Southwest Power Pool

SCHEDULE 1A TASK FORCE MEETING

October 4, 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
Chris Lyons	Customized Energy Solutions
David Erkin	AEP
Jessica Meyer	Lincoln Electric System
Kevin Galke	The Energy Authority for City Utilities of Springfield
Carl Monroe	SPP
Mike Riley	SPP
Scott Smith	SPP
Lee Elliott	SPP
Patti Kelly	SPP
Brent Wilcox	SPP
Steve Davis	SPP
David Daniels	SPP
Dianne Branch	SPP

Minutes from the September 6, 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.

Update on Action Items from 9/6/18 Meeting

1. **Action Item** – With respect to the discussion on the Generation Capacity Analysis, SPP staff was to confirm the following -

   Could the administrative fee be pass through in mitigated offers if generators are assessed a portion of the fee? (to be confirmed with Market Monitor).

   UPDATE: Staff reported that the SPP MMU confirmed the assertion that the administrative fee could be passed through in mitigated offers if generators are assessed a portion of the fee.

2. **Action Item** – With respect to the discussion on the 3 Year Market Transaction Analysis, SPP staff was to confirm the following –

   - How many of the TCRs represent converted ARRs?
   - What is the basis of the ARR and TCR numbers (are both based on hourly/annual)?

   UPDATE: Staff reported that roughly 75% of the TCRs are self- converted from ARRs and that the TCR quantity was an hourly MWh quantity while the ARR quantity was a daily MWh quantity. This information was confirmed directly with the SPP TCR department.

3. **Action Item** – SPP staff to research the filings that other RTO/ISOs have made when proposing changes to their rate structure to understand the level of justification that is typically required in these matters.

   UPDATE: Mike Riley presented an overview of other RTO/ISOs with respect to the initial filings for setting their administrative fee. For each RTO/ISO filing presented, Mike summarized the proposal and the underlying basis supporting the rate proposal. Mike highlighted the following common themes across the proposals:

   - Most of these filings came at the same time or soon after the entities were approved by FERC to operate as an RTO/ISO.
   - Many of the filings coincided with the RTO/ISO expanding its services.
   - All RTO/ISO filings were supported by a report or analysis conducted by a consultant or internal RTO/ISO staff, all of whom submitted testimony supporting and describing the methodologies reflected in the reports.
   - Some RTO/ISO filings included requests for a phase-in period by which the RTO/ISO would apply the new rate design for a specified period of time.

4. **Action Item** - SPP staff to prepare several different strawman scenarios representing alternative rate structures based on the FERC expense categories (market, planning, scheduling).

   UPDATE: Scenarios prepared by staff and included in meeting materials were the basis of discussion for the next agenda item.

Fee Structure Development

Staff presented four distinct scenarios for potential administrative fee allocations. The assumptions are summarized below:

Scenario #1

- Two recovery methods for Net Revenue Requirement
- Market Facilitation to be recovered through Marketplace injections and withdrawals (Real-time generation/load, imports/exports)
- Scheduling, Control & Dispatch and Reliability Planning to be recovered through current transmission demand methodology (12CP billing determinants)

Scenario #2a

- Two recovery methods for Net Revenue Requirement
- Market Facilitation to be recovered through Marketplace injections and withdrawals (Real-time generation/load, imports/exports)
- Reliability Planning to be recovered through current transmission demand methodology (12CP billing determinants)
- Scheduling, Control & Dispatch to be allocated prorata and recovered through energy and demand

Scenario #2b

- Two recovery methods for Net Revenue Requirement
- Market Facilitation to be recovered through Marketplace injections and withdrawals (Real-time generation/load, imports/exports)
- Reliability Planning to be recovered through current transmission demand methodology (12CP billing determinants)
- Scheduling, Control & Dispatch to be allocated prorata and recovered through energy and demand
    - Energy component allocated to generation and imports/exports only (i.e. no allocation to load)

Scenario #3

- Two recovery methods for Net Revenue Requirement
- Market Facilitation to be recovered through Marketplace injections and withdrawals (Real-time generation/load, imports/exports), plus non-physical transactions (Transmission Congestion Rights, Virtual Energy)
- Scheduling, Control & Dispatch and Reliability Planning to be recovered through current demand methodology (12CP Billing Determinants)

Discussion of these scenarios centered on the following topics:

- Billing determinants to be utilized for any type of energy allocation
    - Need to better understand "what's in/what's out" in each of the scenarios, specifically for the denominator
    - Issue of how losses would be treated in an energy based allocation methodology
- Cost categories need to be reviewed again in the context of how to allocate between energy and demand.
- Substantial analysis will be needed to support allocation assumptions for any proposed change in methodology. Of particular concern is scheduling and dispatch costs given there is support to potentially split costs between a demand and energy based allocation.
- Need to better understand the incremental cost associated with the estimated 25% of TCRs that are not converted ARRs.
- There is a desire to review other RTO/ISO cost recovery methods for non-physical transactions (TCRs, virtuals, etc.) in order to assess reasonableness for any proposed methodology.

