Southwest Power Pool

SCHEDULE 1A TASK FORCE MEETING

February 5, 2019

DFW Hyatt Regency – Dallas, TX

• M I N U T E S •

Administrative Items

Chair John Olsen called the meeting to order at 8:05 AM. The following individuals participated in the meeting:

John Olsen	Evergy
Jim Jacoby	AEP-Public Service Company of Oklahoma
Jason Mazigian	Basin Electric
Greg Garst	OPPD
Alfred Busbee	GDS Associates/ETEC
John Varnell	Tenaska
Tim Hall	Southern Power
David Mindham	ITC Holdings Corp.
Wes Berger	Xcel Energy/SPS
Tom Dunn	SPP
Mike Riley	SPP
Dianne Branch	SPP

Those participating by phone were as follows:

Robert Tallman	OG&E
Joel Dagerman	NPPD
Heather Starnes	Healy Law Offices/MJMEUC
Rob Janssen	Dogwood Energy
Ray Bergmeier	Sunflower Electric
Chris Lyons	Customized Energy Solutions
David Erkin	AEP
David Kays	OG&E
Don Frerking	Evergy
Gary Hoffman	WAPA
Ishwar Saini	Macquarie Energy LLC
J.P. Maddock	Basin Electric
Jessica Meyer	Lincoln Electric System
Jessica Kasparek	Lincoln Electric System
Jill Jones	MEAN
Robert Pick	NPPD
Ronald Chartier	Sunflower Electric
Carrie Dixon	Xcel Energy
Shawnee Claiborn Pinto	Public Utility Commission of Texas
Richard Dillon	SPP
Scott Smith	SPP
Nicole Wagner	SPP
Lee Elliot	SPP
Patti Kelly	SPP

Minutes from the January 17, 2019 teleconference meeting were reviewed. Alfred Busbee 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 January 17th Meeting

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.

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 billing determinants for market based rate schedules (RS2-4). Staff examined the monthly billing determinant data using the following criteria –

1) 2015-2018 actual data
2) TCRs awarded and converted for Rate Schedule 2
3) Real time generation, load, import/export, and virtual energy for Rate Schedule 3
4) Real time generation, load, and import/export for Rate Schedule 4

Based on the analysis of monthly trend and rolling 12 month averages from 2015-18, staff summarized their observations as follows -

1) Rolling average for Schedule 3 and 4 billing determinants is relatively flat with only a modest rise over the 4 year period
2) Rolling average for Schedule 2 billing determinants is relatively flat with moderate rise beginning in late 2017 (likely due to increased congestion from wind, increase in financial only asset owners, etc.)

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. 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. Following a fair amount of discussion on the subject, Jim Jacoby made a motion to approve an annual rate setting process for rates that would be in effect for the following calendar year and would be estimated based on billing determinants for previous 12 months (August-July to coincide with the timing of the budget preparation). David Mindham seconded the motion. The motion passed by voice vote with OG&E voting no. Heather Starnes suggested that a quarterly update be provided to the MOPC during the first year after implementation to get everyone comfortable with the new rate setting process. The update would provide a comparison of actual results to budget for both costs and billing determinants.

Tariff Language Review

Mike Riley facilitated the review and edit of the proposed tariff language as provided in the meeting materials. Mike started with a brief overview of the existing Schedule 1A tariff language and then introduced the separate document (Schedule 13) that contained the proposed language for the new rate schedules. The Task Force worked through each of the sections representing the four rate schedules, providing numerous edits and also identifying numerous issues, many of those requiring additional research and analysis. A summary of those issues is as follows:

1) **Rate Cap** - Current Schedule 1A explicitly sets a cap on the administrative fee that SPP can charge. Is a cap needed under the proposed new rate structure? Task Force members were asked to go back and discuss with their respective companies and be prepared to discuss at next meeting. See related action item in section below.

2) **Location of New Tariff Language** - How should the new rate schedules be incorporated in the tariff? Options include leaving all in Schedule 1A, moving all to new section, or leaving only RS 1 in Schedule 1A while including all others in a separate section (e.g. 13 or AE). Moving any or all language from Schedule 1A would necessitate some TOs to make new filings with FERC and possibly trigger state filings for other entities. Task Force members were asked to go back and discuss impacts with their respective companies and be prepared to discuss at next meeting. See related action item in section below.

3) **Bad Debt Expense Reference** – Current Schedule 1A includes language to address bad debt expense. Under the new proposed rate schedules, is this language still necessary? Staff to research and prepare analysis for next meeting. See related action item in section below.

4) **Transmission Service Request Charges** – Current Schedule 1A includes a provision for charging a fee ($100-$200) for each new transmission service request that is then subject to rebate once the transmission customer becomes legally obligated to pay for the applicable point to point service charge or if the requested point to point service is denied. Although this is not a significant source of revenue, the Task Force decided to keep this language in the tariff section describing the RS1 administrative charge.

5) **Monthly Assessments** – Under proposed new rate structure, should monthly assessments be eliminated? This current language resides in the by-laws and would require approval from the Corporate Governance Committee to remove. Staff to prepare analysis for next meeting. See related action item in section below.

6) **Virtual Fees** – Given that virtual participants will now be billed under proposed RS 3, should the $0.05 charge per bid be eliminated from Attachment AE? After some discussion, it was determined that the task force had not previously voted on this issue.

   Greg Garst made a motion to formally eliminate the $0.05 charge on virtual bids. Tim Hall seconded that motion. The motion passed by voice vote with NPPD and OG&E voting no. The following rationale was provided for the No votes:

   a. **NPPD** – Due to the de minimis nature of the charge, no additional change was warranted.
   b. **OG&E**- Virtuals have already been exempted from the majority of costs for the market services they use.

White Paper Review

Due to timing constraints and the desire to incorporate additional analysis and conclusions reached in this meeting, review and approval of the white paper was deferred until the February 21st meeting

Action Items

1) Task force members to contemplate the impacts to their respective companies as it relates to the various options for positioning new rate structure language into the tariff (e.g. all remain in 1A, only RS 1 remain in 1A, all in separate section). Members should be prepared to discuss at February 21st meeting.

2) Task force members to discuss within their respective companies the preference on removing/keeping a cap on the rate schedule(s). Members should be prepared to discuss at February 21st meeting.

3) Staff to incorporate illustrative timeline into the white paper to clearly explain the period for which billing determinants will be utilized in the annual rate setting process and the period for which the established rate would be in effect.

4) Staff to prepare formula templates for proposed rate schedules.

5) Staff to prepare analysis on monthly assessments illustrating materiality and the underlying components of the calculation.

6) Staff to research current tariff language on bad debt, identifying exposure (if any) that would necessitate the inclusion of language in tariff sections under current revision.

Future Meetings

Thursday, February 21st 8AM-2PM – DFW Hyatt Regency

There being no further business, John Olsen adjourned the meeting at 1:55 PM.

Respectfully Submitted,

Dianne Branch
Secretary

Southwest Power Pool

Southwest Power Pool, Inc.

SCHEDULE 1A TASK FORCE MEETING

February 5, 2019

DFW Hyatt Regency

• A G E N D A •

8AM – 2PM 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. Tariff Language Review (150 minutes)…………..………………………………………………. Mike Riley
5. Whitepaper Review (45 minutes)…………………………………………...………………Dianne Branch
6. Outstanding Issues/Roadmap to Implementation (45 minutes)………………………………….Various
7. Closing Items (10 minutes)……………………………………………. ……………………Dianne Branch
   a. Summary of Action Items
   b. Future meetings

Southwest Power Pool

Southwest Power Pool, Inc.

1A TASK FORCE
DFW Hyatt Regency, TX
February 5, 2019

• ATTENDANCE LIST •

Name	System
Tom Dunn	SPP
Mike Riley	SPP
Jim Jacobs	AEP
John Olsen	EVERGY
Jason Mazigian	Basin Electric
Greg Garst	OPPD
Alfred Busbee	ETEC
Jeff D Varnell	TENASKA
Tim Hall	Southern Power
David Mindham	ITC
Wes Berger	Xcel Energy / SPS
Dianne Branch	SPP

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


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

Billing Determinant Historical Analysis

February 5, 2019

1A Task Force – Dallas, TX

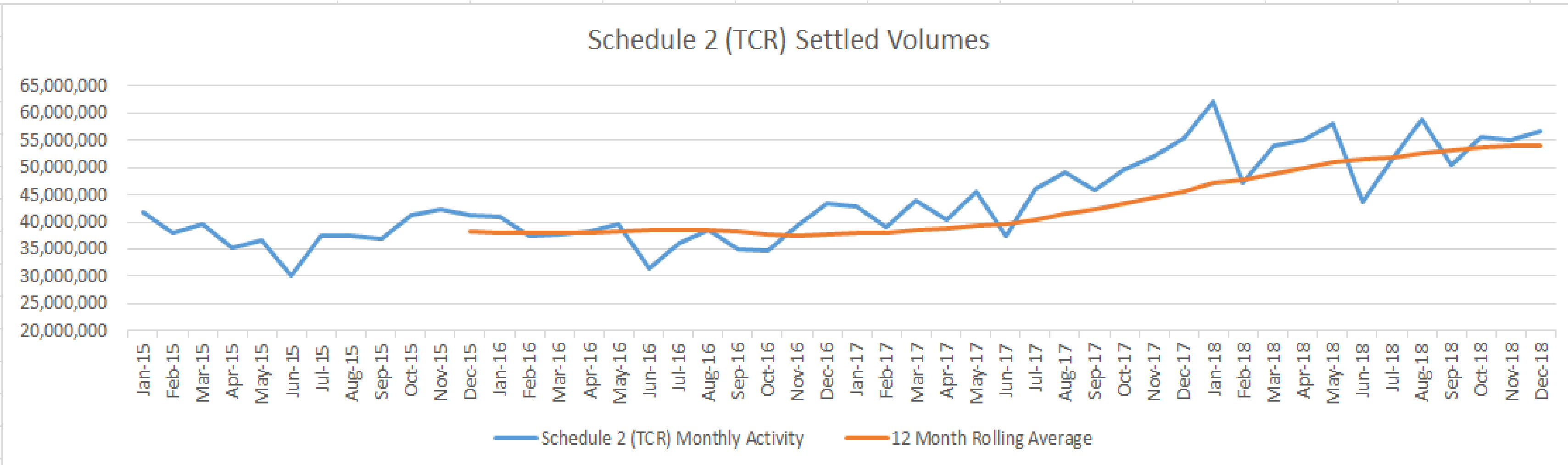
SouthwestPowerPool SPPorg southwest-power-pool

