Southwest Power Pool

SCHEDULE 1A TASK FORCE MEETING

October 15, 2018

SPP Corporate Center – Little Rock, Arkansas

• M I N U T E S •

Administrative Items

Chair John Olsen called the meeting to order at 1:00 PM. The following individuals participated in the meeting:

John Olsen	Evergy
Jason Mazigian	Basin Electric
David Mindham	ITC Holdings
John Varnell	Tenaska
Tim Hall	Southern Power
Robert Tallman	OG&E
Joel Dagerman	NPPD
Heather Starnes	Missouri Joint Municipal Electric Utility Commission
Ray Bergmeier	Sunflower Electric
Jim Jacoby	AEP-Public Service Company of Oklahoma
Bill Grant	Xcel/SPS
Mike Wise	Golden Spread
Shawnee Claiborn Pinto	Public Utility Commission of Texas
Cindy Ireland	Arkansas Public Service Commission
Dennis Reed	Midwest Regulatory Consulting, LLC
Tom Dunn	SPP
Scott Smith	SPP
Micha Bailey	SPP
Brent Wilcox	SPP
David Daniels	SPP
Patti Kelly	SPP
Mike Riley	SPP
Dianne Branch	SPP

Those participating by phone were as follows:

Alfred Busbee	GDS Associates/ETEC
Rob Janssen	Dogwood Energy
Don Frerking	Evergy
Ronald Chartier	Sunflower Electric
Lee Elliot	SPP
Tony Alexander	SPP
Richard Dillon	SPP

Minutes from the October 4, 2018 teleconference meeting were reviewed. Jason Mazigian motioned to approve the minutes. The motion was seconded by Heather Starnes. The minutes were unanimously approved by voice vote.

The following proxies were in effect for the meeting – Bill Grant for Wes Berger and Heather Starnes for Rob Janssen (see attachments).

Review of Energy Billing Determinants

David Daniels (SPP Settlements) walked through all energy charge types as presented in the first exhibit included in the meeting materials. Micha Bailey (SPP Congestion Hedging) facilitated the discussion on TCRs and ARRs. There was a significant amount of discussion and related follow-up questions for staff. After the walkthrough and extended discussion of all the charge types, the task force voted on what billing determinants would be included in the denominator of any energy-based charge.

Motion #1 (Made by Ray Bergmeier, seconded by Heather Starnes)
To include, but not limited to, all megawatts associated with Real-Time Generation and Real-Time Load settlements, including Energy Imports and Energy Exports but excluding Bilateral Transaction settlements, in the denominator of any energy-based charge.

Motion passed unanimously by voice vote

Motion #2 (Made by John Varnell, seconded by Heather Starnes)
To exclude all megawatts associated with Operating Reserve transactions from the denominator of any energy-based charge.

The motion passed by voice vote with an abstention from OG&E

Motion #3 (Made by Bill Grant, seconded by Heather Starnes)
To include all megawatts associated with Demand Response transactions, from real-time metered data, in the denominator of any energy-based charge.

The motion passed by voice vote with an abstention from Tenaska

Motion #4 – (Made by Joel Dagerman, seconded by Jim Jacoby)
To exclude all megawatts associated with Grand-Fathered Agreements from the denominator of any energy-based charge.

The motion passed by voice vote with an abstention from Xcel Energy

Motion #5 (Made by Bill Grant, Seconded by Tim Hall)
To exclude all megawatts associated with Pseudo-Tie transactions from the denominator of any energy-based charge.

The motion passed by voice vote with an abstention from OG&E

There was no consensus reached on potential billing determinants associated with the Virtual Energy and TCR/ARR charge types. Additional data and analysis is needed. The additional items are listed under the respective headings in the recap of Action Items below.

Action Items

Based on the lengthy discussion of market charge types facilitated by SPP staff, the following action items were noted (arranged by the market charge type to which the action item related)**.**

Import Export Schedules

- **Action Item 1** – Further investigate how Dynamic Schedules are settled within the Import/Export charge types.

Demand Response

- **Action Item 2** – Further investigate how Demand Response should be used to allocate SPP Costs. Additionally, determine whether the MWhs would also be recognized in RT Generation or RT Load.

Virtual Energy

- **Action Item 3a** - Investigate and report on how other RTOs (PJM, MISO, ISO-NE) charge market participants for virtual transactions. Are they allocated based upon MWhs or bid/offer submission? Submitted and/or cleared?

