Customer Meeting

May 21, 2015

Colorado River Storage Project Management Center

Western
AREA POWER
ADMINISTRATION

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Welcome to the CRSP Annual Customer Meeting May 21, 2015 11:00 am – 3:00 pm

The meeting will begin at **11:00 am MST**
We have logged on early for connectivity purposes
Please stand-by until the meeting begins.
Please remember to keep your **phone muted** unless you have a question or comment.

Handout Materials
http://www.wapa.gov/crsp/ratescrsp/default.htm

Western AREA POWER ADMINISTRATION

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CRSP Management Center
Annual Customer Meeting
May 21, 2015
11:00 am – 3:00 pm

Welcome and Introductions - Rodney

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Transmission

Jacob Streeper

Transmission Rate in Detail

- How we calculate the Annual Transmission Revenue Requirement (ATRR)
- Difference between the Current and Forward-Looking Methodology
- Details of True-up

FY 2016 Net Investment Cost

- Western's Total Plant in Service minus Allowance for Depreciation
- Current Methodology – $237,862,422

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Fixed Charge – Current

WESTERN AREA POWER ADMINISTRATION		
COLORADO RIVER STORAGE PROJECT		
DETERMINATION OF ANNUAL FIXED CHARGE RATE FOR TRANSMISSION		
BASED ON FY 2014 FINANCIAL DATA		
		Amount
A. Operation and Maintenance Expense		
	Transmission O&M Expense	$ 30,644,498
	Transmission of Electricity by Others	$ 12,475,526
	Total O&M for Transmission	$ 43,120,024
	Net Transmission Investment Cost	**$ 237,862,422**
	O&M as a % of Net Investment Cost	18.128%
B. Administrative and General Expense		
	Transmission A&G Expense	$ 8,807,555
	Net Transmission Investment Cost	**$ 237,862,422**
	A&G as a % of Net Investment Cost	3.70%
C. Depreciation Expense		
	Transmission Depreciation Expense	$ 14,109,125
	Net Transmission Investment Cost	**$ 237,862,422**
	Depreciation as a % of Net Investment Cost	5.932%
D. Interest		
	FY 15 Interest is:	$ 117,952
	Western Unpaid Debt as of FY14:	$ 6,109,805
	Interest Rate	1.93%
E. Annual Fixed Charge Rate		
	Operation and Maintenance Expense	18.128%
	A&G Expense	3.70%
	Depreciation Expense	5.932%
	Interest	1.93%
	Total	29.69%

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Operation and Maintenance

A. Operation and Maintenance Expense			
	Transmission O&M Expense	$	30,644,498
	Transmission of Electricity by Others	$	12,475,526
	Total O&M for Transmission	$	43,120,024
	Net Transmission Investment Cost	**$**	**237,862,422**
	O&M as a % of Net Investment Cost		18.128%

Administrative and General (Overhead)

B. Administrative and General Expense			
	Transmission A&G Expense	$	8,807,555
	Net Transmission Investment Cost	**$**	**237,862,422**
	A&G as a % of Net Investment Cost		3.70%

Depreciation

C. Depreciation Expense		
	Transmission Depreciation Expense	$ 14,109,125
	Net Transmission Investment Cost	**$ 237,862,422**
	Depreciation as a % of Net Investment Cost	5.932%

Interest

D. Interest		
	FY 15 Interest is:	$ 117,952
	Western Unpaid Debt as of FY14:	$ 6,109,805
	Interest Rate	1.93%

Fixed Charge Rate
Current Methodology

E. Annual Fixed Charge Rate	
Operation and Maintenance Expense	18.128%
A&G Expense	3.70%
Depreciation Expense	5.932%
Interest	1.93%
Total	29.69%

Net Transmission Investment	$ 237,862,422
Annual Fixed Charge Rate	29.69%
Annual Cost for Transmission	$ 70,620,459

FY 2016 Transmission Rate
Current Methodology

Western Area Power Administration
Colorado River Storage Project
FY16 Firm Point-to-Point Rate
Based on FY 2014 Financial Data

	FY 2015		FY 2016		Change	% change
Annual Cost for Transmission Service	**$ 61,899,896**		**$ 70,620,459**		$ 8,720,563	14.09%
Transmission Revenue Credits						
Non-FirmTransmission Revenue	$ 582,011		$ 616,394		$ 34,383	5.91%
Ancillary Service Revenue	$ 407,161		$ 541,833		$ 134,672	33.08%
Miscellaneous Revenue	$ 113,497		$ 82,527		$ (30,970)	-27.29%
Phase Shifter Revenue	$ 1,041,386		$ 886,174		$ (155,212)	-14.90%
Provo River Project	$ 29,800		$ 29,800		$ -	0.00%
Exchange Contracts	$ 1,440,000		$ 1,332,000		$ (108,000)	-7.50%
Total Transmission Rev Credits	**$ (3,613,855)**		**$ (3,488,729)**		$ 125,126	-3.46%
Annual Revenue Requirement:	**$ 58,286,041**		**$ 67,131,731**		$ 8,845,690	15.18%
Transmission System Load:						
Firm Power Obligations:						
Contract Rate of Delivery	1,435,886		1,435,886		0	
CRSP Merchant Reservation	1,992,000		2,002,000		10,000	
Tri-State & SRP Exchange	350,000		350,000		0	
Firm Wheeling Contracts	617,250		617,440		190	
Total	**4,395,136**		**4,405,326**		**10,190**	
Firm Point-to-Point Transmission Rate in $/kW:						
	$ 13.26	**kW-year**	**$ 15.24**	**kW-year**	$ 1.977	14.91%
	$ 1.11	**kW-month**	**$ 1.27**	**kW-month**	$ 0.165	14.91%
	$ 0.26	**kW-week**	**$ 0.29**	**kW-week**	$ 0.038	14.91%
	$ 0.04	**kW-day**	**$ 0.04**	**kW-day**	$ 0.005	14.91%
	$ 0.00151	**mills/kwh**	**$ 0.00174**	**mills/kWh**	$ 0.0002	14.91%

ATRR Difference Between Methodologies

	Net Investment
Current	$ 237,862,422
Projected	$ 12,433,130
Forward-Looking	$ 250,295,552

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Fixed Charge – Forward-Looking

WESTERN AREA POWER ADMINISTRATION			
COLORADO RIVER STORAGE PROJECT			
DETERMINATION OF ANNUAL FIXED CHARGE RATE FOR TRANSMISSION			
BASED ON FY 2014 FINANCIAL DATA			
	Current	Projection	Forward-Looking
A. Operation and Maintenance Expense			
Transmission O&M Expense	$ 30,644,498		$ 30,644,498
Transmission of Electricity by Others	$ 12,475,526		$ 12,475,526
Total O&M for Transmission	$ 43,120,024		$ 43,120,024
Net Transmission Investment Cost	**$ 237,862,422**	**$ 12,433,130**	**$ 250,295,552**
O&M as a % of Net Investment Cost	18.128%		17.228%
B. Administrative and General Expense			
Transmission A&G Expense	$ 8,799,299		$ 8,799,299
Net Transmission Investment Cost	**$ 237,862,422**	**$ 12,433,130**	**$ 250,295,552**
A&G as a % of Net Investment Cost	3.70%		3.516%
C. Depreciation Expense			
Transmission Depreciation Expense	$ 14,109,125		$ 14,109,125
Net Transmission Investment Cost	$ 237,862,422	**$ 12,433,130**	**$ 250,295,552**
Depreciation as a % of Net Investment Cost	5.932%		5.637%
D. Interest			
FY 15 Interest is:	$ 117,952		$ 117,952
Western Unpaid Debt as of FY14:	$ 6,109,805		$ 6,109,805
Interest Rate	1.93%		1.93%
E. Annual Fixed Charge Rate	Current		Forward-Looking
Operation and Maintenance Expense	18.128%		17.228%
A&G Expense	3.70%		3.52%
Depreciation Expense	5.932%		5.637%
Interest	1.93%		1.93%
Total	29.69%		28.31%

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Fixed Charge Rate
Forward-Looking Methodology

E. Annual Fixed Charge Rate	Current	Forward-Looking
Operation and Maintenance Expense	18.128%	17.228%
A&G Expense	3.70%	3.52%
Depreciation Expense	5.932%	5.637%
Interest	1.93%	1.93%
Total	29.69%	28.31%

Net Transmission Investment	$ 250,295,552
Annual Fixed Charge Rate	28.31%
Annual Transmission Revenue Requirement	$ 70,860,484

	ATRR Difference
Forward-Looking	$ 70,860,484
Current	$ 70,620,459
	$ 240,025

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True-up to Actuals

- Actuals available at the end of the FY
- Compare projections to actuals
- Apply difference as a True-up

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FY 2017 Net Investment Cost
(Example)

- Example:
  - ➢If $14,433,130 was actually booked in FY 2015
  - ➢$2,000,000 True-up to Net Investment Cost
  - ➢Actual FY 2016 Net Investment Cost would be $252,295,552
  - ➢Recalculate the FY 2016 Rate to determine the True-up to apply to the FY 2017 Rate.

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FY 2016 ATRR True-up
Compare Projected to Actual

	Net Investment
Actual	$ 252,295,552
Projected	$ 250,295,552
True-up	$ 2,000,000

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FY 2016 Recalculation (example)

WESTERN AREA POWER ADMINISTRATION COLORADO RIVER STORAGE PROJECT DETERMINATION OF ANNUAL FIXED CHARGE RATE FOR TRANSMISSION BASED ON FY 2014 FINANCIAL DATA	Projected	Difference	Actual	
A. Operation and Maintenance Expense				
Transmission O&M Expense	$ 30,644,498		$ 30,644,498	
Transmission of Electricity by Others	$ 12,475,526		$ 12,475,526	
Total O&M for Transmission	$ 43,120,024		$ 43,120,024	
Net Transmission Investment Cost	**$ 250,295,552**	**$ 2,000,000**	**$ 252,295,552**	
O&M as a % of Net Investment Cost	17.228%		17.091%	
B. Administrative and General Expense				
Transmission A&G Expense	$ 8,799,299		$ 8,799,299	
Net Transmission Investment Cost	**$ 250,295,552**	**$ 2,000,000**	**$ 252,295,552**	
A&G as a % of Net Investment Cost	3.52%		3.49%	
C. Depreciation Expense				
Transmission Depreciation Expense	$ 14,109,125		$ 14,109,125	
Net Transmission Investment Cost	$ 250,295,552	**$ 2,000,000**	**$ 252,295,552**	
Depreciation as a % of Net Investment Cost	5.637%		5.592%	
D. Interest				
FY 15 Interest is:	$ 117,952		$ 117,952	
Western Unpaid Debt as of FY14:	$ 6,109,805		$ 6,109,805	
Interest Rate	1.93%		1.93%	
E. Annual Fixed Charge Rate	Current		Actual	True-up
Operation and Maintenance Expense	17.228%		17.091%	
A&G Expense	3.52%		3.49%	
Depreciation Expense	5.637%		5.592%	
Interest	1.93%		1.93%	
Total	28.31%		28.10%	
ATRR	$ 70,860,484		$ 70,899,095	$ 38,611

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FY 2017 True-up Example

Western Area Power Administration Colorado River Storage Project FY16 Firm Point-to-Point Rate Based on FY 2015 Financial Data and FY 2016 Projections	FY 2016		FY 2017	True-up	FY 2017	
Annual Cost for Transmission Service	**$70,860,484**		**$69,876,251**	**$ 38,611**	**$69,914,862**	
Transmission Revenue Credits						
Non-FirmTransmission Revenue	$ 616,394		$ 616,394		$ 616,394	
Ancillary Service Revenue	$ 541,833		$ 541,833		$ 541,833	
Miscellaneous Revenue	$ 82,527		$ 82,527		$ 82,527	
Phase Shifter Revenue	$ 886,174		$ 886,174		$ 886,174	
Provo River Project	$ 29,800		$ 29,800		$ 29,800	
Exchange Contracts	$ 1,332,000		$ 1,332,000		$ 1,332,000	
Total Transmission Rev Credits	**$ (3,488,729)**		**$ (3,488,729)**		**$ (3,488,729)**	
Annual Revenue Requirement:	**$67,371,755**		**$66,387,522**		**$66,426,133**	
Transmission System Load:						
Firm Power Obligations:						
Contract Rate of Delivery	1,435,886		1,435,886		1,435,886	
CRSP Merchant Reservation	2,002,000		2,002,000		2,002,000	
SRP Exchange	350,000		350,000		350,000	
Firm Wheeling Contracts	617,440		617,440		617,440	
Total	**4,405,326**		**4,405,326**		**4,405,326**	
Firm Point-to-Point Transmission Rate in $/kW:						
	$ 15.29	**kW-year**	**$ 15.07**	**kW-year**	**$ 15.08**	**kW-year**
	$ 1.27	**kW-month**	**$ 1.26**	**kW-month**	**$ 1.26**	**kW-month**
	$ 0.29	**kW-week**	**$ 0.29**	**kW-week**	**$ 0.29**	**kW-week**
	$ 0.04	**kW-day**	**$ 0.04**	**kW-day**	**$ 0.04**	**kW-day**
	$ 0.00175	**mills/kwh**	**$ 0.00172**	**mills/kWh**	**$ 0.00172**	**mills/kWh**

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FY 2016 Transmission Rate Showing both Methodologies

Western Area Power Administration
Colorado River Storage Project
FY16 Firm Point-to-Point Rate
Based on FY 2014 Financial Data and FY 2015 Projections

		FY 2016 Current			FY 2016 Forward-Looking	
Annual Cost for Transmission Service	$	70,860,484		$	70,897,492	
Transmission Revenue Credits						
Non-FirmTransmission Revenue	$	616,394		$	616,394	
Ancillary Service Revenue	$	541,833		$	541,833	
Miscellaneous Revenue	$	82,527		$	82,527	
Phase Shifter Revenue	$	886,174		$	886,174	
Provo River Project	$	29,800		$	29,800	
Exchange Contracts	$	1,332,000		$	1,332,000	
Total Transmission Rev Credits	$	(3,488,729)		$	(3,488,729)	
Annual Revenue Requirement:	$	66,387,522		$	67,408,763	
Transmission System Load:						
Firm Power Obligations:						
Contract Rate of Delivery		1,435,886			1,435,886	
CRSP Merchant Reservation		2,002,000			2,002,000	
Tri-State & SRP Exchange		350,000			350,000	
Firm Wheeling Contracts		617,440			617,440	
Total		4,405,326			4,405,326	
Firm Point-to-Point Transmission Rate in $/kW:						
	$	15.07	kW-year	$	15.30	kW-year
	$	1.26	kW-month	$	1.28	kW-month
	$	0.29	kW-week	$	0.29	kW-week
	$	0.04	kW-day	$	0.04	kW-day
	$	0.00172	mills/kwh	$	0.00175	mills/kWh

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Questions?

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Salt Lake City Area / Integrated Projects

(SLCA/IP)

Rate

Thomas Hackett

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SLCA/IP Rate

1. Status of Repayment
2. Current SLCA/IP Firm Power Rate (SLIP-F9)
3. Revenue Requirements Comparison Table
4. SLCA/IP Rate
5. Next Steps

Status Of Repayment

(Tab 2)

SLCA/IP Status of Repayment
Power Investment Only
As of September 30, 2014

Project	Investment ($million)	Investment Repaid: Amount ($million)	Percent	Payoff
CRSP	1,187.175	1,118.289	94.20%	2020
CRSP Irrigation	1,185.517	50.164	4.26%	2044
Collbran	22.027	16.594	75.33%	2060
Dolores	38.345	8.498	22.16%	2054
Rio Grande	19.980	16.358	81.87%	2064
Seedskadee	9.432	9.432	100.0%	2013

SLCA/IP Firm Power Rate

(Tab 3)

- Current Firm Power Rate (SLIP-F9)
  - Effective Oct. 1, 2009
  - Energy: 12.19 mills/kWh
  - Capacity: $5.18 kW/month
  - Composite Rate: 29.62 mills/kWh
- Expires September 30, 2015
- Cost Recovery Charge – (Tab 18)
  - 0.00 mills/kWh

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Salt Lake City Area/Integrated Projects Energy Generated Percentages

Based on FY 2014 Data

	% Energy Generated
CRSP	96.75
Glen Canyon	74.12
Other Integrated Projects	
Dolores	0.51
Seedskadee	1.40
Collbran	1.04
Rio Grande	0.30
SLCA/IP	100.00

History of SLIP Rates

	Effective Date (CY)	Capacity $/kW	Energy mills/kWh	Composite mills/kWh
	1993	3.54	8.40	18.70
	1995	3.83	8.90	20.17
	1998	3.44	8.10	17.57
	2002	4.04	9.50	20.72
	2005	4.43	10.43	25.28
Step 1	2008	4.70	11.06	26.80
Step 2	2009	5.18	12.19	29.62

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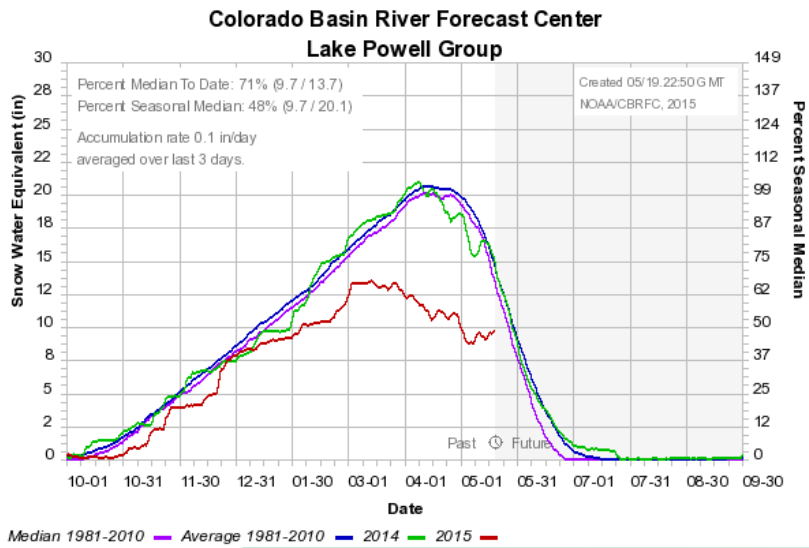
Current Hydrology

(Tab 9)



Preliminary PRS Composite Rate History

- SLIP-F9 Step 2 rate PRS – **29.62** mills/kWh
- FY2010 Preliminary PRS – **31.41** mills/kWh
- FY2011 Preliminary PRS – **29.70** mills/kWh
  - MOA concerning the Upper Colorado Basin Fund (Apportionment)
- FY2012 Preliminary PRS – **29.79** mills/kWh
- FY2013 Preliminary PRS – **32.21** mills/kWh
- FY2014 Preliminary PRS – **28.75** mills/kWh
  - Glen Canyon Cost Reallocation
- FY2015 Preliminary PRS – **29.90** mills/kWh

COLORADO RIVER STORAGE PROJECT
Aid to Participating Projects Irrigation Repayment Obligations & Apportioned Revenues Applied

	Total				Total				Differences	
	Incremental		Cumulative		Incremental		Cumulative		Annual	Cumulative
year	- Obligation	Available W/Appor	Obligation	Available W/Appor	- Obligation	Available W/Appor	Obligation	Available W/Appor	Available w/Appor	Available w/Appor
2015	-	-	-	-	-	-	-	-		
2016	8,610	8,610	8,610	8,610	8,610	40,047	8,610	40,047		(31,437)
2017	4,386	4,386	12,996	12,996	4,386	-	12,996	40,047	4,386	(27,051)
2018	-	-	12,996	12,996	-	-	12,996	40,047	-	(27,051)
2019	-	-	12,996	12,996	-	-	12,996	40,047	-	(27,051)
2020	6,393	6,393	19,389	19,389	6,393	29,735	19,389	69,782	(23,342)	(50,393)
2021	13,650	13,650	33,039	33,039	13,650	-	33,039	69,782	13,650	(36,743)
2022	-	-	33,039	33,039	-	-	33,039	69,782	-	(36,743)
2023	23,836	23,836	56,875	56,875	23,836	70,430	56,875	140,212	(46,594)	(83,337)
2024	-	-	56,875	56,875	-	-	56,875	140,212	-	(83,337)
2025	103,307	103,307	160,182	160,182	103,307	410,067	160,182	550,279	(306,760)	(390,097)
Total 2026–2057	778,430	1,095,060			778,430	1,485,158			(390,098)	(390,098)

Note: Boxed yellow amounts trigger apportionment. Boxed green amounts indicate total available with apportionment. Boxed blue amounts indicate apportionment under MOA agreement.

Glen Canyon Cost Reallocation

- $25,775,772 Capital Investment adjustment
- $10,144,413 O&M adjustment
- $136,762,212 – Reduction to Interest Expense
- 37.8% Annual OM&R Multipurpose Costs reduced

Annual Revenue Requirements Comparison Table

2014 vs. 2015

(Tab 6)

Item	Unit	FY 2014 Preliminary 2016 Workplan	FY 2015 Preliminary 2017 Workplan	FY2014 vs FY2015 Preliminary Comparison Amount	Percent
Rate Setting Period:					
Beginning year	FY	2015	2016		
Pinchpoint year	FY	2025	2025		
Number of rate setting years	Years	11	10		
Annual Revenue Requirements:					
Expenses					
Operation and Maintenance:					
Western	1,000	$52,339	$52,631	$292	0.56%
Reclamation	1,000	$35,840	$34,535	($1,305)	-3.64%
Total O&M	1,000	$88,179	$87,166	($1,013)	-1.15%
Purchased Power 1/	1,000	$7,056	$10,279	$3,223	45.68%
Transmission	1,000	$8,112	$10,421	$2,309	28.46%
Integrated Projects requirements	1,000	$8,427	$8,611	$184	2.18%
Interest	1,000	$2,071	$1,704	($367)	-17.72%
Other 2/	1,000	$15,447	$14,587	($860)	-5.57%
Total Expenses	1,000	$129,292	$132,767	$3,475	2.69%
Principal payments					
Deficits	1,000	$0	$0	$0	
Replacements	1,000	$28,817	$30,264	$1,447	5.02%
Original Project and Additions	1,000	$5,502	$7,423	$1,921	34.92%
Irrigation 3/	1,000	$14,922	$15,771	$849	5.69%
Total principal payments	1,000	$49,241	$53,458	$4,217	8.56%
Total Annual Revenue Requirements	1,000	$178,533	$186,225	$7,692	4.31%
(Less Offsetting Annual Revenue:)					
Transmission (firm and non-firm)	1,000	$16,966	$19,565	$2,599	15.32%
Merchant Function 4/	1,000	$10,267	$9,918	($349)	-3.40%
Other 5/	1,000	$4,999	$5,118	$119	2.38%
Total Offsetting Annual Revenue	1,000	$32,232	$34,602	$2,370	7.35%
Net Annual Revenue Requirements	1,000	**$146,301**	**$151,987**	**$5,686**	**3.89%**
Energy Sales 6/	MWH	**5,089,548**	**5,071,804**	**(17,744)**	**-0.35%**
Capacity Sales	kW	**1,416,945**	**1,407,920**	**-9,025**	**-0.64%**
Composite Rate	mills/kWh	**28.75**	**29.90**	**1.15**	**4.00%**

Annual Revenue Requirements Comparison Table

(Tab 6)

Item	Unit	WAPA 137 Step 2 Rate PRS 2010 Workplan	FY 2015 Preliminary 2017 Workplan	*Change* Amount	Percent
Rate Setting Period:					
Beginning year	FY	2010	2016		
Pinchpoint year	FY	2025	2025		
Number of rate setting years	Years	16	10		
Annual Revenue Requirements:					
Expenses					
Operation and Maintenance:					
Western	1,000	$40,514	$52,631	$12,117	30%
Reclamation	1,000	$30,092	$34,535	$4,443	15%
Total O&M	1,000	$70,606	$87,166	$16,560	23%
Purchased Power 1/	1,000	$5,163	$10,279	$5,116	99%
Transmission	1,000	$10,525	$10,421	($104)	-1%
Integrated Projects requirements	1,000	$7,286	$8,611	$1,325	18%
Interest	1,000	$3,693	$1,704	($1,989)	-54%
Other 2/	1,000	$2,984	$14,587	$11,603	389%
Total Expenses	1,000	$100,257	$132,767	$32,510	32%
Principal payments					
Deficits	1,000	$0	$0	$0	0%
Replacements	1,000	$28,652	$30,264	$1,612	6%
Original Project and Additions	1,000	$17,936	$7,423	($10,513)	-59%
Irrigation 3/	1,000	$38,744	$15,771	($22,973)	-59%
Total principal payments	1,000	$85,332	$53,458	($31,874)	-37%
Total Annual Revenue Requirements	1,000	$185,589	$186,225	$636	0%
(Less Offsetting Annual Revenue:)					
Transmission (firm and non-firm)	1,000	$18,045	$18,896	$851	5%
Merchant Function 4/	1,000	$8,309	$9,918	$1,609	19%
Other 5/	1,000	$7,687	$5,118	($2,569)	-33%
Total Offsetting Annual Revenue	1,000	$34,041	$33,932	($109)	0%
Net Annual Revenue Requirements	1,000	**$151,548**	**$151,987**	**$439**	0%
Energy Sales 6/	MWH	**5,116,346**	**5,071,804**	**(44,542)**	-1%
Capacity Sales	kW	**1,434,946**	**1,407,920**	**(27,026)**	-2%
			0		
Composite Rate	mills/kWh	**29.62**	**29.90**	**0.28**	0.9%

Expenses

May 2015 Update

Annual Revenue Requirements:	Unit	WAPA 137 Step 2 Rate PRS 2010 Workplan	FY 2015 Preliminary 2017 Workplan	Change Amount	Change Percent
Expenses					
Operation and Maintenance:					
Western	1,000	$40,514	$52,631	$12,117	30%
Reclamation	1,000	$30,092	$34,535	$4,443	15%
Total O&M *(Tab 7)*	1,000	$70,606	$87,166	$16,560	23%
Purchased Power *(Tab 8)*	1,000	$5,163	$10,279	$5,116	99%
Transmission	1,000	$10,525	$10,421	($104)	-1%
Integrated Projects Reqs. *(Tab 11)*	1,000	$7,286	$8,611	$1,325	18%
Interest *(See ES)*	1,000	$3,693	$1,704	($1,989)	-54%
Other *(Tab 12 & ES)*	1,000	$2,984	$14,587	$11,603	389%
Total Expenses	1,000	$100,257	$132,767	$32,510	32%

Power Repayment

May 2015 Update

	Unit	WAPA 137 Step 2 Rate PRS 2010 Workplan	FY 2015 Preliminary PRS 2017 Workplan	Change Amount	Change Percent
Principal Payments					
Deficits	1,000	$0	$0	$0	0%
Replacements	1,000	$28,652	$30,264	$1,612	6%
Original Project and Additions	1,000	$17,936	$7,423	($10,513)	-59%
Irrigation	1,000	$38,744	$15,771	($22,973)	-59%
Total Principal Payments *(ES)*	1,000	$85,332	$53,458	($31,874)	-37%

