offers, Decrement Bids, Volumetric Measures, submitted FTR Auction Bids, and cleared FTR auction bids.	• Generators • Transmission owners • Suppliers • Municipal utilities • Alternative resources • End-user customers	***Transaction Units (Virtual Inc/Dec Bids)*** Submitted Energy Offers/Bids - .$0.00500 per Offer or Bid Cleared Energy Offers/Bids - $0.6000 per Offer or Bid ***Financial Transmission Rights*** Submitted FTRs - $2.48240 per Bid Cleared FTRs- $3.04690 per Bid ***Energy Transaction Units*** Block 1 – 1st 12,500 $0.70795 per TU Block 2 – Next 27,000 $0.64360 per TU Block 3 – Over 39,500 $0.57924 per TU ***Volumetric Measures*** Block 1 – 1st 250,000 $0.31610 per MW- hour Block 2 – Next 1,250,000 $0.28736 per MW - hour Block 3 – Over 1,500,000 $0.25862 per MW- hour

SPP

ISO – NE Service Fee Structure and Rates

Schedule	Market Participants	Rates - Monthly
Schedule 3 -Reliability Administration Service Service provided to administer Reliability Markets and associated transactions along with providing other reliability and information services. This applies to: • Each TC taking Through and Out Service that is NOT a MP • Each customer that is a MP	• Generators • Transmission owners • Suppliers • Municipal utilities • Alternative resources • End-user customers	***Market Participant Rates*** ***Real Time Non-Coincident Peak Load Obligation*** - $0.21884 per kW – month **Export MWH** - $0.45 per MW – hour ***Non-Participant Through or Out Transmission Service Rates*** Hourly Service - $3.34 per kW – hour

CAISO Breakout

Rate Schedule	Description	Billing Units	MARKET Account 575.7	SCHEDULING Account 561.4	RELIABILITY Account 561.8	2018 Stated rate	
11.22	**Grid Management Fee**						
	Market Services Charge	MWh	53%	38%	9%	$	0.1100
	Systems Operations Charge	MWh	20%	56%	24%	$	0.2964
	Congestion Revenue Rights (CRR) Svc Charge	MWh	100%	0%	0%	$	0.0038
	Bid Segment Fee	per bid segment	53%	38%	9%	$	0.0050
	Inter Scheduling Coordinator Trade Fee	per Inter SC Trade	53%	38%	9%	$	1.0000
	Scheduling Coordinator ID Monthly Fee	per month	53%	38%	9%	$	1,000
	Transmission Ownership Rights (TOR)Charge	min of supply or demand TOR Mwh	20%	56%	24%	$	0.2400
	Congestion Revenue Rights (CRR) Bid Fee	number of nominations and bids	100%	0%	0%	$	1.0000
29.11(i)(1)	**Energy Imbalance Market Admin Charge**						
	EIM Market Services Charge	MWh	100%	0%	0%	$	0.0869
	EIM Systems Operations Charge	MWh	100%	0%	0%	$	0.1156

SPP

CAISO Service Fee Structure and Rates

Schedule	Market Participants	Rates - Monthly
Section 11.22 – Grid Management Charge Recovers the costs for 1) CAISO Operating Costs, 2) CAISO Other Costs and Revenues, 3) CAISO Financing Costs, 4) CAISO Operating Cost Reserve adjustment and 5) CAISO Cash-Funded Capital and Project Costs through the use of three service categories: Market Services Charge, System Operations Charge and CRR Service Charge.	• Scheduling Coordinators	The Market Services Charge applies to MWh and MW of awarded supply and demand in the ISO market. The Systems Operations Charge applies to MWh of metered supply and demand in the ISO controlled grid. The CRR Service Charge applies to MWh of congestion. Five fees make up the service charges above: 1) Transmission Ownership Rights (TOR) Charge is assessed at $0.24/MWh on the minimum of a Scheduling Coordinator's TOR supply or TOR demand per Settlement Interval. 2) Bid Segment Fee – each Scheduling Coordinator submitting a Bid will be assessed a fee of $0.005 per segment of the Bid. 3) CRR Transaction Fee – each Scheduling Coordinator submitting a CRR Allocation nomination or CRR Auction bid will be subject to a fee of $1.00 per submitted nomination or bid.

