ITEM NO. 3

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: March 21, 2017

REGULAR X **CONSENT** ____ **EFFECTIVE DATE** ____________

DATE: March 14, 2017

TO: Public Utility Commission

FROM: Lance Kaufman and Scott Gibbens

THROUGH: Jason Eisdorfer and Marc Hellman

SUBJECT: PACIFIC POWER: (Docket No. UE 307) Staff's report of the Commission ordered TAM workshops.

STAFF RECOMMENDATION:

Staff has no recommendation at this time.

DISCUSSION:

In the final order of PacifiCorp's most recent net power cost proceeding, the Commission directed PacifiCorp, Staff and other parties to participate in workshops to examine the following GRID issues: (1) Day-Ahead/Real-Time Transaction (DART) adjustments, (2) Energy Imbalance Market (EIM) benefit estimation, and (3) Renewable Energy Credit (REC) valuation. Three workshops were held to address these issues. This memo reports on the results of the workshop.

Analysis

In Docket No. UE 307, PacifiCorp's most recent net power cost proceeding, Staff, the Industrial Customers of Northwest Utilities (ICNU), the Citizens' Utility Board of Oregon (CUB), and Calpine Energy Solutions (Calpine) raised concerns regarding PacifiCorp's treatment of DART, EIM, and/or RECs in the TAM. On December 20, 2016, the Commission issued Order No. 16-482. This order directed parties to hold informal discussions regarding these issues, and directed Staff to report on them prior to PacifiCorp's next TAM filing. The Commission also noted that PacifiCorp's power cost modeling should be transparent, and the Commission indicated that the workshops were intended to address transparency issues. [1]

[1] *See re PacifiCorp*, OPUC Docket No. UE 307, Order No. 16-482 at 24 (Dec. 20, 2016).

Parties held a conference call on February 3, 2017 to discuss the scope of the workshops and to develop workshop agenda items. Agenda items were finalized through email communications. Workshops were held on February 9, February 23, and March 7, 2017. The agendas and presentation slides for the workshops are included with this memo as Attachment A. Following the workshops PacifiCorp responded to several informal data requests.

PacifiCorp, Staff and parties participated in good faith in all three workshops with the objective of enhancing the understanding of PacifiCorp's modeling choices and the reasons behind the modeling choices. In general, Staff found that its prior understanding, as developed and expressed throughout previous TAM dockets, was consistent with the information presented by PacifiCorp in the workshops.

PacifiCorp also used the workshops as an opportunity to clarify key concerns of parties regarding the issues. Holding these workshops outside of a contested case environment served to foster collaborative communication regarding these issues.

DART

PacifiCorp presented material regarding the DART at both the February 9, 2017, and February 23, 2017 meetings. PacifiCorp provided analysis regarding the sensitivity of the DART adjustment to scenarios suggested by the parties, including abnormal weather, thermal outages, and hydro conditions. PacifiCorp indicated a willingness to adjust the historic period used for the DART adjustment. In accordance with this, PacifiCorp proposes to use a 60-month history in the 2018 TAM to achieve better normalization of DART estimates as indicated by its March 1, 2017 Notice of Methodology Changes.

Staff also clarified concerns regarding the applicability of the historic DART calculations to the forward looking NVPC forecast. Staff discussed performing a 'backcast' of power costs to troubleshoot PacifiCorp's NVPC forecasting methodology.[2] PacifiCorp expressed concerns that a backcast may be labor intensive, but indicated it would consider alternative options to achieve the insights provided by backcasting in a less time consuming way.

CUB discussed changing the allocation of the DART adjustment to reflect CUB's assertion that some jurisdictions may cause a larger share of the DART costs. PacifiCorp indicated a willingness to evaluate the allocation issues, but believed that the issue was perhaps more appropriately addressed as part of the multi-state process.

[2] The backcast was described by Staff as a process of reproducing past TAM forecasts with actual values for some inputs replacing the forecasted values.

EIM

PacifiCorp presented material regarding the EIM at the February 9 and February 23, meetings. PacifiCorp provided a general discussion about the EIM process. PacifiCorp also provided information about new EIM participants. CUB raised two concerns, one regarding transmission constraints in the EIM benefit calculation and the other regarding the order of solving GRID market transactions and EIM transactions. PacifiCorp agreed to continue evaluating these issues. PacifiCorp proposed to adjust the calculation of EIM benefits for its 2018 TAM at the March 7th Workshop. This change was noticed in a March 1, 2017 letter to parties to Docket No. UE 307.[3] This adjustment closely mirrors CUB's proposal made in UE 307 and was agreed to by all parties. PacifiCorp further discussed the potential alteration to the market cap calculation in GRID in order to match up with the new EIM adjustment. Parties expressed concern over the lack of information available at the time of the workshop, and PacifiCorp stated it would further evaluate whether to propose this change in the 2018 TAM.

RECs

At the February 23, 2017, and March 7, 2017 meeting PacifiCorp presented material regarding REC valuation as part of the TAM. PacifiCorp indicated an openness to include in the TAM the value of freed-up RECs made available from direct access customers. However, there was disagreement on an appropriate valuation method. PacifiCorp's position is that the benefit of decreased RPS requirements associated with direct access participation is realized at the time when PacifiCorp's need to acquire additional RECs is deferred (currently in the 2028 timeframe). Accordingly, PacifiCorp proposed valuation approaches using the present value of future REC prices. Calpine proposed that RECs be valued at the present market price.

Parties discussed a potential solution to transfer RECs from PacifiCorp to electric service suppliers (ESS) equal to the REC retirement requirements of direct access customers. However, PacifiCorp expressed concerns on whether such an approach would be compatible with Oregon's existing RPS (e.g. whether PacifiCorp could satisfy the compliance obligation for an electric service supplier). Parties also discussed that the administrative burden of this option may be sufficiently high to make it an impractical solution. PacifiCorp agreed to further evaluate these issues. Parties concluded discussion of this topic with an agreement to continue working collaboratively toward an agreeable solution.

Transparency

At the February 23, 2017, meeting PacifiCorp presented material regarding ongoing efforts to increase TAM transparency. Parties discussed transparency concerns arising

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[3] PacifiCorp's letter is attached included with this report as Attachment B.

out of previous TAM proceedings, and PacifiCorp agreed to the following changes to the TAM filing process:

1. PacifiCorp will maintain a step-log of model and input changes that will include changes to the NVPC and transition adjustment estimation process that is not considered a standard annual update.
2. PacifiCorp will provide a summary of input and model changes in filed testimony.

Workshop Evaluation
Staff found these workshops helpful in clarifying the positions of all parties, and in developing additional information regarding the issues. Parties participated in good faith and made good progress towards understanding some of the issues. Staff observed that having multiple workshops on separate days was a key element in making progress on these issues because it allowed time and space for participants to revise and update their understanding and concern regarding the issues. Parties made substantial progress regarding the transparency issue and partial progress on the remaining issues. Parties will likely revisit some issues during the next TAM proceeding. However, in general participants appeared to be satisfied with the progress made during the workshops. Staff found the workshops to be productive, but time consuming. This type of pre-filing collaboration may be worthwhile in the future if parties continue to have major on-going issues related to the TAM.

Staff invited parties to provide written feedback for inclusion in this report. CUB declined to provide feedback and indicated a preference to report directly to the Commission. ICNU stated "ICNU was encouraged by some of the collaborative dialogue during the recent TAM workshops. We'd be supportive of further usage of that sort of process leading up to other proceedings..."

PacifiCorp provided the following feedback to Staff:

> "The Company believes the workshops were valuable and appreciates parties' engagement in meaningful and productive dialogue. As a direct result of this process, the Company will propose modeling changes to its DART and EIM adjustments in the 2018 TAM designed to respond to some of the parties' concerns. The Company also plans to make a proposal to value RECs freed-up by direct access, which was informed by discussions in the workshops. While it is clear that disagreements remain, the process narrowed the issues and helped the Company and parties gain a better understanding of the issues. The

> Company hopes that this will contribute to a constructive resolution of 2018 TAM."

No other party provided written feedback at the time of writing this report.

PacifiCorp has reviewed this memo and has provided no objection.

PROPOSED COMMISSION MOTION:

As of the writing of this memorandum, Staff proposes no motion.

PacifiCorp
Transmission Adjustment Mechanism
Order No. 16-482 Workshop Scoping Issues

WORKSHOP DATES: February 9 at PacifiCorp Learning Center 1:00pm – 5:00pm

1. Day-Ahead/Real-Time (DART) adjustments
    a. PacifiCorp to describe modelling in detail.
    b. PacifiCorp to provide a complete list of all DART modeling changes it will implement in 2017, a complete list of all updates that will be added to the model, and a complete list of all inputs that will be added to the model.
    c. Explore the impact of non-normalized winter weather such as Oregon experienced this current winter on the DART, including its effect on system balancing transactions and unrecovered power costs.
    d. Explore the impact of non-normalized summer weather in PacifiCorp's Eastern Control Area on the DART, including its effect on system balancing transactions and unrecovered power costs.
    e. Description of the difference between the adjustment to reflect additional balancing volumes and the adjustment to prices input into the GRID model.
    f. PacifiCorp provide a back cast of the GRID model demonstrating that the DART adjustment increases the accuracy of NPC forecasts.
    g. Explore whether historic transactions are consistent with the system balancing process described in the TAM testimony.
    h. Explore whether the DART adjustment appropriately models the benefits of ongoing market arbitrage and economic sales and purchases.
    i. Discuss how DART type costs are modeled in IRP.
    j. Discuss PacifiCorp's ability to balance system without market transactions.
2. Energy Imbalance Market (EIM) benefit estimation
    a. PacifiCorp to describe modelling in detail
    b. PacifiCorp to provide a complete list of all EIM modeling changes it will implement in 2017, a complete list of all updates that will be added to the model, and a complete list of all inputs that will be added to the model.
    c. PacifiCorp to detail the cost of EIM dispatch.
    d. PacifiCorp to categorize and calculate the gross benefit of EIM dispatch.
    e. Demonstrate scenarios such as: (a) intrahour changes resulting in a plant in PAC's own BA dispatching differently (say PAC east steps up to meet load in PAC west or vice versa), (b) intra hour changes resulting from PAC east selling to NVE and then PAC West buying from CAISO or PAC West selling to California and PAC East buying from NVE.
    f. Show what constraints in the model have been effective (i.e. transmission implications that are assumed to have an effect on eligible sales or benefits).
    g. Review of historical instructed imbalance payments (and other EIM related charges to and from the CAISO), relative to the amount of benefits forecast using the Company's proposed methodology.