Offsetting Revenues

May 2015 Update

		WAPA 137 Step 2 Rate PRS	FY 2015 Preliminary PRS	*Change*	
	Unit	2010 Workplan	2017 Workplan	Amount	Percent
(Less Offsetting Annual Revenue)					
Transmission (firm/non-firm) *(Tab 14)*	1,000	$18,045	$19,565	$1,520	8%
Merchant Function *(Tab 15)*	1,000	$8,308	$9,918	$1,609	19%
Other *(Tab 15)*	1,000	$7,687	$5,118	($2,569)	-33%
Total Offsetting Annual Revenue	1,000	$34,040	$34,602	$561	2%

Revenue Requirements

May 2015 Update

		WAPA 137 Step 2 Rate PRS	FY 2015 Preliminary PRS	*Change*	
Item	Unit	2010 Workplan	2017 Workplan	Amount	Percent
Total Expenses	1,000	$100, 257	$132,767	$32,510	32%
Total Principal Payments	1,000	$85,332	$53,458	($31,874)	-37%
Total Offsetting Annual Revenue	1,000	$34,041	$34,602	$561	2%
Net Annual Revenue Requirement	1,000	$151,548	**$151,623**	$75	0%
Energy Sales ***(Tab 16)***	MWH	5,116,346	**5,071,804**	(44,542)	-1%
Capacity Sales	kW	1,434,946	1,407,920	(27,026)	-2%
Composite Rate	mills/kWh	29.62	**29.90**	0.28	0.9%

Next Steps

- Rate Order expires September 30, 2015
- Status of Rate Action
  - Proposed Rate Federal Register Notice Published December 2014
  - Public Information Forum January 2015
  - Public Comment Forum February 2015
  - Public Comment Process ended March 2015
  - Submit Final Rate Package to Administrator June 2015
  - Deputy Secretary of Energy Sign NLT September 1, 2015
  - New Rate effective October 1, 2015

Discussion & Comments

CRSP MC Rates Team

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Upper Basin
Drought Contingency Planning

Jeffrey Ackerman

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Extended Operations

- Drought conditions persist across the Colorado River Basin and the elevation of Lake Powell has continued to drop.
- There is a very slight risk developing that Lake Powell elevation may fall below minimum power pool.
- Minimum power pool at Lake Powell is elevation 3490. Current lake elevation is approximately 3590

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Extended Operations

- The risk that Lake Powell could drop below minimum power pool has been assessed by Reclamation to be around 7%. Meaning Reclamations predictive models shot that at this time there is a 7% risk that Lake Powell reservoir could fall below minimum power pool based on historic runoff modeling scenarios.
- Reclamation modeling for this study was run through 2060
- Results focused on the years 2015 – 2034 (20 years)

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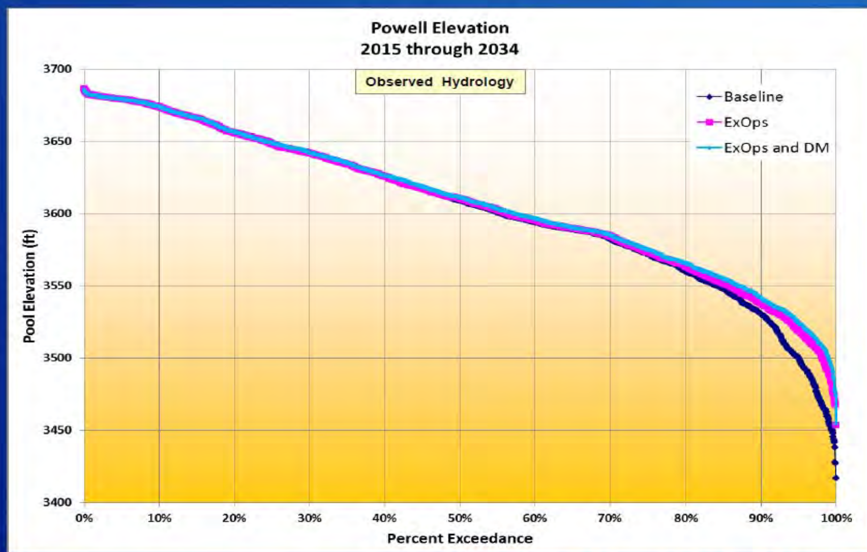
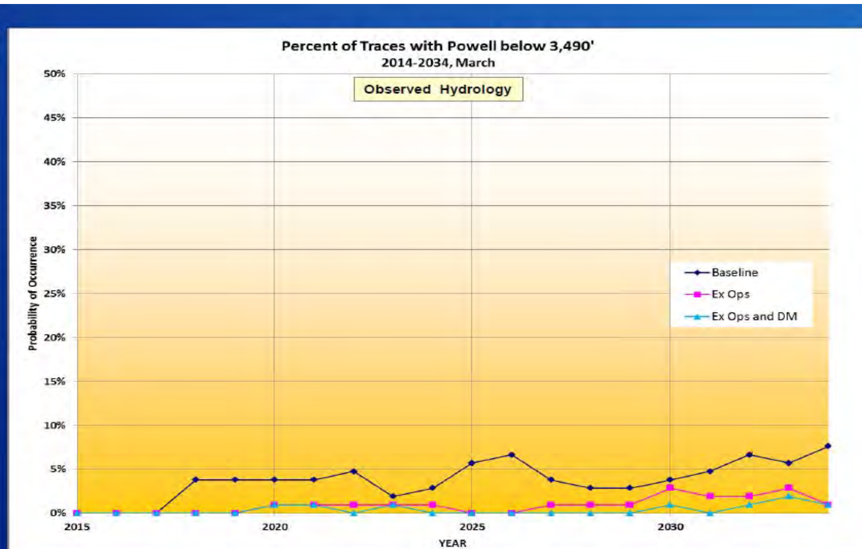
Lake Powell
Percent Exceedance



Preliminary results. Do not cite or distribute RECLAMATION

Percent of Traces Showing Lake Powell Elevation Dropping Below Minimum Power Pool



Preliminary results. Do not cite or distribute RECLAMATION

Extended Operations

- The Extended Operations Plan being developed will be triggered when there is an indication, based on yearly runoff predictions, that Lake Powel may drop below minimum power pool. If the elevation trigger is met, a series of water transfers would take place from Upper Basin Reservoirs (Flaming Gorge, Blue Mesa, Navajo) into Lake Powell in an attempt to maintain a viable reservoir elevation. Upper Basin demand management plans would also be implemented at this time.
- The elevation trigger being contemplated is elevation 3525. Which is 35 feet above the minimum power pool elevation.

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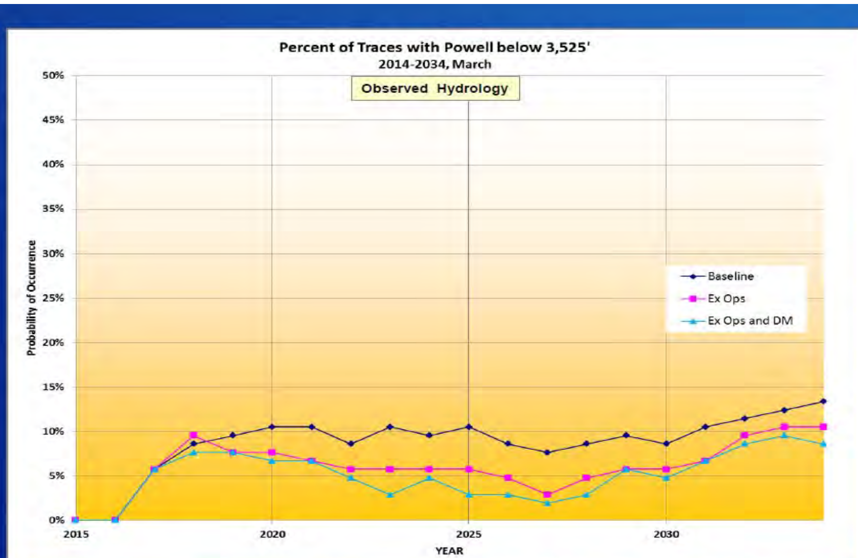
Percent of Traces below Minimum Power Pool with and without Extended Operations and Drought Management



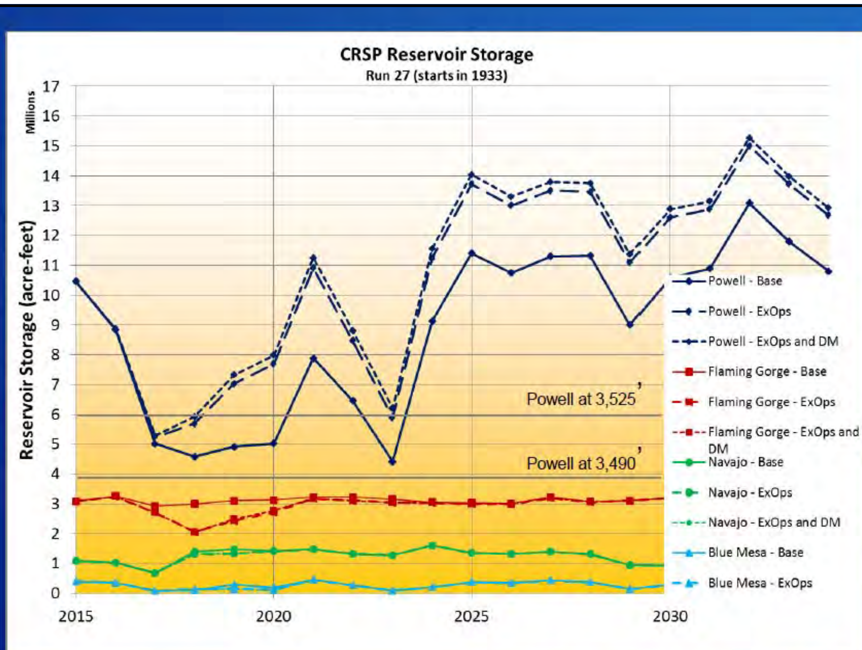
Preliminary results. Do not cite or distribute RECLAMATION

Reclamation Modeling Assumptions

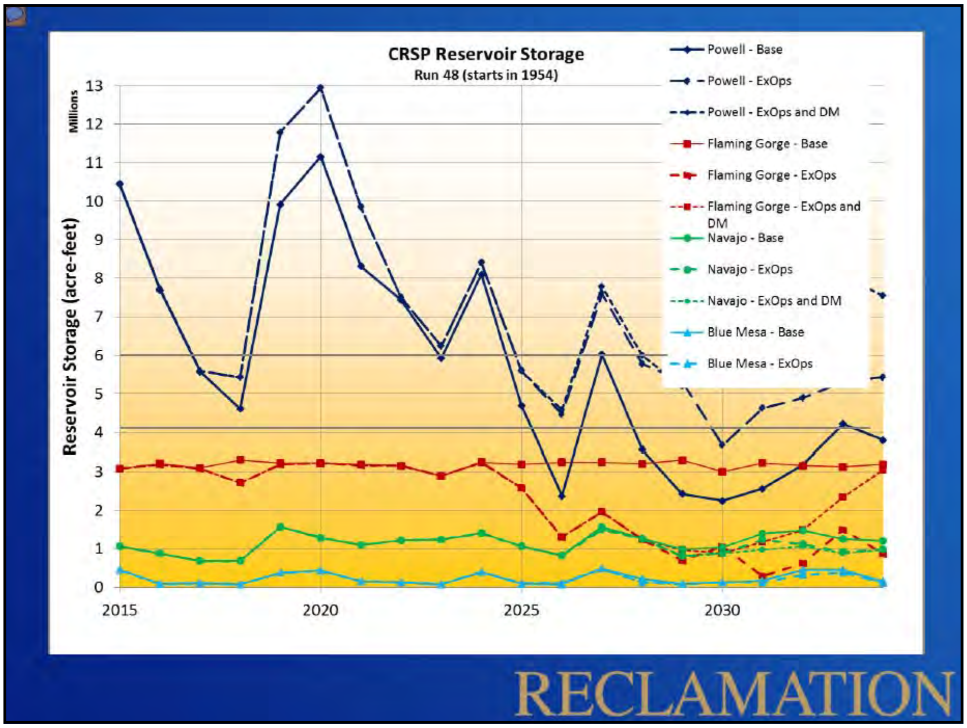
Modeling Assumptions

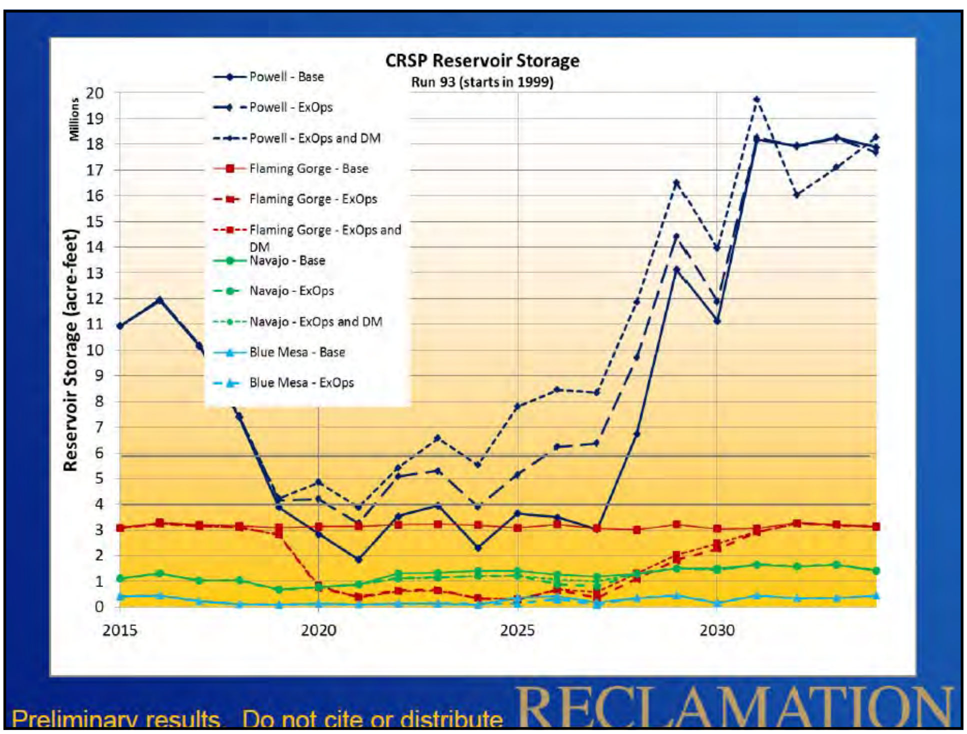
- Extended Operations
  - Implementing UB reservoir extended operations (i.e, release additional water) when Powell forecasted to be below 3,525’ the following March
    - Evaluated 3,490’ in previous model runs
  - If April projected Powell elevation for following March (11 months later), is below 3,525’ move water from Blue Mesa, Navajo, Flaming Gorge during spring season
  - If August projected Powell elevation for following March (7 months later), is below 3,525’ move water from Blue Mesa, Navajo, Flaming Gorge during fall / winter season

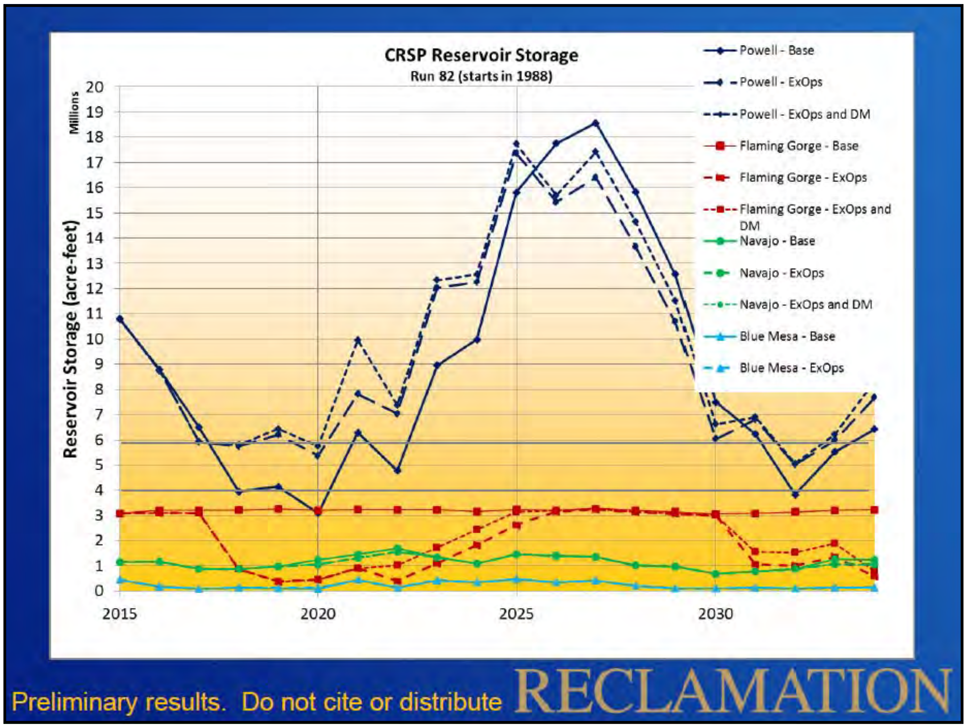
10 RECLAMATION



Preliminary results. Do not cite or distribute RECLAMATION


CRSP Reservoir Storage
Run 48 (starts in 1954)
Millions
Reservoir Storage (acre-feet)
Powell - Base
Powell - ExOps
Powell - ExOps and DM
Flaming Gorge - Base
Flaming Gorge - ExOps
Flaming Gorge - ExOps and DM
Navajo - Base
Navajo - ExOps
Navajo - ExOps and DM
Blue Mesa - Base
Blue Mesa - ExOps
RECLAMATION


CRSP Reservoir Storage
Run 93 (starts in 1999)
Millions
Reservoir Storage (acre-feet)
Powell - Base
Powell - ExOps
Powell - ExOps and DM
Flaming Gorge - Base
Flaming Gorge - ExOps
Flaming Gorge - ExOps and DM
Navajo - Base
Navajo - ExOps
Navajo - ExOps and DM
Blue Mesa - Base
Blue Mesa - ExOps
Preliminary results. Do not cite or distribute
RECLAMATION



Western Modeling Evaluation

- In each water transfer scenario provided by Reclamation, the water transfer result provided an overall benefit to the generation capabilities of the CRSP.
- Further evaluations are being performed to determine financial impacts to the CRSP Basin Fund and CRSP customers in general.
- If finalized, this plan will be followed by Reclamation and the Upper Basin States through the year 2026.

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Benefits of Extended Operations Energy / Value

- Cost/Benefit
- Trace Energy Value 0 Gen (GC) Energy (MWh)
- 93 $176,693,390 38 6,365,036
- 82 $52,705,086 9 1,898,598
- 47 $464,896,320 82 16,746,986
- 48 $315,332,608 54 11,359,244
- 27 $455,713,930 58 16,416,208

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Purchase Power Costs

	# Mos 0 GC gen		Purchase Power (GWh)			Purchase Power Cost ($ millions)		
Trace	Base	ExOps	Base	ExOps	Benefit	Base	ExOps	Benefit
93	48	10	18,774	11,353	7,421	$521.16	$315.15	$206.01
82	9	0	16,162	13,471	2,691	$448.66	$373.96	$74.71
47	110	28	45,379	28,655	16,724	$1,259.72	$795.47	$464.25
48	64	10	28,012	16,801	11,211	$777.60	$466.39	$311.22
27	121	63	43,575	29,474	14,101	$1,209.65	$818.20	$391.45

Modeling Conclusions

- Extended Operations and Demand Management are viable strategies to reduce the probability of Powell reaching critical elevations
  - There are cases when ExOps and DM are not enough to keep Powell above critical elevations at all times
- Extended Operations stay within existing RODs
- All upper CRSP reservoirs contribute during extended ops
- Modeling results approximate existing operations under a range of possible future scenarios

73 RECLAMATION

Upper Basin Drought Contingency Planning

Questions?

Western AREA POWER ADMINISTRATION

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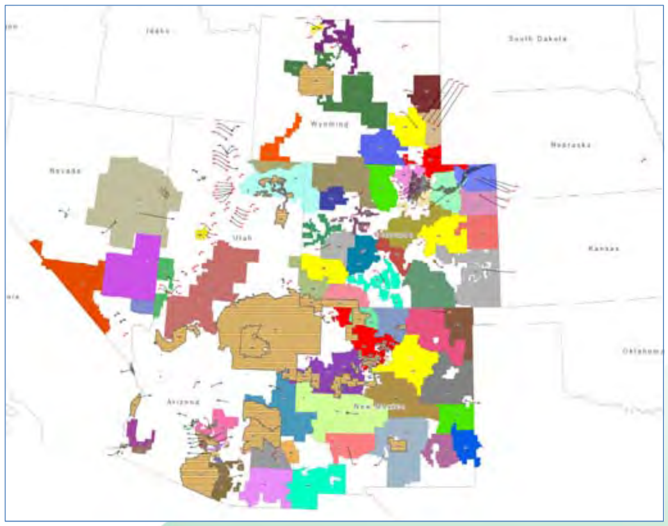
Post 2024 Marketing Plan

Steven Mullen
Public Utilities Specialist
smullen@wapa.gov
(801) 524-6383

Marketing Plan Objective

- The guiding philosophy is to encourage the most widespread use when marketing power, at the lowest possible rates to consumers, consistent with sound business principles.

SLCA/IP Customers – 2004 to 2024



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Precedent Underling Marketing Plans

- Reclamation Act of 1902
- Town Sites & Power Develop. Act of 1906
  - Authorized Reclamation to sell or lease surplus electrical power, with the proceeds to be applied toward repayment of the project construction costs.
  - Contains the first preference clause applicable to electric power.
- Reclamation Project Act of 1939, Section 9(c)
- Flood Control Act of 1944, Section 5

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Precedent Underlying Marketing Plans

- *Preference*
  - Power generated by federal projects would be sold to public bodies and cooperatives, not to investor-owned utilities.
- *Widespread Use*
  - Output of publicly-financed projects located on public waterways should inure to the benefit of as great a portion of the public as is reasonably possible.

E.g., Letter by Secretary of the Interior Ickes to Senator Bailey 4 (June2 , 1944); S. Rpt. No. 1030, 78th Cong., 1st Sess. 3 (1944).

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Preliminary Timeline	Year
❑ Customer Meetings: ▪ Phoenix (06/16), Denver (06/23), Albuquerque (06/25) Salt Lake City (06/30) ❑ FRN: Proposed Power Marketing Criteria ▪ Review and comment period – 120 days from publication of FRN ❑ Customer Meetings: tba	**2015**
❑ FRN: Final Power Marketing Criteria and Call for Applicant Profile Data ❑ LTEMP EIS Record of Decision ❑ Determination of Marketable Resource ❑ Applicant Profile Data due	**2016**
❑ Initial allocations based on existing resource, sets percentage of resource for each customer ❑ FRN: Proposed Allocations ▪ Review and Comment period – 120 days ❑ Customer Meetings: tba	**2017**
❑ FRN: Final Allocations ❑ Draft Firm Electric Service Contract to customers ▪ 12-month review, comment and negotiating period	**2018**
❑ Firm Electric Service Contracts offered to customers	**2019**

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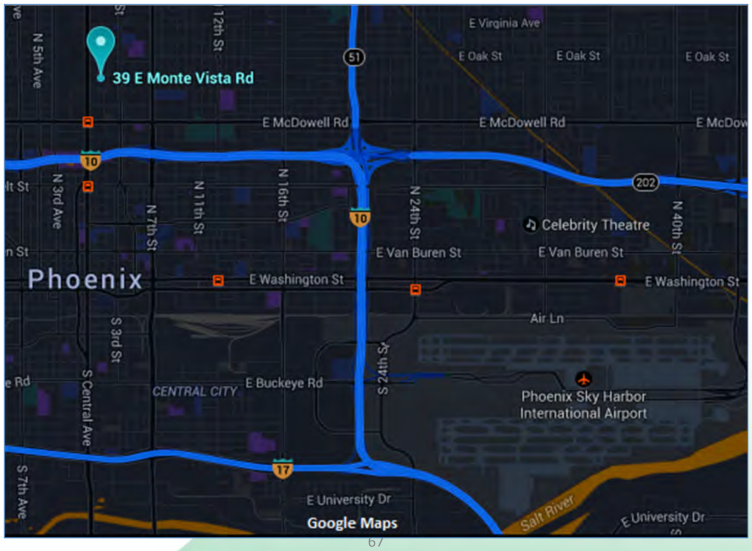
Customer Meetings - Issues of Interest

- Post 2024
  - Marketing Area
  - Power Pool
  - Capacity & Energy
  - LTEMP EIS
  - CROD levels
  - WRP & CDP
  - Transmission System

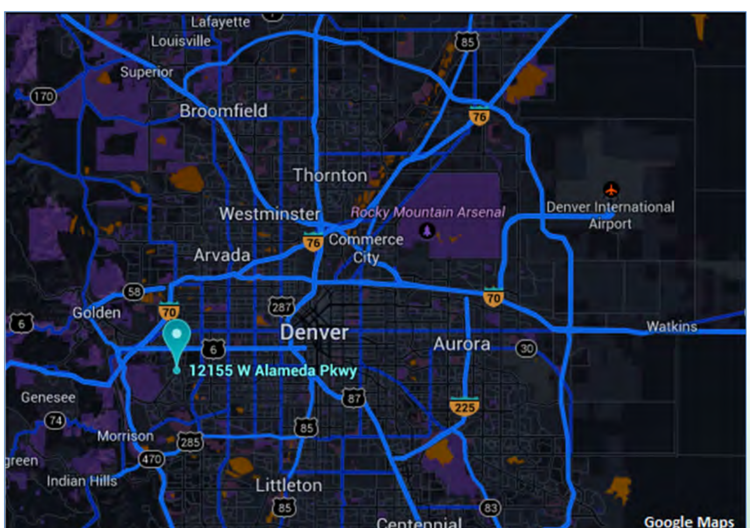
Western Wants to Hear Your Voice

- The objective for these summer Customer Meetings is for Western to hear the opinions of its customers.
  - Stimulate a dialogue
  - Foster a marketplace of ideas
  - Comprehend differing vantage points
  - Understand customer needs and perspectives

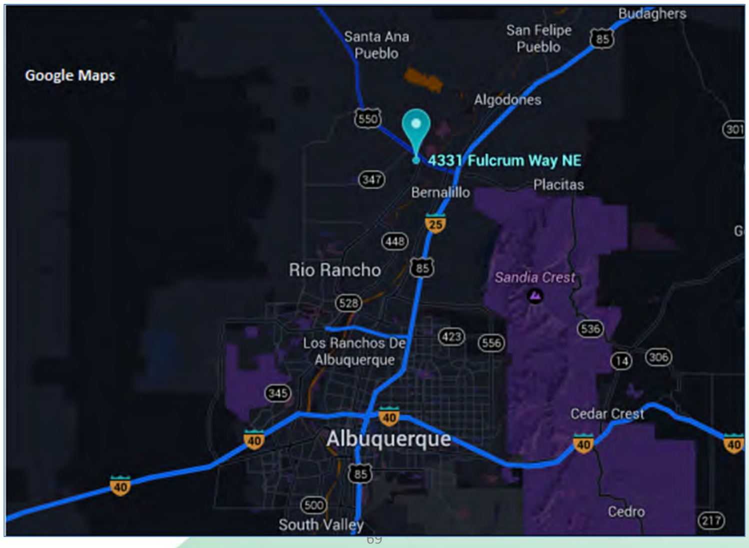
June 16th → Phoenix, AZ @ 2pm



June 23rd → Denver, CO @ 9am



June 25th → Albuquerque, NM @ 9am



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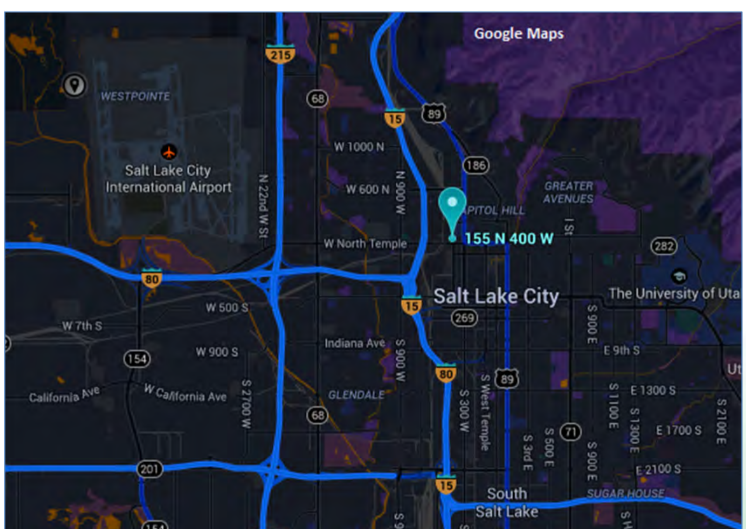
June 30th → Salt Lake City, UT @ 9am



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If You Are Planning to Attend a Meeting

- Please RSVP with your name, organization, contact information to:

SLIPPost2024@wapa.gov

- RSVPs must be received by Monday, June 8th.