Billing Determinant Analysis

- Examined monthly billing determinant data using the following criteria –
  1) 2015-2018 actual data
  2) TCRs awarded and converted under Rate Schedule 2
  3) Real time generation, load, import/export, and virtual energy under Rate Schedule 3
  4) Real time generation, load, and import/export, under Rate Schedule 4
- Analyzed trend and rolling 12 month average from 2015-2018.

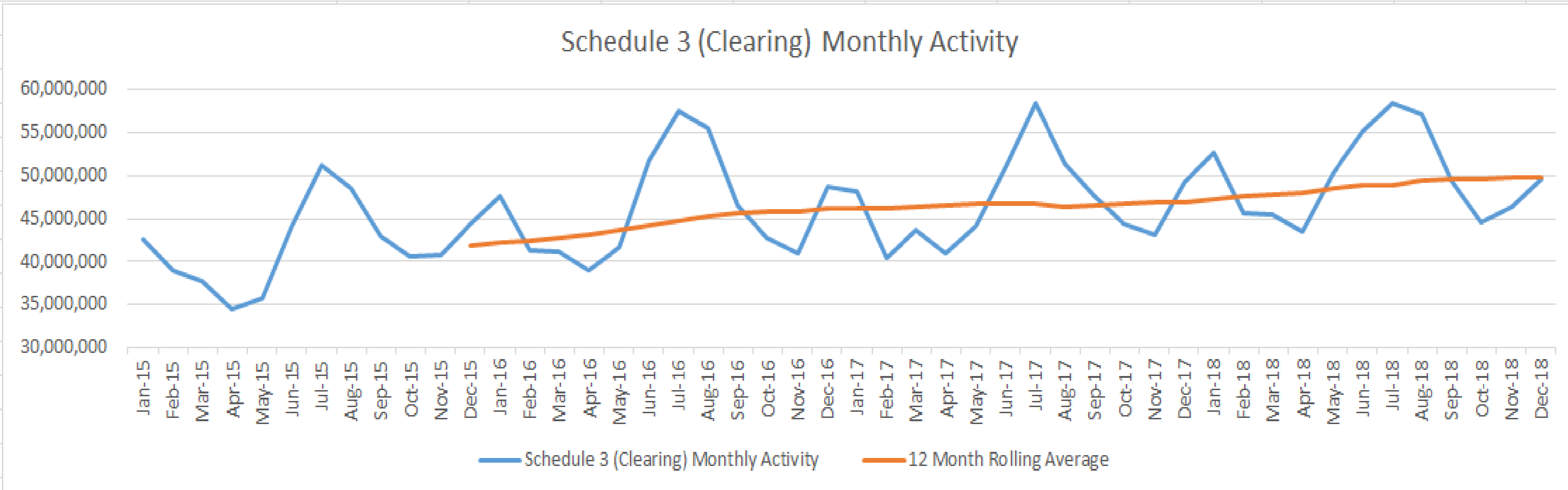
SPP

Schedule 2 Billing Determinant Data



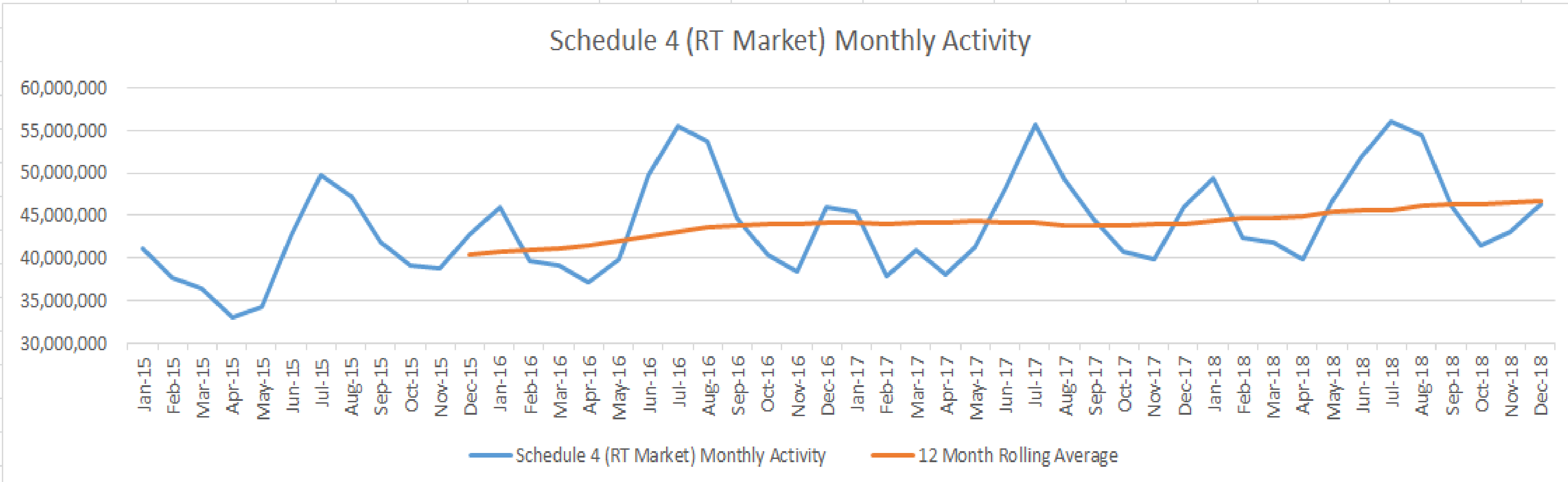
NOTE:
Represents TCRs settled in MWhs on a monthly basis from 2015 -2018.

Schedule 3 Billing Determinant Data



NOTE:
Represents real time generation, load, import/export, and virtual energy cleared in MWhs on a monthly basis from 2015 -2018.

Schedule 4 Billing Determinant Data



NOTE:
Represents real time generation, load, and import/exports cleared in MWhs on a monthly basis from 2015 -2018.

Billing Determinant Analysis

- Observations

1) Rolling average for Schedule 3 and 4 billing determinants is relatively flat with only a modest rise over the 4 year period

2) Rolling average for Schedule 2 billing determinants is relatively flat with moderate rise beginning in late 2017 (likely due to increased congestion from wind, increase in financial only asset owners, etc.)

3) Utilizing a rolling 12 month average as a basis for estimating billing determinants appears to be a reasonable option based on the 2015-2018 historical analysis

SCHEDULE 13

TARIFF ADMINISTRATIVE SERVICES

I. GENERAL

The Transmission Provider shall provide the administrative services described in this Schedule 13 to carry out its responsibilities under this Tariff. Transmission Customers and Market Participants must purchase these services from the Transmission Provider. In projecting and recovering its expenses, the Transmission Provider shall recover 100% of its total expenses through the charges described in this Schedule 13.

II. SCHEDULE 13-1 TRANSMISSION SCHEDULING, SYSTEM CONTROL AND DISPATCH, AND RELIABILITY PLANNING ADMINISTRATIVE SERVICE

Transmission scheduling, system control and dispatch, and reliability planning administrative service is provided by the Transmission Provider to all Transmission Customers under this Tariff. This service includes the provision of: (1) scheduling; (2) system control; (3) dispatching; and, (4) system planning services ("Schedule 13-1 Service").

A. SCHEDULE 13-1 SERVICE CHARGE

The Schedule 13-1 Service charge provides for the recovery of any costs incurred by the Transmission Provider in providing this Schedule 13-1 Service.

1. Costs to Be Recovered

The costs to be recovered under this Schedule 13-1 in the monthly charges include without limitation, any costs of direct resources, system maintenance, debt service (including costs of financing capital purchases associated with providing Schedule 13-1 Service), corporate overhead (including a proportionate allocation of indirect costs associated with providing Schedule 13-1 Service), and other costs associated with providing Schedule 13-1 Service ("Schedule 13-1 Costs").

2. Billing Determinants

Schedule 13-1 Costs are recovered by assessing Point-to-Point Transmission Service and Network Integration Transmission Service. The billing determinant used for the Schedule 13-1 Service rate assessed to Point-To-Point Transmission Service is all capacity reserved by Transmission Customers. The billing determinant used for the Schedule 13-1 Service rate assessed to Network Integration Transmission Service is the 12 month average of the Transmission Customer's coincident Zonal Demands used to determine the Demand Charges under Schedule 9 multiplied by the number of all hours of the applicable month. The charge per MW per hour shall be the same for Point-To-Point Transmission Service as for Network Integration Transmission Service.

