Southwest Power Pool

SCHEDULE 1A TASK FORCE MEETING

January 17, 2019

Teleconference

• M I N U T E S •

Administrative Items
Chair John Olsen called the meeting to order at 9:05 AM. The following individuals participated in the meeting:

John Olsen	Evergy
Jason Mazigian	Basin Electric
David Mindham	ITC Holdings
Tim Hall	Southern Power
Greg Garst	OPPD
Alfred Busbee	GDS Associates/ETEC
Jim Jacoby	AEP – Public Service Co. of Oklahoma
Ray Bergmeier	Sunflower Electric
Robert Janssen	Dogwood Energy, LLC
Bob Tallman	Oklahoma Gas & Electric
Heather Starnes	MJMEUC
Joel Dagerman	NPPD
Chris Lyons	Customized Energy Solutions
Brian Rounds	AESL Consulting
Calvin Daniels	WFEC
David Erkin	AEP
Don Frerking	KCP&L and Westar, Evergy Companies
Jessica Kasparek	Lincoln Electric System
Joe Rivera	MEAN
Ronald Chartier	Sunflower Electric
Sandy Wirkus	WAPA
Carrie Dixon	Xcel
Carl Monroe	SPP
Sam Loudenslager	SPP
Tom Dunn	SPP
Lee Elliot	SPP
Patti Kelly	SPP
Scott Smith	SPP
Dianne Branch	SPP

Minutes from the December 18, 2018 meeting were reviewed. Amendments to the minutes included the correction of a name misspelling. Rob Janssen motioned to approve the minutes. The motion was seconded by Jason Mazigian. The minutes as amended were unanimously approved by voice vote.

Update on Action Items from 12/18/18 Meeting

1 - With respect to the MMU's response to action item # 2 from the November 27th meeting that was communicated during this meeting and the follow up question by Rob Janssen and the related MMU response - a document summarizing these items should be included as an attachment to the December

18th meeting minutes.

UPDATE: Dianne Branch informed the Task Force that both MMU related items were included in the December 18th meeting minutes.

2 – SPP staff to perform a multi-year cash flow analysis utilizing the metrics and rates agreed upon by the 1ATF. A sensitivity analysis should also be incorporated to contemplate impacts that fluctuations in metrics could have on cash flows. The analysis should also identify thresholds that would potentially serve as trigger points for off cycle true-ups.

UPDATE: This item was covered under Agenda Item 3.

True-Up Cadence for Rate Schedules

Dianne Branch presented the results of staff's analysis of the impact of the rate structure on SPP's net cash flows. Staff examined the monthly cash flows for the following scenarios:

1) 2016 and 2017 Actual Results
2) Proposed Rate Structure w/ actual billing determinants
3) Proposed Rate Structure
   Assuming 5% decrease in all market billing determinants across all months
4) Proposed Rate Structure
   Assuming 5% annual decrease in generation/load billing determinants in June – September only

Staff concluded their analysis with the following observations:

1) Seasonality in cash outflows exist today with notable spikes at quarter end (primarily due to debt payments)
2) Seasonal cash flow decreases noted in 2016 and 2017 actuals are representative of historical trends
3) Cash flow position under proposed scenarios does not materially improve or worsen in comparison to actual results under current Schedule 1A methodology
4) Consistent with current practices, seasonal spikes can be managed with existing, short term financing arrangements
5) A net cumulative cash flow impact reaching negative $15.0 MM would create concern and that it would take a 10% annual decrease in billing determinants to get close to that $15.0MM threshold in the 2016-2017 analysis presented

After staff's presentation, there was general discussion by the Task Force as to what the appropriate true-up frequency should be for the proposed rate schedules. Staff indicated that a true-up frequency of more than annually (e.g. monthly, quarterly) could certainly be done, but expressed their concern that it would likely increase administrative costs and produce more volatility in the rates. Certain members thought that a more frequent true-up process made sense as it would more equitably match cost with those receiving benefit while others thought an annual true-up process would ensure that we achieve one of the overarching principles of keeping things simple. The task force concluded that before a decision could be made, additional information was needed surrounding the fluctuation in billing determinants, resulting in the action item summarized in the next section.

Action Items

1 - Staff to prepare historical analysis of billing determinant data for the rate schedules to better understand seasonal fluctuations and other trends. Additionally, key dates/events impacting each billing determinant should be highlighted.

Future Meetings

Tuesday, February 5th 8AM-2PM – Face to Face – DFW Hyatt

There being no further business, John Olsen adjourned the meeting at 9:50 AM.