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Unable to Attend a Customer Meeting?

- You may participate via email, please contact Western through the following address for the summer customer meeting feedback form:

SLIPPost2024@wapa.gov

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Thank You

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OLMSTED POWERPLANT REPLACEMENT PROJECT

Lyle Johnson

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Western AREA POWER ADMINISTRATION

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POWERPLANT HISTORY

- Built in 1904 by Nunn Brothers
- Named for designer Fay Devaux Olmsted
- Worked With George Westinghouse
- Demonstrated Viability of AC Transmission
- Telluride Institute
- Purchased by UP&L in 1912
- National Register of Historic Places

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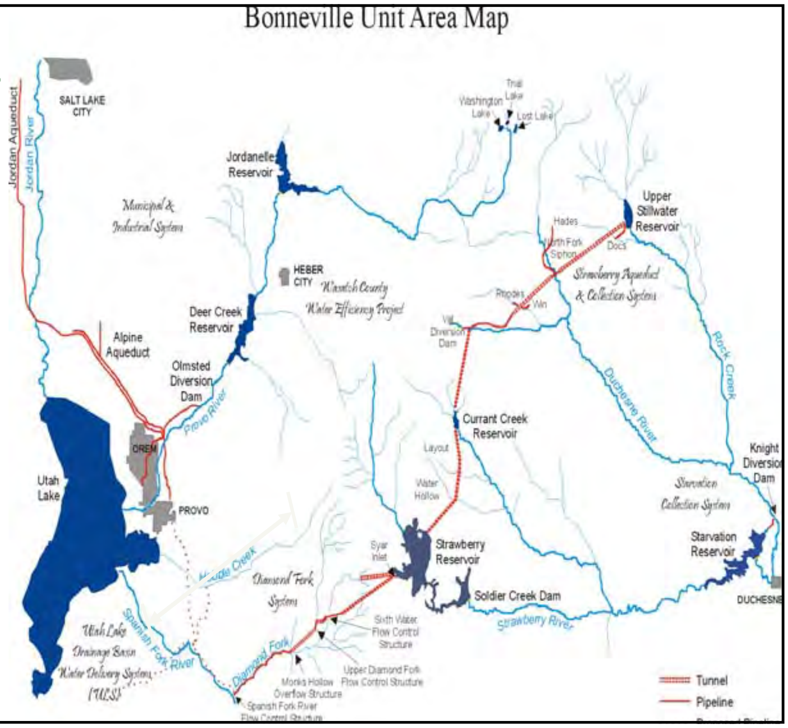
CENTRAL UTAH PROJECT (CUP)

- CRSP participating project



POWERPLANT HISTORY

- Acquired by United States in 1987
- Olmsted facilities and water right needed to deliver CUP water to Salt Lake City
- Leased to PacifiCorp until Sept. 2015
- Will be replaced with new powerplant
- Old powerplant will be preserved and maintained as a museum
- Construction will start Fall 2015

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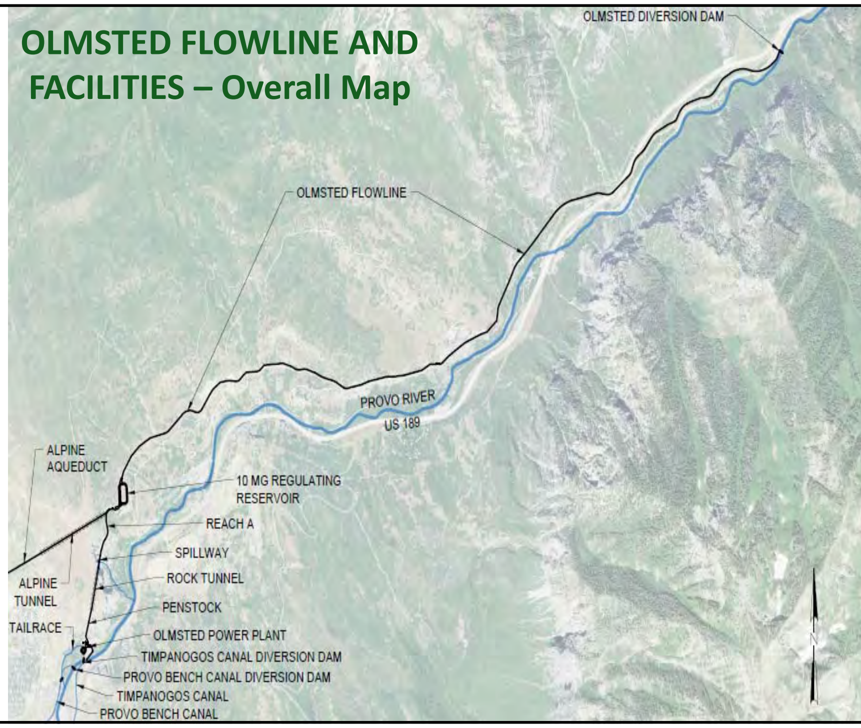
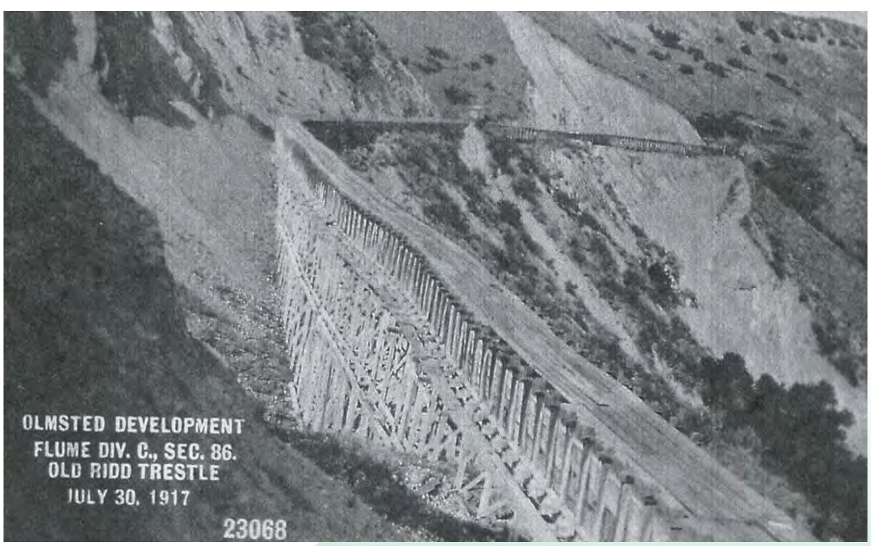
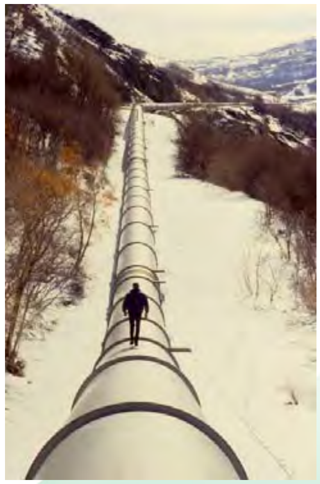

OLMSTED FLOWLINE AND FACILITIES – Overall Map
OLMSTED DIVERSION DAM
OLMSTED FLOWLINE
PROVO RIVER
US 189
ALPINE AQUEDUCT
10 MG REGULATING RESERVOIR
REACH A
SPILLWAY
ROCK TUNNEL
ALPINE TUNNEL
PENSTOCK
TAILRACE
OLMSTED POWER PLANT
TIMPANOGOS CANAL DIVERSION DAM
PROVO BENCH CANAL DIVERSION DAM
TIMPANOGOS CANAL
PROVO BENCH CANAL


OLMSTED DEVELOPMENT
FLUME DIV. C., SEC. 86.
OLD RIDD TRESTLE
JULY 30, 1917
23068

80



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Cooperative Development

- US Department of the Interior Central Utah Project Completion Office
- Central Utah Water Conservancy District
- Bureau of Reclamation
- Western Area Power Administration

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Western's Responsibilities

- Participating Project of the Colorado River Storage Project
- Marketing Power Produced
- Setting Rate
- Marketing Plan Process later this year

83

- Lyle Johnson
- 801-524-5585
- ljohnson@wapa.gov

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CRSP Management Center
Renewable Energy Certificate Program

Parker Wicks

Western
AREA POWER
ADMINISTRATION

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Overview

- Hydropower Attestations
- WREGIS
- Program Specifics

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Previous Program: Annual Hydropower Attestations

- Hydropower Attestations
  - Began in 2011
  - Retroactive to Calendar Year 2010
- MWh generated, sold, and delivered to Firm Electric Customers from the SLCA/IP

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Previous Program: Hydropower Attestations (Continued)

- Attestations were provided in lieu of registering with WREGIS
  - Multiple states and multiple RPS standards created difficulty in determining the best path forward
  - Customers could pursue renewable energy certificates as applicable
  - Could go back retroactively
  - The attestations demonstrated a purchase of clean, renewable hydropower resources
  - Easy to implement
- Ended August 31, 2014

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Attestation Example

Western Area Power Administration - Attestation of Hydropower Deliveries for 2014

Example Org. Contract No. XX-SLC-XXXX

Generator Name	Type	MWh	Date	Unit Size - Name Plate (MW)	Installation Year
Blue Mesa 1	Hydroelectric	34.901	Jan. 1 to Dec. 31, 2014	43.2	1967 (Uprated in 1988)
Blue Mesa 2	Hydroelectric	26.509	Jan. 1 to Dec. 31, 2014	43.2	1967 (Uprated in 1988)
Fontenelle	Hydroelectric	17.109	Jan. 1 to Dec. 31, 2014	10	1968
Morrow Point 1	Hydroelectric	40.100	Jan. 1 to Dec. 31, 2014	86.7	1970 (Uprated in 1992-93)
Morrow Point 2	Hydroelectric	43.311	Jan. 1 to Dec. 31, 2014	86.7	1970 (Uprated in 1992-93)
Flaming Gorge 1	Hydroelectric	45.113	Jan. 1 to Dec. 31, 2014	50.5	1963 (Uprated in 1992)
Flaming Gorge 2	Hydroelectric	43.907	Jan. 1 to Dec. 31, 2014	50.5	1963 (Uprated in 1992)
Flaming Gorge 3	Hydroelectric	47.652	Jan. 1 to Dec. 31, 2014	50.5	1963 (Uprated in 1992)
Crystal	Hydroelectric	48.091	Jan. 1 to Dec. 31, 2014	31.5	1978 (Uprated in 2004)
Lower Molina	Hydroelectric	3.040	Jan. 1 to Dec. 31, 2014	4.9	1962
Upper Molina	Hydroelectric	7.946	Jan. 1 to Dec. 31, 2014	8.7	1962
Glen Canyon 1	Hydroelectric	307.853	Jan. 1 to Dec. 31, 2014	165	1964 (Uprated 1984-87)
Glen Canyon 2	Hydroelectric	126.868	Jan. 1 to Dec. 31, 2014	165	1964 (Uprated 1984-87)
Glen Canyon 3	Hydroelectric	257.335	Jan. 1 to Dec. 31, 2014	165	1964 (Uprated 1984-87)
Glen Canyon 4	Hydroelectric	17.137	Jan. 1 to Dec. 31, 2014	165	1964 (Uprated 1984-87)
Glen Canyon 5	Hydroelectric	337.502	Jan. 1 to Dec. 31, 2014	165	1964 (Uprated 1984-87)
Glen Canyon 6	Hydroelectric	24.173	Jan. 1 to Dec. 31, 2014	125	1964 (Uprated 1984-87)
Glen Canyon 7	Hydroelectric	201.033	Jan. 1 to Dec. 31, 2014	165	1964 (Uprated 1984-87)
Glen Canyon 8	Hydroelectric	236.170	Jan. 1 to Dec. 31, 2014	165	1964 (Uprated in 1997)
Elephant Butte 1	Hydroelectric	1.400	Jan. 1 to Dec. 31, 2014	9.3	1940
Elephant Butte 2	Hydroelectric	1.594	Jan. 1 to Dec. 31, 2014	9.3	1940
Elephant Butte 3	Hydroelectric	1.403	Jan. 1 to Dec. 31, 2014	9.3	1940
McPhee	Hydroelectric	0.158	Jan. 1 to Dec. 31, 2014	1.3	1993
Towaoc	Hydroelectric	4.070	Jan. 1 to Dec. 31, 2014	11.5	1993

New Program: WREGIS

- What is it?
  - Western Renewable Energy Generation Information System
  - Renewable Energy Certificates (REC)
- Why?
  - Flexibility to customer
  - Industry standard
  - Other regions
  - Reasonable cost to implement

New Program: WREGIS (Cont.)

- Replaces Hydropower Attestations
  - Unless you have requested to keep attestations
- Certificates created for generation from September 01, 2014 onward

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WREGIS Program Specifics

- How does it work?
  - SLCA/IP generating facilities registered in WREGIS
  - Generation from each generating unit reported monthly (minus station service)
  - One certificate created for every MWh of energy produced
  - 3 month certificate issuance cycle

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WREGIS Program Specifics (Cont.)

- Certificates "banked" in CRSP WREGIS account
- Transferred annually
  - – Customer sub-account within CRSP WREGIS account
    - Can request "view only" access
  - – Customer WREGIS account
    - Must have independent WREGIS account in order to use for compliance

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WREGIS Program Specifics (Cont.)

- RECs allocated based on organization's percentage of total SLCA/IP resource
- Why doesn't REC distribution match the SLCA/IP allocation exactly?
  - – Firming purchases not included, only actual generation

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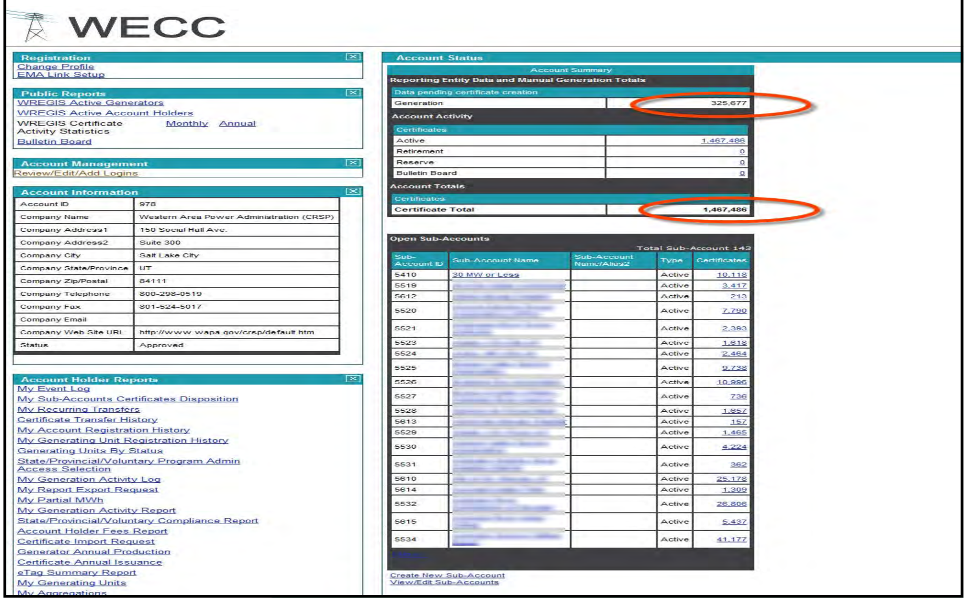
WREGIS Program Specifics (Cont.)

- Cost to Customer
  - Initial transfer fee of banked certificates
  - No other cost to the customer
- Cost to CRSP Management Center
  - Estimated at $30K/year
  - Included in SLCA/IP rate

What can I do with them?

- Can I sell them?
  - No - Federal Resource
- Can I transfer them?
  - Only to member orgs if you are a co-op
- Use them for compliance?
  - Yes! Well… maybe
    - You will need to determine if they meet your State's Renewable Portfolio Standard

WREGIS Screen Shot



WECC

Registration
Change Profile
EMA Link Setup

Public Reports
WREGIS Active Generators
WREGIS Active Account Holders
WREGIS Certificate Activity Statistics — Monthly Annual
Bulletin Board

Account Management
Review/Edit/Add Logins

Account Information

Account ID	978
Company Name	Western Area Power Administration (CRSP)
Company Address1	150 Social Hall Ave.
Company Address2	Suite 300
Company City	Salt Lake City
Company State/Province	UT
Company Zip/Postal	84111
Company Telephone	800-298-0519
Company Fax	801-524-5017
Company Email	
Company Web Site URL	http://www.wapa.gov/crsp/default.htm
Status	Approved

Account Holder Reports
My Event Log
My Sub-Accounts Certificates Disposition
My Recurring Transfers
Certificate Transfer History
My Account Registration History
My Generating Unit Registration History
Generating Units By Status
State/Provincial/Voluntary Program Admin Access Selection
My Generation Activity Log
My Report Export Request
My Partial MWh
My Generation Activity Report
State/Provincial/Voluntary Compliance Report
Account Holder Fees Report
Certificate Import Request
Generator Annual Production
Certificate Annual Issuance
eTag Summary Report
My Generating Units
My Aggregations

Account Status

Account Summary

Reporting Entity Data and Manual Generation Totals

Data pending certificate creation	
Generation	325,677

Account Activity

Certificates	
Active	1,467,486
Retirement	0
Reserve	0
Bulletin Board	0

Account Totals

Certificates	
Certificate Total	1,467,486

Open Sub-Accounts

Total Sub-Account 143

Sub-Account ID	Sub-Account Name	Sub-Account Name/Alias2	Type	Certificates
5410	30 MW or Less		Active	10,118
5519			Active	3,417
5612			Active	213
5520			Active	7,790
5521			Active	2,393
5523			Active	1,618
5524			Active	2,464
5525			Active	9,738
5526			Active	10,996
5527			Active	736
5528			Active	1,657
5613			Active	157
5529			Active	1,465
5530			Active	4,224
5531			Active	362
5610			Active	25,178
5614			Active	1,309
5532			Active	26,806
5615			Active	5,437
5534			Active	41,177

Create New Sub-Account
View/Edit Sub-Accounts

REC Distribution Example

Western Area Power Administration - WREGIS Renewable Energy Certificate (REC) Distribution for 2015

Example Org. Contract No. XX-SLC-XXXX

Generator Name	Type	MWh	Date	Unit Size - Name Plate (MW)	Installation Year
Blue Mesa 1	Hydroelectric	16	Jan. 1 to Dec. 31, 2015	43.2	1967 (Uprated in 1988)
Blue Mesa 2	Hydroelectric	15	Jan. 1 to Dec. 31, 2015	43.2	*1967 (Uprated in 1988)*
Crystal	Hydroelectric	21	Jan. 1 to Dec. 31, 2015	31.5	1978 (Uprated in 2004)
Elephant Butte 1	Hydroelectric	0	Jan. 1 to Dec. 31, 2015	9.315	1940
Elephant Butte 2	Hydroelectric	0	Jan. 1 to Dec. 31, 2015	9.315	1940
Elephant Butte 3	Hydroelectric	0	Jan. 1 to Dec. 31, 2015	9.315	1940
Flaming Gorge 1	Hydroelectric	22	Jan. 1 to Dec. 31, 2015	50.65	1963 (Uprated in 1992)
Flaming Gorge 2	Hydroelectric	24	Jan. 1 to Dec. 31, 2015	50.65	1963 (Uprated in 1992)
Flaming Gorge 3	Hydroelectric	28	Jan. 1 to Dec. 31, 2015	50.65	1963 (Uprated in 1992)
Fontenelle	Hydroelectric	10	Jan. 1 to Dec. 31, 2015	10	1968
Glen Canyon 1	Hydroelectric	98	Jan. 1 to Dec. 31, 2015	165	1964 (Uprated 1984-87)
Glen Canyon 2	Hydroelectric	22	Jan. 1 to Dec. 31, 2015	165	1964 (Uprated 1984-87)
Glen Canyon 3	Hydroelectric	65	Jan. 1 to Dec. 31, 2015	165	1964 (Uprated 1984-87)
Glen Canyon 4	Hydroelectric	104	Jan. 1 to Dec. 31, 2015	165	1964 (Uprated 1984-87)
Glen Canyon 5	Hydroelectric	115	Jan. 1 to Dec. 31, 2015	165	1964 (Uprated 1984-87)
Glen Canyon 6	Hydroelectric	0	Jan. 1 to Dec. 31, 2015	165	1964 (Uprated 1984-87)
Glen Canyon 7	Hydroelectric	70	Jan. 1 to Dec. 31, 2015	157	1964 (Uprated 1984-87)
Glen Canyon 8	Hydroelectric	86	Jan. 1 to Dec. 31, 2015	165	1964 (Uprated in 1997)
Lower Molina	Hydroelectric	2	Jan. 1 to Dec. 31, 2015	4.86	1962
McPhee	Hydroelectric	0	Jan. 1 to Dec. 31, 2015	1.283	1993
Morrow Point 1	Hydroelectric	14	Jan. 1 to Dec. 31, 2015	86.667	1970 (Uprated in 1992-93)
Morrow Point 2	Hydroelectric	20	Jan. 1 to Dec. 31, 2015	86.667	1970 (Uprated in 1992-93)
Towaoc	Hydroelectric	1	Jan. 1 to Dec. 31, 2015	11.495	1993
Upper Molina	Hydroelectric	3	Jan. 1 to Dec. 31, 2015	8.64	1962

Total RECS from Generators < 30 MW	16
Total RECS from Generators > 30 MW	720
TOTAL RECS Distributed	736

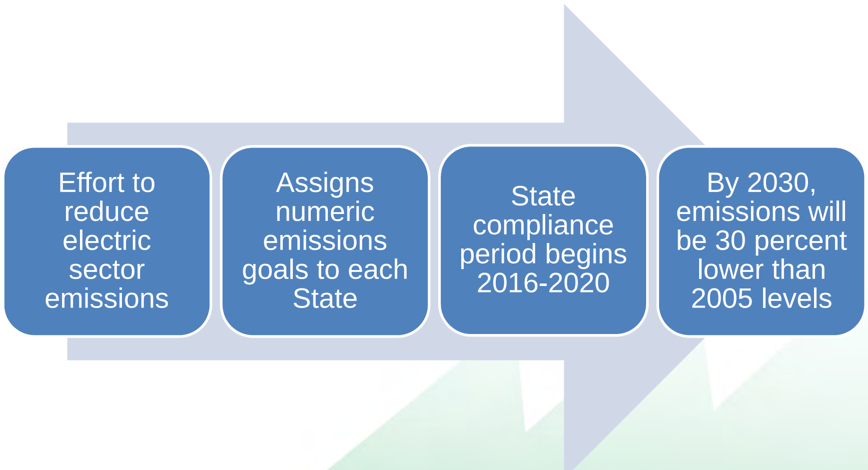
Questions?

EPA's
Clean Power Plan
Proposal

Brent Osiek

May 21, 2015

Overview - EPA's Clean Power Plan



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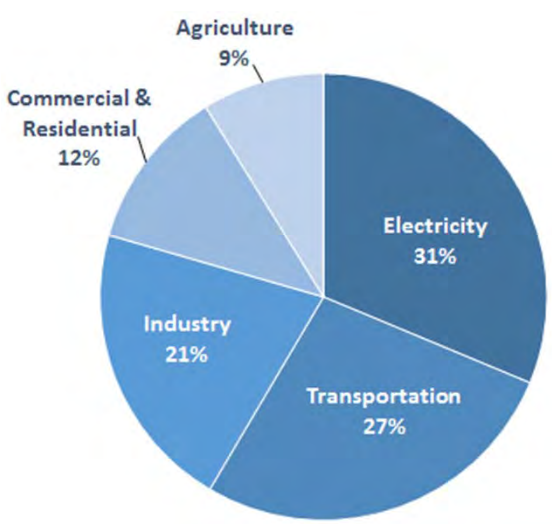
Sources of Greenhouse Gas Emissions



102

New Federal Regulations on Power Plant Carbon Emissions

President Obama's Climate Action Plan

Clean Air Act Section 111(b)

- New Power Plants
- Existing Power Plants
- Modified Power Plants

103

Consistent National Framework

The Clean Power Plan will put in place a consistent national framework that builds on work states are already doing to reduce carbon pollution – especially through programs that encourage renewable energy or energy efficiency, while ensuring a reliable and affordable supply of power.

104

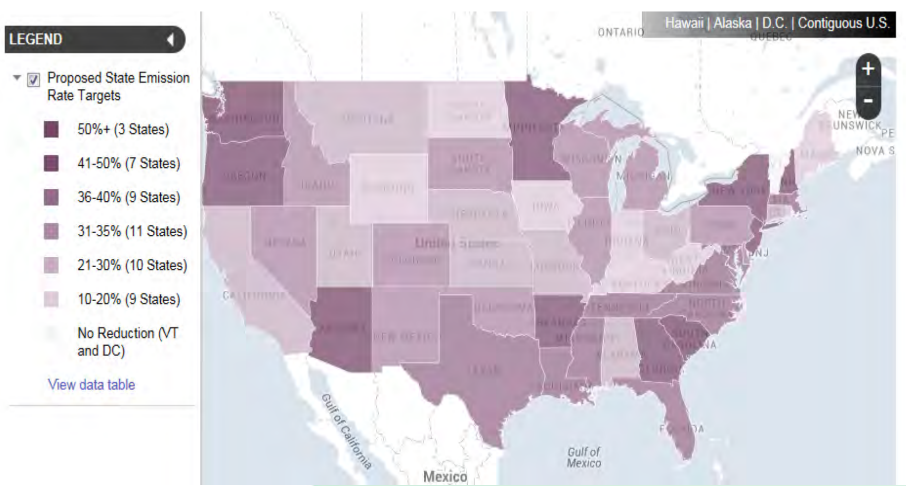
Maximizing Flexibilities

EPA's proposal ensures that states have the flexibility to choose the best set of cost-effective reductions for them.