3. Rate Formula

Annually, the Transmission Provider shall determine the Schedule 13-1 Service rate for each calendar year by dividing the Transmission Provider's projected Schedule 13-1 Costs, adjusted by any prior year under recovery or over recovery, by the projected Schedule 13-1 billing determinants for that year.

B. SCHEDULE 13-1 CHARGES TO TRANSMISSION CUSTOMERS

For each month, the charges for Transmission Customers shall be calculated by multiplying the effective Schedule 13-1 rate as determined above by the Transmission Customer's billing determinants in accordance with this Schedule 13-1.

Transmission Service Request Charges:

The Transmission Customer shall pay the Transmission Provider a charge for each new Transmission Service Request as follows:

(i) For Firm Point-To-Point Transmission Service:

Reservations less than one month: $100

Reservations one month or longer: $200

(ii) For Non-Firm Point-To-Point Transmission Service:

Each Reservation: $0.

However, the Transmission Customer shall have this fee rebated to it once the Transmission Customer becomes legally obligated to pay the applicable Firm Point-To-Point Transmission Service charges under this Tariff or if the requested Firm Point-To-Point Transmission Service is denied by the Transmission Provider.

Bad Debt Expense:

The Transmission Provider shall include in its charges under this Schedule a component to cover estimated bad debts. The Transmission Provider shall reconcile actuals to estimates and shall adjust future monthly charges to reflect either over or under recoveries.

III. SCHEDULE 13-2 TRANSMISSION CONGESTION RIGHTS ADMINISTRATIVE SERVICE

Transmission Congestion Rights administrative service is provided by the Transmission Provider to all Market Participants that own Transmission Congestion Rights ("TCRs") issued by the Transmission Provider through allocation, assignment, auction or any other process under this Tariff. ("TCR Owner"). This service includes the provision of: (1) TCR administration through allocation, assignment, auction or any other process under this Tariff; (2) simultaneous feasibility tests and other applicable studies to determine the total TCRs that can be accommodated by the Transmission System; (3) TCR tools; and, (4) a secondary market for TCRs ("Schedule 13-2 Service").

A. SCHEDULE 13-2 SERVICE CHARGE

The Schedule 13-2 Service charge provides for the recovery of any costs incurred by the Transmission Provider in providing this Schedule 13-2 Service.

1. Costs to Be Recovered

The costs to be recovered under this Schedule 13-2 in the weekly charges include without limitation, any direct resources, system maintenance, debt service (including costs of financing capital purchases associated with providing Schedule 13-2 Service), corporate overhead (including a proportionate allocation of indirect costs associated with providing Schedule 13-2 Service), and all other costs associated with providing Schedule 13-2 Service ("Schedule 13-2 Costs").

2. Billing Determinants

The billing determinant for the Schedule 13-2 Service rate is the total amount of TCR volume for all TCR Owners expressed in MWh. The total TCR volume is the sum of the hourly TCR MWh for each billing period.

3. Rate Formula

Annually, the Transmission Provider will determine the Schedule 13-2 Service rate for each calendar year by dividing the Transmission Provider's projected Schedule 13-2 Costs, adjusted by any prior year under recovery or over recovery, by the projected Schedule 13-2 billing determinant for that year.

B. CHARGES TO MARKET PARTICIPANTS

For each week, the charges for Market Participants will be calculated by multiplying the effective Schedule 13-2 Service rate as determined above by the Market Participant's billing determinant in accordance with this Schedule 13-2.

IV. SCHEDULE 13-3 INTEGRATED MARKETPLACE CLEARING ADMINISTRATIVE SERVICE

Integrated Marketplace clearing administrative service is provided by the Transmission Provider to all Market Participants that participate in transactions pursuant to Attachment AE of this Tariff or an applicable Market Participant Service Agreement as contained in Attachment AH of this Tariff. This service includes the provision of: (1) market settlements; (2) credit evaluation and risk mitigation services; (3) market monitoring functions; (4) information technology support; and, (5) customer service (“Schedule 13-3 Service”).

A. INTEGRATED MARKETPLACE CLEARING ADMINISTRATIVE SERVICE CHARGE

The Schedule 13-3 Service charge provides for the recovery of any costs incurred by the Transmission Provider in providing this Schedule 13-3 Service.

1. Costs To Be Recovered

The costs to be recovered under this Schedule include without limitation, any direct resources, corporate overhead (including a proportionate allocation of indirect costs associated with providing Schedule 13-3 Service), and all other costs associated with providing Schedule 13-3 Service (“Schedule 13-3 Costs”).

2. Billing Determinants

The billing determinants for the Schedule 13-3 Service rate, as expressed in MWh are: 1) all Real-Time energy injected into and withdrawn from the Transmission System by all Market Participants; 2) all Import Interchange Transactions in Real-Time and all Export Interchange Transactions in Real-Time; and, (3) all cleared Virtual Energy Bids and all cleared Virtual Energy Offers.

3. Rate Formula

Annually, the Transmission Provider will determine the Schedule 13-3 Service rate for each calendar year by dividing the Transmission Provider’s projected Schedule 13-3 Costs, adjusted by any prior year under recovery or over recovery, by the projected Schedule 13-3 billing determinants for that year.

B. CHARGES TO MARKET PARTICIPANTS

For each week, the charges for Market Participants will be calculated by multiplying the effective Schedule 13-3 Service rate as determined above by the Market Participant’s billing determinants in accordance with this Schedule 13-3.

V. <u>SCHEDULE 13-4 INTEGRATED MARKETPLACE FACILITATION ADMINISTRATIVE SERVICE</u>

The Integrated Marketplace facilitation administrative service is provided by the Transmission Provider to all Market Participants that participate in transactions, except for cleared Virtual Energy Bids and cleared Virtual Energy Offers, pursuant to Attachment AE of this Tariff or an applicable Market Participant Service Agreement as contained in Attachment AH of this Tariff. This service includes the provision and operation of the: (1) Day-Ahead Market; (2) Real-Time Balancing Market; and, (3) Reliability Unit Commitment processes (Schedule 13-4 Service").

A. INTEGRATED MARKETPLACE FACILITATION ADMINISTRATIVE SERVICE CHARGE

The Schedule 13-4 Service charge provides for the recovery of any costs incurred by the Transmission Provider in providing this Schedule 13-4 Service.

1. Costs To Be Recovered

The costs to be recovered under this Schedule 13-4 include without limitation, any direct resources, system maintenance, debt service (including costs of financing capital purchases associated with providing Schedule 13-4 Service), corporate overhead (including a proportionate allocation of indirect costs associated with providing Schedule 13-4 Service), and other costs associated with providing Schedule 13-4 Service ("Schedule 13-4 Costs").

2. Billing Determinants

The billing determinants for the Schedule 13-4 Service rate are: 1) all Real-Time energy injected into and withdrawn from the Transmission System; and, 2) all Import Interchange Transactions in Real-Time and all Export Interchange Transactions in Real-Time.

3. Rate Formula

Annually, the Transmission Provider will determine the Schedule 13-4 Service rate for each calendar year by dividing the Transmission Provider's projected Schedule 13-4 Costs, adjusted by any prior year under recovery or over recovery, by the projected Schedule 13-4 billing determinants for that year.

B. CHARGES TO MARKET PARTICIPANTS

For each week, the charges for Market Participants will be calculated by multiplying the effective Schedule 13-4 Service rate as determined above by the Market Participant's billing determinants in accordance with this Schedule 13-4.

Schedule 1-A – Tariff Administration Service references in the SPP Tariff

Section 13.7	**Classification of Firm Transmission Service**
Section 14.5	**Classification of Non-Firm Point-To-Point Transmission Service**
Section 34.8	**SPP Costs:**
Schedule 1-A	
Attachment F	**Section 8.4.1 Attachment 1 to the NITs Agreement**
Attachment H	**Contains footnotes in several sections that state: Transmission O&M on this line does not include any SPP charges for Schedule 1-A of the SPP OATT.**
Attachment O	**Sections IV and IX**
Attachment AD	**Article II, Section 5**
Attachment AE	**Section 8.5.17 (Virtual Transaction Fee Amount)**
Attachment AS	**WAPA Agreement**

Section 13.7 – Classification of Firm Transmission Service

(c) The Transmission Provider shall provide firm deliveries of capacity and energy from the Point(s) of Receipt to the Point(s) of Delivery. Each Point of Receipt at which firm transfer capability is reserved by the Transmission Customer shall be set forth in the Firm Point-To-Point Service Agreement for long-term firm Transmission Service along with a corresponding capacity reservation associated with each Point of Receipt. Points of Receipt and corresponding capacity reservations shall be as mutually agreed upon by the Parties for short-term firm Transmission. Each Point of Delivery at which firm transfer capability is reserved by the Transmission Customer shall be set forth in the Firm Point-To-Point Service Agreement for long-term firm Transmission Service along with a corresponding capacity reservation associated with each Point of Delivery. Points of Delivery and corresponding capacity reservations shall be as mutually agreed upon by the Parties for short-term firm Transmission