Respectfully Submitted,

Dianne Branch
Secretary

Southwest Power Pool

Southwest Power Pool, Inc.
SCHEDULE 1A TASK FORCE MEETING
January 17, 2019
Teleconference

• A G E N D A •

9AM – 10AM 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. Review of Past Actions Items (10 minutes)…………………………………………………..Dianne Branch
3. True-Up Cadence for Rate Schedules (30 minutes)………………………….John Olsen/Dianne Branch
4. Closing Items (10 minutes)……………………………………………. ……………………Dianne Branch
   a. Summary of Action Items
   b. Future meetings

   February 5, 2019 – Dallas, TX 8AM-2PM (DFW Hyatt)

Southwest Power Pool

SCHEDULE 1A TASK FORCE MEETING

December 18, 2018

Teleconference

• MINUTES •

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
Tim Hall	Southern Power
Wes Berger	SPS/Xcel Energy
Greg Garst	OPPD
Alfred Busbee	GDS Associates/ETEC
Jim Jacoby	AEP – Public Service Co. of Oklahoma
Ray Bergmeier	Sunflower Electric
Robert Janssen	Dogwood Energy, LLC
Dennis Reed	Midwest Regulatory Consulting, LLC
Chris Lyons	Customized Energy Solutions
Ishwar Saini	Macquarie Energy, LLC
Seth Cochran	DC Energy
Andrea Harrison	Western Farmers Elec Coop.
Brian Rounds	AESL Consulting
J.P. Maddock	Basin Electric
Jessica Meyer	Lincoln Electric System
Lisa Szot	Enel Green Power N.A., Inc.
Sandy Wirkus	WAPA
Carrie Dixon	Xcel
Chris Green	Liberty (Empire)
Carl Monroe	SPP
Tom Dunn	SPP
Mike Riley	SPP
David Daniels	SPP
Scott Smith	SPP
Will Vestal	SPP
John Luallen	SPP
Tony Alexander	SPP
Patti Kelly	SPP
Dianne Branch	SPP

Minutes from the November 27, 2018 meeting were reviewed. Jason Mazigian motioned to approve the minutes. The motion was seconded by Jim Jacoby. The minutes were unanimously approved by voice vote.

The following proxies were in effect for the meeting –Rob Janssen for Heather Starnes and John Olsen for Joel Dagerman (see attachments).

Update on Action Items from 11/27/18 Meeting

1) **Update Proposed Rate Schedules for the following items**
    a. RS 1 – Add Scheduling & Dispatch costs from RS 4
       RS 4 – Remove Scheduling & Dispatch costs
    b. Consider additional costs from Market Facilitation (RS 4) that would be reasonable to include in the Market Clearing cost (RS 3).
    c. Combine RS 3 and RS 4 (as amended for item a. above), utilizing a denominator that would incorporate deviations from the DA market.

    UPDATE: These items were covered under Agenda Items 3 and 4 of the current meeting.

2) **Obtain Opinion from the Market Monitoring Unit**
    Under the assumption that we establish rates based on only RT activity, will the MMU be receptive to market participants adding those rates to both their DA and RT mitigated offers.

    UPDATE: Will Vestal from the MMU provided a response to this action item. His comments addressing this action item during the meeting and the follow-up question by Rob Jannsen has been captured in a separate document that is included as an attachment to these meeting minutes.

3) **Notation in Minutes for TCR Rate Structure**
    Ensure that minutes reflect the TCR rate structure approved by the task force in Motion #1 is based strictly on the system and processes in effect today. Any future changes (and its impact to our rate structure) would need to be contemplated at that future time.

    UPDATE: The approved 11/27 meeting minutes included the appropriate notation regarding the conditions under which the TCR Rate structure was approved.

Day Ahead (DA) and Real Time (RT) Metrics

David Daniels walked through various scenarios utilizing both DA and RT metrics as potential billing determinants for our market based rate schedules. Scenarios presented included 1) taking the maximum value of DA and RT, 2) charging for both DA and RT, and 3) utilizing DA + Incremental (absolute). It was pointed out that the last option is similar to MISO's current methodology. David then presented metrics for DA and RT, illustrating the impact to generation, load, imports, and exports from utilizing the three scenarios previously discussed. David wrapped up his presentation by summarizing some of the potential impacts of utilizing DA information as a billing determinant. He highlighted the potential for discriminatory treatment if different rules were applied to generation and load; the difficulty in forecasting DA activity resulting in potentially large true-ups and increased volatility in rates; and the cost impact to both SPP and market participants. As it relates to the cost impacts, David indicated that while the cost associated with system changes would be small, there was greater concern over the potential for an increase in disputes given the increased complexity from utilizing DA information. More disputes could lead to more FTEs being needed to handle the resolution of those disputes. There was a brief discussion and some general questions that were addressed by staff.