- **Action Item** – In preparation of the 10/15 meeting in Little Rock, SPP staff to prepare analysis to facilitate further discussion of the fee structure development with special attention to addressing the areas of concern noted in the previous discussion points.

Future Meetings

Monday, October 15th 1PM -6PM (Face to Face) – Little Rock
Friday, November 9th 10-Noon – Teleconference
Tuesday, November 27th 8AM-3PM – Dallas, TX AEP
Tuesday, December 18th 1-4PM - Teleconference

There being no further business, John Olsen adjourned the meeting at 12:05 PM.

Respectfully Submitted,

Dianne Branch
Secretary

Southwest Power Pool, Inc.

SCHEDULE 1A TASK FORCE MEETING

October 4, 2018

Teleconference

• AGENDA •

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. Update on Action Items from 9/6 Meeting (20 minutes).....................................Dianne Branch/Various
   a. Confirm MMU position on admin fee inclusion in mitigated offers
   b. Clarify TCR/ARR data –
      i. TCRs representing converted ARRs
      ii. Basis of ARR/TCR data
   c. Research RTO/ISO filings for rate structure changes
   d. Prepare various strawman scenarios for alternative rate structures
3. Fee Structure Development (80 minutes)…………………………………………………..John Olsen
4. Closing Items (10 minutes)…………………………………………… ……………………Dianne Branch
   a. Summary of Action Items
   b. Future meetings

Antitrust: SPP strictly prohibits use of participation in SPP activities as a forum for engaging in practices or communications that violate the antitrust laws. Please avoid discussion of topics or behavior that would result in anti-competitive behavior, including but not limited to, agreements between or among competitors regarding prices, bid and offer practices, availability of service, product design, terms of sale, division of markets, allocation of customers or any other activity that might unreasonably restrain competition.

Southwest Power Pool

SCHEDULE 1A TASK FORCE MEETING

September 6, 2018

DFW Hyatt Regency – Dallas, Texas

• 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
John Varnell	Tenaska
Ray Bergmeier	Sunflower Electric
Robert Tallman	OG&E
Rob Janssen	Dogwood Energy
Wes Berger	SPS/Xcel Energy
Greg Garst	OPPD
Joel Dagerman	NPPD
David Erkin	AEP
Carl Monroe	SPP
Mike Riley	SPP
Dianne Branch	SPP

Those participating by phone were as follows:

Heather Starnes	Missouri Joint Municipal Electric Utility Commission
Chris Lyons	Customized Energy Solutions
Jill Jones	MEAN
Aaron Pupa	LS Power
Brent Wilcox	SPP
Steve Davis	SPP
Scott Smith	SPP
Patti Kelly	SPP

Minutes from the August 24, 2018 meeting were reviewed. Jason Mazigian motioned to approve the minutes. The motion was seconded by Joel Dagerman. The minutes were unanimously approved by voice vote.

The following proxies were in effect for the meeting – Rob Janssen for Tim Hall and David Erkin for Jim Jacoby (see attachments).

Review of Analysis Requested from 8/24 Teleconference

- *Discussion on Schedule 1A Billing Overview*

  Dianne Branch provided an overview of the three components of the Schedule 1A fees as billed today. There was a moderate amount of discussion and questions on the grandfathered agreements, monthly assessments (specifically the origins of this billing component), etc. that were addressed by SPP staff.

- *Discussion on Generation Capacity Analysis*

  Scott Smith provided an overview of the underlying analysis performed in preparing the graphs presented in the materials and fielded general questions from the task force.

  Action Item – SPP staff to confirm the following -
    - o Could the administrative fee be pass through in mitigated offers if generators are assessed a portion of the fee? (to be confirmed with Market Monitor)

- *Discussion on 3 Year Market Transaction Analysis*

  Dianne Branch presented the schedule summarizing billable units by various components of market services. There was a moderate amount of discussion on the various elements included in this analysis with particular emphasis on the TCRs and ARRs. There was concern raised that any allocations based on energy flow could create the potential for overlaps/duplications of billing units.

  Action Item – SPP staff to confirm the following –
    - o How many of the TCRs represent converted ARRs?
    - o What is the basis of the ARR and TCR numbers (are both based on hourly/annual)?