Attachment A

Oregon 2017 TAM

DART and EIM Workshop

February 9, 2017





Redacted Version –
Subject to Protective Order No. 16-128

PACIFIC POWER

Let's turn the answers on.

Agenda

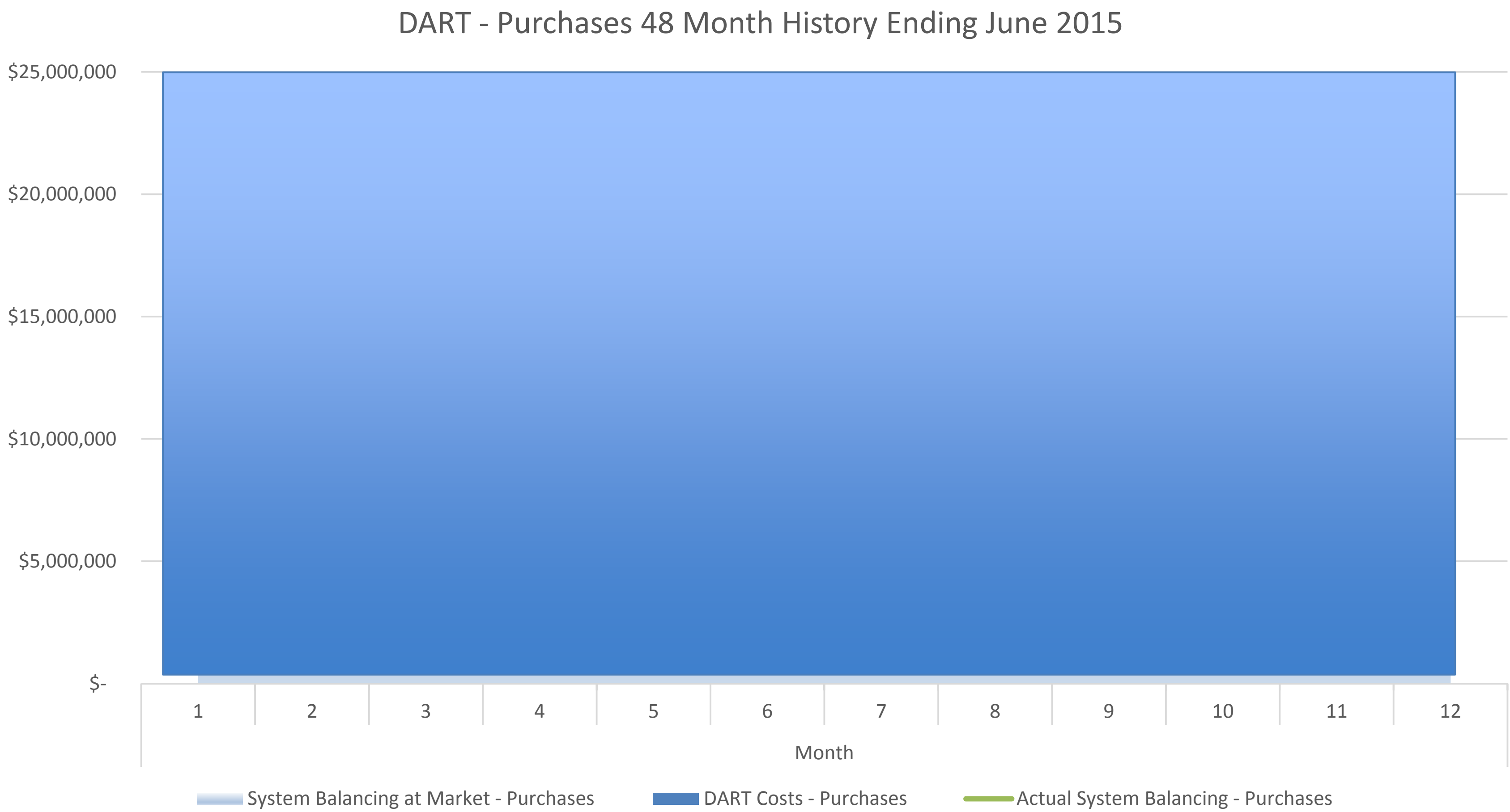
- Overview of the DART Adjustment
- How the DART is calculated
  - Adjustment to prices in GRID
  - Volume adjustment outside of GRID
- Planned changes to the DART in the 2018 TAM
- Impact of extreme weather on the DART
- Impact of DART on prior TAMs
- DART in the IRP
- Other items

What is DART?

- DART (Day Ahead Real Time Adjustment) is an adjustment to more accurately capture the costs associated with balancing the system that historically were not captured in GRID.
- The historical average cost differential vs market for purchases and sales.

Attachment A

What is DART?



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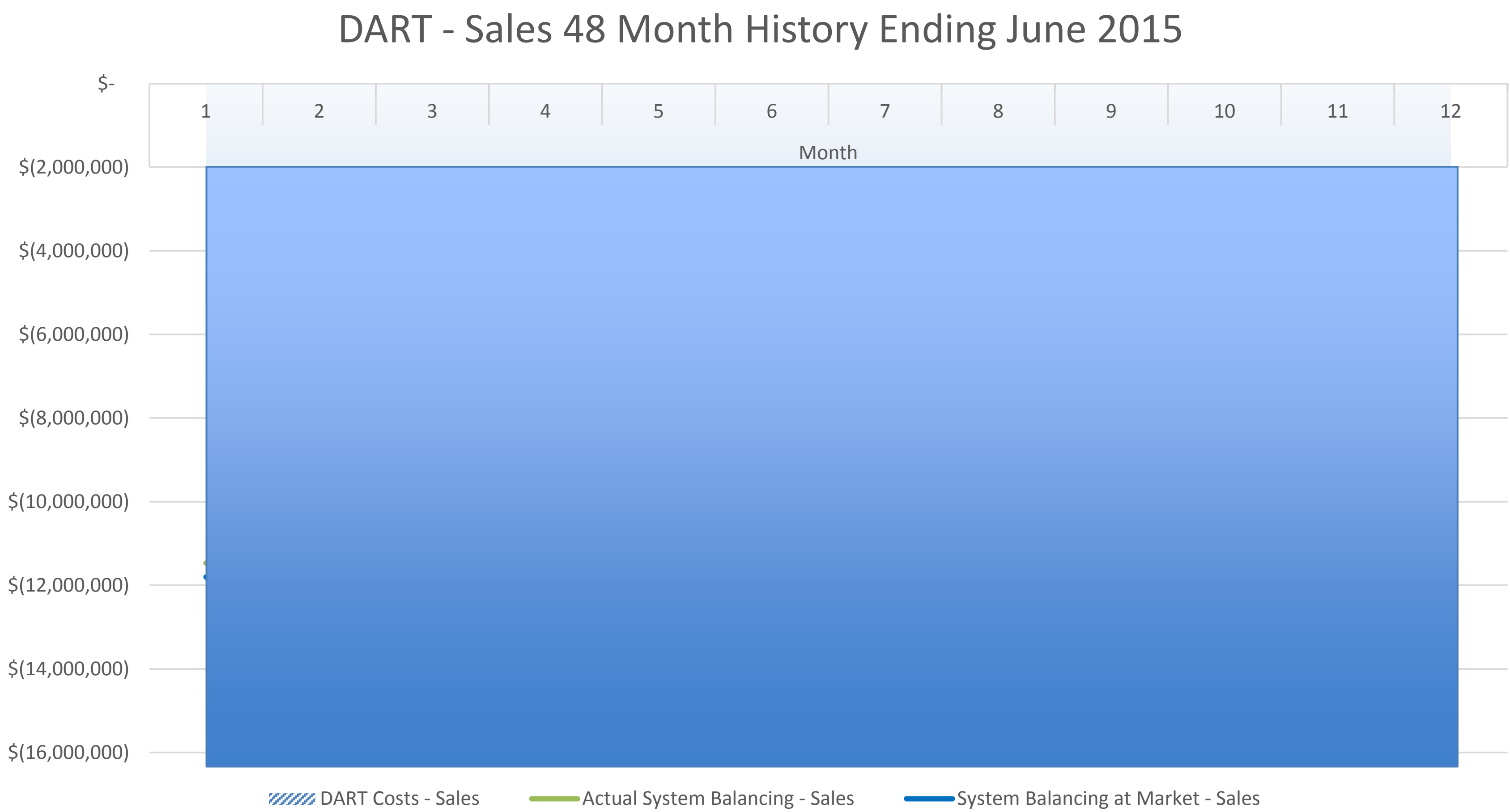
What is DART?