Service. The greater of either (1) the sum of the capacity reservations at the Point(s) of Receipt, or (2) the sum of the capacity reservations at the Point(s) of Delivery shall be the Transmission Customer's Reserved Capacity. The Transmission Customer will be billed for its Reserved Capacity under the terms of Schedules 7 and 11. The Transmission Customer may not exceed its firm capacity reserved at each Point of Receipt and each Point of Delivery except as otherwise specified in Section 22. In the event that a Transmission Customer (including third-party sales by a Transmission Owner) exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery or uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved, the Transmission Customer shall pay the following penalty (in addition to the applicable charges for all of the firm capacity actually used): 100% of the Firm Point-To-Point Transmission Service charges under Schedules 7 and 11 for the period for which the unreserved service was actually used. The charges for the unreserved service shall be based upon the duration of the period when the unreserved capacity was used. For example, one hour shall be billed at the charge for weekday deliveries, repeated daily use of unreserved capacity within a seven day period shall increase the duration of the period to a weekly duration and multiple instances of unreserved use during more than one seven day period during a calendar month shall increase the duration of the period to a monthly duration. The Transmission Provider shall compensate the Transmission Owners for 100% of the (i) Firm Point-To-Point Transmission Service charge, (ii) Base Plan Zonal Charge and (iii) Region-wide Charge for the period for which they have provided service. The penalty revenues in excess of the amount distributed to Transmission Owners shall be used to reduce the Schedule 13-1~~1 A~~ charges collected by the Transmission Provider from the Transmission Customers. All Transmission Customers, except the penalized Transmission Customer, shall receive a reduction of Schedule 13-1~~1 A~~ charges pursuant to this section. Such penalty revenues shall be distributed by the Transmission Provider to Transmission Customers on a pro-rata basis of each Transmission Customer's monthly Schedule 13-1~~1-A~~ charge, except for the penalized Transmission Customer, for the next billing period ending at least 15 calendar days after the date the Transmission Provider collects the penalty revenues from the penalized Transmission Customer. For the amounts exceeding reserved capacity, the Transmission Customer also must purchase losses as required by this Tariff.

14.5 – Classification of Non-Firm Point-To-Point Transmission Service

Non-Firm Point-To-Point Transmission Service shall be offered under terms and conditions contained in Part II of the Tariff. The Transmission Provider and Transmission Owners undertake no obligation under the Tariff to plan the Transmission System in order to have sufficient capacity for Non-Firm Point-To-Point Transmission Service. Parties requesting Non-Firm Point-To-Point Transmission Service for the transmission of firm power do so with the full realization that such service is subject to availability and to Curtailment or Interruption under the terms of the Tariff. The Transmission Customer will be billed for its Reserved Capacity under the terms of Schedules 8 and 11. In the event that a Transmission Customer (including third-party sales by a Transmission Owner) exceeds its non-firm capacity reservation, the Transmission Customer shall pay the following penalty (in addition to the charges for all of the non-firm capacity used): 100% of the Non-Firm Point-To-Point Transmission Service charges under Schedules 8 and 11 for the duration of the period when the additional service was used as specified below not to exceed one month for the amount in excess of such capacity reservation. An excess of one hour or less shall be billed at the charge for weekday deliveries, repeated daily use of unreserved capacity within a seven day period shall increase the duration of the period to a weekly duration and multiple instances of unreserved use during more than one seven day period during a calendar month shall increase the duration of the period to a monthly duration. The Transmission Provider shall compensate the Transmission Owners for 100% of the (i) Non-Firm Point-To-Point Transmission Service charge, (ii) Base Plan Zonal Charge and (iii) Region-wide Charge for the period for which they have provided service. The penalty revenues in excess of the amount distributed to Transmission Owners shall be used to reduce the Schedule 13-1~~1-A~~

charges collected by the Transmission Provider from the Transmission Customers. All Transmission Customers, except the penalized Transmission Customer, shall receive a reduction of Schedule 13-1~~1-A~~ charges pursuant to this section. Such penalty revenues shall be distributed by the Transmission Provider to Transmission Customers on a pro-rata basis of each Transmission Customer's monthly Schedule 13-1~~1-A~~ charge, except for the penalized Transmission Customer, for the next billing period ending at least 15 calendar days after the date the Transmission Provider collects the penalty revenues from the penalized Transmission Customer. For the amounts exceeding the non-firm capacity reservation, the Transmission Customer must purchase losses as required by this Tariff. Non-Firm Point-To-Point Transmission Service shall include transmission of energy on an hourly basis and transmission of scheduled short-term capacity and energy on a daily, weekly or monthly basis, but not to exceed one month's reservation for any one Application, under Schedules 8 and 11.

34.8 SPP Costs:

The Network Customer shall pay SPP's administrative costs in accordance with Schedule 13-1~~1-A~~.

Schedule 1-A – Tariff Administration Service

The Transmission Provider shall provide Tariff Administration Service to carry out its responsibilities under this Tariff. The Transmission Customer must purchase this service from the Transmission Provider. The charges for this Service are to be developed as shown below.

1. Administration Charge:

An administration charge shall be applied to all transmission service under this Tariff to cover the Transmission Provider's expenses related to administration of this Tariff. For Point-To-Point Transmission Service this charge shall be up to $0.43 per MW per hour for all capacity reserved. For Network Integration Transmission Service this charge shall be up to $0.43 per

MW per hour for the 12 month average of the Transmission Customer's coincident Zonal Demands used to determine the Demand Charges under Schedule 9 multiplied by the number of all hours of the applicable month. The charge per MW per hour shall be the same for Point-To-Point Transmission Service as for Network Integration Transmission Service.

For each calendar year, the Transmission Provider shall establish a rate for this administration charge by dividing projected expenses based on its budget for the calendar year divided by the projected annual Schedule 1-A billing units for the calendar year. The Transmission Provider shall reconcile actuals to budgeted figures and shall adjust charges for the following calendar year to reflect either over or under recoveries of its costs for the prior year to allow the Transmission Provider to recover its actual costs. In projecting and recovering its expenses, the Transmission Provider shall recover 100% of its total expenses through this charge up to the cap of $0.43 per MW per hour for all transmission service under the Tariff.

2. <u>Transmission Service Request Charges</u>:

The Transmission Customer shall pay the Transmission Provider a charge for each new Transmission Service Request as follows:

(i) For Firm Point-To-Point Transmission Service:

Reservations less than one month: $100

Reservations one month or longer: $200

(ii) For Non-Firm Point-To-Point Transmission Service:

Each Reservation: $0.

However, the Transmission Customer shall have this fee rebated to it once the Transmission Customer becomes legally obligated to pay the applicable Firm Point-To-Point Transmission Service charges under this Tariff or if the requested Firm Point-To-Point Transmission Service is denied by the Transmission Provider.

3. <u>Bad Debt Expense</u>:

The Transmission Provider shall include in its charges under this Schedule a component to cover estimated bad debts. The Transmission Provider shall reconcile actuals to estimates and shall adjust future monthly charges to reflect either over or under recoveries.

Attachment F - In Attachment 1 to the NITs Agreement:

8.4.1 The following Ancillary Services are required under this Service Agreement.

a) Scheduling, System Control and Dispatch Service per Schedule 1 of the Tariff.

b) Tariff Administration Service per Schedule 13-1~~1-A~~ of the Tariff.

c) Reactive Supply and Voltage Control from Generation Sources Service per Schedule 2 of the Tariff.

d) Regulation and Frequency Response Service per Schedule 3 of the Tariff.

e) Energy Imbalance Service per Schedule 4 of the Tariff.

f) Operating Reserve - Spinning Reserve Service per Schedule 5 of the Tariff.

g) Operating Reserve - Supplemental Reserve Service per Schedule 6 of the Tariff.

The Ancillary Services may be self-supplied by the Network Customer or provided by a third party in accordance with Sections 8.4.2 through 8.4.4, with the exception of the Ancillary Services for Schedules 1, ~~1-A, and~~ 2, and 13-1, which must be purchased from the Transmission Provider.

Attachment H – There are Schedule 1-A references in 10 Transmission Owner formula rate schedules that require TO filings (and SPP filings). See Attachment.

Attachment O – Section IV

(3)(c) The stakeholders may request high priority studies, including a request for the Transmission Provider to study potential upgrades or other investments necessary to integrate any combination of resources, whether demand resources, transmission, or generation, identified by the stakeholders. Annually, the costs of up to three high priority studies requested by the stakeholders and performed by the Transmission Provider shall be recovered pursuant to Schedule 1-A of this Tariff. A high priority study of a potential Balanced Portfolio initiated by the Transmission Provider will not be considered a stakeholder request pursuant to this Section IV.3.c of this Attachment O.

Attachment O – Section IX

1) The Transmission Provider's costs associated with the planning process and associated studies set forth in this Attachment O shall be recovered pursuant to Schedule 1-A of the Tariff.

Attachment AD – SPA Contract

Article II, Section 5(a) (a) For long-term firm transmission (one year or longer) and network integration transmission service contracts executed between December 31, 2006, and January 31, 2009, that involve schedules for the delivery of non-Federal power to load served from the System of Southwestern, only the following billing determinants of the SPP Tariff shall apply: (i) Schedule 1 - Scheduling, System Control and Dispatch Service; (ii) Schedule 13-1~~1-A~~ - Tariff Administration Service; (iii) Schedule 2 - Reactive Supply and Voltage Control from Generation Sources Service; and (iv) Attachment M - Loss Compensation Procedure. With the exception of Schedule 13-1~~1-A~~, SPP shall bill the transmission customer for such billing determinants of the SPP Tariff and apply the SPP Tariff revenue distribution methodology for the amounts received by SPP associated with such SPP billing determinants. Southwestern shall coordinate with SPP to calculate the appropriate Schedule 13-1~~1-A~~ charges, for which Southwestern shall invoice the customer and subsequently provide to SPP in accordance with Section 3 of Article I of this Attachment AD. All other portions of Southwestern's rates and Southwestern's Tariff provisions for transmission service, excluding the SPP Tariff billing determinants noted in this Section 5(a), shall apply to such transactions, and Southwestern shall bill the transmission customer for such portions and retain the revenue.