By setting a state-specific goal and allowing states to work individually or in regional groups, EPA is making sure states have the flexibility they need to drive investment in innovation, while ensuring reliability and affordability.

105

Reduction Requirements Vary by State Neighboring States Can Differ



106

States' Implementation of CPP

States will choose how to meet the goal through whatever measures reflect their particular circumstances and policy objectives

- Use various strategies
- New or existing energy efficiency programs
- Expand renewable energy generation
- Upgrade aging infrastructure
- Better planning processes
- Innovative, cost-effective regulatory strategies
- Develop single state or multi-state plans

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CPP – Future Time Line

Summer 2015

EPA to issue **final rules** on:

- Clean Power Plan for **Existing Power Plants** in States, Indian Country and U.S. Territories
- Carbon Pollution Standards for **New, Modified and Reconstructed Power Plants**

EPA plans to **propose a Federal plan** for meeting Clean Power Plan goals for public review and comment

108

CPP – Time Line

Summer 2016

Proposed due date for states to **submit compliance plans** to EPA – can be complete plans or plans with 1- or 2-year extensions

Summer 2017 and Summer 2018

Due dates for states that request extensions

Summer 2020

Proposed beginning of the Clean Power Plan **compliance period**

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Clean Power Plan Pathway

- States will have a 10-15 year window after the Clean Power Plan is final to plan for and achieve reductions in carbon pollution
- States to submit initial or complete plans by June 30, 2016
- Flexible state-by-state carbon emissions reductions
- EPA will review and approve/disapprove plans
- Options to cut carbon emissions called “building blocks”

110

Flexibility to Use these Building Blocks

The EPA's Proposed Clean Power Plan: Four Building Blocks

Plant Efficiency — **Make fossil fuel power plants more efficient** by implementing a 6 percent (on average) unit heat rate improvement for all affected coal-fired units. The EPA suggests that some plants could further improve process efficiency by 4 percent through the adoption of best operational practices, and an additional 2 percent through capital upgrade investments.

Natural Gas — **Use low-emitting power sources more** by redispatching existing natural gas combined-cycle (NGCC) units before the coal and older oil-gas steam units. EPA draft rate limitations include CO_2 reduction assumptions from the ongoing increases in the use of NGCC capacity (with up to a 70 percent capacity factor). This additional NGCC capacity (440 TWh/year) displaces coal (376 TWh/year) and oil-gas steam generation (64 TWh/year) by 2020, compared to 2012 levels.

Renewable Energy — **Use more zero- and low-emitting power sources** through building capacity by adding both non-hydro renewable generation and five planned nuclear units. EPA calculations assume qualifying non-hydro renewable generation can grow rapidly from 218 TWh/year in 2012, to 281 TWh/year by 2020, to reach 523 TWh/year by 2030.

Energy Efficiency — **Use electricity more efficiently** by significantly expanding state-driven energy efficiency programs to improve annual electricity savings by up to 1.5 percent of retail sales per year. The calculation assumes the states and industry can rapidly expand energy efficiency programs to increase savings from 22 TWh/year in 2012, to 108 TWh/year in 2020, and to 380 TWh/year by 2029. Ultimately, EPA energy efficiency assumptions suggest that electric power savings will outpace electricity demand growth, resulting in negative electricity usage from 2020 through 2030.

111

How are the States to Quantify?

Rate-based goal *(lbs of CO2/MWh)*	Can be translated at option of the States	Mass-based goal *(total lbs CO2 emissions)*
EPA assigns each state an emissions rate goal ***rate goal [lbs/MWh] =*** ***Emissions existing fossil [lbs] /*** ***generation from existing fossil*** ***+*** ***generation from at-risk nuclear +*** ***projected renewables*** ***+*** ***projected demand savings from energy efficiency***	Some confusion about how to do this	**Emission Rate (lbs/MWh) * Generation (MWh) = Mass Emissions (tons)** **Ten states already have carbon trading programs with mass-based caps** **States are expected to select the mass approach over the emission rate approach due to its greater flexibility, as well as ease to enforce and implement** http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Potential_Reliability_Impacts_of_EPA_Proposed_CPP_Final.pdf

Direct Impacts to Resource Adequacy and Electric Infrastructure

- **Fossil-Fired Retirements and Accelerated Declines in Reserve Margins**
- **Coordinated Transmission Planning Needed and Timing Constraints**
- **Regional Reliability Assessment of the Proposed CPP**
- **Reliability Assurance**
- **Coal Retirements and Increased Reliance on Natural Gas for Electric Power**
- **Changing Resource Mix and Maintaining Essential Reliability Services**
- **Increased Penetration of Distributed Energy Resources**

NERC supports a reliability assurance mechanism to manage emerging and impending risks to the bulk power system, and urges policy makers and the EPA to ensure that a flexible and effective reliability assurance mechanism is included in the rule's implementation.

113

At what cost to consumers is the CPP?

- EPA projects retail electricity prices will increase by $1/MWH - $18/MWH under the CPP
- Higher natural gas prices (more demand) and the implementation of new carbon penalties on impacted fossil-fired generators
- As retail power prices increase, some existing customers may install distributed energy resources when economically advantageous

114

Mark Gabriel – February 25, 2015 Statement to FERC Technical Conference

- Better transmission infrastructure needed
- Coordinated planning– It's harder than you think. Many voices and perspectives
- Maximize system capabilities – e.g, synchrophasors
- Better planning and coordination of gas and electric infrastructure
- Reactive power and voltage concerns
- Transmission Planning going in multiple directions, e.g., FERC Order 1000, geomagnetic disturbances, security. Need prioritization from FERC to accommodate CPP
- Will actively participate in regional transmission planning groups to address CPP challenges

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Questions?

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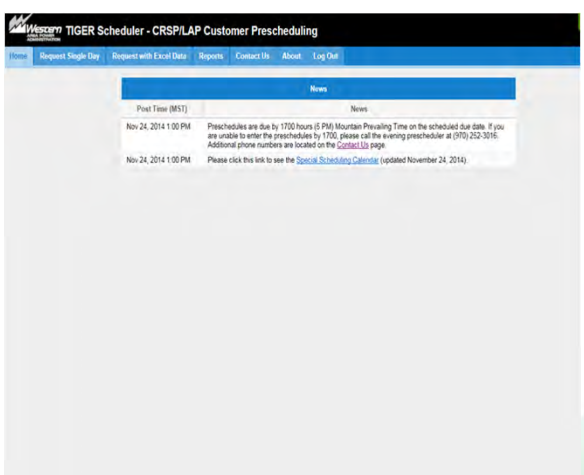
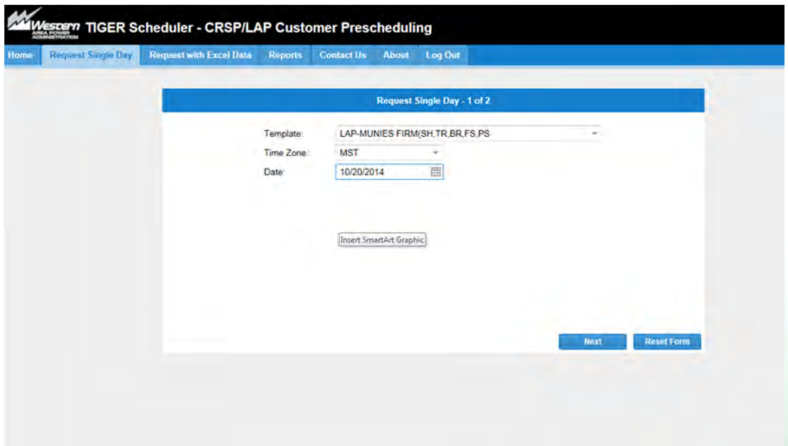
TIGER WEB SCHEDULER

CRSP/LAP PRESCHEDULING

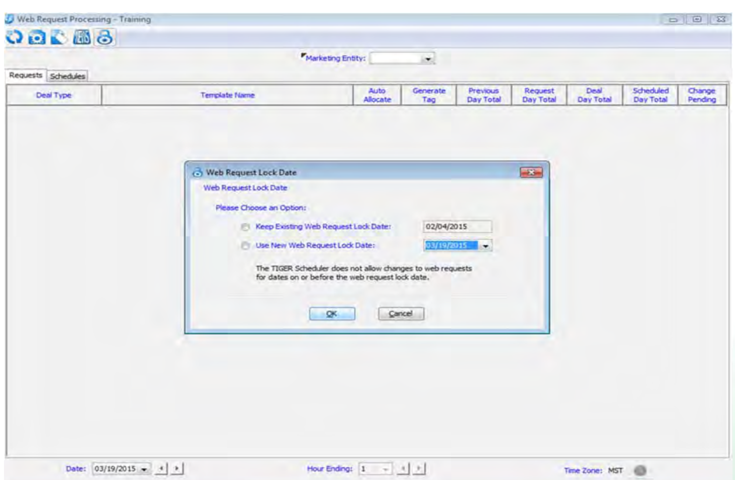
Home Page



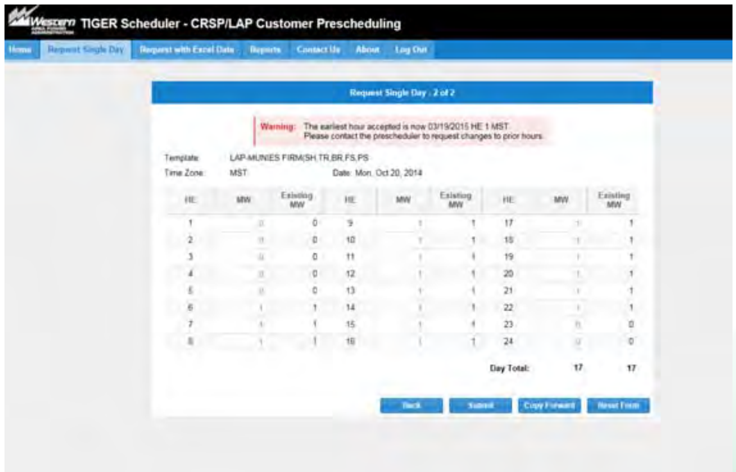
Request Single Day 1-2



Web Request Lock Date



Request Single Day 2-2



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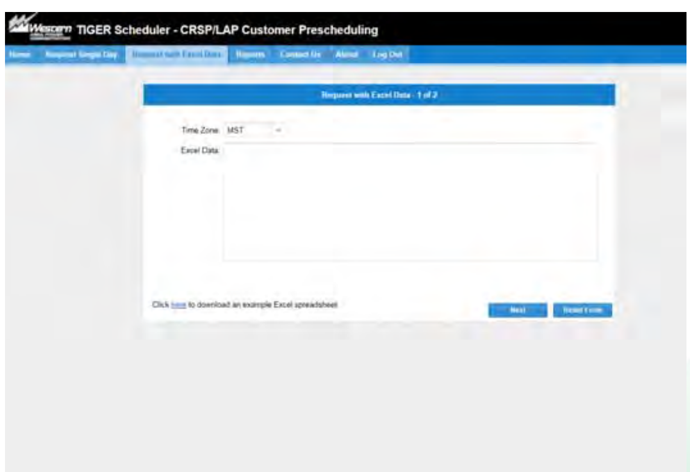
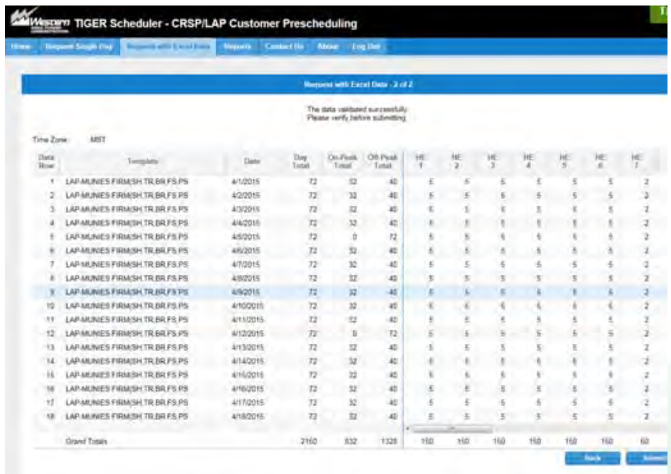
Request with Excel Data 1-2

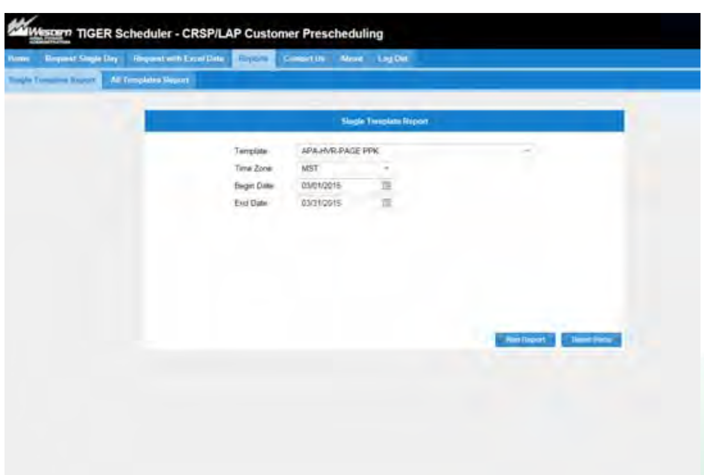


122

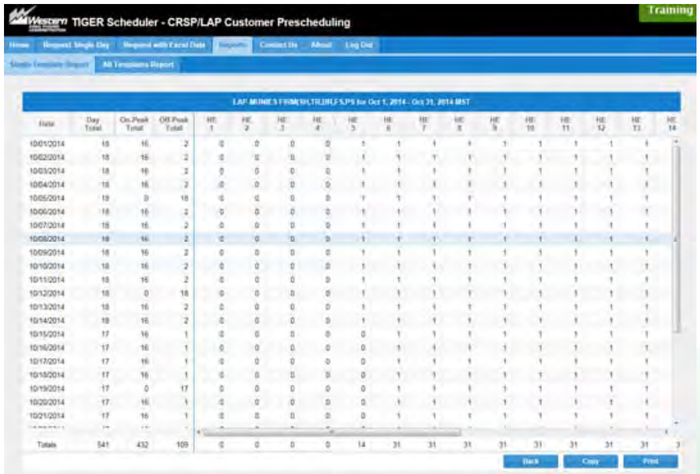
Request with Excel Data 2-2



Reports

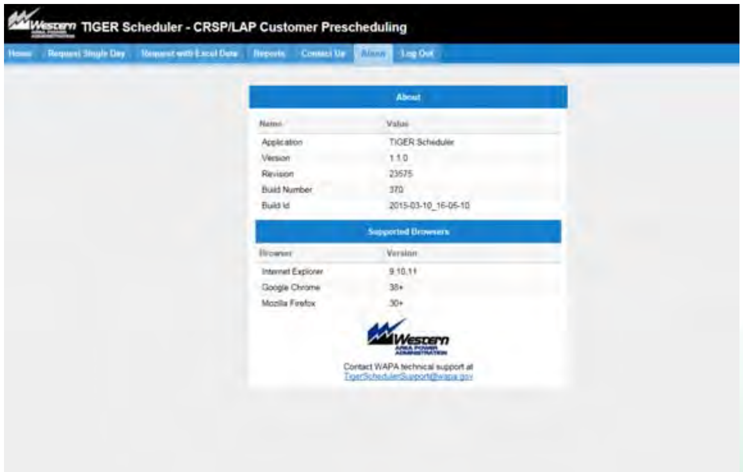


Pulled Report



Contact Us

About



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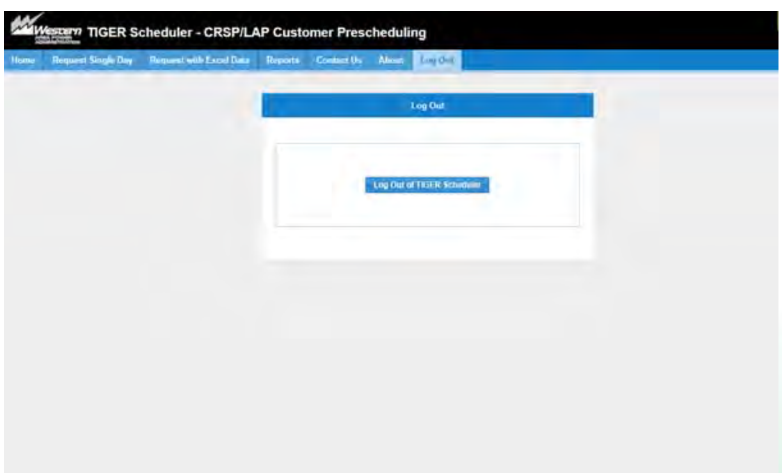
Log Out



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Questions???

Transmission Asset Management Updates

May 21, 2015

Western's Asset Management Philosophy

- Credible and consistent evaluation and results
- Justification and prioritization of projects for the funding
- Improved reliability
- Raise awareness for asset risk

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AM Basics – Risk

Asset Risk = Probability of Failure (POF)

X

Consequence of this Failure

POF: Probability that asset will be out of service in the next year (Uses a Weibull analysis and combines Health Index "HI", Western historical replacement statistics for that asset class, and stress applied to asset)

Consequence: Measurement of the impact to Western if that asset is out of service

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Transformers

Parameters:

- All oil-filled power transformers, including units with LTC's, and oil-filled reactors
- All mobile transformers (separate asset class)
- All phase-shifting transformers (separate asset class)
- Includes units owned or maintained by Western
- Excludes pole mounted
- Excludes station service

Region	Quantity
CRSP	67
DSW	70
RM	103
UGP	222
SN	58

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Transformer Condition Assessment Factors (1 of 2)

(FW =Factor Weight, SFW =Sub Factor Weight)

1. Oil Condition: FW 4

- DGA Recommendation: SFW 3
- Oil Moisture: SFW 3
- Furans (2-FAL): SFW 3

2. Electrical Condition: FW 4

- Bushing Power Factor: SFW 3
- Winding Insulation Power Factor: SFW 3

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Transformer Condition Assessment Factors (2 of 2)

Asset Management

3. Age, Design, Other: FW 2

Age:	SFW 2
Design:	SFW 2
(2 or 3 winding, reactor, auto or phase shifter)	
LTC Issues:	SFW 2

4. O&M History: FW 2

WO History (EM, RM, CM):	SFW 2
Inspections (Visual & IR):	SFW 2
Loading & Temp History:	SFW 2
Thru Faults:	SFW 1

Western AREA POWER ADMINISTRATION

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Breakers

Asset Management

Parameters:

- Power circuit breakers, oil, air, vacuum, and SF-6
- 100-kV and above
- Excludes circuit switchers or other switchgear
- Includes units owned (fully or partially) by Western
- Includes units maintained by Western

Region	Quantity
CRSP	197
DSW	325
RM	273
UGP	577
SN	243

Western AREA POWER ADMINISTRATION

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Breaker Condition Assessment Factors

(FW =Factor Weight, SFW =Sub Factor Weight)

1. **Age:** FW 2

2. **Maintenance History:** FW 2
   - Repair History (EM, RM, CM): SFW 2
   - Recent PM Issues (Doble, other): SFW 2

3. **Design/Obsolescence:** FW 2
   - Interrupt Rating: (% of Max bus fault duty) SFW 2
   - Spare parts Availability: SFW 2

4. **Power System Stress:** FW 2
   - Application: SFW 2
   - Operations Count: SFW 2

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Consequences of Asset Failure Factors and Weighting

Factor	FW	Overall FW	Description
Economic	85%	42.5%	* Contract & Tariff cost related impacts
Asset Cost	15%	7.5%	* Cost estimate to purchase a failed asset
Economic Total:		**50%**	
Critical Service	25%	12.5%	* DOE Labs, sensitive loads, hospitals, infrastructure, radial service, black start path
Tariff (OATT)	20%	10.0%	* Failure to meet OATT commitment
Impacts to Others	35%	17.5%	* Impacts to other entities – adjoining utilities
Marketing	20%	10.0%	* Scheduling services, peaking/load following, critical scheduling hub, curtails ancillary services
Customer Service Total:		**50%**	

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The Transmission Asset Planning and Management (TAPM)

- Evolving the AMPIP
- Proposed support functions
  - RCM, Maximo, GIS
  - technical expertise on maintenance activities
  - coordination of overall Western maintenance related programs and procedures.
- Upcoming Program Schedule:
  - Develop Replacement Strategies for Breakers/Transformers May 2015
  - Run analysis and Reports for FY 15 June 2015

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CRSP 10-Year Plan and Rates

- The 10-Year Plan will include assets from FY15 analysis reports
  - Transformers
  - Breakers
- Completed projects
  - Incorporated into the rate calculations

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Future Program Plans

Asset Management

- WAPA OUO Order Needs to be revised to include guidance
- Preparing physical security plan using asset consequences
- T-Line data collection and follow-up analysis
- Future of oil testing
- Addition of Other Asset Classes

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Environmental Group Activities

Colorado River Storage Project (CRSP)

We are:
Shane Capron
Craig Ellsworth
Clayton Palmer
Jerry Wilhite
Lisa Meyer

Western AREA POWER ADMINISTRATION

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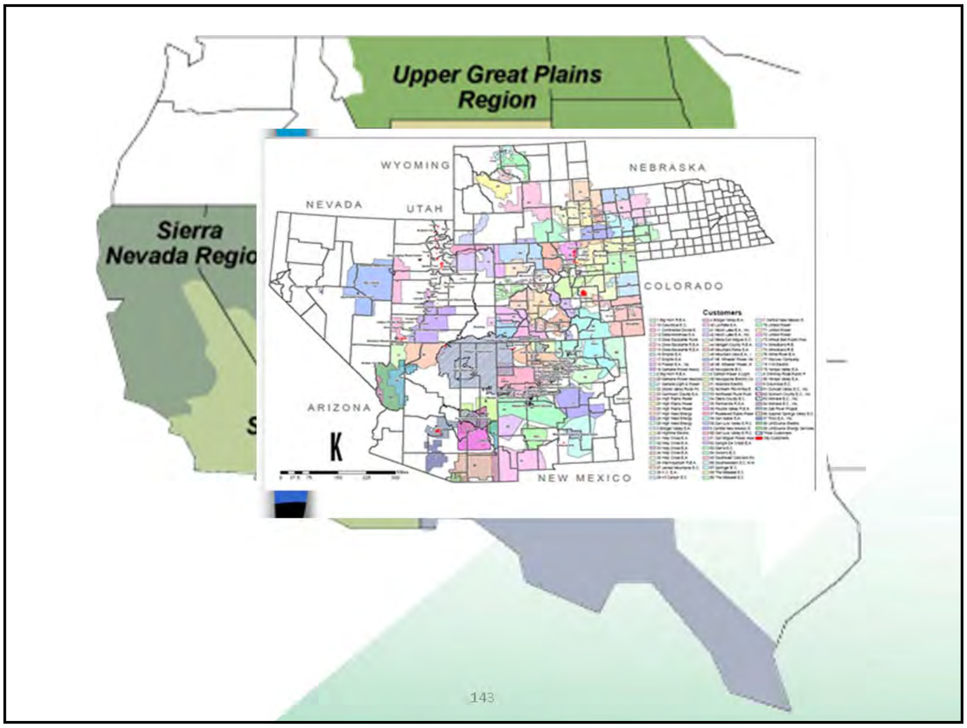
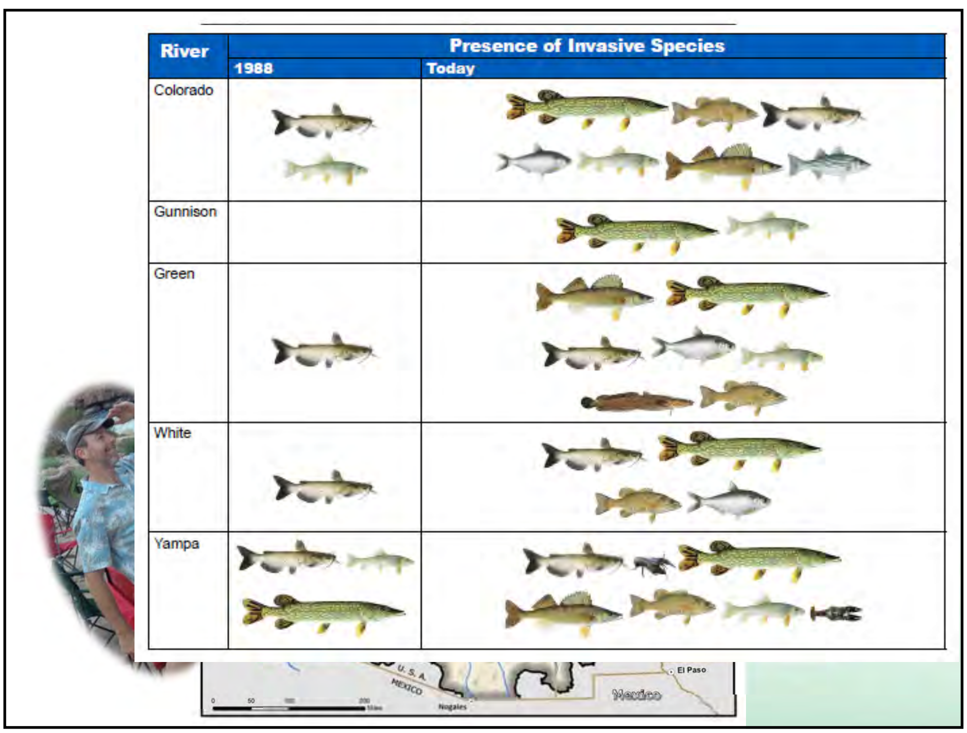
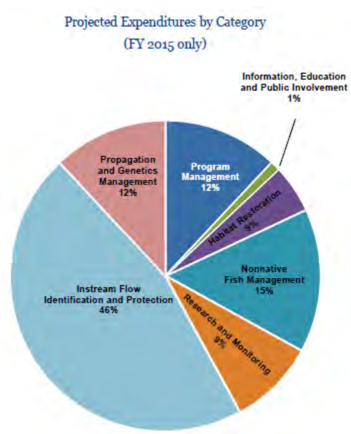

Upper Great Plains
Region
Sierra
Nevada Regio
WYOMING
NEBRASKA
NEVADA
UTAH
COLORADO
ARIZONA
NEW MEXICO
Customers
143


River
Presence of Invasive Species
1988
Today
Colorado
Gunnison
Green
White
Yampa
U.S.A.
MEXICO
El Paso
Mexico
Nogales