- **Action Item 3b** - What is the basis of the other RTOs' charge for virtual fees (i.e. is it cost based or only recovering for incremental activity?)

- **Action Item 3c** - What is SPP's cost for supporting the virtual market?

- **Action Item 3d** - What are the annual MWhs and bid/offer submissions volumes associated with virtual transactions (cleared and submitted)?

Operating Reserves

- **Action Item 4** - Verify that Operating Reserves would not be double-charged when deployed (i.e. also in RT Generation).

Transmission Congestion Rights/Auction Revenue Rights

- **Action Item 5 -** Provide additional analysis on possible TCR allocations. Analysis should include SPP's TCR costs, including overheads, and different scenarios of ARR and TCR combinations. Additionally, the following data should be quantified- number and MWhs for submitted TCRs and MWhs only for cleared TCRs.

The Agenda items for Cost Assignment and Fee Structure Development were deferred until the next scheduled meeting.

Future Meetings

Friday, November 9th 10-Noon – Teleconference
Tuesday, November 27th 8AM-3PM – Dallas, TX AEP Offices
Tuesday, December 18th 1-4PM - Teleconference

There being no further business, John Olsen adjourned the meeting at 5:30 PM.

Respectfully Submitted,

Dianne Branch
Secretary

Dianne Branch

From: Berger, Wes
Sent: Thursday, October 11, 2018 10:28 AM
To: Dianne Branch; Olsen, John
Cc: Grant, William
Subject: **External Email** SPP Sch1A meeting on 10/15 - Proxy

I won't be able to attend the meeting in Little Rock next week. Bill Grant will be attending, and has my proxy. Thanks.

Wes Berger
Xcel Energy | Responsible By Nature
Manager, Rate Cases
790 S. Buchanan St., 7th Floor, Amarillo TX 79101
P: 806.378.2891 C: 806.672.6080

Dianne Branch

From: Olsen, John
Sent: Monday, October 15, 2018 12:34 PM
To: Dianne Branch
Subject: **External Email** Fwd: 1ATF Meeting Proxy

John Olsen
KCP&L and Westar, Evergy Companies
Sr. Director, DSO and Emergency Ops
O: 816-654-1130 M: 785-220-8343
kcpl.com
westarenergy.com
evergyinc.com

From: Rob Janssen <rob.janssen@kelsonenergy.com>
Sent: Monday, October 15, 2018 12:23:42 PM
To: John Olsen; Heather H. Starnes
Subject: 1ATF Meeting Proxy

John,

I will not be able to attend the 1ATF meeting today in person. I will participate as much as possible by phone, but I know that I will miss some portions of the meeting, including the very beginning. I would like Heather Starnes to have my proxy for the meeting when I am not available to participate.

Thanks,
Rob

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Dogwood Energy
6700 Alexander Bell Drive, Suite 360
Columbia, MD 21046
443-542-5125

Southwest Power Pool

Southwest Power Pool, Inc.

SCHEDULE 1A TASK FORCE
SPP Corporate Center, Little Rock, AR
October 15, 2018

• ATTENDANCE LIST •

Name	System
Bill Grant	XCEL/SPS
Ray Bergmeier	SEPC
John Varnell	TENASKA
Shawnee Claiborn-Pinto	PUCT
Cindy Ireland	APSC
Jim Jacoby	AEP
Joel Dagerman	NPPD
John Olsen	Evergy
Jason Marigian	Basin Electric
Dianne Branch	SPP
David Mindham	ITC
Tim Hall	Southern Power
Mike Wise	GSEC
Heather Starnes	MJMEUC
Dennis Reed	MWRC
Mike Riley	SPP
Micha Bailey	SPP
Brent Wilcox	SPP
Tom Dunn	SPP
Patti Kelly	SPP
Scott Smith	SPP

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SPP Southwest Power Pool

Southwest Power Pool, Inc.

SCHEDULE 1A TASK FORCE
SPP Corporate Center, Little Rock, AR
October 15, 2018

• ATTENDANCE LIST •

Name	System
Bob Tallman	OGE
David Daniels	SPP

Southwest Power Pool, Inc.