Fee Structure Development

The remainder of the meeting was spent contemplating various alternatives to allocate the costs as reported in the three FERC categories -

- Scheduling, System Control & Dispatch
- Market Facilitation, Monitoring & Compliance
- Reliability Planning & Standards Development

There was a fair amount of time spent reviewing the components for each of the categories and discussing the methodologies utilized by other RTO/ISOs. Schedules/analysis from previous meetings served as the reference point for much of this discussion.

In contemplating potential structures, members voiced their concern about making this either overly complicated or too simplistic. An overly complicated methodology could result in incremental costs to implement and maintain. At the same time, a simplistic method might be difficult to justify in our FERC filing.

Rob Janssen shared information obtained from the NYISO outlining the process they went thru to restructure their rates, which included the engagement of an external consultant to perform an extensive review of their operating costs, which consisted mainly of assigning all costs as being attributable to load, supply, or non-physical transactions. There was general agreement that the structure ultimately proposed by the task force would have to be thoroughly supported by analysis when submitted to FERC for approval.

Action Item – SPP staff to research the filings that other RTO/ISOs have made when proposing changes to their rate structure to understand the level of justification that is typically required in these matters.

There was discussion on what billing units would be utilized in the denominator for those costs that would potentially be allocated based on energy flow. There was general agreement about the inclusion of generation, load, import/exports, and pseudo ties. Concern about the potential for duplicating charges arose when other determinants were added to the conversation (TCRs, ARRs, virtuals).

Before the meeting closed there was an informal poll taken to assess the level of support for a methodology that would propose market costs be allocated based on energy flow and planning & scheduling costs be allocated based on demand. The results of the informal poll were 9-2-2 (yes-no-abstain).

> **Action Item** – SPP staff to prepare several different strawman scenarios representing alternative rate structures based on the FERC expense categories (market, planning, scheduling).

Future Meetings

Thursday, October 4th 10-Noon – Teleconference
Monday, October 15th 1PM -6PM (Face to Face) – Little Rock

There being no further business, John Olsen adjourned the meeting at 3PM.

Respectfully Submitted,

Dianne Branch
Secretary


SPP Southwest Power Pool
HELPING OUR MEMBERS WORK TOGETHER
TO KEEP THE LIGHTS ON... TODAY AND IN THE FUTURE.

Potential Scenarios for Net Revenue Requirement Allocation

The Goal

- An appropriate methodology to allocate SPP's Net Revenue Requirements to users of SPP's services
- Metrics to consider:

NRR by FERC Account Type

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¢**

	MWhs (in millions)			
Service Category	**2015**	**2016**	**2017**	**MWh Based on**
Real Time Generation	237	261	260	Total for all submitted generation meter MWh data for RT Markets.
Real Time Load	232	252	250	Total for all submitted load meter MWh data for RT Markets.
Transmission Congestion Rights	458	453	547	Total for all TCR instruments MWhs held by an Asset Owner.
Auction Revenue Rights	18	16	14	Total for all ARR instruments MWhs held by Asset Owner
Real Time Imports/Exports Only	16	17	18	Total for all Cleared Import/Export Tags MWhs for RT Markets
Virtual Energy Speculation	17	24	35	Total for all Cleared Virtual Offer/Bids MWhs for DA Markets
Bilateral Settlement Schedule Transactions	68	99	101	Total MWhs for all DA and RT Bilateral Settlement Schedules for the Seller and
Operating Reserves (Reg up, down, spinning and supplemental)	18	19	19	Total MWhs of Cleared activity in RT Markets
Pseudo-Tie	4	6	6	Total MWhs for a Pseudo-tied Out Load or Generation within the RT Markets
Total MWh Billable Units	**1,068**	**1,146**	**1,250**	

Possible Marketplace Billing Determinants

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Scenario #1

- Two recovery methods for Net Revenue Requirement
- Market Facilitation to be recovered through Marketplace injections and withdrawals (Real-time generation/load, imports/exports)
- Scheduling, Control & Dispatch and Reliability Planning to be recovered through current transmission demand methodology (12CP billing determinants)

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Scenario #1

- Energy Rate:

A	Market Facilitation	$94.8	MM
	Real Time Generation	260	TWh
	Real Time Load	250	TWh
	Real Time Import/Export	18	TWh
B	Total Real Time Energy	528	TWh
A/B	Real Time Energy Rate	$0.18	/ MWh

- Transmission Demand Rate:

	Scheduling & Dispatch	$45.8	MM
	Planning	$23.4	MM
C	Sched & Planning Costs	$69.2	MM
D	12CP Billing Determinants	382	TWh
C/D	Transmission Demand Rate	$0.18	/ MWh