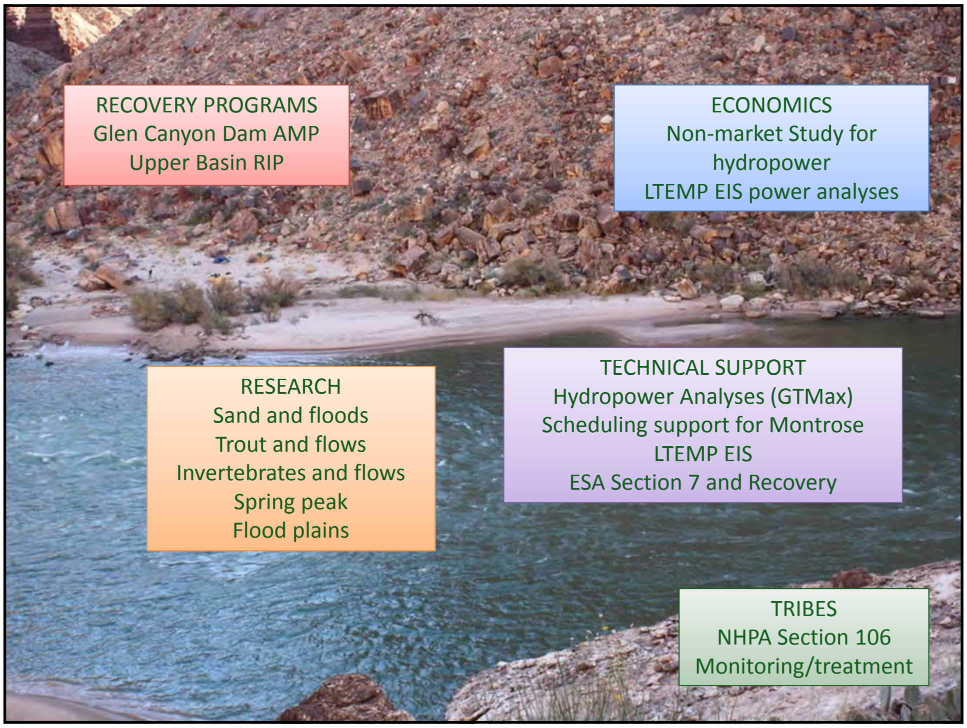
Objective:
Improve environmental conditions while protecting the hydropower resource
*look for win-win scenarios

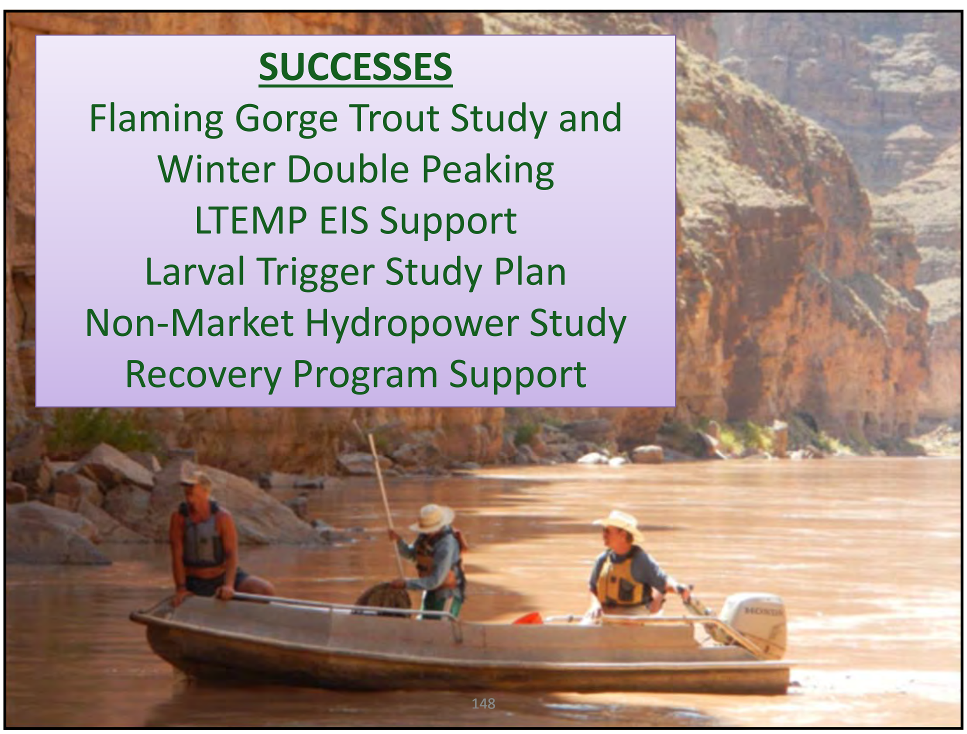
Environment and Cultural Resources Projects Funded by CRSP

- Upper Colorado Recovery Program – endangered fish species program - $6 million, annually
- San Juan Recovery Program – endangered fish species program - $2 million, annually
- Glen Canyon Dam Adaptive Management Program – environmental program in the Grand Canyon - $10 million, annually
- Salinity Control Program – reduce salt in Colorado River water - $2 million
- Other scientific research to support environmental goals – about $1-2 million annually



146


RECOVERY PROGRAMS
Glen Canyon Dam AMP
Upper Basin RIP
ECONOMICS
Non-market Study for hydropower
LTEMP EIS power analyses
RESEARCH
Sand and floods
Trout and flows
Invertebrates and flows
Spring peak
Flood plains
TECHNICAL SUPPORT
Hydropower Analyses (GTMax)
Scheduling support for Montrose
LTEMP EIS
ESA Section 7 and Recovery
TRIBES
NHPA Section 106
Monitoring/treatment

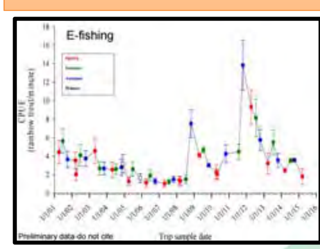

SUCCESSES
Flaming Gorge Trout Study and Winter Double Peaking
LTEMP EIS Support
Larval Trigger Study Plan
Non-Market Hydropower Study
Recovery Program Support
148

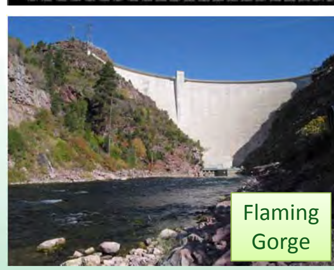
Flaming Gorge Tailrace Trout Survey

- Trout surveys conducted every spring and fall to monitor trout fishery below Flaming Gorge.
- Two 1-mile sections are electrofished using jet boats.
- April 2015 survey results:
  - 523 fish (mostly rainbow trout) were collected in the 1-mile reach directly below the dam.
  - 471 fish (mostly brown trout) were collected further downstream at Little Hole.
  - Numbers and condition were very good!

Lees Ferry Trout Fishery Monitoring IBM Model

- Led by Arizona Game and Fish Department
- Night electrofishing
  - Estimate of fish numbers and condition
- Apply Trout IBM model from Flaming Gorge





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Aquatic Foodbase Research

- Joint research project
  - USGS/GCMRC
  - Utah State University
  - Idaho State University
  - Oregon State University
- Why are foodbase conditions…
  - Poor below Glen Canyon Dam? But great below Flaming Gorge Dam!
- Effects on the Lees Ferry trout fishery and humpback chub

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Green River Backwater Survey

- Annual Backwater survey with Argonne National Lab.
- Conducted in the Ouray NWR reach since 2003.
- Results were used in backwater synthesis which will be used in Flaming Gorge Flow Recommendations evaluation of base flows.
- High flows associated with active monsoon season in 2014 resulted in loss of many backwaters.
- Important in the recovery of Colorado Pikeminnow

Green River Floodplain Breach Survey

- Work with Argonne to survey floodplain breaches to determine magnitude of flow needed to connect important floodplains to the main channel.
- Repeated 2012 survey to evaluate changes in connecting flows after high flows of 2014.
- Results will be used in evaluation of Flaming Gorge peak flow recommendations.
- Results will also be used to determine which floodplains to target during spring peak operations under the Larval Trigger Study Plan.

High Flow Experiment Research

- CRSP MC has hired Dave Rubin at U of California Santa Cruz to critically examine current HFE protocols
- Research questions:
  - Could HFEs be done as effectively using less water and with less hydropower impact?
  - Is the duration, timing, frequency and velocity appropriate to the environmental goals?

GCMRC is assisting in this effort

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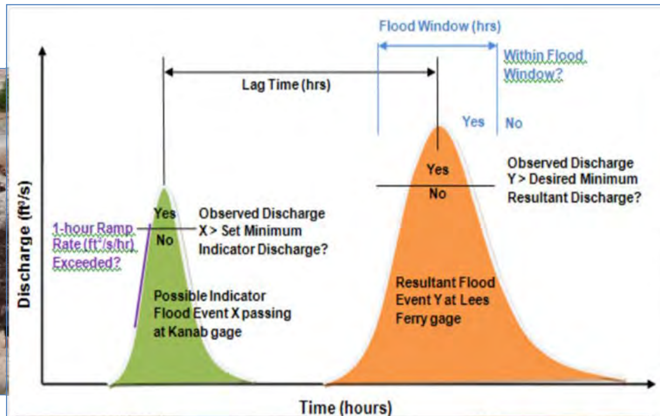
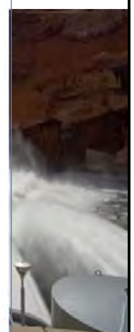
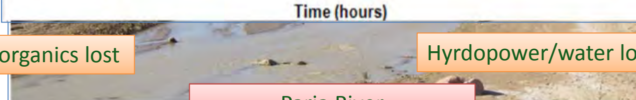
High Flow Experiment Improvement Study







Silt, clay, and organics lost

Hyrdopower/water lost

Paria River

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Humpback Chub Monitoring

- Natal Origins Study (trout/chub interactions)
- Juvenile Chub Monitoring (JCM)
- Little Colorado River
- Aggregation Monitoring
- Translocations

Chub pool in Havasu

156

Economics

- Non market hydropower studies
  - Received two reports, Western is interested in having hydropower value given more serious consideration as a resource in the LTEMP EIS and in future environmental reviews
- LTEMP EIS power analysis
- Cost of experiments and ESA at Glen Canyon Dam and Flaming Gorge
  - Under the GCPA, these costs are provided to the Finance group and are booked as non-reimbursable
  - The economic cost of ESA operations at Flaming Gorge Dam and at the Aspinall Units are being developed. This analysis was requested by the UC RIP as part of the information it provides annually to Congress.

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Closing

- Evaluation Summary
- Rate Action Web Page
  - http://www.wapa.gov/crsp/ratescrsp/WAPA-169.htm
- Power Marketing Action Web Page
  - http://www.wapa.gov/crsp/pmcontractcrsp/default.htm
- WREGIS
  - https://www.wecc.biz/WREGIS/Pages/Default.aspx

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May 21, 2015 CRSP Customer Meeting Contact Information

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SLCA/IP Repayment Milestones

as of September 30, 2014

units: $1,000

Project	Replacements		Original Projects and Additions		Main Stem Irrigation Assistance		Participating Projects Irrigation Assistance		
	Year Paid Off	Currently Unpaid	Year Paid Off	Currently Unpaid	Year Paid Off	Currently Unpaid	Year Paid Off	Currently Unpaid	Total Unpaid Balance
Collbran	2002	$ -	2060	$ 5,433	2010	$ -	N/A	N/A	$ 5,433
CRSP	2015	$ 2,050	2020	$ 66,836	2022	$ 39,925	2044	$ 1,095,061	$ 1,203,872
Dolores	2054	$ 900	2052	$ 28,947	N/A	N/A	N/A	N/A	$ 29,847
Rio Grande	2012	$ -	2064	$ 3,622	1996	$ -	N/A	N/A	$ 3,622
Seedskadee	2013	$ -	2011	$ -	N/A	N/A	N/A	N/A	$ -

FINAL STATUS OF REPAYMENT

COLLBRAN PROJECT

(Dollars in thousands)

	Cumulative 2013 [1]	Adjustment	Annual 2014 [2]	Cumulative 2014
Revenue:				
Gross Operating Revenue	63,979.275	0.000	960.953	64,940.228
Income transfers (net)	35.916	0.000	0.000	35.916
Total Operating Revenue (**A**)	64,015.191	0.000	960.953	64,976.144
Expenses:				
O & M and other	29,638.593	0.000	1,606.925	31,245.518
Purchase power and other	0.000	0.000	0.000	0.000
Interest				
Federally financed	12,071.672	0.000	6.257	12,077.929
Non-Federally financed	0.000	0.000	0.000	0.000
Total Interest	12,071.672	0.000	6.257	12,077.929
Total Expense (**B**)	41,710.265	0.000	1,613.182	43,323.447
(Deficit)/Surplus revenue (**C**)	966.219	0.000	(966.218)	0.001
Investment:				
Federally financed power	16,279.688	0.000	5,747.039	22,026.727
Non-Federally financed power	0.000	0.000	0.000	0.000
Nonpower	5,059.020	0.000	0.000	5,059.020
Total Investment (**D**)	21,338.708	0.000	5,747.039	27,085.747
Investment repaid:				
Federally financed power	16,279.688	0.000	313.989	16,593.677
Non-Federally financed power	0.000	0.000	0.000	0.000
Nonpower	5,059.020	0.000	0.000	5,059.020
Total Investment repaid (**E**)	21,338.708	0.000	313.989	21,652.697
Investment unpaid:				
Federally financed power	0.000	0.001	5,433.050	5,433.050
Non-Federally financed power	0.000	0.000	0.000	0.000
Nonpower	0.000	0.000	0.000	0.000
Total Investment unpaid (**F**)	0.000	0.001	5,433.050	5,433.050
Fund Balances:				
Colorado River Development (G)	0.000	0.000	0.000	0.000
Working capital (H)	0.000	0.000	0.000	0.000
Percent of investment repaid to date:				
Federal	100.00%			75.33%
Non-Federal	N/A			N/A
Nonpower	0.00%			100.00%

1 This column ties to the cumulative FY 2013 numbers on page 122 of the FY 2013 Annual Report Statistical Appendix.

2 Based on FY 2014 audited financial statements.

FINAL STATUS OF REPAYMENT

COLORADO RIVER STORAGE PROJECT

(Dollars in thousands)

	Cumulative 2013 [1]	Adjustment		Annual 2014 [2]	Cumulative 2014
Revenue:					
Gross Operating Revenue	5,314,133.474	0.000		190,581.920	5,504,715.394
Income transfers (net)	(20,691.071)	0.000		(2,363.189)	(23,054.260)
Total Operating Revenue (**A**)	5,293,442.403	0.000		188,218.731	5,481,661.134
Expenses:					
O & M and other	1,747,795.463	25,678.109	3	75,158.490	1,848,632.062
Purchase power and Wheeling	1,617,060.746	(797.000)	4	85,166.808	1,701,430.554
Interest					
Federally financed	762,544.004	(4,645.306)	5	(358.088)	757,540.610
Non-Federally financed	0.000	4,645.306	5	593.491	5,238.797
Total Interest	762,544.004	0.000		235.403	762,779.407
Total Expense (**B**)	4,127,400.213	24,881.109		160,560.701	4,312,842.023
(Deficit)/Surplus revenue (**C**)	0.000	(24,881.109)		24,881.108	(0.001)
Investment:					
Federally financed power	1,177,384.823	0.000		9,789.732	1,187,174.555
Non-Federally financed power	0.000	0.000		0.000	0.000
Nonpower	1,187,329.823	0.000		(1,813.303)	1,185,516.520
Total Investment (**D**)	2,364,714.646	0.000		7,976.429	2,372,691.075
Investment repaid: [4]					
Federally financed power	1,118,288.554	0.000		0.000	1,118,288.554
Non-Federally financed power	0.000	0.000		0.000	0.000
Nonpower	47,753.636	0.000		2,776.922	50,530.558
Total Investment repaid (**E**)	1,166,042.190	0.000		2,776.922	1,168,819.112
Investment unpaid:					
Federally financed power	59,096.269	0.000		9,789.732	68,886.001
Non-Federally financed power	0.000	0.000		0.000	0.000
Nonpower	1,139,576.187	0.000		(4,590.225)	1,134,985.962
Total Investment unpaid (**F**)	1,198,672.456	0.000		5,199.507	1,203,871.963
Fund Balances:					
Colorado River Development (G)	0.000	0.000		0.000	0.000
Working capital (H)	0.000	0.000		0.000	0.000
Percent of investment repaid to date:					
Federal	94.98%				94.20%
Non-Federal	N/A				N/A
Nonpower	4.02%				4.26%

[1] This column ties to the cumulative FY 2013 numbers on page 122 of the FY 2013 Annual Report Statistical Appendix.

[2] Based on the FY 2014 audited financial statements.

[3] Gains & Losses for 2014 (CRSP Losses on Disposition of Assets)

[4] Unbooked Environmental Studies

[5] Reclassified Interest

FINAL STATUS OF REPAYMENT

DOLORES PROJECT

(Dollars in thousands)

	Cumulative 2013 [1]	Adjustment		Annual 2014 [2]	Cumulative 2014
Revenue:					
Gross Operating Revenue	55,387.700	0.000		3,067.909	58,455.609
Income transfers (net)	1,225.793	0.000		0.000	1,225.793
Total Operating Revenue (**A**)	56,613.493	0.000		3,067.909	59,681.402
Expenses:					
O & M and other	7,866.513	(27.322)	3	443.733	8,282.924
Purchase power and other	0.000	0.000		0.000	0.000
Interest					
Federally financed	40,950.151	0.000		1,950.259	42,900.410
Non-Federally financed	0.000	0.000		0.000	0.000
Total Interest	40,950.151	0.000		1,950.259	42,900.410
Total Expense (**B**)	48,816.664	(27.322)		2,393.992	51,183.334
(Deficit)/Surplus revenue (**C**)	(0.001)	27.322		(27.322)	(0.001)
Investment:					
Federally financed power	38,231.125	0.000		114.125	38,345.250
Non-Federally financed power	0.000	0.000		0.000	0.000
Nonpower	0.000	0.000		0.000	0.000
Total Investment (**D**)	38,231.125	0.000		114.125	38,345.250
Investment repaid:					
Federally financed power	7,796.830	0.000		701.239	8,498.069
Non-Federally financed power	0.000	0.000		0.000	0.000
Nonpower	0.000	0.000		0.000	0.000
Total Investment repaid (**E**)	7,796.830	0.000		701.239	8,498.069
Investment unpaid:					
Federally financed power	30,434.295	0.000		(587.114)	29,847.181
Non-Federally financed power	0.000	0.000		0.000	0.000
Nonpower	0.000	0.000		0.000	0.000
Total Investment unpaid (**F**)	30,434.295	0.000		(587.114)	29,847.181
Fund Balances:					
Colorado River Development (G)	0.000	0.000		0.000	0.000
Working capital (H)	0.000	0.000		0.000	0.000
Percent of investment repaid to date:					
Federal	20.39%				22.16%
Non-Federal	N/A				N/A
Nonpower	N/A				N/A

1 This column ties to the cumulative FY 2013 numbers on page 123 of the FY 2013 Annual Report Statistical Appendix.

2 Based on the FY 2014 audited financial statements.

3 Per Sched 11, Net Loss (Gain) on disposition

FINAL STATUS OF REPAYMENT

PROVO RIVER PROJECT

(Dollars in thousands)

	Cumulative 2013 [1]	Adjustment	Annual 2014 [2]	Cumulative 2014
Revenue:				
Gross Operating Revenue	10,147.916	0.000	0.000	10,147.916
Income transfers (net)	0.000	0.000	0.000	0.000
Total Operating Revenue (**A**)	10,147.916	0.000	0.000	10,147.916
Expenses:				
O & M and other	6,888.663	0.000	0.000	6,888.663
Purchase power and other	203.293	0.000	0.000	203.293
Interest				
Federally financed	927.335	0.000	0.000	927.335
Non-Federally financed	0.000	0.000	0.000	0.000
Total Interest	927.335	0.000	0.000	927.335
Total Expense (**B**)	8,019.291	0.000	0.000	8,019.291
(Deficit)/Surplus revenue (**C**)	196.017	0.000	0.000	196.017
Investment:				
Federally financed power	1,741.021	0.000	0.000	1,741.021
Non-Federally financed power	0.000	0.000	0.000	0.000
Nonpower	191.587	0.000	0.000	191.587
Total Investment (**D**)	1,932.608	0.000	0.000	1,932.608
Investment repaid:				
Federally financed power	1,741.021	0.000	0.000	1,741.021
Non-Federally financed power	0.000	0.000	0.000	0.000
Nonpower	191.587	0.000	0.000	191.587
Total Investment repaid (**E**)	1,932.608	0.000	0.000	1,932.608
Investment unpaid:				
Federally financed power	0.000	0.000	0.000	0.000
Non-Federally financed power	0.000	0.000	0.000	0.000
Nonpower	0.000	0.000	0.000	0.000
Total Investment unpaid (**F**)	0.000	0.000	0.000	0.000
Fund Balances:				
Colorado River Development (G)	0.000	0.000	0.000	0.000
Working capital (H)	0.000	0.000	0.000	0.000
Percent of investment repaid to date:				
Federal	100.00%			100.00%
Non-Federal	N/A			N/A
Nonpower	100.00%			100.00%

[1] This column ties to the cumulative FY 2013 numbers on page 142 of the FY 2013 Annual Report Statistical Appendix.

[2] Based on the FY 2014 audited financial statements.

FINAL STATUS OF REPAYMENT

Rio Grande Project
(Dollars in thousands)

	Cumulative 2013 [1]	Adjustment	Annual 2014 [2]	Cumulative 2014
Revenue:				
Gross Operating Revenue	106,067.330	0.000	2,526.616	108,593.946
Income transfers (net)	0.026		0.000	0.026
Total Operating Revenue (**A**)	106,067.356	0.000	2,526.616	108,593.972
Expenses:				
O & M and other	64,741.580	0.000	2,080.496	66,822.076
Purchase power and other	4,774.405	0.000	0.000	4,774.405
Interest				
Federally financed	14,680.207	0.000	116.193	14,796.400
Non-Federally financed	0.000	0.000	0.000	0.000
Total Interest	14,680.207	0.000	116.193	14,796.400
Total Expense (**B**)	84,196.192	0.000	2,196.689	86,392.881
(Deficit)/Surplus revenue (**C**)	(264.376)	0.000	305.424	41.048
Investment:				
Federally financed power	19,900.666	0.000	79.512	19,980.178
Non-Federally financed power	0.000	0.000	0.000	0.000
Nonpower	5,801.911	0.000	0.000	5,801.911
Total Investment (**D**)	25,702.577	0.000	79.512	25,782.089
Investment repaid:				
Federally financed power	16,333.629	0.000	24.503	16,358.132
Non-Federally financed power	0.000	0.000	0.000	0.000
Nonpower	5,801.911	0.000	0.000	5,801.911
Total Investment repaid (**E**)	22,135.540	0.000	24.503	22,160.043
Investment unpaid:				
Federally financed power	3,567.037	0.000	55.009	3,622.046
Non-Federally financed power	0.000	0.000	0.000	0.000
Nonpower	0.000	0.000	0.000	0.000
Total Investment unpaid (**F**)	3,567.037	0.000	55.009	3,622.046
Fund Balances:				
Colorado River Development (G)	0.000	0.000	0.000	0.000
Working capital (H)	0.000	0.000	0.000	0.000
Percent of investment repaid to date:				
Federal	82.08%			81.87%
Non-Federal	N/A			N/A
Nonpower	100.00%			100.00%

[1] This column ties to the cumulative FY 2013 numbers on page 123 of the FY 2013 Annual Report Statistical Appendix.

[2] Based on the FY 2014 audited financial statements.

FINAL STATUS OF REPAYMENT

SEEDSKADEE PROJECT

(Dollars in thousands)

	Cumulative 2013 [1]	Adjustment		Annual 2014 [2]	Cumulative 2014
Revenue:					
Gross Operating Revenue	32,991.114	0.000		1,136.350	34,127.464
Income transfers (net)	600.632	0.000		0.000	600.632
Total Operating Revenue (**A**)	33,591.746	0.000		1,136.350	34,728.096
Expenses:					
O & M and other	16,467.223	(17.711)	3	952.134	17,401.646
Purchase power and other	0.000	0.000		0.000	0.000
Interest					
Federally financed	6,287.833	0.000		184.921	6,472.754
Non-Federally financed	0.000	0.000		0.000	0.000
Total Interest	6,287.833	0.000		184.921	6,472.754
Total Expense (**B**)	22,755.056	(17.711)		1,137.055	23,874.400
(Deficit)/Surplus revenue (**C**)	1,749.914	17.711		(345.842)	1,421.783
Investment:					
Federally financed power	9,086.776	0.000		345.140	9,431.916
Non-Federally financed power	0.000	0.000		0.000	0.000
Nonpower	0.000	0.000		0.000	0.000
Total Investment (**D**)	9,086.776	0.000		345.140	9,431.916
Investment repaid:					
Federally financed power	9,086.776	0.000		345.137	9,431.913
Non-Federally financed power	0.000	0.000		0.000	0.000
Nonpower	0.000	0.000		0.000	0.000
Total Investment repaid (**E**)	9,086.776	0.000		345.137	9,431.913
Investment unpaid:					
Federally financed power	0.000	0.000		0.003	0.003
Non-Federally financed power	0.000	0.000		0.000	0.000
Nonpower	0.000	0.000		0.000	0.000
Total Investment unpaid (**F**)	0.000	0.000		0.003	0.003
Fund Balances:					
Colorado River Development (G)	0.000	0.000		0.000	0.000
Working capital (H)	0.000	0.000		0.000	0.000
Percent of investment repaid to date:					
Federal	100.00%				100.00%
Non-Federal	N/A				N/A
Nonpower	N/A				N/A

[1] This column ties to the cumulative FY 2013 numbers on page 124 of the FY 2013 Annual Report Statistical Ap

[2] Based on the FY 2014 audited financial statements.

[3] Gains and Losses

Salt Lake City Area Integrated Projects Firm Power, Transmission & Ancillary Services
Current Rate/Charges Summary

	Provided By	Rate/Charges	Rate/Charges Effective Through (or until superceded)
Firm Power Service			
Firm Sales (SLIP-F9)	SLIP	29.62 mills/kWh	9/30/2015
Transmission Service			
Firm Point-to-Point Transmission (SP-PTP-7)	CRSP	$1.14/kWmonth	9/30/2015
Network Integration Transmission (SP-NW3)	CRSP	$1.14/kWmonth	9/30/2015
Non-Firm Point-to-Point Transmission (SP-NFT6)	CRSP	$1.14/kWmonth	9/30/2015
Ancillary Services			
Scheduling, System Control, & Dispatch (SP-SD3)	CRSP	See Rate Schedule	9/30/2015
Reactive Supply & Voltage Control (SP-RS3)	CRSP	See Rate Schedule	9/30/2015
Energy Imbalance (SP-EI3)	CRSP	See Rate Schedule	9/30/2015
Regulation & Frequency Response (SP-FR3)	CRSP	See Rate Schedule	9/30/2015
Spinning & Supplemental Reserves (SP-SSR3)	CRSP	See Rate Schedule	9/30/2015

Rate Schedule SLIP-F9
(Supersedes Schedule SLIP-F8)

UNITED STATES DEPARTMENT OF ENERGY
WESTERN AREA POWER ADMINISTRATION

SALT LAKE CITY AREA INTEGRATED PROJECTS
ARIZONA, COLORADO, NEVADA, NEW MEXICO, UTAH, WYOMING

SCHEDULE OF RATES FOR FIRM POWER SERVICE

Effective:

The first step of the stepped rate will be effective on the first day of the first full billing period beginning on or after October 1, 2008; the second step will be effective on the first day of the first full billing period on or after October 1, 2009, extending through September 30, 2013, or until superseded by another rate schedule, whichever occurs earlier.