SCHEDULE 1A TASK FORCE MEETING

October 15, 2018

SPP Corporate Offices

• A G E N D A •

1PM – 6PM 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. Energy Billing Determinants (90 minutes) ....John Olsen
3. Cost Assignment Discussion (90 minutes)… ……………..………………………………..John Olsen
4. Fee Structure Development (90 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

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

Market Charge Types	Description	Additional Information
Energy		
Real Time Load	This represents billable meter data in the Integrated Marketplace. Does not include losses.	
Real Time Generation	Billable meter for generation represents the actual energy put on the SPP grid. Does not include losses.	
Import/Export Schedules	Represents the actual MWh injection/withdrawal at a specific settlement location. They most likely would have a transmission reservation, but markets would use the actual Import/Export Schedule.	
Bilateral Settlement Agreements	These are used to move financial responsibility of the energy from one Asset Owner to another Asset Owner. This is often done between MP's, but can also be done within the same MP.	
Virtual Energy	These transactions utilizes the Day-Ahead quantity as an input to both the Day-Ahead and Real-Time settlement.	
Operating Reserve Charge Types	Includes determinants from the operating reserve charge type group commonly referred to as Regulation Down, Regulation Up, Spin and Supplemental. Excludes billing determinants associated with payments being distributed to load members through Operating Reserve Distribution Charges.	Including these volumes accounts for the differences in how the market clears transactional volume. Since entities bid only a price for ancillary market services, it is SPP's Market Systems that determine the allocation of energy vs. operating reserve volumes in the market.
Demand Response Charge Types	Represent the amount of DR energy that clears in the market, reducing the amount of physical energy required to be produced and delivered. It should be noted that we currently don't have any Demand Response registered in our market. We had some initially, but they were never used and thus unregistered.	The Demand Response Charge Types were added as a result of FERC Order 745. The purpose of these charge types is to provide host load demand reduction credits and to allocate the costs associated with payment to Demand Response Resources to those MPs that benefited from the DRR output.
Transmission Congestion Rights **Auction Revenue Rights**	Represent the amount of TCR MWhs that are **a)** settled through the SPP Market system (i.e. all TCRs regardless if awarded through ARR process or through the auction); or **b)** awarded in the TCR auction (excludes all TCRs that are awarded as a result of the ARR process) and settled through the SPP market system; or **c)** the TCR volumes that exceed the load values for a specific settlement location, which represents those TCRs that are in excess of hedges for native load.	Important notes: **a)** This matches how Settlements currently processes TCRs. **b)** This would require Congestion Hedging to pass additional information to Settlements to indicate the TCR was awarded based on the ARR process. **c)** This would require more involved analysis and additional information to capture the desired volumes.
Grandfathered Agreement Charge Types	**Uplift** - Excludes transaction with Grandfathered Agreements from Market Settlement of congestion, losses, and hedging instruments. These charges create uplift to the market. **Distribution** - A RT charge or credit calculated for each Resource or Load, internal to the SPP footprint, that has pseudo-tied out of the SPP Balancing Authority to cover Congestion Charges.	
Pseudo-Tie Charges	These are source / sink combinations that use a firm transmission reservation to move a specific generation unit to a specific sink location. These schedules are exempt from market energy charges but do pay for **congestion** and **losses**. The MP's may setup whatever transmission reservation/service that best benefits them (transmission service and marketplace charges are not tied together).	**Congestion** - A RT charge or credit will be calculated for each Resource or Load, internal to SPP footprint, that has pseudo-tied out of the SPP Balancing Authority for congestion costs. **Losses** - A RT charge or credit will be calculated for each Resource or Load, internal to SPP footprint, that has pseudo-tied out of the SPP Balancing Authority for losses.

575.7 - Market Facilitation, Monitoring & Compliance (in $000)				
	2018 Budget	**%**	**Cost Type**	**Energy or Demand**
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%**		

561.4 - Scheduling, Sys Control & Dispatch (in $000)				
	2018 Budget	**%**	**Cost Type**	**Energy or Demand**
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 (a)	$1,055	2.3%	Services	
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.

561.8 - Reliability Planning & Standards Dev (in $000)				
	2018 Budget	**%**	**Cost Type**	**Energy or Demand**
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 (a)	($3,194)	-13.7%	Revenue	
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.

Corporate Support (in $000)				
	2018 Budget	%	Cost Type	Energy or Demand
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 and Services	
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 (a)	($2,824)	-3.6%	Revenue	
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.