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What is DART?

DART Costs - 48 Months History Ending June 2015							
Month	System Balancing at Market -	Actual System Balancing - Purchases	DART Costs - Purchases	System Balancing at Market - Sales	Actual System Balancing - Sales	DART Costs - Sales	Total DART Costs
1							
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
Total							

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Purposes of DART Adjustment

- Improve the accuracy of Net Power Cost forecast
- Better reflect the market prices available to the company when transacts in the markets
- Better reflect the combination of monthly, daily and hourly products that must be used to balance the system

Dual Purchase/Sale Markets

- Wholesale market hubs are divided into separate markets for purchases and sales
  - Historical results show that the Company is typically buying when prices are higher than the monthly average and selling when prices are lower than the monthly average
  - Forecasted prices for purchases and sales are adjusted from the OFPC based on four-year average of historical results
- Previously, the same price was used for purchases and sales
  - Monthly average price (now differentiated by purchases and sales)
  - No variation over the month – identical scalars for each weekday of the month (no change)
  - Hourly shape applied using a scalar (no change)

Dual Purchase/Sale Markets

- A separate purchase bubble was added to wholesale markets in the GRID model topology
  - Sales continue to be made in the original bubble
  - Transfers from purchase to sale bubble not limited

Adjustments to Forward Price Curve

Step 1: Calculate the average price of actual day-ahead and real-time transactions from the 48 month historical period.

- **Done separately for each market, month, HLH/LLH, and Purchase/Sale**

Step 2: Compare the average price of actual real-time and day-ahead transactions to the average market price.

Step 3: Calculate the average cost differential between actual day-ahead and real-time transactions and the average market price. Calculate the average historical volume.

Step 4: Divide the average cost differential by the average historical volume to get the price adder. Adjust the forward price curve by the price adder and input to GRID to simulate system dispatch.

Example - Mid Columbia HLH

Average Price ($/MWh)

	Period	Company Purchases	Market	Company Sales
Step 1	Sep-11			
	Sep-12			
	Sep-13			
	Sep-14			

Cost vs Market Average ($/MWh)

	Period	
Step 2	Sep-11	
	Sep-12	
	Sep-13	
	Sep-14	

Volume (MWh)

	Period	
	Sep-11	
	Sep-12	
	Sep-13	
	Sep-14	

Step 3

Volume Weighted Average Cost vs Market ($)

MWh - Monthly Average

Step 4

Actual vs Monthly Price - September Adder ($/MWh)

Additional Balancing Transactions

- **Volume:**
  – Identify monthly and daily 25MW standard HLH/LLH products that minimize the need for rebalancing with hourly products
  – Rebalancing results in additional offsetting purchase and sale volumes to achieve GRID's forecasted market position.
- **Cost:**
  - Offsetting monthly, daily, and hourly transactions are equal in volume but not equal in price. Incremental volumes are priced at monthly market index plus the difference between:
  – Historical average day-ahead and real-time cost vs. market (Slide 11, Step 3)
  – Day-ahead and real-time cost vs market in the GRID balancing result.

  GRID balancing cost vs market + Additional balancing cost vs market

  = Historical average cost vs market
- **Final Result:** NPC forecast matches the historical average cost differential vs market for purchases and sales.

Additional Balancing Transactions - Example

UE 307
PAC/100 Dickman/21, Figure 2

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Example - Mid Columbia HLH

	Period		Net Sales	GRID Sales	GRID Purchases
		MWh			
Step 1	Sep-17	aMW			
		25MW Blocks Net Sales			

		Volume (MWh)			
Step 2	Sep-17	Monthly 25MW blocks			
		Daily Blocks			
		Hourly			
		Incremental Volume = (Monthly + Daily + Hourly - GRID)			

Step 3	Sep-17	$		
Step 4	Sep-17	$/MWh		

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48 Month History

- To normalize the DART it is based on the 48 month history
- Using a 48 month history is consistent with the following Net Power Costs items in the TAM
    - Market Capacity
    - Lost Hydro Capacity – planned and forced outages for storage hydro
    - Contract inputs
        - Large QF generation
        - Various other PPA and Sale take patterns
        - Non-owned generation – reserve requirements for OATT/Legacy generation in PAC BA
    - Short-term (Non-firm) Wheeling
    - Wind PPAs
    - Thermal Attributes
        - Equivalent Outage Rate
        - Ramp Losses
        - Station Service
        - Planned Outage Rate
        - Heat Rate Coefficients

Planned Changes to the DART

- Update 48 month history (will impact prices in GRID and volume adjustment)
  - July 2012 – June 2016
- No other changes

Extreme Weather

	Summer Months 2016			
Salt Lake City, UT	**June**	**July**	**August**	**September**
Actual Temperature	78.2	83.8	80.5	67.2
Normal Temperature	70.9	79.9	77.8	67.7
Delta	7.31	3.94	2.70	(0.57)

	Winter Months 2016			
Portland, OR	**January**	**February**	**November**	**December**
Actual Temperature	41.7	46.7	49.7	36.3
Normal Temperature	39.6	42.1	44.7	39.4
Delta	2.14	4.59	5.02	(3.13)

Extreme Weather

NPC	$	Delta
48month	[redacted]	
Extreme Weather (Jun 2016)		
Extreme Weather (Dec 2016)		

Total DA RT Amount	$	Delta
48month	[redacted]	
Extreme Weather (Jun 2016)		
Extreme Weather (Dec 2016)		

	Mid Columbia HLH Buy	Mid Columbia HLH Sell
48month Adders		
Jun-17	[redacted]	
Dec-17		
Extreme Weather Adders		
Jun-16		
Dec-16		

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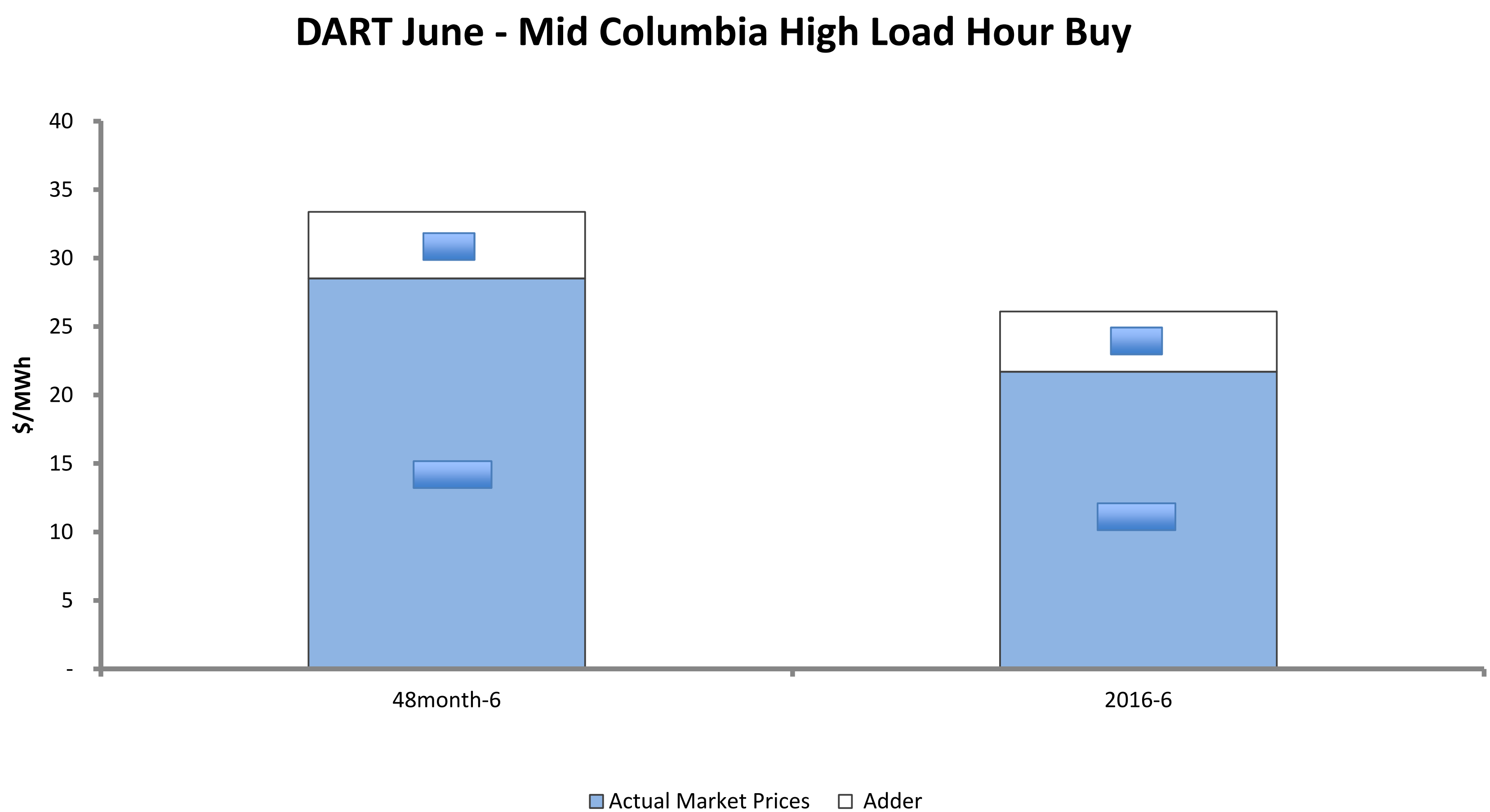
Extreme Weather