SPP

Scenario #2a

- Two recovery methods for Net Revenue Requirement
- Market Facilitation to be recovered through Marketplace injections and withdrawals (Real-time generation/load, imports/exports)
- Reliability Planning to be recovered through current transmission demand methodology (12CP billing determinants)
- Scheduling, Control & Dispatch to be allocated prorata and recovered through energy and demand

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Scenario #2a

Scheduling Allocation	%
$22.9	50%
$22.9	50%
$45.8	100%

- Energy Rate:

	Market Facilitation	$94.8	MM
	Scheduling Allocation	$22.9	MM
A	Cost Recovered thru Energy	$117.7	MM
	Real Time Generation	260	TWh
	Real Time Load	250	TWh
	Real Time Import/Export	18	TWh
B	Total Real Time Energy	528	TWh
A/B	Real Time Energy Rate	$0.22	/ MWh

- Transmission Demand Rate:

	Planning	$23.4	MM
	Scheduling Allocation	$22.9	MM
C	Sched & Planning Costs	$46.3	MM
D	12CP Billing Determinants	382	TWh
C/D	Transmission Demand Rate	$0.12	/ MWh

Scenario #2b

- Two recovery methods for Net Revenue Requirement
- Market Facilitation to be recovered through Marketplace injections and withdrawals (Real-time generation/load, imports/exports)
- Reliability Planning to be recovered through current transmission demand methodology (12CP)
- Scheduling, Control & Dispatch to be allocated prorata and recovered through energy and demand
  - Energy component allocated to generation and imports/exports only (i.e. no allocation to load)

Scenario #2b

Scheduling Allocation	%
$22.9	50%
$22.9	50%
$45.8	100%

- Energy Rate:

		Market Recovery	Scheduling Recovery
	Market Facilitation	$94.8 MM	
	Scheduling Allocation		$22.9 MM
A	Cost Recovered thru Energy	$94.8 MM	$22.9 MM
	Real Time Generation	260 TWh	260 TWh
	Real Time Load	250 TWh	
	Real Time Import/Export	18 TWh	11 TWh *
B	Total Real Time Energy	528 TWh	271 TWh
A/B	Real Time Energy Rate	$0.18 / MWh	$0.08 / MWh

** Assumes 60% Exported Energy*

- Transmission Demand Rate:

		Planning Recovery	Scheduling Recovery
	Planning	$23.4 MM	
	Scheduling Allocation		$22.9 MM
C	Sched & Planning Costs	$23.4 MM	$22.9 MM
D	12CP Billing Determinants	382 TWh	382 TWh
C/D	Transmission Demand Rate	$0.06 / MWh	$0.06 / MWh

Scenario #3

- Two recovery methods for Net Revenue Requirement
- Market Facilitation to be recovered through Marketplace injections and withdrawals (Real-time generation/load, imports/exports), plus non physical transactions (Transmission Congestion Rights, Virtual Energy)
- Scheduling, Control & Dispatch and Reliability Planning to be recovered through current demand methodology (12CP Billing Determinants)

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Scenario #3

- Energy Rate:

A	Market Facilitation	$94.8	MM
	Real Time Generation	260	TWh
	Real Time Load	250	TWh
	Real Time Import/Export	18	TWh
	Trans Congestion Rights	547	TWh
	Virtual Energy	35	TWh
B	Total Real Time Energy	1,110	TWh
A/B	Real Time Energy Rate	$0.09	/ MWh

- Transmission Demand Rate:

	Scheduling & Dispatch	$45.8	MM
	Planning	$23.4	MM
C	Sched & Planning Costs	$69.2	MM
D	12CP Billing Determinants	382	TWh
C/D	Transmission Demand Rate	$0.18	/ MWh

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Rate Impact
Demand to Energy Flow

	Schedule 1A Rate $0.42						
	12 CP	Hours	Total MWH	Demand fee	Load	Avg $/MWH	LF
Jan	2,539	744	1,889,016	$793,387	1,345,504	$0.59	71%
Feb	2,261	672	1,519,392	$638,145	1,074,279	$0.59	71%
Mar	2,108	744	1,568,352	$658,708	1,140,313	$0.58	73%
Apr	2,103	720	1,514,160	$635,947	1,061,020	$0.60	70%
May	2,661	744	1,979,784	$831,509	1,171,389	$0.71	59%
Jun	3,186	720	2,293,920	$963,446	1,431,150	$0.67	62%
Jul	3,475	744	2,585,400	$1,085,868	1,658,016	$0.65	64%
Aug	2,923	744	2,174,712	$913,379	1,433,056	$0.64	66%
Sept	3,070	720	2,210,400	$928,368	1,293,922	$0.72	59%
Oct	2,472	744	1,839,168	$772,451	1,149,817	$0.67	63%
Nov	2,037	720	1,466,640	$615,989	1,119,224	$0.55	76%
Dec	2,555	744	1,900,920	$798,386	1,321,193	$0.60	70%
Totals		8760	22,941,864	$9,635,583	15,198,883	$0.63	66%