Available:

In the area served by the Salt Lake City Area Integrated Projects.

Applicable:

To the wholesale power customer for firm power service supplied through one meter at one point of delivery, or as otherwise established by contract.

Character:

Alternating current, 60 hertz, three-phase, delivered and metered at the voltages and points established by contract.

Monthly Rate:

First step, effective October 1, 2008:

DEMAND CHARGE: $4.70/kilowatt of billing demand.

ENERGY CHARGE: 11.06 mills/kilowatthour of use.

Second step, effective October 1, 2009, and not to exceed the following:

DEMAND CHARGE: $5.22/kilowatt of billing demand.

ENERGY CHARGE: 12.29 mills/kilowatthour of use.

COST RECOVERY CHARGE: This charge will be recalculated annually before May 1, and Western will provide notification to the customers. The charge, if needed, will be placed into effect from October 1 through September 30. If triggered by the Shortage Criteria, the CRC will be re-calculated at that time and may be implemented at any time of the year upon 45-day notice to customers. (See Shortage Criteria Trigger explanation below.) The CRC will be calculated as follows:

CRC CALCULATION			
		Description	**Formula**
STEP ONE	**Determine the Net Balance available in the Basin Fund.**		
	BFBB	Basin Fund Beginning Balance ($)	Financial forecast
	BFTB	Basin Fund Target Balance ($)	.15 * PAE (not less than $20 million)
	PAR	Projected Annual Revenue ($) w/o CRC	Financial forecast
	PAE	Projected Annual Expense ($)	Financial forecast
	NR	Net Revenue ($)	PAR - PAE
	NB	Net Balance ($)	BFBB + NR
STEP TWO	**Determine the Forecasted Energy Purchased Expenses.**		
	EA	SHP Energy Allocation (GWh)	Customer contracts
	HE	Forecasted Hydro Energy (GWh)	Hydrologic & generation forecast
	FE	Forecasted Energy Purchased (GWh)	EA - HE
	FFC	Forecasted Avg Energy Price per MWh($)	From commercially available price indices
	FX	Forecasted Energy Purchased Expense ($)	FE * FFC
STEP THREE	**Determine the amount of Funds Available for firming energy purchases, and then determine additional revenue to be recovered. The following two formulas will be used to determine FA, the lesser of the two will be used.**		
	FA1	Basin Fund Balance Factor ($)	If (NB>BFBB,FX,FX -(BFTB - NB))
	FA2	Revenue Factor ($)	If (NR>-.25*BFBB,FX,FX+NR+.25*BFBB)
	FA	Funds Available ($)	Lesser of FA1 or FA2 (not less than $0)
	FARR	Additional Revenue to be Recovered ($)	FX - FA
STEP FOUR	**Once the FA for purchases has been determined, the CRC can be calculated, and the WL can be determined.**		
	WL	Waiver Level (GWh)	If (EA<HE,EA,HE+(FE*(FA/FX))), but not less than HE
	WLP	Waiver Level Percentage of Full SHP	WL/EA*100
	CRCE	CRC Energy (GWh)	EA - WL
	CRCEP	CRC Energy Percentage of Full SHP	CRCE/EA*100
	CRC	Cost Recovery Charge (mills/kWh)	FARR/(EA*1,000)

<u>Narrative CRC Example</u>

<u>STEP ONE</u>: Determine the net balance available in the Basin Fund.

BFBB – Western will forecast the Basin Fund Beginning Balance for the next FY.

BFTB – Determine the Basin Fund Target Balance for the next FY. The BFTB will not be less than $20 million. The target is 15 percent of projected annual expenses for the coming FY. **BFTB=0.15*PAE**

PAR – Projected Annual Revenue is Western's estimate of revenue for the next FY.

PAE – Projected Annual Expenses is Western's estimate of expenses for the next FY. The PAE includes all expenses plus non-reimbursable expenses, which are capped at $27 million per year plus an inflation factor. This limitation is for CRC formula calculation purposes only, and is not a cap on actual non-reimbursable expenses.

NR – Net Revenue equals revenues minus expenses. **NR=PAR-PAW**

NB – Net Balance is the Basin Fund Beginning Balance plus net revenue. **NB=BFBB+NR**

<u>STEP TWO</u>: Determine the forecasted energy purchased expenses.

EA – The Sustainable Hydropower Energy Allocation. This does not include Project Use customers.

HE – Western's forecast of Hydro Energy available during the next FY developed from Reclamation's April, 24-month, study.

FE – Forecasted Energy purchases are the difference between the sustainable hydropower allocation and the forecasted hydro energy available for the next FY, or the anticipated firming purchases for the next year. **FE=EA-HE**

FFC - The forecasted energy price for the next FY per MWh.

FX – Forecasted energy purchased power expenses based on the current year April 24-month study, representing an estimate of the total costs of firming purchases for the coming FY. **FX=FE*FFC**

<u>STEP THREE</u>: Determine the amount of Funds Available (FA) to expend on firming energy purchases, and then determine additional revenue to be recovered (FARR). The following two formulas will be used to determine FA; the lesser of the two will be used. Funds available shall not be less than zero.

A. <u>Basin Fund Balance Factor (FA1)</u>

The first factor ensures that the Net Balance will not go below 15 percent of the total expenses for that FY. If the Net Balance is greater than the Basin Fund Target Balance, then use the value for forecasted energy purchased power expenses. If the net balance is less than the Basin Fund Target Balance, then reduce the value of the Forecasted Energy Purchased Power Expenses by the difference between the Basin Fund Target Balance and the Net Balance.

FA1=if (NB>BFTB,FX,FX-(BFTB-NB))

If the Net Balance is greater than the Basin Fund Target Balance, then **FA1=FX**.

If the Net Balance is less than the Basin Fund Target Balance, then **FA1=FX-(BFTB-NB)**.

B. <u>Basin Fund Revenue Factor (FA2)</u>

The second factor ensures that the net revenue does not result in a loss that exceeds 25 percent of the Basin Fund Beginning Balance. If the Net Revenue is greater than a minus 25 percent of the Basin Fund Beginning Balance, then use the value for forecasted energy purchased power expenses. If the Net Revenue is less than a minus 25 percent of the Basin Fund Beginning Balance, then add the Net Revenue; and 25 percent of the Basin Fund Beginning Balance to the forecasted energy purchased power expenses.

FA2=If (NR>-0.25*BFBB,FX,FX+NR+0.25*BFBB)

If the Net Revenue does not result in a loss that exceeds 25 percent of the Basin Fund Beginning Balance, then **FA2=FX.**

If the Net Revenue results in a loss that exceeds 25 percent of the Basin Fund Beginning Balance, then **FA2+FX+NR+0.25*BFBB.**

FA – Determine the funds available for purchasing firming energy by using the lesser of FA1 and FA2.

FARR – Calculate the additional revenue to be recovered by subtracting the Funds Available from the forecasted energy purchased power expenses. **FARR=FX-FA**

<u>STEP FOUR</u>: Once the funds available for purchases have been determined, the CRC can be calculated and the Waiver Level (WL) can be determined.

A. <u>Cost Recovery Charge</u>: The CRC will be a charge to recover the additional revenue required as calculated in Step 3. The CRC will apply to all customers who choose not to request a waiver of the CRC, as discussed below. The CRC equals the additional revenue to be recovered divided by the total energy allocation to all customers for the FY.

CRC=FARR/(EA*1,000)

B. <u>Waiver Level</u>:

Western established an energy WL that provides customers the ability to reduce their purchased power expenses by scheduling less energy than their contractual amounts. Therefore, Western will establish an energy WL. For those customers who voluntarily schedule no more energy than their proportionate share of the WL, Western will waive the CRC for that year.

After the Funds Available have been determined, the WL will be set at the sum of the energy that can be provided through hydro generation and purchased with Funds Available. The WL will not be less than the forecasted Hydro Energy.

WL=If (EA<HE, EA, HE +(FA/FX))

If SHP Energy Allocation is less than forecasted Hydro Energy available, then **WL=EA.**

If SHP Energy Allocation is greater than forecasted Hydro Energy available, then **WL=HE+(FE*(FA/FX))**.

PRIOR YEAR ADJUSTMENT: The CRC PYA for subsequent years will be determined by comparing the prior year's estimated firming-energy cost to the prior year's actual firming-energy cost for the energy provided above the WL. The PYA will result in an increase or decrease to a customer's firm energy costs over the course of the following year. The following table is the calculation of a PYA.

PYA CALCULATION			
		Description	**Formula**
STEP ONE	**Determine actual expenses and purchases for previous year's firming. This data will be obtained from Western's financial statements at the end of the FY.**		
	PFX	Prior Year Actual Firming Expenses ($)	Financial Statements
	PFE	Prior Year Actual Firming Energy (GWh)	Financial Statements
STEP TWO	**Determine the actual firming cost for the CRC portion.**		
	EAC	Sum of the energy allocations of customers subject to the PYA (GWh)	
	FFC	Forecasted Firming Energy Cost – ($/MWh)	From CRC Calculation
	AFC	Actual Firming Energy Cost – ($/MWh)	PFX/PFE
	CRCEP	CRC Energy Percentage	From CRC Calculation
	CRCE	Purchased Energy for the CRC (GWh)	EAC*CRCEP
STEP THREE	**Determine Revenue Adjustment (RA) and PYA.**		
	RA	Revenue Adjustment ($)	(AFC-FFC)*CRCE*1,000
	PYA	**Prior Year Adjustment (mills/kWh)**	(RA/EAC)/1,000

<u>Narrative PYA Calculation</u>

<u>STEP ONE</u>: Determine actual expenses and purchases for previous year's firming. This data will be obtained from Western's financial statements at the end of the FY.

PFX - Prior year actual firming expense

PFE - Prior year actual firming energy

<u>STEP TWO</u>: Determine the actual firming cost for the CRC portion.

EAC - Sum of the energy allocations of customers subject to the PYA

CRCE - The amount of CRC Energy needed

AFC - The Actual Firming Energy Cost is the PFX divided by the PFE

AFC=(PFX/PFE)/1,000

<u>STEP THREE</u>: Determine Revenue Adjustment (RA) and Prior Year Adjustment (PYA).

RA - The Revenue Adjustment is AFC less FFC times CRCE.

RA=(AFC-FFC)*CRCE)*1,000

PYA = The PYA is the RA divided by the EAC for the CRC customers only.

PYA=(RA/EAC)/1,000

The customer's PYA will be based on their prior year's energy multiplied by the resulting mills/kWh to determine the dollar amount that will be assessed. The customers will be charged or credited for this dollar amount equally in the remaining months of the next year's billing cycle. Western will attempt to complete this calculation by December of every year. Therefore, if the PYA is calculated in December, the charge/credit will be spread over the remaining 9 months of the FY (January through September).

<u>Shortage Criteria Trigger</u>:

In the event that Reclamation's 24-month study projects that Glen Canyon Dam water releases will drop below 8.23 MAF in a water year (October through September), Western will recalculate the CRC to include those lower estimates of hydropower generation and the estimated costs for the additional purchased power necessary to meet contractual requirements. Western, as in the yearly projection for the CRC, will give the customers a 45-day notice to request a waiver of the CRC, if they do not want to have the CRC charge added to their energy bill. This recalculated CRC will remain in effect for the remainder of the current FY.

In the event that Glen Canyon Dam water releases return to 8.23 MAF or higher level during the trigger implementation, the CRC will be recalculated and the customer will be notified.

<u>Billing Demand</u>:

The billing demand will be the greater of:

1. The highest 30-minute integrated demand measured during the month up to, but not more than, the delivery obligation under the power sales contract, or
2. The Contract Rate of Delivery.

<u>Billing Energy</u>:

The billing energy will be the energy measured during the month up to, but not more than, the delivery obligation under the power sales contract.

Adjustment for Waiver:

Customers may choose to take a reduced SHP energy allocation as determined in the attached formulas for the CRC, and they will be billed the Energy and Capacity rates listed above, but not the CRC.

Adjustment for Transformer Losses:

If delivery is made at transmission voltage but metered on the low-voltage side of the substation, the meter readings will be increased to compensate for transformer losses as provided in the contract.

Adjustment for Power Factor:

The customer will be required to maintain a power factor at all points of measurement between 95 percent lagging and 95 percent leading.

Adjustment for Western Replacement Power:

Pursuant to the Contractor's Firm Electric Service Contract, as amended, Western will bill the Contractor for its proportionate share of the costs of Western Replacement Power (WRP) within a given time period. Western will include in the Contractor's monthly power bill the cost of the WRP and the incremental administrative costs associated with WRP.

Adjustment for Customer Displacement Power Administrative Charges:

Western will include in the Contractor's regular monthly power bill the incremental administrative costs associated with Customer Displacement Power.

Rate Schedule SPPTP7
(Supersedes Schedule SPPTP6)

UNITED STATES DEPARTMENT OF ENERGY
WESTERN AREA POWER ADMINISTRATION

COLORADO RIVER STORAGE PROJECT
ARIZONA, COLORADO, NEW MEXICO, UTAH

SCHEDULE OF RATE FOR FIRM POINTTOPOINT TRANSMISSION SERVICE

Effective:

The first day of the first full billing period beginning on or after October 1, 2008, and extending through September 30, 2015, or until superseded by another rate schedule, whichever occurs earlier.

Available:

In the area served by the Colorado River Storage Project (CRSP) transmission system.
Applicable:

To firm point-to-point transmission service customers for which power and energy are supplied to the CRSP transmission system at points of interconnection with other systems and transmitted and delivered, less losses, to points of delivery on the CRSP transmission system established by contract.

Character and Conditions of Service:

Transmission service for alternating current, 60 hertz, three-phase, delivered and metered at the voltages and points of delivery established by contract.

Point-to-Point Rate Formula:

The firm point-to-point rate is based on a test year using an annual fixed charge methodology. The test year is the most recent historical data available. The annual revenue requirement is reduced by revenue credits. The resultant net annual cost to be recovered is divided by the capacity reservation needed to meet firm power and transmission commitments in kW, including the total network integration loads at system peak, to derive a cost/kWyear. The cost/kWyear is calculated using the following formula:

1. ATRR TRC = NATRR

2. NATRR

TSTL

Where:

ATRR = Annual Transmission Revenue Requirement. The costs associated with facilities that support the transfer capability of the CRSP transmission system, excluding generation facilities. These costs include investment costs, interest expense, depreciation expense, administrative and general expenses, and operation and maintenance expenses, including transmission purchases. Transmission purchases reflect those costs associated with CRSP contractual rights.

TRC = Transmission Revenue Credits. The revenues generated by the CRSP transmission system, such as scheduling and dispatch ancillary service revenues and phase shifter revenues, and excluding longterm firm transmission revenues.

NATRR = Net Annual Transmission Revenue Requirement. The Annual Revenue Requirement less Transmission Revenue Credits.

TSTL = CRSP Transmission System Total Load. The sum of the total CRSP transmission capacity under the long-term reservation plus the total network integration loads at system peak.

This formula will be recalculated annually by applying the data from the most current historical test year. If needed, a revised rate will be placed into effect every October 1. Western will provide notification 30 days prior to a revised rate becoming effective. The rate for transmission service includes scheduling, system control, and dispatch. Rate Schedule SPRS3, or any superseding rate schedule, for reactive supply and voltage control is attached as part of this Rate Schedule and applies to firm pointtopoint transmission customers.

Billing:

The point-to-point transmission customer will be billed monthly by applying the resulting rate to the maximum amount of capacity reserved, payable whether used or not, except as otherwise provided in existing contracts.

Requirements for Reactive Power:

Requirements for reactive power shall be as established by contract; otherwise, there shall be no entitlement to transfer of reactive kilovolt amperes at delivery points except when such transfers may be mutually agreed upon by the Contractor and the contracting officer or their authorized representatives.

Adjustment for Losses:

Power and energy losses incurred in connection with the transmission and delivery of power and energy under this rate schedule shall be supplied by the customer as established by contract. If losses are not fully provided by a transmission customer, charges for financial compensation may apply.

Adjustment for Industry Restructuring:

Any transmission-related costs incurred by Western due to electric industry restructuring or other industry changes associated with providing CRSP transmission service will be passed through to each transmission customer, as appropriate.

Rate Schedule SPNW3
(Supersedes Schedule SPNW2)

UNITED STATES DEPARTMENT OF ENERGY
WESTERN AREA POWER ADMINISTRATION

COLORADO RIVER STORAGE PROJECT
ARIZONA, COLORADO, NEW MEXICO, UTAH

MONTHLY CHARGE CALCULATION FOR NETWORK INTEGRATION TRANSMISSION SERVICE

Effective:

The first day of the first full billing period beginning on or after October 1, 2008, and extending through September 30, 2015, or until superseded by another rate schedule, whichever occurs earlier.

Available:

In the area served by the Colorado River Storage Project (CRSP) transmission system.

Applicable:

To network transmission service customers for which power and energy are supplied to the CRSP transmission system at points of interconnection with other systems and transmitted and delivered, less losses, to points of delivery on the CRSP transmission system established by contract.

Character and Conditions of Service:

Transmission service for alternating current, 60 hertz, three-phase, delivered and metered at the voltages and points of delivery established by contract.

Monthly Network Formula:

The Network integration transmission service charge will be the product of the network customer's load ratio share times one twelfth (1/12) of the total net annual transmission revenue requirement. The same Net Annual Transmission Revenue Requirement is used in determining the rate for network transmission service as for point-to-point transmission service. It is based on a test year using an annual fixed charge methodology. The test year is the most recent year for which historical data is available. The annual revenue requirement is reduced by revenue credits. The formula is as follows:

1. ATRR TRC = NATRR

2. $\frac{\text{NATRR}}{12}$ X Transmission customer's Load-Ratio Share

Where:

ATRR = Annual Transmission Revenue Requirement. The costs associated with facilities that support the transfer capability of the CRSP transmission system, excluding generation facilities. These costs include investment costs, interest expense, depreciation expense, administrative and general expenses, and operation and maintenance expenses, including transmission purchases. Transmission purchases reflect those costs associated with CRSP contractual rights.

TRC = Transmission Revenue Credits. The revenues generated by the CRSP transmission system, such as scheduling and dispatch ancillary services revenues and phase shifter revenues, and excluding long-term firm transmission revenues.

NATRR = Net Annual Transmission Revenue Requirement. The Annual Revenue Requirement less Transmission Revenue Credits.

Load-Ratio Share = Network customer's hourly load (including its designated network load not physically interconnected with Western) coincident with Western's monthly CRSP transmission system peak.

This formula will be recalculated annually by applying the data from the most current historical test year. If needed, a revised rate will be placed into effect every October 1. Western will provide notification 30 days prior to a revised rate becoming effective.
The monthly charge for network transmission service includes scheduling, system control, and dispatch. Rate Schedule SPRS3, or any superseding rate schedule, will be attached as part of this Rate Schedule and applies to network transmission customers.

<u>Billing:</u>

Billing determinants for the formula rate above will be as specified in the service agreement.

<u>Requirements for Reactive Power:</u>

Requirements for reactive power shall be as established by contract; otherwise, there shall be no entitlement to transfer of reactive kilovolt amperes at delivery points except when such transfers may be mutually agreed upon by the Contractor and the contracting officer or their authorized representatives.

<u>Adjustment for Losses:</u>

Power and energy losses incurred in connection with the transmission and delivery of power and energy under this rate schedule shall be supplied by the customer as established by contract. If losses are not fully provided by a transmission customer, charges for financial compensation may apply.

Adjustment for Industry Restructuring:

Any transmission-related costs incurred by Western due to electric industry restructuring or other industry changes associated with providing CRSP transmission service will be passed through to each transmission customer, as appropriate.

Rate Schedule SPNFT6
(Supersedes Schedule SPNFT5)

UNITED STATES DEPARTMENT OF ENERGY
WESTERN AREA POWER ADMINISTRATION

COLORADO RIVER STORAGE PROJECT
ARIZONA, COLORADO, NEW MEXICO, UTAH

SCHEDULE OF RATE FOR NONFIRMPOINTTOPOINT TRANSMISSION SERVICE

Effective:

The first day of the first full billing period beginning on or after October 1, 2008, and extending through September 30, 2015, or until superseded by another rate schedule, whichever occurs earlier.

Available:

In the area served by the Colorado River Storage Project (CRSP) transmission system.

Applicable:

To non-firm point-to-point transmission service customers for which power and energy are supplied to the CRSP transmission system at points of interconnection with other systems and transmitted and delivered, less losses, to points of delivery on the CRSP transmission system as established by contract.

Character and Conditions of Service:

Transmission service on an interruptible basis for three-phase alternating current 60 hertz, delivered and metered at the voltages and points of delivery specified in the service contract or in advance by the Western Area Power Administration (Western). Conditions for curtailment shall be determined by Western and in accordance with Western’s Tariff.

Rate:

The proposed rate for non-firm, point-to-point, CRSP transmission service is based upon the firm point-to-point rate expressed in mills/kWh. This rate may be discounted.

Billing:

The rate will be applied to each kWh delivered at the point of delivery, as specified in the service contract.

Adjustments for Reactive Power:

None. There shall be no entitlement to transfer of reactive kilovolt-amperes at delivery points, except when such transfers may be mutually agreed upon by the Contractor and the contracting officer or their authorized representatives.

Adjustments for Losses:

Power and energy losses incurred in connection with the transmission and delivery of power and energy under this rate schedule shall be supplied by the customer in accordance with the service contract. If losses are not fully provided by a transmission customer, charges for financial compensation may apply.

Adjustment for Industry Restructuring:

Any transmission-related costs incurred by Western due to electric industry restructuring or other industry changes associated with providing CRSP transmission service will be passed through to each transmission customer, as appropriate.

Rate Schedule SP-SD3
(Supersedes Schedule SP-SD2)

UNITED STATES DEPARTMENT OF ENERGY
WESTERN AREA POWER ADMINISTRATION

COLORADO RIVER STORAGE PROJECT
ARIZONA, COLORADO, NEW MEXICO, UTAH

SCHEDULE OF RATE FOR SCHEDULING, SYSTEM CONTROL, AND DISPATCH ANCILLARY SERVICES

Effective:

Beginning on October 1, 2008, and extending through September 30, 2015.

Available:

In the area served by the Colorado River Storage Project (CRSP) transmission system.

Applicable:

To all CRSP transmission customers receiving this service.

Character of Service:

Scheduling, System Control, and Dispatch service is required to schedule the movement of power through, out of, within, or into a balancing authority.

Rate:

Included in appropriate transmission rates.

Rate Schedule SP-RS3
(Supersedes Schedule SP-RS2)

UNITED STATES DEPARTMENT OF ENERGY
WESTERN AREA POWER ADMINISTRATION

COLORADO RIVER STORAGE PROJECT
ARIZONA, COLORADO, NEW MEXICO, UTAH

SCHEDULE OF RATE FOR REACTIVE SUPPLY AND VOLTAGE CONTROL ANCILLARY SERVICE

Effective:

Beginning on October 1, 2008, and extending through September 30, 2015.

Available:

In the area served by the Colorado River Storage Project (CRSP) Transmission system.

Applicable:

To all CRSP transmission customers receiving this service.

Character of Service:

Reactive power is support provided from generation facilities that is necessary to maintain transmission voltages within acceptable limits of the system.

Rate:

Provided through WALC balancing authority under Rate Schedule DSW-RS2 or WACM balancing authority under Rate Schedule L-AS2, or as superseded.

Rate Schedule SP-EI3
(Supersedes Schedule SP-EI2)

UNITED STATES DEPARTMENT OF ENERGY
WESTERN AREA POWER ADMINISTRATION

COLORADO RIVER STORAGE PROJECT
ARIZONA, COLORADO, NEW MEXICO, UTAH

SCHEDULE OF RATE FOR ENERGY IMBALANCE ANCILLARY SERVICE

Effective:

Beginning on October 1, 2008, and extending through September 30, 2015.

Available:

In the area served by the Colorado River Storage Project (CRSP) transmission system.

Applicable:

To all CRSP transmission customers receiving this service.

Character of Service:

Provided when a difference occurs between the schedules and the actual delivery of energy to a load located within a balancing authority over a single hour.

Rates:

Provided through WALC balancing authority under Rate Schedule DSW-EI2 or WACM balancing authority under Rate Schedule L-AS4, or as superseded, or the customer can make alternative comparable arrangements to satisfy its Energy Imbalance service obligations.

Rate Schedule SP-FR3
(Supersedes Schedule SP-FR2)

UNITED STATES DEPARTMENT OF ENERGY
WESTERN AREA POWER ADMINISTRATION

COLORADO RIVER STORAGE PROJECT
ARIZONA, COLORADO, NEW MEXICO, UTAH

SCHEDULE OF RATE FOR REGULATION AND FREQUENCY RESPONSE ANCILLARY SERVICE

Effective:

Beginning on October 1, 2008, and extending through September 30, 2015.

Available:

In the area served by the Colorado River Storage Project (CRSP) transmission system.

Applicable:

To all CRSP transmission customers receiving this service.

Character of Service:

Necessary to provide the continuous balancing of resources, generation and interchange, with load and for maintaining schedules interconnection frequency at 60 cycles per second (60 Hz).

Rate:

If the CRSP MC has regulation available for sale, the SLCA/IP firm power capacity rate, currently in effect, will be charged. If regulation is unavailable from SLCA/IP resources, the WALC or WACM balancing authorities can provide the service, in accordance with their respective rate schedules.

Rate Schedule SP-SSR3
(Supersedes Schedule SP-SSR2)

UNITED STATES DEPARTMENT OF ENERGY
WESTERN AREA POWER ADMINISTRATION

COLORADO RIVER STORAGE PROJECT
ARIZONA, COLORADO, NEW MEXICO, UTAH

SCHEDULE OF RATES FOR SPINNING AND SUPPLEMENTAL RESERVE ANCILLARY SERVICE

Effective:

Beginning on October 1, 2008, and extending through September 30, 2015.

Available:

In the area served by the Colorado River Storage Project (CRSP) transmission system.

Applicable:

To all CRSP transmission customers receiving this service.

Character of Service:

Spinning Reserve is defined in Schedule 5 of Western Area Power Administration's Open Access Transmission Tariff.

Supplemental Reserve is defined in Schedule 6 of Western Area Power Administration's Open Access Transmission Tariff.

Rate:

If CRSP resources are available, the charge will be determined based on market rates plus administrative costs. If CRSP resources are not available, CRSP will purchase spinning reserves and pass through the costs associated with these purchases, including administrative costs.

The Power Repayment BackUp Study is no longer being published in the binder.

If you feel we should still provide the BackUp Study, please let us know if you would like a copy of the BackUp Study sent to you by emailing the rates section at the CRSP- MC.

Also, feel free to provide feedback through the survey and if results warrant it we'll ad it back to the binder.