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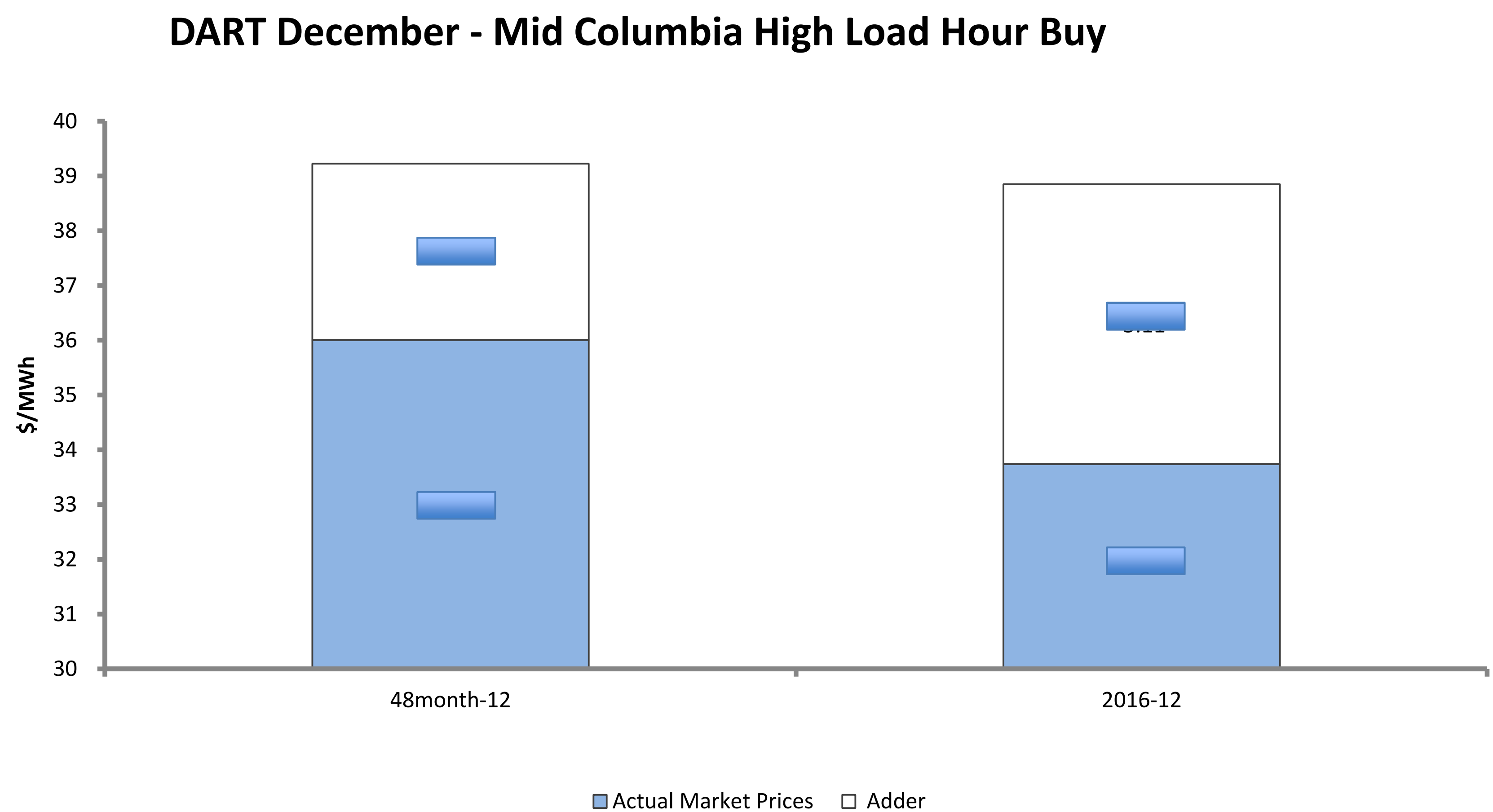
Extreme Weather



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Impact of DART on Prior TAMs

Total Company NPC Comparison ($/MWh)			
Year	Actual NPC	TAM	TAM + DART
2013	$ [redacted]		
2014			
2015			

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DART in the IRP

- The IRP identifies future resources needed to provide reliable, reasonable-cost service to customers with manageable risks.
- The IRP compares the relative differences between scenarios and the DART is not included as part of any scenario.
- Including DART in the IRP would result in zero impact.

Other Items

- Explore whether historical transactions are consistent with the system balancing process described in the TAM testimony.
- Explore whether the DART adjustment appropriately models the benefits of ongoing market arbitrage and economic sales and purchases.
- Discuss PacifiCorp's ability to balance system without market transactions.

Oregon 2017 TAM

Energy Imbalance Market

February 9, 2017




PACIFICORP

Energy Imbalance Market Outline

- Daily operations and bid submission
- California Independent System Operator (ISO) EIM benefit explanation
- EIM revenue/cost calculation of the import/export
- EIM dispatch cost to facilitate the import/export
- Total EIM benefit calculation

EIM Day-Ahead Setup

- Variables considered in the day-ahead setup
  - Reserve requirement
  - Load
  - EIM flex requirements
  - Plant operating costs ($/MWh)
- The day-ahead schedule includes known updates for ramp capability, max and min capacity, outages and unit testing requirements
- Bids are submitted by end-of-day for all participating resources in EIM
  - Includes fuel price, unit heat rate, variable operation and maintenance and a ten percent adder

EIM Resources

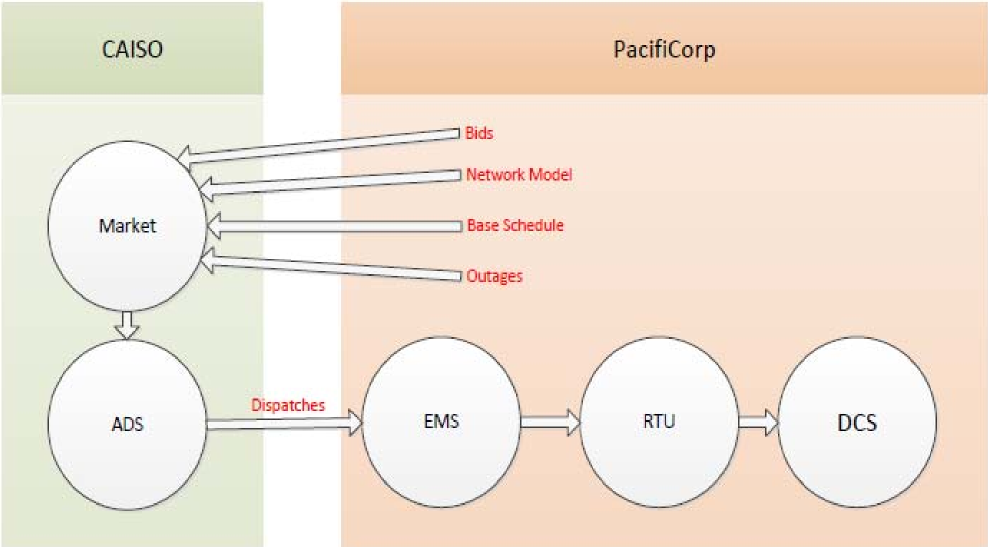
- Participating resources that are bid into the market are optimized by the ISO market model every fifteen minutes and again every five minutes to achieve the least-cost dispatch to serve load across the EIM footprint
  – PacifiCorp has chosen to maximize its participating resources to allow the most efficient optimization of the system within the hour
- Non-participating resources are not optimized by the ISO market model within the hour and maintain an hourly base schedule
  – Non-participating resources include resources that are shared units and not under PacifiCorp's operational control as well as run-of-river and constrained hydro resources
    - Hunter 1&2
    - Cholla
    - Craig
    - Hayden
    - Hydro resources other than Swift 1 and Yale

Market Timeline

- Base Schedule Balancing Test
- Bid Capacity Range Test
- Flex Ramp Required Sufficiency Test

EIM Plant Dispatch

- Coordinating dispatches with plant operators
- Plant status feedback
- Data flow and generation control