Attachment AE – Section 8.5.17 Day Ahead Virtual Energy Transaction Fee Amount

A Day-Ahead Market charge for each submitted Virtual Energy Offer and Virtual Energy Bid will be calculated for each Asset Owner for each Operating Day. Charges collected by the Transmission Provider under this charge type are used by the Transmission Provider to reduce the Transmission Provider budgeted expenses used to calculate the rate specified under Schedule 1-A of the Tariff and are calculated as follows:

Day-Ahead Virtual Energy Transaction Fee Amount =

[(Day-Ahead Virtual Energy Transaction Daily Count) * (Day-Ahead Virtual Energy Transaction Fee Rate)]

(1) Day-Ahead Virtual Energy Transaction Daily Count is equal to the sum of Virtual Energy Bids and Virtual Energy Offers submitted as of the close of the Day-Ahead Market for all Settlement Locations and hours in the Operating Day.

(2) Day-Ahead Virtual Energy Transaction Fee Rate is $0.05 for each Virtual Energy Offer or Virtual Energy Bid.

Attachment AS – WAPA Contract

Article I – Section 1 (b) SPP, on behalf of Western-UGP, shall administer and provide Transmission Service and ancillary services as the TSP on the West Facilities-UGP beginning October 1, 2015. The term Transmission Service, where used herein, shall include both Point-to-Point Transmission Service ("PTP") and Network Integration Transmission Service ("NITS") as defined under the SPP OATT for the use of the West Facilities-UGP for the movement of electric capacity or energy on either a firm or non-firm basis. The term Transmission Customer shall be as defined in the SPP OATT. Transmission Service provisions and charges, Schedule 1 and Schedule 2 ancillary services provisions and charges, and losses, shall be according to the SPP OATT; SPP's Administration Charge shall be according to Schedule 13-1~~1 A~~ of the SPP OATT. The term "Administration Charge" as used herein shall be as defined in SPP's OATT.

Other Tariff Changes Needed

Defined terms used in Draft Schedule 13 that are currently only defined in Attachment AE. In order for those defined terms to be applicable to Schedule 13, those defined terms should be removed from Attachment AE definitions to Tariff, Part I Common Service Provision Definitions.

Integrated Marketplace

Transmission Congestion Right

Import Interchange Transaction

Export Interchange Transaction

Real-Time

Virtual Energy Bid

Virtual Energy Offer

Day-Ahead Market

Real-Time Balancing Market

Reliability Unit Commitment

SPP Bylaws

Section 8.4	Monthly Assessments

Attachment H Addendum 2-A Part 1 (OG&E)

Worksheet E, Line 7

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet E

Adjustments to Transmission Expense to Reflect TO's LSE Cost Responsibility

			Relevant Year
1	Other Expenses:		
2	Direct Assignment Charge		
3	Sponsored (Requested or Economic) Upgrades Charge		
4	Firm and Non-Firm Point-To-Point Charges		
5	Base Plan Charges		
6	Schedule 9 Charges		
7	SPP Schedule 1-A		
8	SPP Annual Assessment		
9	NERC Assessment		
10	Ancillary Services Expenses		
11	Other		
12	Other		
13	Other		
14	Total	(Sum of lns 2 through 13)	$ -

Attachment H Addendum 39 (WFEC) Part 1

Schedule 1, Line 10

Page No.

Schedule 1

Western Farmers Electric Cooperative, Inc.

Schedule 1 Revenue Requirements

Year Ending December 31,

A	B	C	D	E	
Line No.	**Account Number**	**Description**	**Reference**	**Amount**	
1		<u>A, Schedule 1: Annual Revenue Requirement</u>			
2		Schedule 1 expenses	Worksheet B, Line 41 Col L	#DIV/0!	
3		<u>Adjustments</u>			
4		Transmission Service Studies	Worksheet F, Line 5 Col G	$	-
5		Generation Interconnection Studies	Worksheet F, Line 6 Col G	$	-
6		Regional Planning & Standards development	Worksheet F, Line 7 Col G	$	-
7		NERC Assessment Fee	Worksheet F, Line 8 Col G	$	-

8		FERC Assessment Fee	Worksheet F, Line 9 Col G	$ -
9		SPP Schedule 1 Charges	Worksheet F, Line 10 Col G	$ -
10	561.0040	SPP Schedule 1A Charges	Worksheet F, Line 11 Col G	$ -

Worksheet F

							Worksheet F
Western Farmers Electric Cooperative, Inc.							
General Input Section							
Year Ending December 31,							
B	**C**	**D**	**E**	**F**	**G**		
Account Number	**Description**	**Reference**	**BoY**	**EoY**	**Value or Amount $**		
	Billing Lag in days	**Industry Standard**			**45**		
	CWIP to included in Rate Base	**ER16-1774 Settlement**			**50%**		
	Return on Equity	**ER16-1774 Settlement**			**9.27%**		
	Target Equity Floor	**ER16-1774 Settlement**			**35.24%**		
					Year End r 31,		
561.60	**Transmission Service Studies**	**Trial Balance Amount**					
561.70	**Generation Interconnection Studies**	**Trial Balance Amount**					
561.80	**Regional Planning & Standards development**	**Trial Balance Amount**					
	NERC Assessment Fee	**Trial Balance Amount**					
	FERC Assessment Fee	**Trial Balance Amount**					
	SPP Schedule 1 Charges	**Trial Balance Amount**					

561.0040	**SPP Schedule 1A Charges**	**Trial Balance Amount**					
	Schedule 1-Adjustment						

Attachment H Addendum 3 (Westar) Part 1

Actual Gross Rev Page 5 of 5, Note D

Rate Formula Template

Utilizing FERC Form 1 Data

Actual Gross Revenue Requirements

For the 12 months ended - December 31, xxxx

WESTAR ENERGY, INC. (Westar Energy and Kansas Gas and Electric)

(WESTAR)

NOTES

General Note: References to pages in this formula rate are indicated as: (page#, line#, col.#).

References to data from FERC Form 1 are indicated as: page#.line#.col

Note Letter

A Reserved for future use.

B Identified in Form 1 as being only transmission related.

C Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 2, line 11, col. 7.

Prepayments are the electric related prepayments booked to Account No. 165 and reported on FERC Form 1, p. 111, ln. 57.c.

D Transmission O&M expense does not include any SPP charges for Schedule 1-A of the SPP OATT.

E Transmission By Others, Account 565 includes only costs associated with transmission facilities which are assigned to the Westar pricing zone by SPP.

F Industry Association Dues are capped at $1,000,000. Line 6 - EPRI Annual Membership Dues listed in Form 1 at p. 335,

Line 6a Remove all Advertising expenses in Account 930.1.

Line 6b Remove all Regulatory Commission Expenses itemized at 351.h.

Line 6c - Add in wholesale Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.

Line 6d Add in Safety related advertising that are in Account 930.1.

G Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year.

Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.

H The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p ="the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a

work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce

rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 28). When FIT or SIT statutory tax rate changes take effect on other than a calendar year basis, the statutory

rates to be used in the formula rate template shall be weighted averages for the calendar year determined by weighting the statutory tax rates by the number days each such tax rate was in effect during the calendar year for which the costs are being determined.

Inputs Required: FIT =

SIT=		(State Income Tax Rate or Composite SIT)
p =		(percent of federal income tax deductible for state purposes)

I	Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until FERC Form 1 balances are adjusted to reflect application of seven-factor test).
J	Unless otherwise specified, OATT refers to the Westar and SPP OATTs.
K	Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to be included in OATT ancillary services. For these purposes, generation step-up facilities are those
	facilities at a generator substation on which there is no through-flow when the generator is shut down.
L	Removes dollar amount of transmission expenses included in the OATT ancillary services rates. Costs related to Ancillary 1, Scheduling and Control, Acct 561 is shown on Actual Gross Rev, page 2, line 2.
M	Enter dollar amounts
N	For Account 216.1, enter zero if the actual balance is negative
O	Debt cost rate = long-term interest (line 15) / long term debt (line 21). Preferred cost rate = preferred dividends (line 16) / preferred stock (line 22).
	The approved ROE is 11.3%, no change in ROE may be made absent a filing with FERC. Any incentive ROEs approved by the Commission are shown by project in Worksheet A-11.
P	If the transmission related component of property tax is specifically identified in Form 1, then a TP allocator shall be used. Property tax shall be allocated to transmission by the GP allocator if transmission related property tax is not specifically identified in the Form 1.
Q	The initial depreciation rates below will be used to calculate depreciation expense and accumulated depreciation balances absent an appropriate filing with FERC.

(KCP&L)

General Note: References to pages in this formula rate are indicated as: (page#, line#, col.#).

References to data from FERC Form 1 are indicated as: page#.line#.col

Note Letter	
A	Reserved for future use.
B	Includes only Transmission plant.
C	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 2, line 7, col. 7.
	Prepayments are the electric related prepayments booked to Account No. 165 and reported on FERC Form 1, p. 111, ln. 57.c.
D	Expenses recorded in Account 565, Transmission of Electricity by Others, are not recoverable through the

formula rate.

E Lease and joint facilities charges included on line 6, page 2 of 5, are those costs attributable to transmission facilities.

F Transmission O&M on this line does not include any SPP charges for Schedule 1-A of the SPP OATT.

G Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year.

Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template.