Rate Impact
Demand to Energy Flow

Schedule 1A Task Force Update

Finance Committee Meeting

September 25, 2018

Activities To Date

- Approved Charter
- Performed in depth review of the classification of costs by FERC category
- Reviewed billing methodologies utilized by other RTO/ISOs, including allocation between FERC categories
- Reviewed current processes and underlying methodologies for billing schedule 1A -
  - Network, PTP, Monthly Assessments
- Reviewed 3 year trend analysis for Schedule 1A billing components
- Reviewed 3 year trend analysis for potential billing units for market services

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2018 Admin Fee Allocation

Admin Fee Allocation Summary (in $000)					
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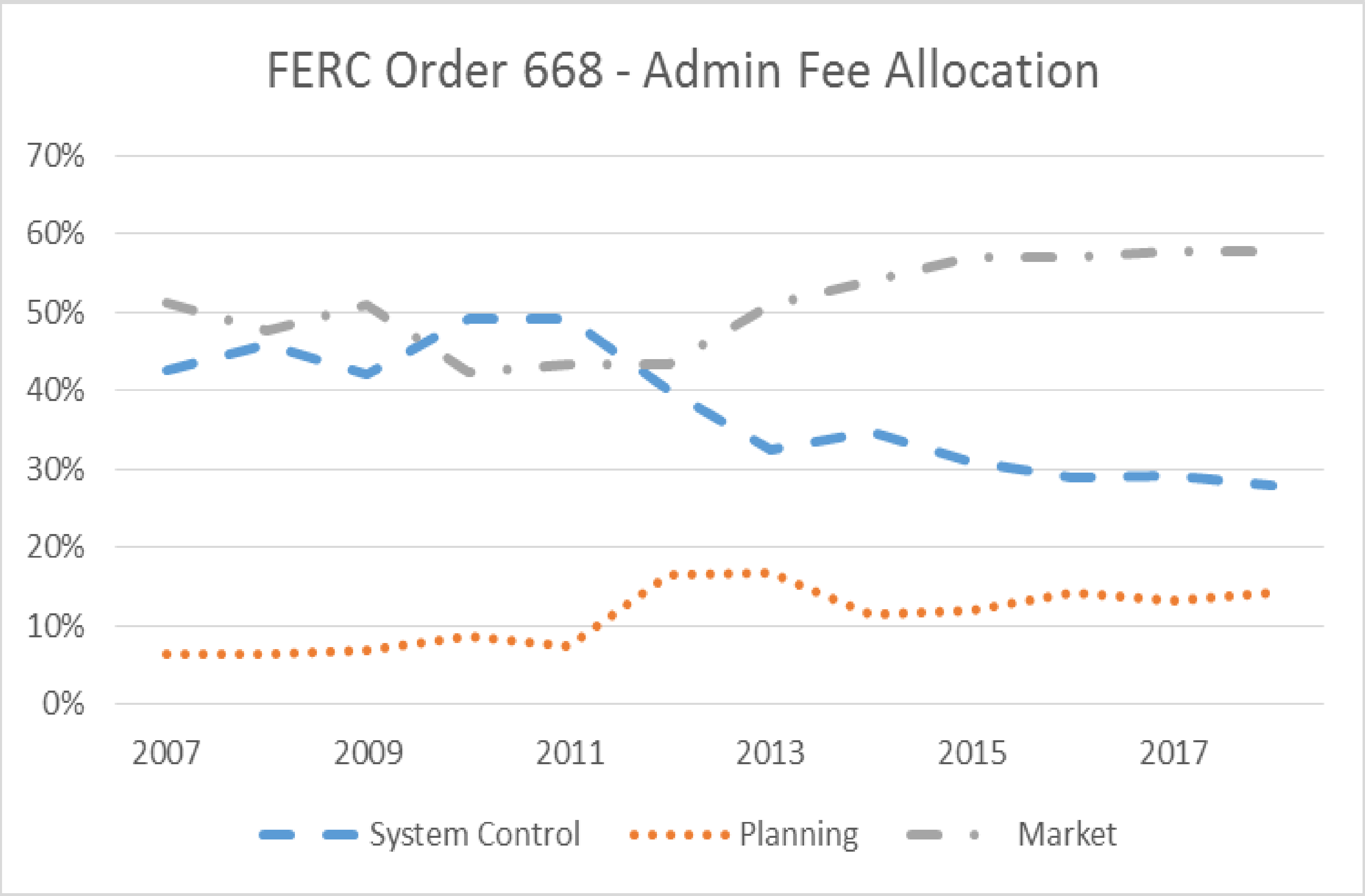
Corporate Support	$79,496	($79,496)	-	-	-
Total	**$164,001**	**-**	**$164,001**	**100.0%**	**42.9¢**