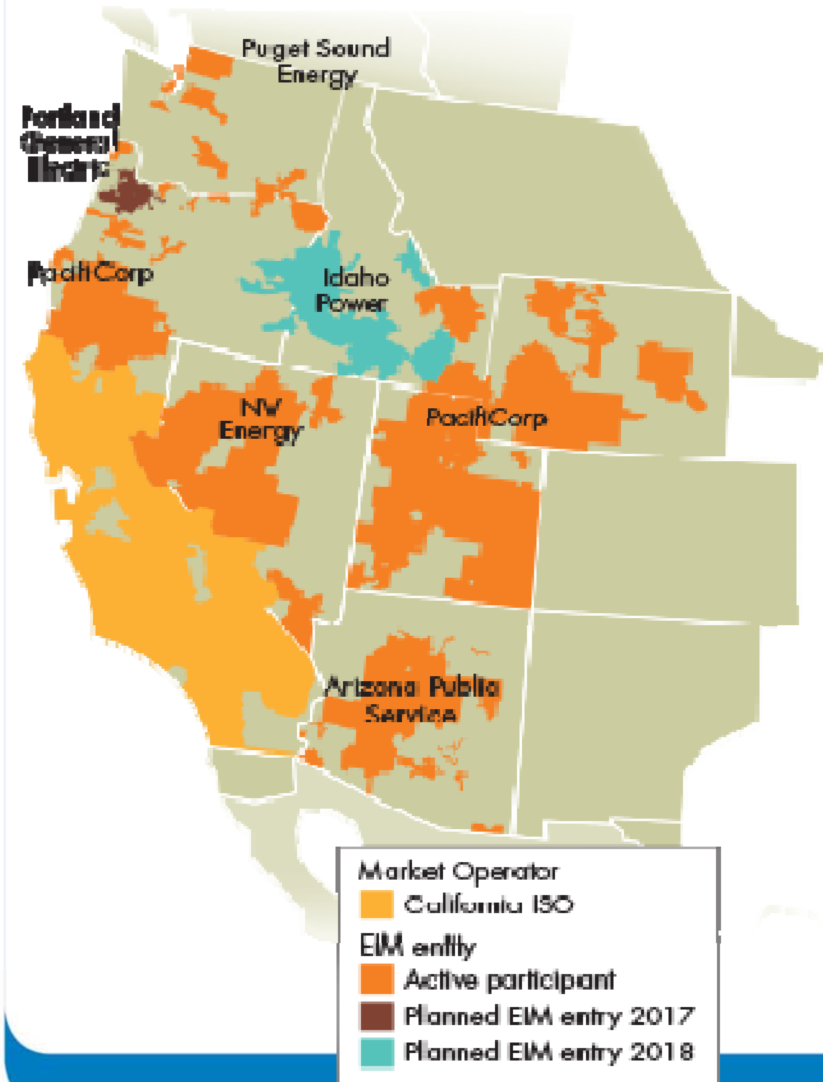
Daily Bid Prices

- PacifiCorp is currently bidding in its thermal resources consistent with the DEB to accurately reflect the operating cost of its units
- Resource operating requirements for hydro facilities requires PacifiCorp to provide the market a correct price signal that can be at or below the DEB
  - During high run-off conditions PacifiCorp may submit a bid for the hydro resources that reflect a lower incremental cost and allow the resource to be dispatched first and decremented last in the PacifiCorp stack of resources
  - During periods of normal hydro operations PacifiCorp will maximize its hydro resource bid to the DEB price

- It is in the best interest of PacifiCorp to accurately reflect its cost of operations at each plant in order to achieve the most efficient market outcome in the reliable operation of the system.

- The ISO utilizes PacifiCorp's resource bids to create a "stack" of resources that is used by the market model to solve for a least-cost dispatch solution to meet demand

Energy Imbalance Market Expansion



- Arizona Public Service Company and Puget Sound Energy went live October 1, 2016
- Portland General Electric - Fall 2017
- Idaho Power - Spring 2018
- Entities exploring future entry
  - CENACE
  - Baja CA
  - Balancing Authority of Northern California (BANC)
  - Los Angeles Department of Water & Power (LADWP)
  - Seattle City Light (SCL)

EIM Benefits in the TAM

Total-Company EIM-Related Benefits and Costs

$ millions	**2016 TAM**	**2017 TAM (Nov Final)**
Inter-regional dispatch	$8.4	$17.5
Flexibility Reserves	$1.7	$4.1
Test-period EIM benefits	**$10.1**	**$21.6**
Test-period EIM costs	**$5.1**	**$6.2**

- EIM benefits reflected in the TAM continue to grow as the EIM expands with new entities

ISO EIM Benefit Calculation

- The California ISO utilizes a counter-factual analysis to calculate the EIM Benefits of each participant
  - The ISO estimates both intra and inter-regional EIM benefits in its analysis
- The intra-regional EIM benefit calculates what the costs would have been to serve load within each Balancing Area if the EIM did not exist
  - The ISO determines the load change within each area and utilizes the "stack" of resources within each area to determine what the dispatch would have been

EIM Benefits

- PacifiCorp calculates its EIM benefits based on the transfers that occur in the market and does not calculate the intra-regional benefits
  - All resources in the EIM footprint are put into a “stack” with highest cost resources at the top and lowest cost resources at the bottom. Dispatch of the stack of resources moves from bottom to top in order to serve demand at the lowest cost.
  - EIM Imports allow PacifiCorp to avoid dispatching more expensive resources
  - EIM Exports allow PacifiCorp to earn a margin on available capacity on its resources

EIM Stack and Dispatch Example

Day	hour	Interval	BAA	Price	Segment (MW)	Resource	Unit mimimum (MW)	Unit maximum (MW)	Base Schedule (MW)	EIM Dispatch (MW)	Difference (MW)
1-Jul-15	16	6	ISO	$80.0	200	California Resource	100	200	200	100	(100)
1-Jul-15	16	6	PACW	$45.0	150	Yale	80	150	99	80	(19)
1-Jul-15	16	6	PACE	$25.0	600	Lake Side 2	300	600	500	519	19
1-Jul-15	16	6	PACE	$24.0	500	Current Creek	250	500	400	500	100
								Total MW	1,199	1,199	-
								Total Cost	$3,546	$3,048	($498)

- Illustrative example of one five-minute interval in the EIM where the load did not change from the base schedule of 1,199 MW to the EIM dispatch of 1,199 MW
- All resources in the EIM Footprint are re-dispatched within their operating constraints to produce the least-cost dispatch solution, taking into consideration transmission constraints, resource ramping constraints and reserve requirements

EIM Transfers

Day	hour	Interval	BAA	Price	Segment (MW)	Resource	Unit mimimum (MW)	Unit maximum (MW)	Base Schedule (MW)	EIM Dispatch (MW)	Difference (MW)
1-Jul-15	16	6	ISO	$80.0	200	California Resource	100	200	200	100	(100)
1-Jul-15	16	6	PACW	$45.0	150	Yale	80	150	99	80	(19)
1-Jul-15	16	6	PACE	$25.0	600	Lake Side 2	300	600	500	519	19
1-Jul-15	16	6	PACE	$24.0	500	Current Creek	250	500	400	500	100

Total MW	1,199	1,199	-
Total Cost	$3,546	$3,048	($498)

- The above dispatch example shows that ISO resources decreased (net) in EIM 100 MW, PACW decreased 19 MW and PACE increased 119 MW
- Looking at resource dispatch that correspond with the changes in EIM, PACW transferred 100 MW to ISO and PACE transferred 119 MW to PACW so that all systems would have balanced

EIM Revenue Calculation of Transfer

- PacifiCorp uses the 15-minute (FMM) and 5-minute (rtd) prices and volumes to calculate the EIM Revenue of the transfer
- Using the previous slides EIM Dispatch example, the following table shows prices and transfers that correspond with the actual EIM dispatch

	PACE FMM	PACW FMM	CAISO FMM
Price	$25.00	$25.00	$80.00
Transfer Volume	50	50	-50
Revenue	$104.17	$218.75	-$218.75

	PACE rtd	PACW rtd	CAISO rtd
Price	$25.00	$25.00	$80.00
Transfer Volume	69	50	-50
Revenue	$143.75	$218.75	-$218.75

	PACE RTD	PACW RTD	CAISO RTD
Actual Transfer Volume	119	100	-100
Total Revenue	$247.92	$437.50	-$437.50

PACE FMM Revenue =(($25 + $25)/2) * 50/12 = $104.17
PACW FMM Revenue =(($25 + $80)/2) * 50/12 = $218.75
CAISO FMM Revenue =(($25 + $80)/2)*-50/12 = -$218.75

PACE FMM Revenue =(($25 + $25)/2) * 69/12 = $143.75
PACW FMM Revenue =(($25 + $80)/2) * 50/12 = $218.75
CAISO FMM Revenue =(($25 + $80)/2)*-50/12 = -$218.75

PACE RTD Revenue = $104.17 + $143.75 = $247.92
PACW RTD Revenue = $218.75 + $218.75 = $437.5
CAISO RTD Revenue = -$218.75 + -$218.75 = -$437.5

PacifiCorp EIM Dispatch Cost

- In the example provided PACW exported 100 MW to ISO and was paid $437.50
- The cost to serve that export was the cost it paid to PACE for the transfer of 119 MW or $247.92
- PACE costs to serve the 119 MW transfer was the 100 MW provided by Current Creek and 19 MW provided by Lake Side 2

Day	hour	Interval	BAA	Price	Segment (MW)	Resource	Unit mimimum (MW)	Unit maximum (MW)	Base Schedule (MW)	EIM Transfer Dispatch (MW)	Transfer (MW)
1-Jul-15	16	6	PACE	$25.0	600	Lake Side 2	300	600	500	519	19
1-Jul-15	16	6	PACE	$24.0	500	Current Creek	250	500	400	500	100

Transfer MW	119
Transfer Cost	$2,875.00
Five-Minute Total Cost	$239.58

PacifiCorp EIM Benefit Calculation

- The transfer revenue that was calculated for PACW and PACE is added together and the dispatch Cost to facilitate the transfer is subtracted to calculate the marginal revenue or EIM benefit for the five-minute interval
- The benefit for the ISO was its avoided cost of $80/MWh for 100 MW, or $666.67, at a cost of only $437.50
- The example also illustrated an intra-regional benefit of utilizing PACE resources to displace the Yale resource (19 MW)
  - The total EIM benefit (shown on slide 10) of $498.00 was $427.08 of inter-regional benefit and $71.25 of intra-regional benefit

	Revenue	Cost	EIM Benefit
PACW	$437.50	$247.92	$189.58
PACE	$247.92	$239.58	$8.33
ISO	-$437.50	$666.67	$229.17
Total	$685.42	$487.50	$427.08

PacifiCorp
Transmission Adjustment Mechanism
Order No. 16-482 Workshop Scoping Issues

WORKSHOP DATES: February 9 at PacifiCorp Learning Center 1:00pm – 5:00pm
February 23 at location OPUC - SALEM 1:00pm – 5:00pm
February 24 at location TBD 9:00am – 12:00pm

Topics 1 and 2 were discussed at the February 9, 2017 workshop. Carryover items from Topics 1 and 2 are listed in new Topic 4.