H The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "percentage of federal income tax deductible for state income tax purposes". Furthermore, a utility that elected to utilize amortization of tax credits against taxable income rather than book tax credits to Account 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 2, line 21). When FIT or SIT statutory tax rate changes take effect on other than a calendar year basis, the statutory rates to be used in the formula rate template shall be weighted averages for the calendar year determined by weighting the statutory tax rates by the number days each such tax rate was in effect during the calendar year for which the costs are being determined. KCMO Earnings Tax is not included in the calculation of the Composite State Income Tax Rate.

Inputs Required:	FIT =	0.00%	Federal Income Tax Rate
	SIT =	0.00%	Composite State Income Tax Rate or Composite SIT
	p =	0.00%	Percentage of federal income tax deductible for state income tax purposes

The Composite State Income Tax Rate reflects the effective rate for each tax jurisdiction, as well as the Composite Portion of FIT Deduction in State Returns:

	% of FIT	Portion of Fed Tax

	Apportionment Factor	Rate	Effective Rate	Deductible	Deductible = p
Missouri	0.00%	0.00%	0.0000%	0.00%	0.0000%
Kansas	0.00%	0.00%	0.0000%	0.00%	0.0000%
KS City	0.00%	0.00%	0.0000%	0.00%	0.0000%
Composite State Income Tax Rate			0.0000%		
Composite Portion of FIT Deduction for State Returns					0.0000%

Attachment H Addendum 11 (KCPL-GMO) Part 1A

Actual Gross Rev Page 5 of 5, Note F

Rate Formula Template

Utilizing FERC Form 1 Data

Actual Gross Revenue Requirements

For the 12 months ended - December 31, 20XX

KCP&L GREATER MISSOURI OPERATIONS COMPANY.

Actual Gross

(KCP&L-GMO)

General Note: References to pages in this formula rate are indicated as: (page#, line#, col.#).

References to data from FERC Form 1 are indicated as: page#.line#.col

Note Letter	
A	Reserved for future use.
B	Includes only Transmission plant.
C	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 2, line 7, col. 7.
	Prepayments are the electric related prepayments booked to Account No. 165 and reported on FERC Form 1, p. 111, ln. 57.c.
D	Expenses recorded in Account 565, Transmission of Electricity by Others, are not recoverable through the formula rate.
E	Lease and joint facilities charges included on line 6, page 2 of 5, are those costs attributable to transmission facilities.
F	Transmission O&M on this line does not include any SPP charges for Schedule 1-A of the SPP OATT.
G	Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year.
	Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template.

H The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "percentage of federal income tax deductible for state income tax purposes". Furthermore, a utility that elected to utilize amortization of tax credits against taxable income rather than book tax credits to Account 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 2, line 21). When FIT or SIT statutory tax rate changes take effect on other than a calendar year basis, the statutory rates to be used in the formula rate template shall be weighted averages for the calendar year determined by weighting the statutory tax rates by the number days each such tax rate was in effect during the calendar year for which the costs are being determined. KCMO Earnings Tax is not included in the calculation of the Composite State Income Tax Rate.

Inputs Required:	FIT =	0.00%	Federal Income Tax Rate
	SIT=	0.00%	Composite State Income Tax Rate or Composite SIT
	p =	0.00%	Percentage of federal income tax deductible for state income tax purposes

Attachment H Addendum 18 (Empire)

Page 13 of 28, Attachment E, Note 3

ADDENDUM 18 TO ATTACHMENT H - Page 13 of 28
The Empire District Electric Company

Attachment 3 - Revenue Credits
(For Rate Year Beginning July 1, 20 , Based on 20 Data)

Account 454 - Rent from Electric Property		
1	Rent from Electric Property [FF1, Pg. 300, Ln. 19, Col. b] [From Inputs, Pg. 2, Ln. 72]	-
2	T/D Revenue Allocation Factor [From Appendix A, Ln. 19]	-
3	Rent from Electric Transmission Property [Line 1 x Line 2]	-
Other Electric Revenues (Note 1)		
4	SPP Schedule 7 & 8 Transmission Revenues (Note 1 & Note 4) [From Inputs, Pg. 3, Ln. 18]	-
5	This Line Not Used	
6	This Line Not used	
7	Non-Firm Point-to-Point Service revenues for which the load is not included in the divisor received by	

Transmission Owner (Note 4) [From Inputs, Pg. 3, Ln. 20]	-
8 Direct Assigned Facilities Revenues (Note 2) [From Inputs, Pg. 3, Ln. 15]	-
9 Other Revenues Associated with Loads Outside of Empire's Zone [From Inputs, Pg. 3, Ln. 19]	-
10 Gross Revenue Credits (sum Lines 3 thru 9) [To Appendix A, Line 122]	-

Note 1: All Schedule 7 & 8 revenues derived as a Transmission Owner from SPP for loads not included in the system peak and for which the cost of the service is recovered under this formula will be included in this revenue credit. These revenues are booked in Accounts 457.137 (Firm Point-to- Point) and 457.138 (Non-Firm Point-to-Point). All current NITS customers in the Empire zone are included in the Load Divisor.

Note 2: If the costs associated with Directly Assigned Transmission Facility Charges are included in this TFR, the associated revenues will be included in this TFR. If the costs associated with the Directly Assigned Transmission Facility Charges are not included in this TFR, the associated revenues will not be included in this TFR.

Note 3: Schedule 1A charges are assessed by SPP directly to the transmission customers and are retained by SPP. Schedule 12 revenues associated with Transmission Service are collected by SPP and remitted to FERC by SPP. Any Schedule 1a or Schedule 12 revenues collected by Empire on behalf of Zonal customers are not retained by Empire, but are simply passed through to SPP.

Note 4: The portion of Point-to-Point revenues collected by SPP and assigned to Empire are included on ATT 3, Ln. 4. Any demand revenue margins collected directly by Empire for "grandfathered" bundled contracts will be included on ATT 3, Ln. 8. See note on "Inputs" worksheet, Pg. 3, Ln. 20 regarding remaining pre-OATT contracts.

Attachment H Addendum 19 (MKEC) Part 1

Actual Gross Rev Req Page 5 of 5, Note H

Page 8 of 71	Actual Gross Rev Req
	Page 5 of 5
Mid-Kansas Electric Company, LLC (MKEC) **Rate Formula Template** **Actual Gross Revenue Requirements** **For the 12 months ended - December 31, 2010**	
General Note: References to pages in this formula rate are indicated as: (Pg. #, L(in) #, Col.#).	
References to data from MKEC's Annual Report to the KCC are	

indicated as: (Pg. #, L(in) #, Col. #)

Note	
A	MKEC records expense associated with providing Schedule 1, Scheduling, System Control, and Dispatch Service, in both Accts. 561 and 565. See Actual Sch 1 Rev Req, and Workpaper S1.
B	Includes only Land Held for Future Use associated with Transmission facilities.
C	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at Pg. 2, L73, Col. 6.
D	Prepayments are the electric related prepayments booked to Acct. 165 and reported on MKEC's KCC Annual Report Pg. 17, L20, Col. b.
E	Expenses recorded in Account 565, Transmission of Electricity by Others, are not recoverable through the formula rate. The amount shown above excludes $ - which was manually reclassified to other accounts.
F	Lease and joint facilities charges included on L61, page 2 of 5, are those costs attributable to transmission facilities.
G	This line sahll not be populated unless authorized by the Commission.
H	Transmission O&M on this line does not include any SPP charges for Schedule 1-A of the SPP OATT.
I	Includes only unallocated FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Pursuant to RUS accounting standards, the majority of this other tax expense is allocated
	directly to the appropriate O&M accounts. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template.
J	Removes transmission plant determined by Commission order to be excluded from RTO transmission rate base to the extent that plant balances are not adjusted.
K	Removes generator step-up facilities determined by Commission order to be excluded from RTO transmission rate base to the extent plant balances are not adjusted. MKEC records this investment in a production plant account.
L	As more fully described in Section C.3.e. of the Protocols, any amounts received from ITC Great Plains, LLC (ITC), shall be booked as non-operating income in the year received except for amounts designated as a “Maintenance Retainer,” which shall be deferred and amortized into non-operating income over three years
M	If the transmission related component of property tax is specifically identified in MKEC's KCC Annual Report, then a TP allocator shall be used. Property tax shall be allocated to transmission by the GP allocator if transmission related property tax is not specifically identified in the KCC Annual Report.
N	Return is based on the maximum of either a MFI or DSC test.
O	Reserved for future use.
P	The approved MFI and DSC ratios will be established by the KCC. No change in MFI and DSC may be made absent a filing with the KCC. Any incentive ROEs approved by the FERC are shown by project in Worksheet A-9.
Q	The current depreciation rates used to calculate depreciation expense and accumulated depreciation balances are shown in worksheet A-5 (Act. Depreciation Rate).
R	Reserved for future use.

S		The Unamortized Abandoned Transmission Plant can only be included in rate base if authorized by the Commission.
T		Reserved for future use.
U		Reserved for future use.

Attachment H Addendum 20 (Sunflower) Part 1

Actual Gross Rev Req Page 5 of 5, Note H

Page 8 of 81		Actual Gross Rev Req Page 5 of 5
Sunflower Electric Power Corporation (SEPC) **Rate Formula Template** **Actual Gross Revenue Requirements** **For the 12 months ended - December 31, 2012**		
General Note: References to pages in this formula rate are indicated as: (Pg. #, L(in) #, Col.#).		
References to data from SEPC's Annual Report to the KCC are indicated as: (Pg. #, L(in) #, Col. #)		
Note		
A		Reduce Rate Base by Unrefunded Transmission customer advances for construction. This line shall be directly assigned 100% to Transmission. Provide separate workpaper to support adjustment.
B		Includes only Land Held for Future Use associated with Transmission facilities.
C		Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at Pg. 2, L74, Col. 6.
D		Prepayments are the electric related prepayments booked to Acct. 165 and reported on SEPC's KCC Annual Report Pg. 17, L20, Col. b.
E		Expenses recorded in Account 565, Transmission of Electricity by Others, are not recoverable through the formula rate.
F		Lease and joint facilities charges included on L62, page 2 of 5, are those costs attributable to transmission service.
G		This line shall not be populated unless authorized by the Commission.