Salt Lake City Area Integrated Projects
Annual Revenue Requirements and Firm Power Rates Comparison Table

Item	Unit	WAPA 137 Step 2 Rate PRS 2010 Workplan	FY 2015 Preliminary 2017 Workplan	Change Amount	Change Percent
Rate Setting Period:					
Beginning year	FY	2010	2016		
Pinchpoint year	FY	2025	2025		
Number of rate setting years	Years	16	10		
Annual Revenue Requirements:					
Expenses					
Operation and Maintenance:					
Western	1,000	$40,514	$52,631	$12,117	30%
Reclamation	1,000	$30,092	$34,535	$4,443	15%
Total O&M	1,000	$70,606	$87,166	$16,560	23%
Purchased Power 1/	1,000	$5,163	$10,279	$5,116	99%
Transmission	1,000	$10,525	$10,421	($104)	-1%
Integrated Projects requirements	1,000	$7,286	$8,611	$1,325	18%
Interest	1,000	$3,693	$1,704	($1,989)	-54%
Other 2/	1,000	$2,984	$14,587	$11,603	389%
Total Expenses	1,000	$100,257	$132,767	$32,510	32%
Principal payments					
Deficits	1,000	$0	$0	$0	0%
Replacements	1,000	$28,652	$30,264	$1,612	6%
Original Project and Additions	1,000	$17,936	$7,423	($10,513)	-59%
Irrigation 3/	1,000	$38,744	$15,771	($22,973)	-59%
Total principal payments	1,000	$85,332	$53,458	($31,874)	-37%
Total Annual Revenue Requirements	1,000	$185,589	$186,225	$636	0%
(Less Offsetting Annual Revenue:)					
Transmission (firm and non-firm)	1,000	$18,045	$19,565	$1,520	8%
Merchant Function 4/	1,000	$8,309	$9,918	$1,609	19%
Other 5/	1,000	$7,687	$5,118	($2,569)	-33%
Total Offsetting Annual Revenue	1,000	$34,041	$34,602	$561	2%
Net Annual Revenue Requirements	1,000	**$151,548**	**$151,623**	**$75**	0%
Energy Sales 6/	**MWH**	**5,116,346**	**5,071,804**	**(44,542)**	-1%
Capacity Sales	**kW**	**1,434,946**	**1,407,920**	**(27,026)**	-2%
			0		
Composite Rate	**mills/kWh**	**29.62**	**29.90**	**0.28**	0.9%

1/ FY 2015-19 are projected costs using the April 2015 24-month study.
FY 2019 and beyond are based on $4 million in purchase power for the administrative merchant function activities.

2/ Includes the cost of salinity, federal benefits costs, CME interest, reimbursable environmental costs, and MOA costs.

3/ Aid to Irrigation plus Aid to Participating Projects minus Annual Surplus M&I

4/ Includes transaction fees and resale energy.

5/ Other revenues include ancillary services such as spinning reserves, facility use charges, and other misc. service charges.

6/ April 2015 project use estimates from Reclamation. (Average MWH Annual Sales for 2015 - 2025 minus Other Energy Sales)

Salt Lake City Area Integrated Projects
Annual Revenue Requirements and Firm Power Rates Comparison Table

Item	Unit	WAPA 137 Step 2 Rate PRS 2010 Workplan	FY 2010 Preliminary 2012 Workplan	FY 2011 Preliminary 2013 Workplan	FY 2011 New PP 2013 Workplan	FY 2012 Preliminary 2014 Workplan	FY 2013 Preliminary 2015 Workplan	FY 2014 Preliminary 2016 Workplan	FY 2015 Preliminary 2017 Workplan	FY2014 vs FY2015 Preliminary Comparison Amount	 Percent	Step 2 vs FY2015 Preliminary Comparison Amount	 Percent
Rate Setting Period:													
Beginning year	**FY**	2010	2011	2012	2012	2013	2014	2015	2016				
Pinchpoint year	**FY**	2025	2025	2025	2021	2021	2025	2025	2025				
Number of rate setting years	**Years**	16	15	14	10	9	12	11	10				
Annual Revenue Requirements:													
Expenses													
Operation and Maintenance:													
Western	1,000	$40,514	$47,726	$50,100	$49,787	$50,310	$52,215	$52,339	$52,631	$292	0.56%	$12,117	30%
Reclamation	1,000	$30,092	$33,087	$33,699	$33,636	$34,265	$34,550	$35,840	$34,535	($1,305)	-3.64%	$4,443	15%
Total O&M	1,000	$70,606	$80,813	$83,799	$83,423	$84,575	$86,765	$88,179	$87,166	($1,013)	-1.15%	$16,560	23%
Purchased Power 1/	1,000	$5,163	$4,698	$3,554	$3,376	$5,399	$7,445	$7,056	$10,279	$3,223	45.68%	$5,116	99%
Transmission	1,000	$10,525	$10,514	$9,456	$9,456	$9,096	$9,111	$8,112	$10,421	$2,309	28.46%	($104)	-1%
Integrated Projects requirements	1,000	$7,286	$8,071	$8,315	$8,338	$9,217	$8,383	$8,427	$8,611	$184	2.18%	$1,325	18%
Interest	1,000	$3,693	$4,008	$5,414	$7,348	$7,226	$5,513	$2,071	$1,704	($367)	-17.72%	($1,989)	-54%
Other 2/	1,000	$2,984	$3,015	$14,858	$14,909	$14,206	$15,391	$15,447	$14,587	($860)	-5.57%	$11,603	389%
Total Expenses	1,000	$100,257	$111,119	$125,396	$126,850	$129,719	$132,608	$129,292	$132,767	$3,475	2.69%	$32,510	32%
Principal payments													
Deficits	1,000	$0	$0	$0	$0	$0	$0	$0	$0	$0		$0	0%
Replacements	1,000	$28,652	$26,376	$22,354	$25,550	$27,743	$32,558	$28,817	$30,264	$1,447	5.02%	$1,612	6%
Original Project and Additions	1,000	$17,936	$17,407	$17,313	$18,423	$18,375	$17,069	$5,502	$7,423	$1,921	34.92%	($10,513)	-59%
Irrigation 3/	1,000	$38,744	$41,270	$17,764	$11,700	$13,025	$16,398	$14,922	$15,771	$849	5.69%	($22,973)	-59%
Total principal payments	1,000	$85,332	$85,053	$57,431	$55,673	$59,143	$66,025	$49,241	$53,458	$4,217	8.56%	($31,874)	-37%
Total Annual Revenue Requirements	1,000	$185,589	$196,172	$182,827	$182,523	$188,862	$198,633	$178,533	$186,225	$7,692	4.31%	$636	0%
(Less Offsetting Annual Revenue:)													
Transmission (firm and non-firm)	1,000	$18,045	$17,997	$15,948	$15,903	$19,363	$17,382	$16,966	$19,565	$2,599	15.32%	$1,520	8%
Merchant Function 4/	1,000	$8,309	$9,043	$8,239	$8,239	$11,038	$11,223	$10,267	$9,918	($349)	-3.40%	$1,609	19%
Other 5/	1,000	$7,687	$8,027	$7,124	$7,124	$6,703	$5,846	$4,999	$5,118	$119	2.38%	($2,569)	-33%
Total Offsetting Annual Revenue	1,000	$34,041	$35,067	$31,311	$31,266	$37,104	$34,451	$32,232	$34,602	$2,370	7.35%	$561	2%
Net Annual Revenue Requirements	1,000	**$151,548**	**$161,105**	**$151,516**	**$151,257**	**$151,758**	**$164,182**	**$146,301**	**$151,623**	**$5,322**	**3.64%**	**$75**	0%
Energy Sales 6/	**MWH**	**5,116,346**	**5,129,841**	**5,098,603**	**5,093,750**	**5,094,141**	**5,098,255**	**5,089,548**	**5,071,804**	**(17,744)**	**-0.35%**	**(44,542)**	-0.9%
Capacity Sales	**kW**	**1,434,946**	**1,418,980**	**1,418,821**	**1,418,821**	**1,415,778**	**1,417,883**	**1,416,945**	**1,407,920**	**-9,025**	**-0.64%**	**(27,026)**	-2%
										0			
Composite Rate	**mills/kWh**	**29.62**	**31.41**	**29.73**	**29.70**	**29.79**	**32.21**	**28.75**	**29.90**	**1.15**	**4.00%**	**0.28**	0.9%

1/ FY 2015-19 are projected costs using the April 2015 24-month study.
FY 2019 and beyond are based on $4 million in purchase power for the administrative merchant function activities.
2/ Includes the cost of salinity, federal benefits costs, CME interest, reimbursable environmental costs, and MOA costs.
3/ Aid to Irrigation plus Aid to Participating Projects minus Annual Surplus M&I
4/ Includes transaction fees and resale energy.
5/ Other revenues include ancillary services such as spinning reserves, facility use charges, and other misc. service charges.
6/ April 2015 project use estimates from Reclamation. (Average MWH Annual Sales for 2015 - 2025 minus Other Energy Sales)

COLORADO RIVER STORAGE PROJECT					
AVERAGE O&M BUDGET PROJECTIONS COMPARISONS					
FY 2015 PRS (FY 2017 Work Plan) v. Step II PRS (FY 2011 Work Plan)					
		Step 2 Rate	FY2017 Workplan	Average per year	Percent
ITEM	**TYPE**	**2009-2025**	**2016-2025**	**Increase**	**Increase**
WESTERN *					
DESERT SOUTHWEST					
GWA	O&M	$1,030,762	$1,162,134	$131,372	13%
O&M TRANSMISSION LINES	O&M	$546,149	$1,914,732	$1,368,582	251%
O&M SUBSTATIONS	O&M	$4,103,657	$4,857,405	$753,748	18%
OTHER EXP (except int)	O&M	$406,261	$457,698	$51,437	13%
DEPRECIATION	Other	$92,945	$80,417	($12,528)	
RETIRE, REPLACE, ADDITIONS	Other	$1,479,429	$2,826,000	$1,346,571	
POWER BILLING	O&M	$301,256	$140,198	($161,059)	-53%
C&RE	O&M	$8,279	$4,282	($3,997)	-48%
POWER MARKETING	O&M	$38,033	$14,281	($23,751)	-62%
SYSTEM OPERATION & LOAD DISP	O&M	$1,429,631	$410,863	($1,018,768)	-71%
DSW TOTAL BUDGET		**$9,436,403**	**$11,868,009**	**$2,431,606**	
DSW PRS O&M		**$7,864,029**	**$8,961,593**	**$1,097,564**	**14%**
ROCKY MOUNTAIN					
GWA	O&M	$1,960,010	$3,098,324	$1,138,314	58%
O&M TRANSMISSION LINES	O&M	$3,097,835	$5,687,098	$2,589,263	84%
O&M SUBSTATIONS	O&M	$10,646,027	$13,270,951	$2,624,924	25%
OTHER EXP (except int)	O&M	$632,603	$1,821,081	$1,188,478	188%
DEPRECIATION	Other	$209,412	$266,182	$56,770	
RETIRE, REPLACE, ADDITIONS	Other	$3,882,083	$4,802,045	$919,962	
PURCHASED POWER & WHEELING	Other	$0	$0	$0	
POWER BILLING	O&M	$245,730	$148,162	($97,568)	-40%
C&RE	O&M	$6,329	$5,324	($1,005)	-16%
POWER MARKETING	O&M	$1,239,692	$1,029,001	($210,690)	-17%
SYSTEM OPERATION & LOAD DISP	O&M	$3,940,584	$7,855,834	$3,915,250	99%
RM TOTAL BUDGET		**$25,860,303**	**$37,984,001**	**$12,123,698**	
RM PRS O&M		**$21,768,809**	**$32,915,775**	**$11,146,966**	**51%**
CRSP MC					
GWA	O&M	$978,157	$1,559,444	$581,287	59%
O&M TRANSMISSION LINES	O&M	$0	$0	$0	0%
O&M SUBSTATIONS	O&M	$0	$0	$0	0%
OTHER EXP (except int)	O&M	$174,759	$46,363	($128,396)	-73%
INTEREST	Other	$1,170,009	$4,552,693	$3,382,684	
PURCHASED POWER & WHEELING	Other	$158,806,697	$92,816,206	($65,990,491)	
RETIRE, REPLACE, ADDITIONS	Other	$30,000	$13,600	($16,400)	
DEPRECIATION	Other	$74,706	$82,935	$8,230	
POWER BILLING	O&M	$0	$0	$0	
C&RE	O&M	$179,500	$199,112	$19,612	11%
POWER MARKETING	O&M	$7,808,234	$9,089,249	$1,281,015	16%
Grand Canyon Protection Act (Non-reimb)	Environ	$0	$0	$0	
Recovery Implementation Program (Non-reimb)	Environ	$1,330,797	$1,869,719	$538,922	
SYSTEM OPERATION & LOAD DISP	O&M	$0	$0	$0	$0
STATE OF COLORADO (RIP) LOAN	O&M	$0	($886,000)	($886,000)	$0
CRSP MC TOTAL BUDGET		**$170,552,859**	**$109,343,321**	**($61,209,538)**	
CRSP MC PRS O&M		**$9,140,650**	**$10,008,167**	**$867,517**	**9%**

TOTAL WESTERN					
GWA	O&M	$3,968,929	$5,819,902	$1,850,973	47%
O&M TRANSMISSION LINES	O&M	$3,643,984	$7,601,830	$3,957,846	109%
O&M SUBSTATIONS	O&M	$14,749,683	$18,128,356	$3,378,672	23%
OTHER EXPENSES	O&M	$1,213,624	$2,325,142	$1,111,519	92%
INTEREST	Other	$1,170,009	$4,552,693	$3,382,684	
PURCHASED POWER & WHEELING	Other	$158,806,697	$92,816,206	($65,990,491)	
Depreciation	Other	$377,063	$429,534	$52,471	
RETIRE, REPLACE, ADDITIONS	Other	$5,391,511	$7,641,645	$2,250,133	
POWER BILLING	O&M	$546,987	$288,360	($258,627)	-47%
C&RE	O&M	$194,108	$208,717	$14,610	8%
POWER MARKETING	O&M	$9,085,959	$10,132,531	$1,046,573	12%
GCPA(Non-reimb)	Environ	$0	$0	$0	
RIP (Non-reimb)	Environ	$1,330,797	$1,869,719	$538,922	
SYSTEM OPERATION & LOAD DISP	O&M	$5,370,215	$8,266,697	($234,442)	-4%
STATE OF COLORADO (RIP) LOAN	O&M	$0	($886,000)	($886,000)	0%
Western Budget		**$205,849,565**	**$159,195,332**	**($46,654,234)**	
WESTERN TOTAL O&M		**$38,773,488**	**$51,885,535**	**$13,112,047**	**34%**
CME DEPRECIATION		**$1,741,000**	**$745,000**	**($996,000)**	**-57%**
WESTERN PRS O&M		**$40,514,488**	**$52,630,535**	**$12,116,047**	**30%**
**BUREAU OF RECLAMATION ** **					
Water and Energy Mgmt and Dvlp	0.00%	$2,201,000	$1,987,771	($213,229)	
Land Mgmt and Dvlp	0.00%	$532,059	$659,035	$126,976	
Fish and Wildlife Mgmt and Dvlp:			$0		
GC Adaptive Mtmt Prg	0.00%	$10,495,404	$12,115,234	$1,619,830	
Endangered fish (RIP) base funding	0.00%	$7,818,073	$9,205,899	$1,387,826	
Endangered fish (RIP) capital	0.00%	$0	$0	$0	
Flaming Gorge studies	90.00%	$0	$0	$0	
Glen Canyon Studies	0.00%	$0	$0	$0	
Navajo studies	83.00%	$0	$0	$0	0%
Aspinall studies	97.00%	$79,529	$0	($79,529)	-100%
Subtotal Bureau Budget		**$21,126,065**	**$23,967,939**	**$2,841,874**	**13%**
Total PRS O&M		**$77,144**	**$0**	**($77,144)**	**-100%**
Water Operations:					
Subtotal Bureau Budget	0.00%	**$6,441,778**	**$7,864,683**	**$1,422,905**	**22%**
Total PRS O&M		**$6,377,360**	**$6,168,097**	**($209,263)**	**-3%**
Power Operations:					
Subtotal Bureau Budget		**$18,783,952**	**$23,201,415**	**$4,417,464**	**24%**
Total PRS O&M		**$18,783,952**	**$23,201,415**	**$4,417,464**	**24%**
Miscellaneous:	100.00%	**$586,287**	**$736,588**	**$150,301**	**26%**
Security:	70.00%	**$1,758,012**	**$2,775,699**	**$1,017,686**	**58%**
Extraordinary Maintenance Expensed:					
Navajo	83.00%	$333,529	$132,667	($200,862)	-60%
Blue Mesa	97.00%	$102,094	$147,764	$45,670	45%
Morrow Point	100.00%	$311,788	$128,917	($182,871)	-59%
Crystal	100.00%	$51,353	$150,083	$98,730	192%
Flaming Gorge	90.00%	$149,365	$132,667	($16,698)	-11%
Glen Canyon	62.00%	$431,412	$1,222,917	$791,505	183%
Denver	97.00%	$106,353	$0	($106,353)	-100%
Subtotal Bureau Budget		**$1,485,894**	**$1,915,014**	**$429,120**	**29%**
Total PRS O&M		**$1,399,376**	**$1,410,053**	**$165,985**	**12%**

Replacements Expensed:		**This section expanded in FY15**			
Blue Mesa	99.00%		$0	$0	0%
Morrow Point	100.00%		$82,500	$0	0%
Crystal	100.00%		$0	$0	0%
Curecanti	100.00%		$27,500	$0	0%
Flaming Gorge	90.00%		$114,583	$0	0%
Glen Canyon	90.00%		$28,500	$0	0%
Denver	50.00%		$0	$0	0%
Subtotal Bureau Budget		**$435,224**	**$253,083**	**($182,140)**	**-42%**
Total PRS O&M		**$430,871**	**$238,875**	**($191,996)**	**-45%**
Total Reclamation Budget		**$48,272,912**	**$61,425,825**	**$13,152,913**	**27%**
Reclamation CME DEPRECIATION		**$222,000**	**$0**	**($222,000)**	**-100%**
Reclamation Reimbursable by power		**$29,635,002**	**$34,535,277**	**$4,900,275**	**17%**
Total PRS O&M		**$70,149,490**	**$87,165,811**	**$17,016,322**	**24%**
Environmental Costs:					
Western					
GCPA (Non-reimb)	Environ	$0	$0	**$0**	
RIP (Non-reimb)	Environ	$1,330,797	$1,869,719	**$538,922**	
USBR					
Fish and Wildlife Mgmt and Dvlp:					
Nonreimbursable					
GC Adaptive Mtmt Prg	0.00%	$10,495,404	$12,115,234	**$1,619,830**	
Endangered fish (RIP) base funding	0.00%	$7,818,073	$9,205,899	**$1,387,826**	
Glen Canyon Studies	0.00%	$0	$0	**$0**	
Total non-reimbursable		$19,644,274	$23,190,853	**$3,007,656**	
Reimbursable					
Flaming Gorge studies	100.00%	$0	$0	**$0**	**0%**
Navajo studies	100.00%	$0	$0	**$0**	**0%**
Aspinall studies	100.00%	$79,529	$0	**($79,529)**	**-100%**
Endangered fish (RIP) capital	0.00%	$0	$0	**$0**	**0%**
Total reimbursable		$79,529	$0	**($79,529)**	**-100%**

COLORADO RIVER STORAGE PROJECT
O&M BUDGET PROJECTIONS
FY 2017 Work Plan

* Western budget data from FY 2017 Work Plan dated 3/13/15
** Bureau budget data from FY 2017 Preliminary Work Program Schedules dated 4/15/2015

ITEM	TYPE	Current Year 2015	1 2016	2 2017	3 2018	4 2019	5 2020	Future 10 Year Projection 2021-2025	10 Year Annual Average 2016-2025
WESTERN *									
DESERT SOUTHWEST									
GWA	O&M	$856,689	$969,982	$1,104,081	$1,137,203	$1,171,320	$1,206,459	$1,206,459	$1,162,134
O&M TRANSMISSION LINES	O&M	$4,304,727	$4,259,870	$4,232,209	$1,269,176	$1,307,251	$1,346,468	$1,346,468	$1,914,732
O&M SUBSTATIONS	O&M	$4,376,063	$4,615,390	$4,556,594	$4,693,292	$4,834,091	$4,979,114	$4,979,114	$4,857,405
OTHER EXPENSES	O&M	$419,836	$459,376	$426,816	$439,621	$452,809	$466,394	$466,394	$457,698
Depreciation	Other	$79,568	$70,590	$76,040	$78,321	$80,671	$83,091	$83,091	$80,417
RETIRE, REPLACE, ADDITIONS	Other	$5,250,000	$1,655,000	$3,475,000	$3,345,000	$3,345,000	$2,740,000	$2,740,000	$2,826,000
POWER BILLING	O&M	$197,250	$121,542	$132,725	$136,707	$140,808	$145,033	$145,033	$140,198
C&RE	O&M	$9,405	$4,328	$3,990	$4,109	$4,233	$4,360	$4,360	$4,282
POWER MARKETING	O&M	$29,452	$7,048	$14,073	$14,495	$14,930	$15,378	$15,378	$14,281
SYSTEM OPERATION & LOAD DISP	O&M	$431,411	$345,396	$390,083	$401,785	$413,839	$426,254	$426,254	$410,863
DSW TOTAL BUDGET		**$15,954,400**	**$12,508,523**	**$14,411,611**	**$11,519,710**	**$11,764,951**	**$11,412,550**	**$11,412,550**	**$11,868,009**
DSW PRS O&M		**$10,624,832**	**$10,782,933**	**$10,860,571**	**$8,096,388**	**$8,339,281**	**$8,589,459**	**$8,589,459**	**$8,961,593**
ROCKY MOUNTAIN									
GWA	O&M	$2,735,000	$2,765,000	$2,925,000	$3,012,750	$3,103,133	$3,196,226	$3,196,226	$3,098,324
O&M TRANSMISSION LINES	O&M	$6,415,545	$5,979,587	$5,902,657	$5,358,736	$5,519,498	$5,685,084	$5,685,084	$5,687,098
O&M SUBSTATIONS	O&M	$11,730,149	$12,277,157	$12,483,578	$12,858,085	$13,243,827	$13,641,143	$13,641,143	$13,270,951
OTHER EXPENSES	O&M	$1,862,831	$1,835,429	$1,697,412	$1,748,335	$1,800,785	$1,854,808	$1,854,808	$1,821,081
Depreciation	Other	$215,000	$250,000	$250,000	$257,500	$265,225	$273,182	$273,182	$266,182
RETIRE, REPLACE, ADDITIONS	Other	$14,517,903	$5,523,251	$6,636,020	$4,784,052	$4,924,614	$4,358,752	$4,358,752	$4,802,045
PURCHASED POWER & WHEELING	Other							$0	$0
POWER BILLING	O&M	$118,414	$116,155	$141,539	$145,785	$150,159	$154,664	$154,664	$148,162
C&RE	O&M	$5,000	$5,000	$5,000	$5,150	$5,305	$5,464	$5,464	$5,324
POWER MARKETING	O&M	$958,585	$982,732	$964,758	$993,701	$1,023,512	$1,054,218	$1,054,218	$1,029,001
SYSTEM OPERATION & LOAD DISP	O&M	$6,268,558	$6,587,827	$7,460,201	$7,684,007	$7,914,528	$8,151,963	$8,151,963	$7,855,834
RM TOTAL BUDGET		**$44,826,985**	**$36,322,138**	**$38,466,165**	**$36,848,101**	**$37,950,586**	**$38,375,504**	**$38,375,504**	**$37,984,001**
RM PRS O&M		**$30,094,082**	**$30,548,887**	**$31,580,145**	**$31,806,549**	**$32,760,747**	**$33,743,570**	**$33,743,570**	**$32,915,775**
CRSP MC									
GWA	O&M	$1,269,593	$1,299,309	$1,481,781	$1,526,234	$1,572,021	$1,619,182	$1,619,182	$1,559,444
O&M TRANSMISSION LINES	O&M							$0	$0
O&M SUBSTATIONS	O&M							$0	$0
OTHER EXPENSES	O&M	$10,913	$50,224	$38,467	$34,857	$35,774	$50,718	$50,718	$46,363
INTEREST	Other	$10,101,507	$7,926,930	$7,000,000	$6,500,000	$4,900,000	$3,200,000	$3,200,000	$4,552,693
PURCHASED POWER & WHEELING	Other	$80,595,916	$90,057,495	$96,260,507	$92,730,507	$92,730,507	$92,730,507	$92,730,507	$92,816,206
RETIRE, REPLACE, ADDITIONS	Other	$85,000	$96,000	$0	$40,000	$0	$0	$0	$13,600
Depreciation	Other	$48,653	$49,869	$80,798	$83,222	$85,719	$88,291	$88,291	$82,935
POWER BILLING	O&M							$0	$0
C&RE	O&M	$166,674	$165,134	$192,059	$196,576	$201,228	$206,020	$206,020	$199,112
POWER MARKETING	O&M	$9,349,203	$9,059,346	$8,635,637	$8,779,809	$9,004,318	$9,235,563	$9,235,563	$9,089,249
GCPA(Non-reimb)	Environ							$0	$0
RIP (Non-reimb)	Environ	$1,570,690	$1,810,964	$1,750,372	$1,802,880	$1,856,964	$1,912,669	$1,912,669	$1,869,719
SYSTEM OPERATION & LOAD DISP	O&M	$0	$0	$0	$0	$0	$0	$0	$0
STATE OF COLORADO LOAN	O&M	($886,000)	($886,000)	($886,000)	($886,000)	($886,000)	($886,000)	($886,000)	($886,000)
MC TOTAL BUDGET		**$102,312,149**	**$109,629,271**	**$114,553,621**	**$110,808,085**	**$109,500,531**	**$108,156,950**	**$108,156,950**	**$109,343,321**
MC PRS O&M		**$9,910,383**	**$9,688,013**	**$9,461,944**	**$9,651,476**	**$9,927,341**	**$10,225,483**	**$10,225,483**	**$10,008,167**