Topics 3 and 4 are proposed for discussion at the February 23, 2017 workshop to be held at the OPUC in Salem.

1. Day-Ahead/Real-Time (DART) adjustments
    a. PacifiCorp to describe modelling in detail.
    b. PacifiCorp to provide a complete list of all DART modeling changes it will implement in 2017, a complete list of all updates that will be added to the model, and a complete list of all inputs that will be added to the model.
    c. Explore the impact of non-normalized winter weather such as Oregon experienced this current winter on the DART, including its effect on system balancing transactions and unrecovered power costs.
    d. Explore the impact of non-normalized summer weather in PacifiCorp's Eastern Control Area on the DART, including its effect on system balancing transactions and unrecovered power costs.
    e. Description of the difference between the adjustment to reflect additional balancing volumes and the adjustment to prices input into the GRID model.
    f. PacifiCorp provide a back cast of the GRID model demonstrating that the DART adjustment increases the accuracy of NPC forecasts.
    g. Explore whether historic transactions are consistent with the system balancing process described in the TAM testimony.
    h. Explore whether the DART adjustment appropriately models the benefits of ongoing market arbitrage and economic sales and purchases.
    i. Discuss how DART type costs are modeled in IRP.
    j. Discuss PacifiCorp's ability to balance system without market transactions.
2. Energy Imbalance Market (EIM) benefit estimation
    a. PacifiCorp to describe modelling in detail
    b. PacifiCorp to provide a complete list of all EIM modeling changes it will implement in 2017, a complete list of all updates that will be added to the model, and a complete list of all inputs that will be added to the model.
    c. PacifiCorp to detail the cost of EIM dispatch.
    d. PacifiCorp to categorize and calculate the gross benefit of EIM dispatch.
    e. Demonstrate scenarios such as: (a) intrahour changes resulting in a plant in PAC's own BA dispatching differently (say PAC east steps up to meet load in PAC west or vice versa), (b) intra hour changes resulting from PAC east selling to NVE and

then PAC West buying from CAISO or PAC West selling to California and PAC East buying from NVE.

f. Show what constraints in the model have been effective (i.e. transmission implications that are assumed to have an effect on eligible sales or benefits).
g. Review of historical instructed imbalance payments (and other EIM related charges to and from the CAISO), relative to the amount of benefits forecast using the Company's proposed methodology.

3. **REC valuation**
    a. **PacifiCorp to provide a complete list of any REC modeling changes it will implement in 2017, a complete list of all updates that will be added to the model, and a complete list of all inputs that will be added to the model.**
    b. **Use of RFP Results for REC Valuation**
    c. **PacifiCorp's REC Valuation in Inter-regional Benefits Calculations: (See PAC/900, Brown/5-6; Tr. at 86-87); PAC/900, Brown/5-6 discusses how PacifiCorp values dispatch costs of wind facilities for EIM benefits purposes and states: "PacifiCorp's participating wind resources are bid in as a resource that would be paid to reduce production (negative price) with a price that is calculated based on the lost production tax credit plus the value of the renewable energy credit." See also Tr. at 86-87. Staff opposed this treatment, arguing that the marginal cost of wind units is viewed as zero, UE 307 Staff Response Br. at 44-45. The final order adopted PacifiCorp's valuation including a REC value. We'd like to know this REC valuation.**
    d. **PacifiCorp valuation of Company REC sales credited to non-RPS PacifiCorp jurisdictions.**
    e. **REC Values used in RPS Implementation Plan or IRP. What values does PacifiCorp use for planning purposes? Are there different values for bundled and unbundled RECs?**

4. **Follow-up items from February 9 workshop**
    a. **Analysis of market arbitrage – comparison between GRID and actual**
    b. **Further analysis of the DART**
        i. **Remove extreme weather in place of using only extreme weather**
        ii. **Good hydro year vs. bad hydro year**
        iii. **Effects of plant outage**
    c. **Provide requested materials from DART and EIM presentations:**
        i. **Supporting workpapers for the weather analysis of DART**
        ii. **Supporting workpapers/example of how bids are calculated**
        iii. **Supporting workpapers for calculations used in the example EIM bids**

5. Transparency
    a. Step-log of changes
    b. TAM guidelines and how DART and EIM adjustments fit in

<u>Order No. 16-482 provides the following guidance on these workshops:</u>

"We also direct PacifiCorp, Staff, and parties to participate in workshops to examine the following GRID issues: (1) Day-Ahead/Real-Time Transaction (DART) adjustments, (2) Energy Imbalance Market (EIM) benefit estimation, and (3) Renewable Energy Credit (REC) valuation.

With respect to the first two issues, our intent is for PacifiCorp to describe its modeling approach in detail during the workshops to facilitate the parties' deeper understanding of these issues. We expect parties challenging PacifiCorp's modeling choices to engage in these discussions in order to fully understand the rationale behind the adjustments. Our goal is to create an improved evidentiary record on these disputed issues going forward. While the workshops are intended to be informational in nature, parties may also use the workshops to discuss whether any adjustments to PacifiCorp's existing methodologies may be appropriate. With respect to the REC issue, the parties should discuss whether there is a reasonable method to value RECs based on delaying the time when PacifiCorp is required to take any substantive action to ensure RPS compliance, as discussed later in this order. Staff is to report back to us on the results of these workshops before PacifiCorp's 2018 TAM is filed.[2]*"*

[2] We do not seek recommendations from Staff based on tis set of informational workshops but simply a report on the parties' discussions.

Attachment A

Oregon Transition Adjustment Mechanism Workshop

REC Valuation for Direct Access Customers

February 23, 2017

PACIFICORP
A BERKSHIRE HATHAWAY ENERGY COMPANY

Commission Conclusions in 2015 & 2016 TAM Orders

- In both the 2015 and 2016 TAM proceedings, the Commission stated that it saw little or no benefit to the company from a reduction in renewable portfolio standard (RPS) obligation due to loss of load from direct access.
  - December 2015, Docket No. UE-296 Order 15-394: "At best, the net present value of the value of any freed-up REC is *de minimis*"
  - Docket No. UE-307 Order 16-482 12/20/16: "PacifiCorp has stated that it will continue to bank RECs rather than sell them, so there is no benefit to other customers from a potential sale of RECs. Over the long run, if there is a guaranteed loss of load due to direct access, then there may be benefits to other customers by altering the point in time when PacifiCorp would need to take resource actions to comply with the RPS. However, based on the record, PacifiCorp would not need to take such action to ensure compliance with the RPS until the mid-2020s. No party has offered a reliable way to estimate the value of loss of load in that time period and we note the complexities to derive such an estimate. We also find that any reasonable estimate of benefits from that time period would be *de minimis* when discounted to today's dollars."

- Notwithstanding these findings, the Commission directed the company, staff, and parties to discuss REC valuation in workshops

Renewable Energy Credit Valuation for Direct Access Load

- Concept: decreased load can result in decreased RPS compliance requirements i.e., fewer renewable energy credits (RECs) may ultimately be required to be retired to demonstrate compliance

- If RPS compliance requirements are decreased in a particular year, the benefit of this decrease is not realized until the need to acquire additional RECs is deferred
  - PacifiCorp has a significant REC bank which currently extends an RPS compliance need to approximately 2028
  - A decrease in load may extend the compliance need for a certain period of time e.g., the RPS benefit of decreased load in 2018 may not be realized until the REC bank is exhausted in 2028

- A potential valuation methodology may look at future avoided compliance requirements

Potential REC Valuation Methodology

- The following example illustrates a potential methodology for valuing the future benefit of an avoided compliance requirement:
  - Estimate reduced load associated with Direct Access customer for the period of time the customer has chosen to opt-out and then estimate current benefit by calculating net present value of future benefit.
  - 50 aMW is subtracted from 2018 load resulting in reducing the 2028 RPS compliance requirement by 65,700 MWh
  - The cost of future need ($/REC) is discounted to present value to estimate incremental costs savings:

Cost of Future Need ($/REC)	Incremental Cost Savings ($/MWh of DA load)
$1	$0.08
$5	$0.40
$10	$0.79
$15	$1.19

- The challenge will be how to value cost of future need in terms of $/REC

Options for Estimating Future Value

- Future REC prices are very difficult to predict – no professional market forecasts exist and the market is volatile and illiquid

- RFP results from recent PacifiCorp REC RFP for long-term REC purchases
  - Issue if there is not a recent RFP for future vintage RECs

- Recent sales of PacifiCorp east-side allocated RECs
  - Generally short-term sales so do not reflect longer-term value
  - REC market is volatile and illiquid – prices vary based on compliance need and factors impacting production
  - Not all RECs are created equal (currently Pacific Northwest RECs have premium value over remainder of WECC)
  - Not all RECs are saleable

- EIM bid valuation
  - REC price in bid generally based on recent REC sales and observations regarding the current REC market

Attachment A

Oregon 2017 TAM

DART and TAM Transparency

February 23, 2017

Redacted Version –
Subject to Protective Order No. 16-128

PACIFIC POWER

Let's turn the answers on.

