Department of Energy
Western Area Power Administration
Desert Southwest Customer Service Region
P.O. Box 6457
Phoenix, AZ 85005-6457

AUG - 3 2012

Dear Intertie Project and Parker-Davis Project Customers and Interested Parties,

On June 28, 2012, the Western Area Power Administration (Western) conducted a public information forum to explain the proposed rates for the Pacific Northwest-Pacific Southwest Intertie Project (Intertie Project). In addition, Western held an informal meeting to review the proposed rates for the Parker-Davis Project (P-DP).

In accordance with existing procedures for public participation in rate adjustments (10 CFR Part 903), Western is providing the enclosed responses to questions not answered at the public information forum. While the P-DP informal meeting does not fall under the requirements set forth in 10 CFR Part 903, responses to questions not answered from that meeting are included for your convenience.

A copy of the responses for the Intertie Project will also be posted on Western's website at http://www.wapa.gov/dsw/pwrmkt/Intertie/RateAdjust.htm. A copy of the responses for the P-DP will be posted at http://www.wapa.gov/dsw/pwrmkt/RateAdjust/Main.htm.

For additional information concerning the purchase power response, please contact John Paulsen of Western's Energy Management and Marketing Office for the Desert Southwest Region at 602-605-2557. For other inquiries, please contact Jack Murray at 602-605-2441 or Todd Statler at 602-605-2781 (Intertie Project) or Scott Lund at 602-605-2441 (P-DP).

Sincerely,

for Deborah K. Emler
Assistant Regional Manager
for Power Marketing

3 Enclosures

Intertie Project – Public Comment Forum
Responses to Outstanding Questions

1. Question: Based on the P-DP rate presentation this morning (6/28/12), can we expect an additional explanation of the purchase power costs that are being included as a new element in the proposed rates for the Intertie?

   Request: Please provide documentation on the assumptions used in forecasting purchase power costs and allocating these costs to specific components of the BA?

   Response: Please refer to the attached document titled "Explanation of Purchase Power Costs."

2. Request: Please provide a table that summarizes the reservations that are no longer valid in the sales projections for the current rates? Specifically, what are the points of receipt and delivery for those reservations?

   Question: What was the basis for those sales projections and what has changed since then and where is the transmission capacity available on the Intertie?

   Response: The sales projections (kW) for transmission service that were used to develop the current rates are as follows:

Fiscal Year	230/345-kV	500-kV	Total
2007	1,064,540	612,000	1,676,540
2008	1,064,540	709,000	1,773,540
2009	1,064,540	737,200	1,801,740
2010	1,064,540	793,600	1,858,140
2011	1,064,540	850,000	1,914,540
2012	1,064,540	906,400	1,970,940
2013+	1,064,540	962,500	2,027,040

The approach taken during the last rate adjustment (2007) involved restructuring the 500-kV sales assumptions by extending the original phase-in period by five years in order to attain a reservation level of 962,500 kW. At the time, the 500-kV transmission system had a reservation level of 612,000 kW and the majority of Western's portion of the transmission capacity from Perkins Switchyard (located next to Westwing Substation) to Mead Substation and on to Marketplace Switching Station (located next to McCullough Substation) and Adelanto Switchyard was under contract.

However, Western's portion of the transmission capacity from Adelanto Switchyard to Marketplace Switching Station through Mead Substation on to Perkins Switchyard was still available. Since additional reservations could have occurred on various segments of this transmission path over the next five years, specific points of delivery or receipt were not established. The market for this transmission service was considered undeveloped and extending the phase-in period provided additional time for potential prospects to evolve. Unfortunately, the market remained underdeveloped and demand for this transmission service was significantly lower than planned. As a result, the phase-in period is being discontinued and the proposed rates were developed using sales projections of 612,000 kW for 500-kV transmission service.

3. Request: Please provide an explanation of the purchase transmission capacity shown on slide ten of the presentation?

Response: Western's participation in the Mead-Adelanto Project included a share of the capacity in the 500-kV transmission line between Marketplace Switching Station and the Adelanto Switching Station. Since Adelanto resides within Los Angeles' Department of Water and Power (LADWP) balancing authority, Western desired transmission beyond Adelanto to a point where LADWP's control area interconnects with Southern California Edison's (now the California ISO) balancing authority. As a result, Western executed an agreement with LADWP to purchase transmission between Adelanto and the midpoint of the 500-kV Victorville-Lugo transmission line. The annual costs associated with purchasing this transmission capacity were included in the current rates and continue to be included in the proposed rates.

Explanation of Purchase Power Costs

The purchase power cost estimates included in the Desert Southwest Region's (DSW) project rate calculations include both estimated purchases of reserve capacity, which is typically purchased as spinning reserve when hydroelectric capacity is not available to provide reserve margins, and estimated purchases of energy to supplement hydroelectric generation. Decisions to purchase reserves and energy are made at the macro level (DSW-wide) in order to make sure that loads and resources are properly balanced and reserve requirements are met. The costs for both types of purchases are distributed based on available data to attribute shortages at the micro level (project and service specific). There are shortages that can be attributed to a project or service based on direct relationships; available generation compared to energy deliveries, or metered quantities; and there are others that arise out of the nature of the operation of the Western Area Lower Colorado (WALC) Balancing Authority Area (BA). When shortages are attributable to the WALC BA, the costs are split among the DSW transmission projects served by the WALC BA. The split is based on the losses attributable to each transmission system which is representative of the use of each system. The unit cost per MW or MWh is based on either historical or forward prices.