Schedule 1A Charge Categories -
% of total (2007-2017)



General Direction

- Agree costs as classified in FERC expense categories should be basis for allocation
- Agree method should not be overly complicated but must be supported by substantive rationale
- Majority prefer a demand and energy mix for cost recovery
- Majority prefer market costs recovered through energy flow
- Majority agree planning costs should be recovered through demand
- Current highly contested issues are:
  - Scheduling & dispatch costs
  - Billing determinants

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Analysis in Process

- Staff currently preparing high level strawman proposal for two primary scenarios –

  1) Market Facilitation - energy flow (generation/load)*
  Scheduling & Dispatch, Reliability Planning – demand

  2) Market Facilitation - energy flow (generation/load)*
  Scheduling & Dispatch – energy flow and demand
  Reliability Planning – demand

  *Additional scenarios will also be prepared to illustrate the impact of alternative billing units (+TCRs, virtuals, etc.)

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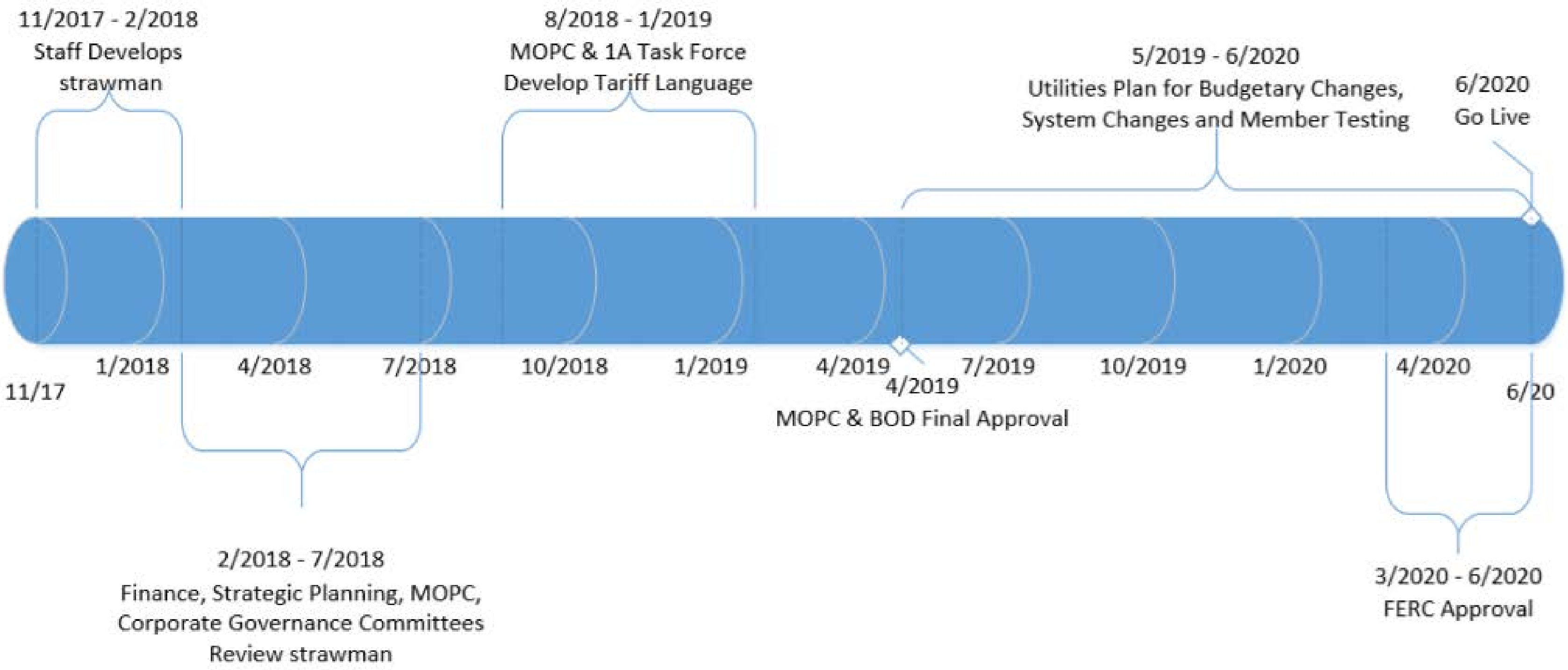
Original Timeline



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Upcoming Meetings

- October 4, 2018 – Teleconference
- October 15, 2018 – Meeting in Little Rock
- October 16, 2018 - MOPC


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HELPING OUR MEMBERS WORK TOGETHER
TO KEEP THE LIGHTS ON... TODAY AND IN THE FUTURE.