Review of Market Based Rate Schedules

Dianne Branch presented an overview of the rate schedules that had been previously approved (Rate Schedule 1 and 2) and the market related rate schedules that were still under debate (Rate Schedules 3 and 4). A summary of those rate schedules is as follows:

- Rate Schedule 1 (RS 1) – Planning and Scheduling & Dispatch costs based on 12 CP billing determinants
- Rate Schedule 2 (RS 2)– TCR administration costs based on TCRs awarded and converted
- Rate Schedule 3 (as originally presented) – Market clearing costs based on RT billing determinants (including virtuals)
- Rate Schedule 4 (as originally presented) – Market administration costs (excluding TCR and market clearing costs) based on RT billing determinants (excluding virtuals)
- Rate Schedules 3 and 4 (combined view) – Market administration costs (excluding TCR costs) based on RT billing determinants (including virtuals)

Dianne Branch also presented revisions to RS 3 and RS 4 that reflected a shift in costs for IT staffing costs identified as being associated with the market clearing process. Shifting these costs from RS 4 to RS 3 had a cost impact of approximately $0.01/MWh (increase to RS 3, decrease to RS 4).

Following a fair amount of discussion about the analysis presented by David Daniels regarding the utilization of DA metrics as a billing determinant and the presentation of RS 3 and RS 4 that reflected the adjustments for the shift in IT costs, Rob Jannsen made a motion to approve RS 3 and RS 4 as summarized below:

- Rate Schedule 3 (as adjusted) – Market clearing costs based on RT billing determinants (including virtuals)
- Rate Schedule 4 (as adjusted) – Market administration costs (excluding TCR and market clearing costs) based on RT billing determinants (excluding virtuals)

The motion was seconded by Jim Jacoby. A roll call was utilized to collect the votes on this motion. The results were as follows – 10 voted for the motion, 1 voted against the motion, and 1 abstained from the vote. The following rational was provided for the No vote –

> Xcel (SPS) – While in agreement on the components of the numerator and denominator, representative believes that it would be more appropriate to use the maximum of the Day-ahead and Real-time for the denominator as opposed to simply using Real-time.

Discussion on True-Up Cadence for Rate Schedules

Dianne Branch provided a recap of the frequencies utilized by other RTO/ISOs to update their rates. The RTO/ISOs captured in this analysis included MISO, PJM, CAISO, ISO-NE, and NYISO. With the exception of MISO, all entities utilized an annual rate setting/true-up process. Conversely, MISO performs true-ups/rate adjustments on a monthly basis. While there was a brief, general discussion on preferences and potential advantages/disadvantages of using an annual vs. more frequent alternative, it was agreed that a final decision on frequency of true-ups could not be made until SPP staff performed additional analysis on cash flows utilizing the agreed upon rate schedules.

Action Items

1 - With respect to the MMU's response to action item # 2 from the November 27th meeting that was communicated during this meeting and the follow up question by Rob Jannsen and the related MMU response - a document summarizing these items should be included as an attachment to the December 18th meeting minutes.

2 – SPP staff to perform a multi-year cash flow analysis utilizing the metrics and rates agreed upon by the 1ATF. A sensitivity analysis should also be incorporated to contemplate impacts that fluctuations in metrics could have on cash flows. The analysis should also identify thresholds that would potentially serve as trigger points for off cycle true-ups.

Future Meetings

Thursday, January 17th 9-10AM – Teleconference/Web-Ex
Tuesday, February 5th 8AM-2PM – Face to Face – DFW Hyatt

There being no further business, John Olsen adjourned the meeting at 3:10 PM.