CAISO Service Fee Structure and Rates

Schedule	Market Participants	Rates - Monthly
Section 11.22 – Grid Management Charge (Continued)		4) Inter-Scheduling Coordinator Trade Transaction Fee – each Scheduling Coordinator submitting an Inter-Scheduling Coordinator Trade will be subject to a fee of $1.00 per party per trade. 5) Scheduling Coordinator ID Charge – equals $1,000 per month per Scheduling Coordinator ID Code for any trading month in which the Scheduling Coordinator has market activity.
Section 29.11(i)(1) – EIM Administrative Charge The EIM Administrative Charge consists of an EIM Market Services Charge and an EIM System Operations Charge.	• EIM Transmission Service Provider	The EIM Market Services Charge shall be the product of the Market Services Charge for each Scheduling Coordinator and the sum of Gross FMM Instructed Imbalance Energy (excluding FMM Manual Dispatch Energy) and Gross RTD Instructed Imbalance Energy (excluding RTD Manual Dispatch Energy Standard Ramping Deviation, Ramping Energy Deviation, Residual Imbalance Energy, and Operational Adjustments). The EIM System Operations Charge shall be the product of the System Operations Charge for each Scheduling Coordinator and the absolute difference between metered energy and the EIM Base Schedules.

CAISO Service Fee Structure and Rates

Schedule	Market Participants	Rates - Monthly
Section 29.11(i)(1) – EIM Administrative Charge (Continued)		The CAISO will calculate a minimum EIM Administrative Charge as the product of the sum of the EIM Market Service Charge and the EIM System Operations Charge and (A) 5%of the total gross absolute value of Supply of all EIM Market Participants; plus (B) 5% of the total gross absolute value of Demand of all EIM Market Participants.

NYISO Breakout

Rate Schedule	Description	Billing Metric	MARKET Account 575.7	SCHEDULING Account 561.4	RELIABILITY Account 561.8	2017 Stated Rate
6.1.2	Withdrawals	per MWh	58.941%	31.824%	9.24%	0.67392
6.1.2	Injections	per MWh	58.941%	31.824%	9.24%	0.26208
					Tariff Rate	$ 0.9360 per MWh

NOTE: The only breakout available was for the annual budget charge for transmission customers participating in physical market activity. Per the following pages, there are details to support the billing of customers for virtual transactions and transmission congestion contracts.

Based on the original document providing the above breakout information, it was noted that recoveries from virtual transactions and transmission congestion contracts are refunded to withdrawal and injections on a 72/28 basis.

New York Service Fee Structure and Rates

Schedule	Market Participants	Rates – Monthly
6.1.2 - ISO Annual Budget Charge The ISO shall charge, and each Transmission Customer shall pay, a charge for the ISO's recovery of its annual budgeted costs. The ISO shall calculate the charge for the recovery of these ISO annual budgeted costs from each Transmission Customer on the basis of its participation in physical market activity. The ISO shall calculate this charge for each Transmission Customer on the basis of its participation in non-physical market activity, the Special Case Resource program, and the Emergency Demand Response program.	Transmission Customers • Wholesale • Retail • Power Marketer • Electric Utility • Federal Power Marketing Agency • Electric Generators	**6.1.2.2 Calculation of the ISO Annual Budget Charge for Transmission Customers Participating in Physical Market Activity** ISO Annual Budget Charge$_{c,P}$ = (InjectionUnits$_{c,P}$ * (0.28 * ISOCosts$_{Annual}$ / TotalEstWithdrawalUnits$_{Annual}$)) + (Withdrawalunits$_{c,P}$ * (0.72 * ISOCosts$_{Annual}$ / TotalEstWithdrawalUnits$_{Annual}$)) c = Transmission Customer P = The relevant Billing Period ISOCosts$_{Annual}$ = sum of the ISO's annual budgeted costs for the current calendar year InjectionUnits$_{c,P}$ = Injection Billing Units, in MWh, for c in P Withdrawalunits$_{c,P}$ = Withdrawal Billing Units, in MWh, for c in P TotalEstWithdrawalUnits$_{Annual}$ = sum, in MWh, of estimated Withdrawal Billing Units for all Transmission Customers in the current calendar year as determined by the ISO in the summer prior to the current calendar year

New York Service Fee Structure and Rates

Schedule	Market Participants	Rates – Monthly
6.1.2 - ISO Annual Budget Charge (Continued)		**6.1.2.4.1 Charge for Transmission Customers Engaging in Virtual Transactions** $VT\ Charge_{c,P} = VT\ Rate * VT\ Cleared_{c,P}$ VTRate = rate set in Section 6.1.2.4.4 $VT\ Cleared_{c,P}$ = total cleared Virtual Transactions, in MWh, for c in P **6.1.2.4.2 Charge for Transmission Customers Purchasing Transmission Congestion Contracts** $TCCCharge_{c,P} = TCCRate * TCCSettled_{c,P}$ TCCRate = rate set in Section 6.1.2.4.4 $TCCSettled_{c,P}$ = total settled Transmission Congestion Contracts, excluding Transmission Congestion Contracts created prior to January 1, 2010, in MWh, for c in P

Midwest ISO Breakout

Not available at this time.
Efforts to obtain are ongoing.

ERCOT Breakout

Not applicable given they are not under FERC's jurisdiction