Reserve Capacity:

Reserves are purchased throughout the month based on a forecasted shortage of federal hydroelectric reserve margins. Since we purchase based on a forecasted value and actual values will vary, we need an allocation percentage by project to attribute the cost of reserve purchases.

The DSW projects in the WALC BA are required to carry both contingency and regulating reserves. Contingency reserves are allocated under WALC membership in the Southwest Reserve Sharing Group (SRSG). Regulating reserves are a function of actual regulation needed to operate the WALC BA reliably.

The significant factor in determining DSW's contingency reserve requirement is load responsibility/firm commitment. For firm commitment, DSW is required to calculate a net of all firm exports and loads versus firm imports and report the results to SRSG. Roughly speaking this value can have the effect of either increasing or decreasing DSW's contingency requirement. DSW requires its BA customers to provide firm resources to serve load. Therefore, DSW's only firm commitment not served by firm imports is Parker and Davis (PDP) generation used for PDP Firm Electric Service deliveries.

DSW's regulating reserve requirement is based on historical trends of WALC's regulation response. That response can be triggered by both load and resource imbalances and various sorts of disturbances of the interconnected transmission system. DSW has taken actual sub-minute load changes into account to quantify the portion of regulating reserve requirement attributable to load and resource imbalances. The rest of the regulating reserve requirement (not attributable directly to load activity) is therefore attributable to imbalances of the interconnected transmission system.

Reserve purchase responsibility is therefore split into the following categories for attribution by project with actual percentages calculated based on the most recent historical data:

1. Contingency
2. Regulating
    a. Attributable to WALC BA Load fluctuations
    b. Not attributable to WALC BA Load fluctuations

The PDP generation project is responsible for the percentage of the DSW contingency requirement compared to the total DSW reserve requirement. This is based on the direct relationship of firm PDP deliveries to the calculation of the DSW firm commitment for SRSG.

The percentage of the DSW regulation requirement is first compared to the total DSW reserve requirement and then split between the percentage of the requirement that is caused by WALC BA load customers and the rest. The former is collected through the Ancillary Service rate for Regulation and the latter is split amongst the PDP, Intertie, and CAP transmission projects.

Energy Purchases:

Energy is purchased to balance the actual usage of energy (both scheduled and unscheduled) with available hydro generation. The availability of hydro in DSW is set by the Bureau of Reclamation for the purpose of water distribution and there is very limited flexibility to deviate from the water requirements.

Energy purchases attributable to the PDP generation project are based on the amount of energy purchases needed to balance available PDP generation with energy deliveries to the PDP Firm Electric Service contractors. Additional purchases beyond those needed to balance PDP are deemed to be the responsibility of the WALC BA and are split amongst the PDP, Intertie, and CAP transmission projects.

Energy/Capacity Costs used for Estimates:

The estimated cost of the reserve capacity is based on historical prices for reserves as seen in the most recent year at the time the estimates were calculated. That figure was $18. The cost of reserves can vary based on the time of day and availability. DSW is typically short of reserves in the highest load portion of the day.

The estimated cost of the energy purchases is based on ICE Palo Verde on peak forwards for the applicable month. Since DSW will most often purchase at Mead or Pinnacle Peak, we include a spread for the higher prices typically paid at those locations relative to prices at Palo Verde. The time of day DSW purchases is also weighted to higher load hours when we are short and those hours will trade at higher prices than the flat on peak profiles reflected in the ICE forwards. We also believe that the risk of upward price volatility should be factored into our estimate since the forwards used for these rate estimates were obtained in May 2012 for projected purchases as far out as September of 2013. We estimated all of these factors to be an $8 adder to the ICE forward prices.

Parker-Davis Project
Informal Rate Meeting - Responses/Additional Information

Illustration of the Change in Multi-Project (MP) Costs/Revenue Accounting Treatment[1]

Previous Accounting Treatment	
MP Expense	
Mead Svc Center	144,681
Total MP Expense	144,681
MP Other Revenue	
Phoenix Svc Center	1,874,899
SCADA	372,969
Total MP Other Revenue	2,247,868
Rate Impact (Exp minus Rev)	(2,103,187)

Current Accounting Treatment ("Negative Expense")	
MP Expense	
Mead Svc Center	144,681
Phoenix Svc Center	(1,874,899)
SCADA	(372,969)
Total MP Expense	(2,103,187)
MP Other Revenue	-
Total MP Other Revenue	-
Rate Impact (Exp minus Rev)	(2,103,187)

Detail of CME & Multi-Project Costs/Revenue and Comparison Between Rate Windows[1]

	a	b	c	d = a - b + c
	FY13-17 Expense	FY12-16 Expense	FY12-16 Other Rev	Difference
CME	1,130,780	1,143,069	-	(12,289)
FY11 Phoenix Svc Center[2]	(1,855,031)		1,855,031	-
Future Phoenix Svc Center[3]	(19,868)		85,755	65,887
FY11 SCADA[2]	(299,510)		299,510	-
Future SCADA[3]	(73,459)		128,158	54,699
FY11 Mead Svc Center[2]	144,681	144,681	-	-
	(972,407)	1,287,750	2,368,454	108,297

[1] Average annual amounts from FY13-17 rate window as presented at the Informal Rate Meeting on June 28, 2012

[2] Amounts calculated in accordance with the Multi-Project Cost Procedures

[3] Estimate of future revenues/expenses based on projects included in Western's Ten-Year Plan