Respectfully Submitted,

Dianne Branch
Secretary


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

Proposed Rate Structure Cash Flow Analysis

January 17, 2019

1A Task Force - Teleconference

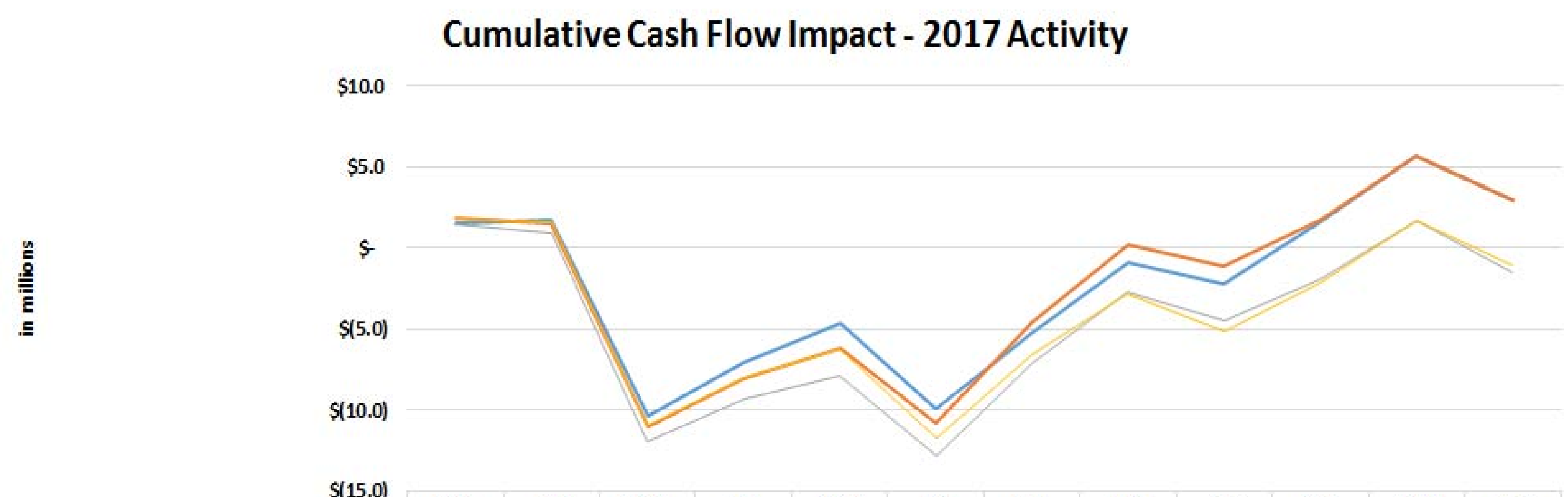
SouthwestPowerPool SPPorg southwest-power-pool

Cash Flow Analysis

- Examined monthly cash flows for the following scenarios –
  1) 2016 and 2017 Actual Results
  2) Proposed Rate Structure w/ actual billing determinants
  3) Proposed Rate Structure Assuming 5% decrease in all market billing determinants across all months
  4) Proposed Rate Structure Assuming 5% annual decrease in generation/load billing determinants in June – September only.

- Analyzed cumulative impact on net cash flows for each scenario.

2017 Cash Flow Analysis



	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Actual Net Cash Flows	$1.5	$1.7	$(10.4)	$(7.1)	$(4.7)	$(10.0)	$(5.2)	$(0.9)	$(2.2)	$1.6	$5.7	$2.9
Proposed Rate Structure	$1.8	$1.5	$(11.0)	$(8.0)	$(6.2)	$(10.8)	$(4.6)	$0.2	$(1.2)	$1.7	$5.6	$2.9
Proposed w/ 5% decrease	$1.4	$0.8	$(12.0)	$(9.4)	$(7.9)	$(12.9)	$(7.1)	$(2.8)	$(4.5)	$(1.9)	$1.6	$(1.5)
Proposed w/ 5% decrease in June-Sept	$1.8	$1.5	$(11.0)	$(8.0)	$(6.2)	$(11.8)	$(6.6)	$(2.8)	$(5.1)	$(2.2)	$1.7	$(1.1)

NOTE:
Results represent cumulative cash flows (net of cash outflows) for each scenario

SPP

2016 Cash Flow Analysis

Cumulative Cash Flow Impact - 2016 Activity

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Actual Net Cash Flows	$6.4	$3.7	$(8.9)	$(6.1)	$(2.8)	$(4.8)	$(1.5)	$(0.5)	$(2.3)	$(1.2)	$3.8	$(0.8)
Proposed Rate Structure	$6.5	$3.9	$(9.4)	$(7.4)	$(4.9)	$(6.3)	$(1.5)	$0.8	$(0.9)	$(0.6)	$3.6	$(0.8)
Proposed w/ 5% decrease	$6.1	$3.2	$(10.4)	$(8.7)	$(6.5)	$(8.3)	$(3.9)	$(2.0)	$(4.1)	$(4.1)	$(0.2)	$(5.0)
Proposed w/ 5% decrease in June-Sept	$6.5	$3.9	$(9.4)	$(7.4)	$(4.9)	$(7.3)	$(3.4)	$(2.0)	$(4.7)	$(4.4)	$(0.2)	$(4.6)

NOTE:
Results represent cumulative cash flows (net of cash outflows) for each scenario

SPP

Cash Flow Analysis

- Observations

1) Seasonality in cash outflows exist today with notable spikes at quarter end (primarily due to debt payments)
2) Seasonal cash flow decreases noted in 2016 and 2017 actuals are representative of historical trends
3) Cash flow position under proposed scenarios does not materially improve or worsen in comparison to actual results under current Schedule 1A methodology
4) Consistent with current practices, seasonal spikes can be managed with existing, short term financing arrangements

SPP