Summary of RTO/ISO Filings

Initial Filings to Allocate Administrative Costs

Mike Riley

Summary of RTO/ISO Filings

- Initial Filings to Allocate Administrative Costs
- This research reflects the filings made by RTO/ISOs to request an allocation of their administrative and operating costs in a manner other than in one "bundled" rate.
- Each proposed rate design is summarized and the basis upon which the RTO/ISO provided FERC is identified.
- Most RTO/ISOs have made subsequent filings to request adjustments to its rate design.

SPP

Initial Filings to Allocate Administrative Costs

RTO	FERC DOCKET	SUMMARY OF PROPOSAL	BASIS
CAISO	ER01-313	Initial FERC filing to unbundle the costs of operating CAISO assessed by its Grid Management Charge. An Unbundling Study produced by a consultant was conducted, which recommended dividing CAISO services into Control Area Operations and Market Operations. After further stakeholder action, the filing proposed further dividing CAISO services into three service categories: (1) Control Area Services; (2) Inter-Zonal Scheduling; and, (3) Market Operations.	"CAISO's costs should be attributed to those entities that caused them to be incurred and charging entities for the services they use."

SPP

Initial Filings to Allocate Administrative Costs

RTO	FERC DOCKET	SUMMARY OF PROPOSAL	BASIS
PJM	ER00-298	PJM's initial 1999 FERC filing to unbundle the rate charged to recover its operating expenses was ultimately resolved via a settlement agreement. However, PJM initially proposed that its costs be divided into eight separate schedules: (1) Control Area Administration Service; (2) Capacity Adequacy Administration Service; (3) "Point-to-Point and Network Import Transmission Administration Service; (4) Fixed Transmission Rights Administration Service; (5) Market Support Service; (6) Regulation and Frequency Response Administration Service; (7) Internal Energy Transaction Administration Service; and, (8) Capacity Resource and Obligation Management Service. FERC set PJM's proposal to settlement procedures. In June 2000, FERC accepted a Settlement Agreement that resolved the rate design proposal.	"Unbundling….will align the cost recovery for PJM's varied services with the parties that benefit from those services, allow customers to pay only for those services that they use, and send more accurate price signals." Principles guiding PJM's Unbundling: "Customers should pay only for the services they actually receive; Customers wish to predict their charges from PJM with a reasonable degree of certainty; Unbundled services should be material; True-up adjustments should be directed to services where they are less likely to result in substantial changes to the unadjusted rate; PJM's working capital needs should be minimized; and, PJM should be able to support long-term financing."

SPP

Initial Filings to Allocate Administrative Costs

RTO	FERC DOCKET	SUMMARY OF PROPOSAL	BASIS
MISO	ER02-2595	In 2002, MISO filed two new rate Schedules 16 and 17 to recover the costs incurred to implement its energy markets and FTRs. Prior to that date, MISO recovered all of its operating costs under its Schedule 10, which were not recovered through its Schedule 1 (Scheduling) charges. Schedule 10 charges were paid by all transmission customers. The proposed Schedules 16 and 17 were the first time MISO separately charged for separate services. Schedule 16 was intended to recover the costs incurred to implement and administer FTRs. MISO provides the FTR Service to all holders of FTR capacity, which are transmission customers, transmission owners, users or other entities that hold FTRs issued through allocation, assignment or auction. Schedule 17 was intended to recover the costs incurred for the development, implementation and operation of the MISO energy markets. MISO provides Energy Market Service under Schedule 17 to all entities that participate in transaction using the transmission system as well as all other participants in the energy markets.	"Requiring current transmission users to fund development of the FTR and Energy Market Services would unfairly focus the burden of pre-operational expense on a set of entities that may differ from those who will hold FTRs and participant in Energy Markets. The proposed Schedules 16 and 17 reflect MISO's view of the most equitable manner in which the cost of developing, implementing and administering these services can be recovered."