Agenda

- Follow-Up DART Analysis
  - Remove Extreme Weather
  - DART and Hydro Generation
  - DART and Thermal Outages
- TAM Transparency

Attachment A

DART - Extreme Weather

48month Winter Months Drybulb Temperature

	January	February	November	December
2011			43.68	35.74
2012	39.24	41.69	46.69	39.88
2013	35.39	41.38	43.81	33.41
2014	39.57	41.74	45.29	43.85
2015	41.85	47.23		

48month Summer Months Drybulb Temperature

	June	July	August	September
2011		78.29	78.95	68.85
2012	74.90	82.11	81.45	69.68
2013	76.89	83.88	82.15	69.54
2014	70.74	81.88	73.80	69.59
2015	78.14			

DART - Extreme Weather

[redacted]

Conclusion: Weather has a moderate affect on the DART adjustment.

DART – Hydro Generation

	DART Cost			Hydro Generation (MWh)
	Purchase	Sales	Total	
CY2012	[redacted]			
CY2016				
CY2014				
CY2013				
CY2015				
48month				

Conclusion: Hydro generation and DART costs are not strongly correlated.

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DART – Thermal Outages

Forced Outage Events

[redacted]

Conclusion: Thermal outages alone are not a significant driver of DART costs.

DART Conclusions

- There is no single driver of DART costs.
- The DART costs are the result of multiple variables within a dynamic system in which the Company has historically bought more during higher-than-average price periods and sold more during lower-than-average price periods.
- Four years of historic data is sufficient to normalize the DART adjustment in the TAM.

TAM Transparency

- As part of the current TAM Guidelines PacifiCorp provides all parties:
  - A pre-filing review of any proposed changes to the GRID model 30 days before the initial filing.
  - A one-off study showing the impact of the proposed changes to the GRID model as reported in the pre-filing review.
  - Corrections to the components in the initial filing per the TAM Guidelines.

TAM Transparency

- PacifiCorp proposes to provide an initial filing step log which will include:
  - The description and impact of any changes identified in the prefilling review.
  - The description and impact of non-routine updates to inputs.

Step Number	Description of Model Change/Input Update	Total NPC	NPC Delta	Cumulative Delta

Attachment A

TAM Transparency

- As per TAM Guidelines After the initial filing any changes to the TAM will continue to be captured in the step log.

[redacted]

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TAM Transparency

- All parties are given access to GRID.
- All GRID and forecast inputs provided to parties in electronic format as part three and five day workpapers.
  - Data provided for all filings; initial, rebuttal, indicative, and final.
- Any other relevant data will be provided upon request of parties.
- GRID training is available if needed.
  - Staff onsite visit and GRID training 2016
  - CUB onsite visit and GRID training February 2017

PacifiCorp
Transmission Adjustment Mechanism
Order No. 16-482 Workshop Scoping Issues

WORKSHOP DATES: February 9 at PacifiCorp Learning Center 1:00pm – 5:00pm
February 23 at location OPUC - SALEM 1:00pm – 5:00pm
March 7 at OPUC – SALEM 9:30am – 11:30am

Topics 1 and 2 were discussed at the February 9, 2017 workshop. Carryover items from Topics 1 and 2 are listed in new Topic 4.

Topics 3, 4 and 5 were discussed at the February 23, 2017 workshop.

Topic 6 includes follow-up items from previous workshops and was discussed at the March 7, 2017 workshop.

1. Day-Ahead/Real-Time (DART) adjustments (discussed at February 9 workshop)
   a. PacifiCorp to describe modelling in detail.
   b. PacifiCorp to provide a complete list of all DART modeling changes it will implement in 2017, a complete list of all updates that will be added to the model, and a complete list of all inputs that will be added to the model.
   c. Explore the impact of non-normalized winter weather such as Oregon experienced this current winter on the DART, including its effect on system balancing transactions and unrecovered power costs.
   d. Explore the impact of non-normalized summer weather in PacifiCorp's Eastern Control Area on the DART, including its effect on system balancing transactions and unrecovered power costs.
   e. Description of the difference between the adjustment to reflect additional balancing volumes and the adjustment to prices input into the GRID model.
   f. PacifiCorp provide a back cast of the GRID model demonstrating that the DART adjustment increases the accuracy of NPC forecasts.
   g. Explore whether historic transactions are consistent with the system balancing process described in the TAM testimony.
   h. Explore whether the DART adjustment appropriately models the benefits of ongoing market arbitrage and economic sales and purchases.
   i. Discuss how DART type costs are modeled in IRP.
   j. Discuss PacifiCorp's ability to balance system without market transactions.

2. Energy Imbalance Market (EIM) benefit estimation (discussed at February 9 workshop)
   a. PacifiCorp to describe modelling in detail
   b. PacifiCorp to provide a complete list of all EIM modeling changes it will implement in 2017, a complete list of all updates that will be added to the model, and a complete list of all inputs that will be added to the model.
   c. PacifiCorp to detail the cost of EIM dispatch.
   d. PacifiCorp to categorize and calculate the gross benefit of EIM dispatch.

   e. Demonstrate scenarios such as: (a) intrahour changes resulting in a plant in PAC's own BA dispatching differently (say PAC east steps up to meet load in PAC west or vice versa), (b) intra hour changes resulting from PAC east selling to NVE and then PAC West buying from CAISO or PAC West selling to California and PAC East buying from NVE.
   f. Show what constraints in the model have been effective (i.e. transmission implications that are assumed to have an effect on eligible sales or benefits).
   g. Review of historical instructed imbalance payments (and other EIM related charges to and from the CAISO), relative to the amount of benefits forecast using the Company's proposed methodology.

3. REC valuation (discussed at February 23 workshop)
   a. PacifiCorp to provide a complete list of any REC modeling changes it will implement in 2017, a complete list of all updates that will be added to the model, and a complete list of all inputs that will be added to the model.
   b. Use of RFP Results for REC Valuation
   c. PacifiCorp's REC Valuation in Inter-regional Benefits Calculations: (See PAC/900, Brown/5-6; Tr. at 86-87); PAC/900, Brown/5-6 discusses how PacifiCorp values dispatch costs of wind facilities for EIM benefits purposes and states: "PacifiCorp's participating wind resources are bid in as a resource that would be paid to reduce production (negative price) with a price that is calculated based on the lost production tax credit plus the value of the renewable energy credit." See also Tr. at 86-87. Staff opposed this treatment, arguing that the marginal cost of wind units is viewed as zero, UE 307 Staff Response Br. at 44-45. The final order adopted PacifiCorp's valuation including a REC value. We'd like to know this REC valuation.
   d. PacifiCorp valuation of Company REC sales credited to non-RPS PacifiCorp jurisdictions.
   e. REC Values used in RPS Implementation Plan or IRP. What values does PacifiCorp use for planning purposes? Are there different values for bundled and unbundled RECs?

4. Follow-up items from February 9 workshop (discussed at February 23 workshop)
   a. Analysis of market arbitrage – comparison between GRID and actual
   b. Further analysis of the DART
      i. Remove extreme weather in place of using only extreme weather
      ii. Good hydro year vs. bad hydro year
      iii. Effects of plant outage
   c. Provide requested materials from DART and EIM presentations:
      i. Supporting workpapers for the weather analysis of DART
      ii. Supporting workpapers/example of how bids are calculated
      iii. Supporting workpapers for calculations used in the example EIM bids

5. Transparency (discussed at February 23 workshop)
   a. Step-log of changes
   b. TAM guidelines and how DART and EIM adjustments fit in

6. Follow-up items from previous workshops (discussed at March 7 workshop)
    a. Use of 5-year normalization for DART
    b. REC transfers – what are the difficulties, how can they be overcome
    c. $/MW EIM benefit calculation

<u>Order No. 16-482 provides the following guidance on these workshops:</u>

"We also direct PacifiCorp, Staff, and parties to participate in workshops to examine the following GRID issues: (1) Day-Ahead/Real-Time Transaction (DART) adjustments, (2) Energy Imbalance Market (EIM) benefit estimation, and (3) Renewable Energy Credit (REC) valuation.

With respect to the first two issues, our intent is for PacifiCorp to describe its modeling approach in detail during the workshops to facilitate the parties' deeper understanding of these issues. We expect parties challenging PacifiCorp's modeling choices to engage in these discussions in order to fully understand the rationale behind the adjustments. Our goal is to create an improved evidentiary record on these disputed issues going forward. While the workshops are intended to be informational in nature, parties may also use the workshops to discuss whether any adjustments to PacifiCorp's existing methodologies may be appropriate. With respect to the REC issue, the parties should discuss whether there is a reasonable method to value RECs based on delaying the time when PacifiCorp is required to take any substantive action to ensure RPS compliance, as discussed later in this order. Staff is to report back to us on the results of these workshops before PacifiCorp's 2018 TAM is filed.[2]*"*

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[2] We do not seek recommendations from Staff based on tis set of informational workshops but simply a report on the parties' discussions.

Oregon 2017 TAM

2018 Modeling Changes

March 7, 2017

Redacted Version –
Subject to Protective Order No. 16-128

PACIFIC POWER

Let's turn the answers on.

Agenda

- 2018 TAM Potential Modeling Changes (subject to discussion and agreement with parties)
  - EIM Benefit Calculation
  - DA/RT Normalization

Proposed EIM Benefit Calculation

- The EIM benefit realized from exporting energy to the CAISO will no longer be based on available transmission capacity in GRID. The EIM benefit from exports to CAISO will be based on a dollars per month approach, which is the same method used to estimate the benefit of exports to other EIM participants. To mitigate the potential of overstating the sales benefit at the COB market, the COB market cap in GRID will be based on a historic period that corresponds to EIM participation -November 2014 to June 2016 in place of a 48 month history.