H		Transmission O&M on this line does not include any SPP charges for Schedule 1-A of the SPP OATT.
I		Includes only unallocated FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Pursuant to RUS accounting standards, the majority of this other tax expense is allocated
		directly to the appropriate O&M accounts. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template.
J		Removes transmission plant determined by Commission order to be excluded from RTO transmission rate base to the extent that plant balances are not adjusted.
K		Removes generator step-up facilities determined by Commission order to be excluded from RTO transmission rate base to the extent plant balances are not adjusted. SEPC records this investment in a transmission plant account.
L		As more fully described in Section C.3.e. of the Protocols, any amounts received from ITC Great Plains, LLC (ITC), shall be booked as non-operating income in the year received.
M		If the transmission related component of property tax is specifically identified in SEPC's KCC Annual Report, then a TP allocator shall be used. Property tax shall be allocated to transmission by the GP allocator if transmission related property tax is not specifically identified in the KCC Annual Report.
N		Return is based on the maximum of either a TIER or DSC test.
O		Does not include leases since return associated with leased facilities is included in the lease payment.
P		The approved TIER and DSC rations will be established by the KCC. No change in TIER and DSC may be made absent a filing with the KCC. Any incentive ROEs approved by the FERC are shown by project in Worksheet A-9.
Q		The current depreciation rates used to calculate depreciation expense and accumulated depreciation balances are shown in worksheet A-5 (Act. Depreciation Rate).
R		Reserved for future use.
S		The Unamortized Abandoned Transmission Plant can only be included in rate base if authorized by the Commission.
T		The GP allocator is primarily used to allocate prepaid insurance payments; and Sunflower provide property insurance for leased facilities.
U		Reserved for future use.
V		Includes depreciation of capital lease improvements.
W		Reserved for future use.
X		Excludes Residual Value Note (RVN) balloon principal payment

Attachment H Addendum 22 (Basin Electric)

Worksheet # 3, Line 7

Basin Electric Power Cooperative							
Formula Rate Template							
Load Dispatching & LSE Costs							
							Worksheet #3
							Page 1 of 1
						Schedule 1 (Per SPP Tariff) Revenue Requirement	**Schedule 1 (Per SPP Tariff) Revenue Requirement**
						(Historical)	**(Estimate)**
1		Account 561 Load Dispatching				-	-
2		Less LSE Related Costs				-	-
3		0		(Sum of lines 1 through 2)		$ -	$ -
Adjustments to Transmission Expense to Reflect TO's LSE Cost Responsibility in Accounts other than Account 561							
2		Direct Assignment Charge				-	-

3		Sponsored (Requested or Economic) Upgrades Charge			-	-
4		Firm and Non-Firm Point-To-Point Charges			-	-
5		Base Plan Charges			-	-
6		Schedule 9 Charges			-	-
7		SPP Schedule 1-A			-	-
8		SPP Annual Assessment			-	-
9		NERC Assessment			-	-
10		Ancillary Services Expenses			-	-
11		Other			-	-
12		Other			-	-
13		Other			-	-
14		Total		(Sum of lines 2 through 13)	$ -	$ -
15		Total Adjustments to O&M		(Sum line 1 and line 14)	-	-
Note:						
The addition of new lines and the removal of outdated lines necessary to populate or remove data in the worksheet with the changes in future years does not require a Federal Power Act section 205 or 206 filing. However, the addition or removal of columns and formulas contained within those columns cannot be changed absent a Federal Power Act section 205 or 206 filing, except to reflect the addition of new lines and the removal of outdated lines in the formulas.						

Attachment H Addendum 26 Part 1 (Corn Belt)

Worksheet 2 Page 1 of 1, Line 12

						Worksheet 2
						Page 1 of 1
	Corn Belt Power Cooperative					
	Worksheet 2 - Ancillary Schedule 1 Revenue Requirements and Other Adj to Transmission Expense					
					Historic 20xx	
Ancillary Schedule 1 Revenue Requirements						
1		Account 561			12I.A.2.a	$ -
2		Less LSE Related Costs in 561			line 14	$ -
3		Less MAPP MAPCOR			Co. Records	$ -
4		Less MRO-NERC			Co. Records	$ -
5		Less Line Rentals			Co. Records	$ -
6		Ancillary Schedule 1 Revenue Requirements		to Sch 1, page 3, line 2		$ -
Adjustments to Transmission Expense to Reflect TO's LSE Cost Responsibility in Accounts other than Account 561						
7		Direct Assignment Charge				$ -
8		Sponsored (Requested or Economic) Upgrades Charge				$ -
9		Firm and Non-Firm Point-To-Point Charges				$ -

10		Base Plan Charges				$ -
11		Schedule 9 Charges				$ -
12		SPP Schedule 1-A				$ -
13		SPP Annual Assessment				$ -
14		NERC Assessment				$ -
15		Ancillary Services Expenses				$ -
11		Other				$ -
12		Other				$ -
13		Other				$ -
14		Total		(Sum of lines 7 through 13)		$ -

SCHEDULE 1A TASK FORCE WHITE PAPER

February 2019

Schedule 1A Task Force

REVISION HISTORY

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION	COMMENTS
1/29/2019	D.Branch	Initial Draft	

CONTENTS

SECTION 1: INTRODUCTION & BACKGROUND

SPP currently recovers the vast majority of its operating and capital costs from transmission customers who are taking service under the SPP tariff. This recovery approach was implemented when SPP solely provided transmission service under the SPP tariff. The SPP's operating and capital costs increased with the addition of the Energy Imbalance Services market in 2007 and again in 2014 with the implementation of the Integrated Marketplace. These increases in services and costs warrant a review of SPP's current cost recovery mechanism. There is a desire to have those who use and benefit from SPP's services help pay for those services.

The Schedule 1A Task Force (the "Task Force") was formed to develop a potential rate structure that would recover SPP's costs from the various users of SPP's services with the overarching principles of simplicity, better alignment of payer cost/benefit, and inclusion of energy transactions. The Task Force was comprised of the following members:

John Olsen, Evergy (Chair)
Joel Dagerman, Nebraska Public Power District
David Mindham, ITC Holdings Corp.
John Varnell, Tenaska
Rob Janssen, Dogwood Energy
Alfred Busbee, GDS Associates/ East Texas Electric Cooperatives
R.J. Tallman, Oklahoma Gas & Electric
Wes Berger, Southwestern Public Service Co.
Ray Bergmeier, Sunflower Electric Power Corporation
Greg Garst, Omaha Public Power District
Heather Starnes, Missouri Joint Municipal EUC
Tim Hall, Southern Power
Jason Mazigian, Basin Electric Power Cooperative
Jim Jacoby, American Electric Power-Public Service Company of Oklahoma

SECTION 2: PROCESS OVERVIEW

Before arriving at their final recommendation, the Task Force performed the following activities:

- Reviewed extensively SPP's cost in the FERC 668 reporting categories
- Examined RTO/ISO cost recovery methodologies for other regions
- Reviewed the current Schedule 1A billing processes

- Reviewed multiple iterations of strawman proposals (including staff whitepaper)
- Conducted multiple brain storming sessions on rate design
- Analyzed "cost shifts" between customer groups associated with proposed rate structures
- Reviewed cash flow analysis to assess impact of the proposed rate structures on SPP's cash position throughout the year
- Consulted with SPP's market monitor unit (MMU) to ascertain whether proposed changes would be problematic from a market monitor perspective

Early in the process, the Task Force agreed to use the cost reporting framework that followed the FERC's requirement under Order 668. In summary, all operating costs would be evaluated in the categories that include FERC accounts 575.7 - Market Facilitation, Monitoring & Compliance; 561.4 - Scheduling, System Control & Dispatch; and 561.8 – Reliability Planning & Standards Development.

The Task Force quickly reached general agreement that the proposed structure should use a mix of demand and energy charges. The Task Force also reached general agreement that market costs should be recovered through energy charges and transmission planning costs should be recovered through demand charges. Additional discussions were necessary to determine the ultimate recommendation for 1) allocating Scheduling & Dispatch costs, 2) appropriate energy billing determinants, and 3) treatment of financial instruments (e.g. virtual transactions, TCRs).

After additional analyses and related discussions, the majority of the Task Force voted to 1) combine Scheduling & Dispatch costs with Reliability Planning and these will be part of the demand structure (similar to the current Schedule 1A billing practices); 2) include real time generation, load, and import/exports as energy billing determinants, 3) exclude day ahead market products; and 4) include TCRs and virtual transactions as billable transactions. Using these agreed upon concepts, the Task Force arrived at a four-part rate schedule cost recovery methodology summarized in the following section.

SECTION 3: OVERVIEW OF RATE SCHEDULES

RATE SCHEDULE #1 (RS 1) -
TRANSMISSION SCHEDULING, SYSTEM CONTROL AND DISPATCH, AND RELIABILITY PLANNING ADMINISTRATIVE SERVICE

RS 1 provides for the recovery of costs incurred by the Transmission Provider in providing scheduling, system control, dispatching, and system planning services. The costs to be recovered under RS 1 in the monthly charges include any costs of direct resources, system maintenance, debt service, corporate overhead, and other costs associated with administering this service.