Initial Filings to Allocate Administrative Costs

RTO	FERC DOCKET	SUMMARY OF PROPOSAL	BASIS
ISO-NE	ER01-316	In 1998, ISO-NE filed a different rate design mechanism to recover its calendar year 1999 expenses utilizing three rate schedules: (1) Rate Schedule 1: Scheduling, System Control and Dispatch Service; (2) Rate Schedule 2: Energy Administration Services; and, (3) Rate Schedule 3: Reliability Administration Services. FERC rejected the Rate Schedule 3 allocation proposal and the matter was sent to settlement. Ultimately, the proposal was resolved in settlement. The Settlement Agreement allocated 50% of Schedule 2 expenses based on Participants' load and 50% on Participants' Generation Ownership share. 55% of Schedule 3 charges were allocated on load and 45% on generation, plus a flat, non-Participant fee. In November 1999, ISO-NE proposed changes to the Settlement Agreement to add customer charges to all three Rate Schedules. ISO-NE proposed that 25% of Schedule 2 and Schedule 3 charges be allocated to the number of "transaction units" incurred by a Participant with respect to each energy and reliability product; the remainder of Schedule 2 charges were allocated pursuant to the 1999 Settlement Agreement split between load and generation; and, the remainder of Schedule 3 charges were changed to a 50/50 split between load and generation.	ISO-NE cited a June 1997 Order that required ISO-NE to adopt a self-funding structure in order to ensure independence. ISO-NE noted that "once the Markets are implemented and operating for a reasonable amount of time, the ISO will likely have information (through its studies and accounting mechanisms) sufficient to develop more refined transaction-based fees. The ISO intends to develop and utilize such fees based on experience gained during this period." In response to the November 1999 proposal, FERC ordered ISO-NE to reinstate Settlement Agreement rate design. FERC stated that "the selection of how costs are recovered, i.e., rate design, can have significant market implications. For example, customer charges can discourage small participants, per-transaction charges can chill needed trading, resource-based (generation) charges internalize costs to the supplier while load-based charges do the opposite. The ISO has little hard data upon which the Commission could make informed choices and has provided nothing which would assist the Commission in assessing the impact of different rate designs on the market. For these reasons, we find that, insofar as the rate design is concerned, the status quo should be kept in place until the ISO has a full year of operational experience. At that time, the ISO can submit a proposal which reflects a better picture of normal operations, which includes better data on labor distribution and which addresses the impact of the rate design choices on the market."

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ISO-NY	ER02-1961	In 2002, ISO-NY filed to divide the ISO operating costs 85% load and 15% supply. FERC accepted and encouraged ISO-NY to examine its variable components of its charges and responsibilities for virtual bidding. The ISO-NY completed a study in 2004 reviewing five components of expenses in order to determine the primary beneficiaries of the services associated with its major cost centers. The five components reviewed were: 1) System Reliability Costs (100% Load); 2) Real-Time Operation Costs (100% Load); 3) Energy and Ancillary Services Markets Costs (60.5% Load/39.5% Supply); 4) Capacity Markets Costs (50% Load/50% Supply); and 5) Transmission Congestion Contracts Markets Costs (60.5% Load/39.5% Supply). Based on the consultant's recommendation, ISO-NY elected not to unbundle its rates and instead adopt an 80/20 split using allocation percentages to closely approximate the results of a full unbundling and changed allocation to 80% load and 20% supply. ISO-NY committed to 5 year review of allocation methodology. In 2011, ISO-NY again justified cost allocation revisions based on the results of a study conducted by a third party consultant and discussions among stakeholders. These proposed revisions allocated 72% to Load and 28% to Suppliers. Further, the revisions updated the rates used to calculate the portion of NYISO's Operating Costs charged to market participants that engage in non-physical transactions. FERC noted that as expert opinions may vary based upon the market participant represented, the ISO-NY tariff properly leaves determination of operating cost allocation to an independent consultant with no stake in the outcome.	"NYISO closely analyzed the components of its overhead expenses, interviewing key personnel in each department, to determine the primary beneficiaries of the services associated with the NYISO's major cost centers. The NYISO determined that approximately 14.5% of its overhead costs were incurred in the performance of functions that most directly benefit Suppliers."

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Common Themes

- Most of these filings came at the same time or soon after the entities were approved by FERC to operate as an RTO/ISO.
- Many of the filings coincided with the RTO/ISO expanding its services.
- All RTO/ISO filings were supported by a report or analysis conducted by a consultant or internal RTO/ISO staff, all of whom submitted testimony supporting and describing the methodologies reflected in the reports.
- Some RTO/ISO filings included requests for a phase-in period by which the RTO/ISO would apply the new rate design for a specified period of time. FERC rejected one proposal because it did not contain the rate design that would be in effect at the expiration of the phase-in period, or a commitment to re-file a rate design.

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