EIM Interregional Benefits	CY2017 (in Millions)
ORTAM17	[redacted]
ORTAM17 (new format)	[redacted]
Difference	[redacted]

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Proposed EIM Benefit Calculation

2018 TAM COB Market Cap Comparison

	UExxx (48ME June16)				Only Uses Nov 14+			
2018	COB HLH	Cap Month	COB LLH	Cap Month	COB HLH	COB LLH	Delta HLH	Delta LLH
January	[redacted]							
February								
March								
April								
May								
June								
July								
August								
September								
October								
November								
December								

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Proposed DA/RT Adjustment

- To increase normalization, the DA/RT adjustment will be based on a 60 month history as opposed to a 48 month history as used in the 2017 TAM.

Historical Period	DART Cost (in Millions)
48month (Jul11-Jun15)	[redacted]
48month (Jul12-Jun16)	[redacted]
60month (Jul11-Jun16)	[redacted]

Attachment A

Oregon Transition Adjustment Mechanism Workshop

REC Transfers for Direct Access Customers

March 7, 2017




PACIFICORP
A BERKSHIRE HATHAWAY ENERGY COMPANY

REC Transfer Alternatives

- Concept: when a Direct Access customer opts-out, the loss of load results in "freed-up" RECs that the company does not have to retire in that compliance year

- The company has identified two different options for determining which RECs can be transferred to an ESS
  - 1) Pro-rata share of RECs generated or acquired during the opt-out year(s)
  - 2) Pro-rata share of RECs used for compliance during the opt-out year(s)

- Both of these options are likely to be overly complex and administratively burdensome in light of the very small volume of RECs that are likely to be transferred
  - Not all RECs are created equal and with the passage of SB 1547 there are many different REC categories
    - Geographic and type variation of resources
    - Golden RECs v. 5-year RECs
    - Elimination of first-in first-out rule creates additional complexity in terms of which RECs are retired in a particular compliance year

Attachment A

Option 1: Share of RECs Generated

- Table below shows an example (amounts are all hypothetical) all of the categories of Oregon-allocated RPS RECs generated in 2018

2018 Vintage		5-year Life Bundled	Golden Bundled	5-year Life Unbundled	Golden Unbundled	2018 Vintage		5-year Life Bundled	Golden Bundled	5-year Life Unbundled	Golden Unbundled
Base Resources	Biogas	3,500	0	0	0	Oregon Situs (Including ETO)	Biogas	0	0	0	0
	Geothermal	18,000	0	0	0		Geothermal	0	0	0	0
	Wind	1,000,000	0	0	0		Wind	100,000	0	0	0
	Hydro - Low Impact	200,000	0	0	0		Hydro - Low Impact	0	0	0	0
	Hydro - Incremental	8,000	0	0	0		Hydro - Incremental	0	0	0	0
	Solar - OSIP	0	0	0	0		Solar - OSIP	14,500	0	0	0
	Solar - Utility	0	0	0	0		Solar - Utility	9,200	0	0	0
Resources with COD Between SB 1547 Passing and 12/31/22	Biogas	0	0	0	0	2016 REC RFP Purchase	Biogas	0	0	0	0
	Geothermal	0	0	0	0		Geothermal	0	0	0	0
	Wind	0	110,000	0	0		Wind	0	0	0	0
	Hydro - Low Impact	0	0	0	0		Hydro - Low Impact	0	0	0	0
	Hydro - Incremental	0	0	0	0		Hydro - Incremental	0	0	0	0
	Solar - OSIP	0	0	0	0		Solar - OSIP	0	0	0	0
	Solar - Utility	0	30,000	0	0		Solar - Utility	24,000	80,000	75,000	140,000
Total 2018 RECs						1,812,200					

- Given the various ‘buckets’ and sheer number of resources, transferring a pro-rata share of RECs generated in a given year creates a significant administrative burden
- RECs would need to be transferred from over 60 generating resources.

Option 2: Share of RECs Used for Compliance

- To demonstrate the impact of Direct Access on Pacific Power's RPS compliance, we use compliance year 2018 as an example, to illustrate the compliance position with and without an ESS's 2018 Direct Access load (load amounts are not actual forecasts):

	Without Direct Access	With Direct Access
2018 Oregon Retail Sales	13,000,000	13,200,000
2018 RPS Target Percentage	1,950,000	1,980,000
2018 RECs Retired	1,950,000	1,980,000
Delta	-30,000	
Delta (Percentage)	1.54%	
	(30,000 / 1,950,000)	

- Under this option, 1.54% of RECs retired from each RPS resource in 2018 would be transferred to the ESS
- Creates the same administrative challenges of Option 1 (too many REC buckets)
- Assumes there ARE adequate RECs from each resource in a compliance year to be transferred.
- Creates accounting issues with fractional/partial RECs

Company Proposal

- REC transfer options are administratively burdensome and overly complex given the very small quantity of RECs to be transferred
- PacifiCorp will not be able to transfer bundled RECs—when an ESS has bundled REC requirements, they may not be satisfied with the REC transfer option; therefore REC transfer option is only a short-term solution
- Company will propose to value RECs based on present value of future compliance need—the below table shows examples of how the incremental savings would be calculated based on a range of REC prices:

Cost of Future Need ($/REC)	Incremental Cost Savings ($/MWh of DA load)
$1	$0.08
$5	$0.40
$10	$0.79
$15	$1.19

- RECs will be valued based on recent REC RFP (weighted average $/REC in year of need)
- Applies to 1- and 3-year opt-out customers
- 5-year opt-out customers ineligible for this adjustment since these customers do not contribute to schedule 203
  - Subject to revision if the company acquires OR-situs renewable resource

PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

March 1, 2017

VIA ELECTRONIC MAIL

Attn: Parties to Docket UE 307

RE: 2018 Transition Adjustment Mechanism
Pacific Power's Notice of Methodology Changes

Under the Transition Adjustment Mechanism (TAM) Guidelines, PacifiCorp d/b/a Pacific Power (PacifiCorp or Company) provides this Notice of Methodology Changes for the 2018 TAM. This notice complies with an amendment to the TAM Guidelines adopted by the Public Utility Commission of Oregon (Commission) in Order No. 09-432. This amendment provides that "[t]he Company will provide notice of substantial changes to the methodologies used to calculate the cost elements and other inputs to the GRID[1] model or to the logic of the GRID model by March 1st of the year of a stand-alone TAM filing." Under another amendment to the TAM Guidelines adopted in Order No. 13-474 in Docket UE 263, the Commission removed the requirement for filing general rate cases concurrently with the TAM by March 1, allowing the Company to file a general rate case at any time during the year. Because the Company does not plan to file a general rate case by the April 1 filing date for the 2018 TAM, the Company is treating the 2018 TAM as a stand-alone filing for purposes of the methodology change notice requirement.

Per Order No. 16-482 (2017 TAM Order), the Company has held a series of collaborative workshops with parties[2] to examine the Day-Ahead/Real-Time Transaction (DA/RT) adjustment, the Energy Imbalance Market (EIM) benefit estimation, and the valuation of Renewable Energy Credits (REC) for direct access customers. The Company also convened separate workshops, as ordered by the Commission, to discuss the Company's approach to developing its long-term fuel strategy for the Jim Bridger plant. While discussions continue between the Company and parties regarding DA/RT and EIM, potential changes to these calculations are listed below. The final workshop is scheduled for March 7, 2017; if parties agree, the following changes will be made:

- <u>Day-Ahead and Real-Time Balancing Transactions</u> – To increase normalization, the DA/RT adjustment will be based on a 60 month history as opposed to a 48 month history as used in the 2017 TAM.
- <u>EIM Benefits</u> – The EIM benefit realized from exporting energy to the CAISO[3] will no longer be based on available transmission capacity in GRID. The EIM benefit from exports to CAISO will be based on a dollars per month approach, which is the same method used to estimate the benefit of exports to other EIM participants. To mitigate the potential of overstating the sales benefit at the COB[4] market, the COB market cap in

[1] Generation and Regulation Initiative Decision tools model.
[2] Parties participating in the workshops include Commission Staff, Citizens' Utility Board of Oregon, Industrial Customers of Northwest Utilities and Calpine Energy Solutions LLC.
[3] California Independent System Operator.
[4] California-Oregon Border.

GRID will be based on a historic period that corresponds to EIM participation - November 2014 to June 2016 in place of a 48 month history.

In addition, the Company plans to continue discussions with parties concerning the valuation of RECs for direct access customers. To comply with Order No. 16-482 that the REC valuation "focus on the potential benefits that it may derive at the time PacifiCorp must take substantive action to comply with its RPS targets", the Company may propose a REC value for direct access customers equal to net present value of the future benefit. The Company may also propose a different methodology for REC valuation based on continued discussion with the parties.

The Company will include an exhibit to testimony in the direct filing identifying all changes based on discussions with parties as outlined above.

The Company also provides notice of the following planned changes to the 2018 TAM:

- Coal fuel costs at the Jim Bridger plant will reflect updated depreciation expense that corresponds to the operations of the underground mine; and
- Amortization of prepaid wheeling expenses associated with the Cholla coal plant will reflect an amortization period that correlates with the Oregon depreciable life of the plant. Previously, the amortization schedule erroneously correlated to the non-Oregon depreciable life of the plant.

Please direct informal correspondence and questions regarding this notice to Natasha Siores at 503-813-6583.

Sincerely,

R. Bryce Dalley
Vice President, Regulation

cc: UE 307 Service List