RS 1 costs will be recovered by assessing customers who use Point-to-Point Transmission Service and Network Integration Transmission Service under the SPP tariff. The billing determinant used for this rate schedule assessed to Point-To-Point Transmission Service is all capacity reserved by the Transmission Customers. The billing determinant used for this rate schedule assessed to Network Integration Transmission Service is the 12 month average of the Transmission Customer's coincident Zonal Demands used to determine the Demand Charges under Schedule 9 multiplied by the number of all hours of the applicable month. The charge per MW per hour shall be the same for Point-To-Point Transmission Service as for Network Integration Transmission Service.

Below is an illustration of the calculation for RS 1 utilizing 2017 data for costs and 12CP estimate from the 2018 budget.

Rate Schedule #1		
Planning and Scheduling & Dispatch		
Reliability Planning	$21.6	MM
Scheduling & Dispatch	$42.3	MM
TOTAL COSTS	$64.0	
12CP Billing Determinants	382	TWh
Planning and Scheduling Rate	$0.167	/ MWh

RS1 Voting Results

For 10
Against 2
Abstain 2

Dissenting Opinions

OG&E – Is not convinced that the denominator for RS 1 is correct for these costs, further stating that dispatch is a service to generators and that supply should share in the costs for SPP providing that function.

OPPD – Believes that the scheduling and dispatch costs should be based on energy usage (RS 4) rather than demand (RS 1).

RATE SCHEDULE #2 (RS 2) -
TRANSMISSION CONGESTION RIGHTS ADMINISTRATIVE SERVICE

RS 2 provides for the recovery of any costs incurred by the Transmission Provider in providing 1) TCR administration through allocation, assignment, auction or any other process under this Tariff; 2) simultaneous feasibility tests and other applicable studies to determine the total TCRs that can be accommodated by the Transmission System; 3) TCR tools; and 4) a secondary market for TCRs. The costs to be recovered under RS 2 charges include any direct resources, system maintenance, debt service, corporate overhead, and all other costs associated with the Transmission Provider administering this service.

The billing determinant used for RS 2 is the total amount of TCR volume for all TCR Owners expressed in MWh. The total TCR volume is the sum of the hourly TCR MWh for each billing period.

Below is an illustration of the calculation for RS 2 utilizing 2017 data for costs and billing determinants:

Rate Schedule #2		
TCR Administration		
TCR Administration Costs	$4.4	MM
TCRs Awarded & Converted	547	TWh
TCR Administration Rate	$0.008	/ MWh

RS 2 Voting Results

For	11
Against	2
Abstain	1

Dissenting Opinions

AEP (PSCO) - Did not agree that the denominator should include all "TCRs awarded or converted" and specifically noted that TCRs converted from ARRs should be excluded given that ARRs have already been paid through transmission service charges, and therefore should be excluded from this separate TCR administrative charge.

NPPD – Preferred a denominator that included only those 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. Using this approach would provide for a reasonable compromise to ensure fair but not excessive costs and would preclude any unnecessary double "administrative" billing to hedge native load.

RATE SCHEDULE #3 (RS 3) -
INTEGRATED MARKETPLACE CLEARING ADMINISTRATIVE SERVICE

RS 3 provides for the recovery of costs incurred by the Transmission Provider in providing 1) market settlements; 2) credit evaluation and risk mitigation services; 3) market monitoring functions; 4) information technology support; and, 5) customer service. The costs to be recovered under RS 3 are any direct resources, corporate overhead, and all other costs associated with administering this service.

The billing determinants used for RS 3, as expressed in MWh are: 1) all Real-Time energy injected into and withdrawn from the Transmission System by all Market Participants; 2) all Import Interchange Transactions in Real-Time and all Export Interchange Transactions in Real-Time; and, 3) all cleared Virtual Energy Bids and all cleared Virtual Energy Offers.

Below is an illustration of the calculation for RS 3 utilizing 2017 data for costs and billing determinants:

Rate Schedule #3		
Market Clearing		
Market Monitoring	$3.0	MM
Settlements	$2.8	MM
Information Technology (allocation)	$2.4	MM
Credit	$0.7	MM
Customer Relations (allocation)	$0.9	MM
Clearing Overhead	$9.2	MM
Market Clearing Costs	$19.0	MM
Real Time Generation	260	TWh
Real Time Load	250	TWh
Real Time Import/Export	18	TWh
Virtual Energy	35	TWh
Market Clearing Denominator	563	TWh
Market Clearing Rate	$0.034	/ MWh

Due to the strong relationship between RS 3 and RS 4, one vote was held to accept/reject the schedules collectively. See voting results below the discussion of RS 4.

RATE SCHEDULE #4 (RS 4) -
INTEGRATED MARKETPLACE FACILITATION ADMINISTRATIVE SERVICE

RS 4 provides for the recovery of any costs incurred by the Transmission Provider in providing the 1) Day-Ahead Market; 2) Real-Time Balancing Market; and, 3) Reliability Unit Commitment Processes. The costs to be recovered under RS 4 include any direct resources, system maintenance, debt service, corporate overhead, and other costs associated with administering this service.

The billing determinants used for RS 4, as expressed in MWh, are: 1) all Real-Time energy injected into and withdrawn from the Transmission System and 2) all Import Interchange Transactions in Real-Time and all Export Interchange Transactions in Real-Time.

Below is an illustration of the calculation for RS 4 utilizing 2017 data for costs and billing determinants -

Rate Schedule #4		
Market Faciliation		
Market Facilitation	$87.6	MM
Less: TCR Admin Costs	($4.4)	MM
Less: Market Clearing Costs	($19.0)	MM
Market Facilitation Costs	$64.3	MM
Real Time Generation	260	TWh
Real Time Load	250	TWh
Real Time Import/Export	18	TWh
Market Denominator	528	TWh
Market Facilitation Rate	$0.122	/ MWh

Due to the strong relationship between RS 3 and RS 4, one vote was held to accept/reject both schedules.

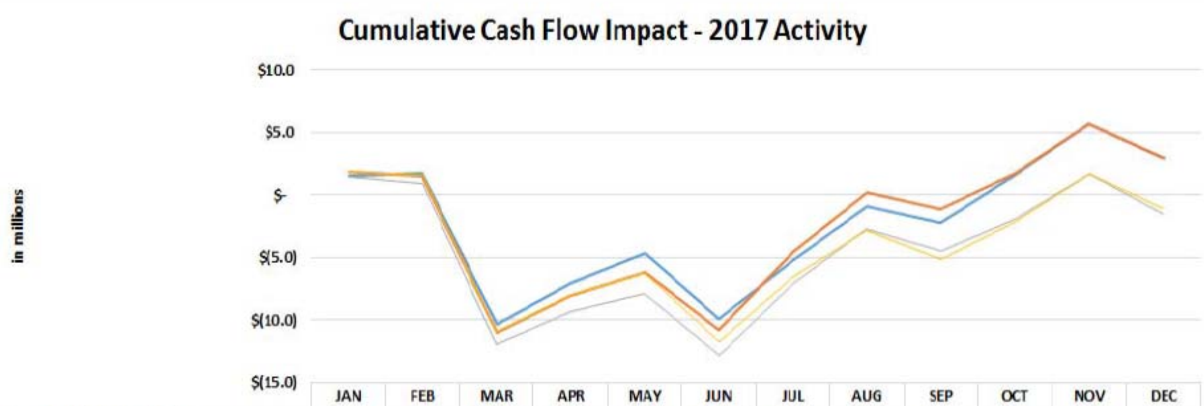
<u>RS 3 and 4 Voting Results</u>
For 10
Against 1
Abstain 1

<u>Dissenting Opinion</u>

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.

SECTION 4: CASH FLOW ANALYSIS

Once the proposed rate structure was in place, staff performed a review of the impact that the new structure would have on our cash flows, including a sensitivity analysis to contemplate the impacts that fluctuations in billing metrics could have on cash flows. An exhibit from that analysis is presented below for illustrative purposes.



	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)

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 the periods examined 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 actionable concern and that it would take a 10% annual decrease in billing determinants to get close to that $15.0MM threshold in the periods examined in this analysis.

NOTE: Once the Task Force reviews billing determinant trending analysis and makes a final decision on true-up cadence at its 2/5 meeting, SPP staff will add concluding language to this section.

SECTION 5: CONCLUSION

SPP's current administrative fee structure was established when SPP first provided transmission service under its tariff in 1998 and obviously never contemplated the additional energy market services currently provided. The overarching principles guiding the Task Force since its inception was to develop a rate structure that was simple to implement/administer, provided better alignment of beneficiary with payer, and included energy transactions. The Task Force carefully researched and evaluated the costs comprising SPP's administrative fee in relationship to our required reporting under FERC Order 668, considered the structure and methodology utilized by other RTO/ISOs, and deliberately examined the services provided by SPP through the lens of the beneficiary versus payer. Through much analysis and spirited debate, the Task Force has agreed upon a four-rate schedule cost recovery methodology described in detail in this document. This proposed methodology allocates a proportionate share of recoverable costs to our market participants including financial only entities. Additionally, staff believes that the current proposed structure will not translate to any material system or staffing costs to implement/administer. In conclusion, the Task Force recommends the four-rate schedule cost recovery methodology as described in this document for further consideration/approval by all relevant governing bodies to move forward with all activities necessary for full implementation.