ITEM	TYPE	Current Year 2015	1 2016	2 2017	3 2018	4 2019	5 2020	Future 10 Year Projection 2021-2025	10 Year Annual Average 2016-2025
TOTAL WESTERN									
GWA	O&M	$4,861,282	$5,034,291	$5,510,862	$5,676,187	$5,846,474	$6,021,867	$6,021,867	$5,819,902
O&M TRANSMISSION LINES	O&M	$10,720,272	$10,239,457	$10,134,866	$6,627,912	$6,826,749	$7,031,552	$7,031,552	$7,601,830
O&M SUBSTATIONS	O&M	$16,106,212	$16,892,547	$17,040,172	$17,551,377	$18,077,918	$18,620,257	$18,620,257	$18,128,356
OTHER EXPENSES	O&M	$2,293,580	$2,345,029	$2,162,695	$2,222,813	$2,289,368	$2,371,920	$2,371,920	$2,325,142
INTEREST	Other	$10,101,507	$7,926,930	$7,000,000	$6,500,000	$4,900,000	$3,200,000	$3,200,000	$4,552,693
PURCHASED POWER & WHEELING	Other	$80,595,916	$90,057,495	$96,260,507	$92,730,507	$92,730,507	$92,730,507	$92,730,507	$92,816,206
Depreciation	Other	$343,221	$370,459	$406,838	$419,043	$431,615	$444,564	$444,564	$429,534
RETIRE, REPLACE, ADDITIONS	Other	$19,852,903	$7,274,251	$10,111,020	$8,169,052	$8,269,614	$7,098,752	$7,098,752	$7,641,645
POWER BILLING	O&M	$315,664	$237,697	$274,264	$282,492	$290,967	$299,697	$299,697	$288,360
C&RE	O&M	$181,079	$174,462	$201,049	$205,835	$210,766	$215,844	$215,844	$208,717
POWER MARKETING	O&M	$10,337,240	$10,049,126	$9,614,468	$9,788,005	$10,042,760	$10,305,159	$10,305,159	$10,132,531
GCPA(Non-reimb)	Environ	$0	$0	$0	$0	$0	$0	$0	$0
RIP (Non-reimb)	Environ	$1,570,690	$1,810,964	$1,750,372	$1,802,880	$1,856,964	$1,912,669	$1,912,669	$1,869,719
SYSTEM OPERATION & LOAD DISP	O&M	$6,699,969	$6,933,223	$7,850,284	$8,085,792	$8,328,367	$8,578,217	$8,578,217	$8,266,697
STATE OF COLORADO LOAN	O&M	($886,000)	($886,000)	($886,000)	($886,000)	($886,000)	($886,000)	($886,000)	($886,000)
Western Budget		**$163,093,534**	**$158,459,932**	**$167,431,397**	**$159,175,896**	**$159,216,068**	**$157,945,004**	**$157,945,004**	**$159,195,332**
PRS O&M		**$50,629,297**	**$51,019,833**	**$51,902,660**	**$49,554,413**	**$51,027,369**	**$52,558,512**	**$52,558,512**	**$51,885,535**
CME Depreciation		**$745,000**	**$745,000**	**$745,000**	**$745,000**	**$745,000**	**$745,000**	**$745,000**	**$745,000**
Total WESTERN PRS O&M		**$51,374,297**	**$51,764,833**	**$52,647,660**	**$50,299,413**	**$51,772,369**	**$53,303,512**	**$53,303,512**	**$52,630,535**

BUREAU OF RECLAMATION **

Water and Egy Mgmt and Dvlp	0.00%	1,801,700	2,045,107	1,981,400	1,981,400	1,981,400	1,981,400	$1,981,400	$1,987,771
Land Mgmt and Dvlp	0.00%	585,040	602,591	620,669	639,289	658,468	678,222	$678,222	$659,035
Fish and WL Mgmt and Dvlp:									$0
GC Adaptive Mtmt Prg	0.00%	10,754,967	11,077,616	11,409,944	11,752,243	12,104,810	12,467,954	$12,467,954	$12,115,234
Endangered fish (RIP) base funding	0.00%	8,172,285	8,417,454	8,669,977	8,930,076	9,197,979	9,473,918	$9,473,918	$9,205,899
Endangered fish (RIP) capital	0.00%	$0	$0	$0	$0	$0	$0	$0	$0
Flaming Gorge studies	90.00%	$0	$0	$0	$0	$0	$0	$0	$0
Glen Canyon Studies	0.00%	$0	$0	$0	$0	$0	$0	$0	$0
Navajo studies	83.00%	$0	$0	$0	$0	$0	$0	$0	$0
Aspinall studies	97.00%	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal Budget		$21,313,992	$22,142,768	$22,681,991	$23,303,008	$23,942,657	$24,601,494	$24,601,494	$23,967,939
Total PRS O&M		$0	$0	$0	$0	$0	$0	$0	$0

ITEM	TYPE	Current Year 2015	1 2016	2 2017	3 2018	4 2019	5 2020	Future 10 Year Projection 2021-2025	10 Year Annual Average 2016-2025
Water Operations:									
Navajo	83.00%	1,576,191	1,623,477	1,672,181	1,722,346	1,774,017	1,827,237	$1,699,242	$1,711,547
Blue Mesa	97.00%	794,577	818,414	842,967	868,256	894,303	921,133	$856,608	$862,811
Crystal	100.00%	618,044	636,585	655,683	675,353	695,614	716,482	$666,294	$671,118
Morrow Point	100.00%	687,592	708,220	729,466	751,350	773,891	797,108	$741,271	$746,639
Flaming Gorge	90.00%	862,656	888,536	915,192	942,648	970,927	1,000,055	$930,002	$936,737
Glen Canyon	62.20%	2,442,597	2,515,875	2,591,351	2,669,092	2,749,164	2,831,639	$2,633,286	$2,652,355
Subtotal Budget		$6,981,657	$7,191,107	$7,406,840	$7,629,045	$7,857,916	$8,093,654	$8,093,654	$7,864,683
Total PRS O&M (88%)		$5,680,300	$5,850,709	$6,026,230	$6,207,017	$6,393,227	$6,585,025	$6,123,751	$6,168,097
Power Operations:									
Subtotal Budget		20,596,421	21,214,313	21,850,743	22,506,265	23,181,453	23,876,897	$23,876,897	$23,201,415
Total PRS O&M		$20,596,421	$21,214,313	$21,850,743	$22,506,265	$23,181,453	$23,876,897	$23,876,897	$23,201,415
Miscellaneous:	100.00%	643,484	673,503	693,708	714,519	735,955	758,033	$758,033	$736,588
Security:		3,591,012	3,737,416	3,731,919	3,839,827	3,950,971	4,065,451	$4,065,451	$3,965,284
Reimbursable	70.00%	$2,513,708	$2,616,191	$2,612,343	$2,687,879	$2,765,680	$2,845,815	$2,845,815	$2,775,699
Additional OM&R (MOA Revenue)	0.00%	$11,500,000	$11,500,000	$11,500,000	$11,500,000	$11,500,000	$11,500,000	$11,500,000	$11,500,000
Total PRS O&M (Already in as Misc)	0.00%	$0	$0	$0	$0	$0	$0	$0	$0
Extraordinary Maintenance:									
Expensed									
Navajo	83.00%	250,000	330,000	130,000	150,000	0	0	$143,333	$132,667
Blue Mesa	97.00%	24,169	0	0	25,000	750,000	20,000	$136,528	$147,764
Morrow Point	100.00%	150,000	0	60,000	200,000	30,000	345,000	$130,833	$128,917
Crystal	100.00%	140,000	20,000	60,000	0	70,000	605,000	$149,167	$150,083
Flaming Gorge	90.00%	360,000	360,000	0	50,000	150,000	0	$153,333	$132,667
Glen Canyon	62.00%	100,000	25,000	1,000,000	1,000,000	4,000,000	600,000	$1,120,833	$1,222,917
Denver	97.00%	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal Budget		$1,024,169	$735,000	$1,250,000	$1,425,000	$5,000,000	$1,570,000	$1,834,028	$1,915,014
Total PRS O&M		$980,944	$678,900	$847,900	$1,013,750	$3,442,500	$1,341,400	$1,364,316	$1,414,603

ITEM	TYPE	Current Year 2015	1 2016	2 2017	3 2018	4 2019	5 2020	Future 10 Year Projection 2021-2025	10 Year Annual Average 2016-2025
Capitalized									
Navajo	83.00%	422,911	235,000	1,700,000	900,000	0	0	$542,985	$554,993
Blue Mesa	97.00%	0	0	0	0	0	0	$0	$0
Morrow Point	100.00%	0	0	100,000	342,000	0	0	$73,667	$81,033
Crystal	100.00%	0	0	0	0	0	0	$0	$0
Flaming Gorge	90.00%	40,000	520,000	580,000	1,000,000	0	0	$356,667	$388,333
Glen Canyon	90.00%	2,000,000	1,900,000	500,000	500,000	2,000,000	1,400,000	$1,383,333	$1,321,667
Denver	97.00%	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal Budget		$2,462,911	$2,655,000	$2,880,000	$2,742,000	$2,000,000	$1,400,000	$2,356,652	$2,346,026
Total PRS O&M		$2,187,016	$2,373,050	$2,483,000	$2,439,000	$1,800,000	$1,260,000	$2,090,344	$2,080,677
Replacements:									
Expensed									
Blue Mesa	99.00%	0	0	0	0	0	0	$0	$0
Morrow Point	100.00%	0	0	50,000	300,000	100,000	0	$75,000	$82,500
Crystal	100.00%	0	0	0	0	0	0	$0	$0
Curecanti	100.00%	0	0	150,000	0	0	0	$25,000	$27,500
Flaming Gorge	90.00%	110,000	0	0	510,000	65,000	0	$114,167	$114,583
Glen Canyon	90.00%	100,000	80,000	30,000	0	0	0	$35,000	$28,500
Denver	50.00%	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal Budget		$210,000	$80,000	$230,000	$810,000	$165,000	$0	$249,167	$253,083
Total PRS O&M		$189,000	$72,000	$227,000	$760,000	$158,500	$0	$234,250	$238,875
Capitalized									
Blue Mesa	99.00%	4,950,000	4,550,000	4,560,000	4,145,000	650,000	155,000	$3,168,333	$2,990,167
Morrow Point	100.00%	3,050,000	1,150,000	1,110,000	5,980,000	5,510,000	850,000	$2,941,667	$2,930,833
Crystal	100.00%	649,000	0	0	1,080,000	500,000	2,250,000	$746,500	$756,250
Curecanti	99.00%	35,000	90,000	435,000	40,000	255,000	170,000	$170,833	$184,417
Flaming Gorge	99.00%	50,000	325,000	115,000	515,000	640,000	2,425,000	$678,333	$741,167
Glen Canyon	99.00%	13,375,000	20,860,000	19,010,000	9,950,000	9,500,000	500,000	$12,199,167	$12,081,583
Denver	50.00%							$0	$0
UCPO Modernize Plant Controls	100.00%	$150,000	$500,000	$2,200,000	$9,500,000	$3,550,000	$3,350,000	$3,208,333	$3,514,167
Subtotal Budget		$22,259,000	$27,475,000	$27,430,000	$31,210,000	$20,605,000	$9,700,000	$23,113,167	$23,198,583
Total PRS O&M		$22,074,900	$27,216,750	$27,188,800	$31,063,500	$20,494,550	$9,667,500	$22,951,000	$23,038,610
Total Reclamation Budget		$79,082,646	$85,904,107	$88,155,200	$94,179,664	$87,438,952	$74,065,529	$88,948,542	$87,448,616
Reclamation CME DEPRECIATION		$0	$0	$0	$0	$0	$0	$0	$0

ITEM	TYPE	Current Year 2015	1 2016	2 2017	3 2018	4 2019	5 2020	Future 10 Year Projection 2021-2025	10 Year Annual Average 2016-2025
Total USBR O&M Reimbursable by power		**$30,603,857**	**$31,105,617**	**$32,257,924**	**$33,889,430**	**$36,677,315**	**$35,407,170**	**$35,203,062**	**$34,535,277**
Total WAPA and USBR PRS O&M		**$81,978,155**	**$82,870,449**	**$84,905,585**	**$84,188,843**	**$88,449,684**	**$88,710,682**	**$88,506,574**	**$87,165,811**
Environmental Costs:									
Western									
GCPA (Non-reimb)	0.00%	$0	$0	$0	$0	$0	$0	$0	$0
RIP(Non-reimb)	0.00%	$1,570,690	$1,810,964	$1,750,372	$1,802,880	$1,856,964	$1,912,669	$1,912,669	$1,869,719
USBR									
Fish and Wildlife Mgmt and Dvlp:									
Nonreimbursable									
GC Adaptive Mgmt Prg	0.00%	$10,754,967	$11,077,616	$11,409,944	$11,752,243	$12,104,810	$12,467,954	$12,467,954	$12,115,234
Endangered fish (RIP) base funding	0.00%	$8,172,285	$8,417,454	$8,669,977	$8,930,076	$9,197,979	$9,473,918	$9,473,918	$9,205,899
Glen Canyon Studies	0.00%	$0	$0	$0	$0	$0	$0	$0	$0
Total non-reimbursable		$20,497,942	$21,306,034	$21,830,294	$22,485,199	$23,159,753	$23,854,542	$23,854,542	$23,190,853
Reimbursable									
Flaming Gorge studies	90.00%	$0	$0	$0	$0	$0	$0	$0	$0
Navajo studies	97.00%	$0	$0	$0	$0	$0	$0	$0	$0
Aspinall studies	83.00%	$0	$0	$0	$0	$0	$0	$0	$0
Endangered fish (RIP) capital	0.00%	$0	$0	$0	$0	$0	$0	$0	$0
Total reimbursable as O&M		$0	$0	$0	$0	$0	$0	$0	$0

Note: Gray Shaded amounts are not included in PRS O&M.

OPERATIONS AND MAINTENANCE COSTS - OFA INPUTS

			Data									
POWER SYS	Project Number	FUND	Sum of FY12	Sum of FY13	Sum of FY14	Sum of FY15	Sum of FY16	Sum of FY17	Sum of Out Yr 1	Sum of Out Yr 2	Sum of Out Yr 3	Sum of Out Yr 4
LLCO	%WES M-WMA	WMA	$ 13,450	$ 13,508	$ 13,937	19087	16162	$ 16,546	$ 16,967	$ 17,401	$ 17,848	$ 18,309
	CLB 001B	WMF	$ 50,000	$ 293,000	$ -	0	0		$ -	$ -	$ -	$ -
	N/FLCO GWAMM-WM	WMA	$ 1,198	$ 1,349	$ 1,336	930.06	1593.49	$ 1,667	$ 1,717	$ 1,768	$ 1,821	$ 1,876
	N/FLCO MRKTM-WMA	WMA	$ 8,874	$ 7,426	$ 6,064	4303	6095.63	$ 6,470	$ 6,653	$ 6,842	$ 7,037	$ 7,237
	N/FLCO NDUE1	WMA	$ -	$ -	$ 20,332	56915	0		$ -	$ -	$ -	$ -
	UM LM WES M-WMA	WMA	$ 15,450	$ 15,508	$ 16,937	15087	17662	$ 18,046	$ 18,467	$ 18,901	$ 19,348	$ 19,809
LLCO Total			$ 88,972	$ 330,791	$ 58,606	96322.06	41513.12	$ 42,728	$ 43,805	$ 44,913	$ 46,055	$ 47,231
LLCR	MOC%	VMF	$ -	$ -	$ -	10000	0		$ -	$ -	$ -	$ -
	N/FLCR CAREM	VMF	$ 180,006	$ 179,171	$ 163,663	166674	165134	$ 202,059	$ 208,121	$ 214,364	$ 220,795	$ 227,419
	N/FLCR DEPR-M	VMF	$ 75,000	$ 60,000	$ 45,300	48653	49869	$ 80,183	$ 80,798	$ 83,222	$ 85,719	$ 88,290
	N/FLCR GWAMM	VMF	$ 1,032,047	$ 1,108,517	$ 1,123,757	1269592.51	1299308.98	$ 1,481,781	$ 1,526,234	$ 1,572,021	$ 1,619,182	$ 1,667,757
	N/FLCR KPPWW	RPF	$ 28,357,624	$ 40,025,000	$ 29,030,000	20330000	20350000	$ 25,030,000	$ 25,030,000	$ 25,030,000	$ 25,030,000	$ 25,030,000
	N/FLCR MOVP1	VMF	$ 50,000	$ 50,000	$ 50,000	85000	96000		$ 40,000	$ -	$ -	$ -
	N/FLCR MRKTM	VMF	$ 10,067,829	$ 9,511,207	$ 8,451,828	8965458	8690527.59	$ 8,335,757	$ 8,470,932	$ 8,686,176	$ 8,907,876	$ 9,136,227
	N/FLCR NDUE1	VMF	$ 7,626,609	$ 7,512,607	$ 4,310,053	10101507	7926930	$ 4,990,966	$ 4,565,020	$ 2,912,190	$ 1,377,578	$ 1,008,074
	N/FLCR NRMBM	VMF	$ 1,415,391	$ 1,690,591	$ 1,581,932	1570690	1810964	$ 1,750,372	$ 2,044,880	$ 2,077,334	$ 2,110,761	$ 2,145,190
	N/FLCR PPW1W	VMF	$ 100,650,000	$ 81,750,000	$ 67,900,000	71500000	80390000	$ 85,840,000	$ 82,310,000	$ 82,310,000	$ 82,310,000	$ 82,310,000
	N/FLCR PPW4W	VMF	$ 10,520,327	$ 9,500,000	$ 9,443,280	9095916	9657495	$ 10,420,507	$ 10,420,507	$ 10,420,507	$ 10,420,507	$ 10,420,507
	N/FLCR PWMKT	VMF	$ 240,938	$ 217,000	$ 382,633	383745	391118	$ 299,880	$ 308,876	$ 318,143	$ 327,687	$ 337,518
	N/FLCR SAFEM	VMF	$ 10,832	$ 15,866	$ 12,000	10913	30224	$ 18,467	$ 14,257	$ 14,556	$ 28,863	$ 15,180
	N/FLCR TRANM	VMF	$ -	$ -	$ -	0	20000	$ 20,000	$ 20,600	$ 21,218	$ 21,855	$ 22,510
LLCR Total			$ 160,226,603	$ 151,619,959	$ 122,494,446	123538148.5	130877570.6	$ 138,469,971	$ 135,040,226	$ 133,659,730	$ 132,460,822	$ 132,408,673
LLDO	%WESM	VMF	$ 68,398	$ 68,706	$ 71,998	74798	86858	$ 90,918	$ 93,166	$ 95,481	$ 97,865	$ 100,321
	N/FLDO GWAMM	VMF	$ 1,198	$ 1,349	$ 1,336	930.06	1593.49	$ 2,024	$ 2,085	$ 2,147	$ 2,212	$ 2,278
	N/FLDO MRKTM	VMF	$ 8,457	$ 7,426	$ 6,064	4868	6095.63	$ 6,470	$ 6,653	$ 6,842	$ 7,037	$ 7,237
	N/FLDO NDUE1	VMF	$ 2,090,445	$ 2,051,897	$ 2,127,696	1889154	1784490	$ 1,831,182	$ 1,803,428	$ 1,775,724	$ 1,746,289	$ 1,715,015
	various	VMF	$ -	$ -	$ -	2000	22000	$ 20,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000
	(blank)	VMF	$ -	$ -	$ -	215000	588200		#VALUE!	$ -	$ -	$ -
LLDO Total			$ 2,168,498	$ 2,129,378	$ 2,207,094	2186750.06	2489237.12	$ 1,950,594	#VALUE!	$ 1,900,194	$ 1,873,402	$ 1,844,851
LLGF	N/FLGF AAGEA	RAF	$ 1,237,066	$ 1,186,249	$ 1,234,041	1156379	1301812	$ 1,996,867	$ 2,055,809	$ 2,116,521	$ 2,179,053	$ 2,243,462
	N/FLGF DATAA	RAF	$ 456,978	$ 515,600	$ 364,128	119400	62800	$ 104,200	$ 105,166	$ 106,161	$ 107,186	$ 108,241
LLGF Total			$ 1,694,044	$ 1,701,849	$ 1,598,169	1275779	1364612	$ 2,101,067	$ 2,160,975	$ 2,222,682	$ 2,286,239	$ 2,351,703
LLRG	N/FLRG GWAMM-WM	WMA	$ 1,198	$ 1,686	$ 1,336	930.06	1593.49	$ 2,024	$ 2,085	$ 2,147	$ 2,212	$ 2,278
	N/FLRG MRKTM-WMA	WMA	$ 10,765	$ 9,526	$ 8,064	6868	6095.63	$ 6,470	$ 6,653	$ 6,842	$ 7,037	$ 7,237
	N/FLRG NDUE1	WMA	$ -	$ 181	$ 638	61053	9498	$ 115,863	$ 117,391	$ 118,966	$ 121,354	$ 123,859
	N/FLRG SUBSM-WMA	WMA	$ 5,150	$ 5,169	$ 5,312	6363	7555	$ 7,682	$ 7,822	$ 7,967	$ 8,116	$ 8,270
LLRG Total			$ 17,113	$ 16,562	$ 15,350	75214.06	24742.12	$ 132,039	$ 133,951	$ 135,922	$ 138,718	$ 141,644
LLSE	% WES1M or WESM	VMF	$ 24,899	$ 25,014	$ 25,874	29174	30322	$ 31,094	$ 31,937	$ 32,805	$ 33,699	$ 34,620
	N/FLSE COMMM	VMF	$ 24,899	$ 25,014	$ 25,874	26174	28322	$ 28,094	$ 28,937	$ 29,805	$ 30,699	$ 31,620
	N/FLSE GWAMM	VMF	$ 1,663	$ 1,876	$ 522	619.37	1489.31	$ 2,143	$ 2,207	$ 2,273	$ 2,342	$ 2,412
	N/FLSE MRKTM	VMF	$ 14,340	$ 13,088	$ 5,651	5665	8844.84	$ 9,081	$ 9,339	$ 9,605	$ 9,879	$ 10,161
	N/FLSE NDUE1	VMF	$ -	$ 96,318	$ 136,965	5377	8101	$ 22,268	$ 2,540	$ -	$ -	$ -
	various	VMF	$ -	$ -	$ -	0	3000	$ 4,000	$ 4,000	$ 4,000	$ 4,000	$ 4,000
LLSE Total			$ 65,801	$ 161,310	$ 194,886	67009.37	80079.15	$ 96,680	$ 78,960	$ 78,488	$ 80,619	$ 82,813
LLOM	(blank)	VMF										
LLOM Total												
Grand Total			$ 164,261,032	$ 155,959,848	$ 126,568,551	127239223.1	134877754.1	$ 142,793,078	#VALUE!	$ 138,041,929	$ 136,885,856	$ 136,876,915

Salt Lake City Area Integrated Projects

Purchased Power Comparisons

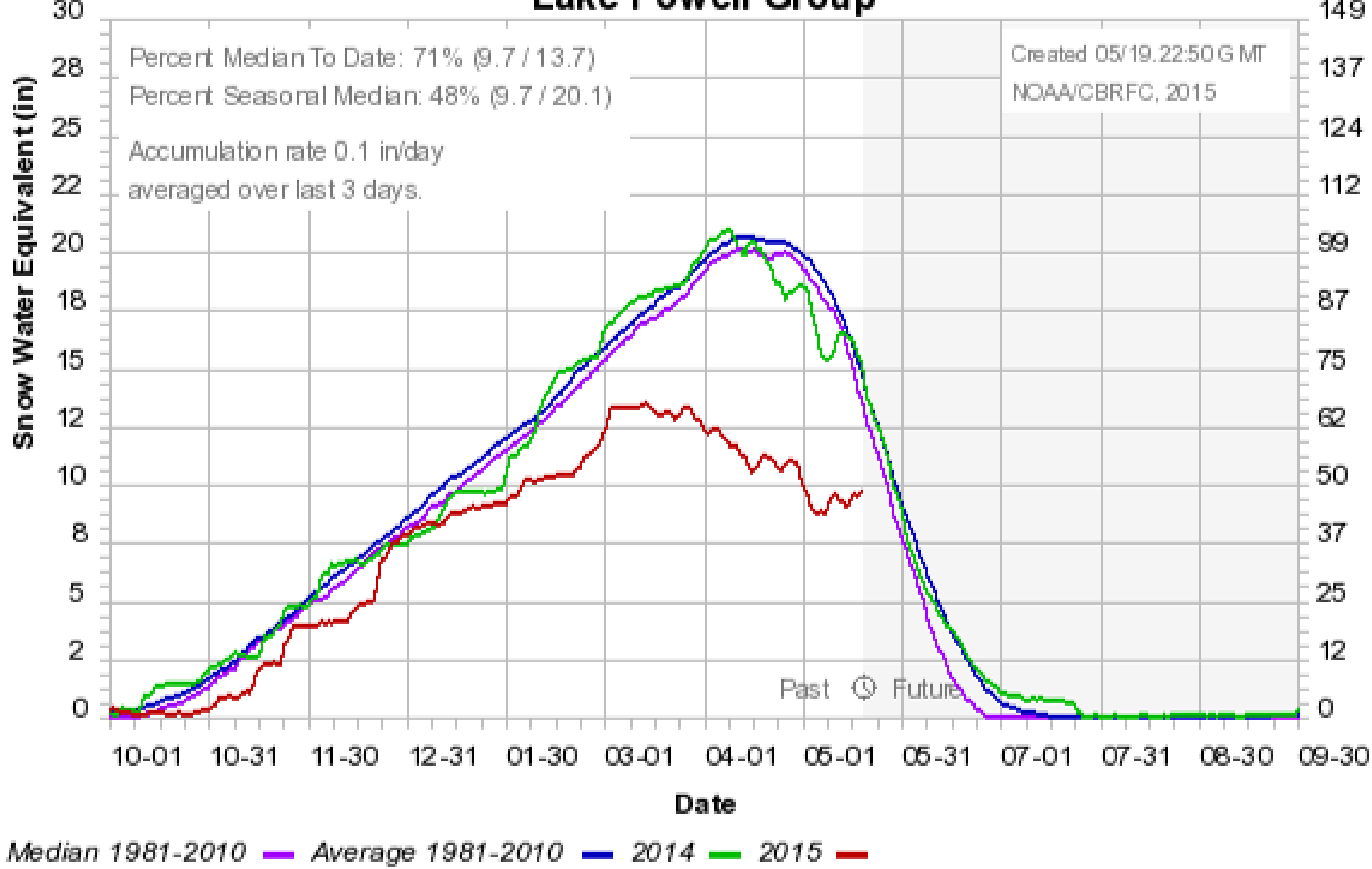
	Step 2 Rate 1/			FY 2015 Preliminary 2/			Expense Difference
	Purchases	Price	Expense	Purchases	Price	Expense 3/	
FY	(MWH)	($/MWH)	($1,000)	(MWH)	($/MWH)	($1,000)	($1,000)
2011	340,481	49.14	16,730			$ 37,376	$ 20,646
2012	222,887	50.20	11,190			$ 32,783	$ 21,593
2013	144,999	46.14	6,690			$ 66,290	$ 59,600
2014	N/A	N/A	4,000			$ 78,037	$ 74,037
2015	N/A	N/A	4,000	530,065	$ 31.84	$ 24,486	$ 20,486
2016	N/A	N/A	4,000	1,030,922	$ 27.59	$ 28,440	$ 24,440
2017	N/A	N/A	4,000	609,284	$ 29.54	$ 18,000	$ 14,000
2018	N/A	N/A	4,000	518,408	$ 31.13	$ 16,140	$ 12,140
2019	N/A	N/A	4,000	490,748	$ 33.03	$ 16,210	$ 12,210
2020	N/A	N/A	4,000	N/A	N/A	$ 4,000	$ -
2021	N/A	N/A	4,000	N/A	N/A	$ 4,000	$ -
2022	N/A	N/A	4,000	N/A	N/A	$ 4,000	$ -
2023	N/A	N/A	4,000	N/A	N/A	$ 4,000	$ -
2024	N/A	N/A	4,000	N/A	N/A	$ 4,000	$ -
2025	N/A	N/A	4,000	N/A	N/A	$ 4,000	$ -
Average 2011-2025			5,507	Average 2015-2025		$ 11,570.53	$ 6,063

1/ 2011-2013 projections based on Reclamation's 2009 median hydrology.

2/ 2015-2019 is based on projected costs using the April 2015 24-month study.
2019 on included $4 million for administrative merchant function activities.

3/ Expenses are net of sales above SHP.

Colorado Basin River Forecast Center
Lake Powell Group



TAB-9-0

Salt Lake City Integrated Projects

unit: 1,000

Average Annual Transmission Expense Comparison

Item	Step 2 Rate	FY 2015 Preliminary	Difference
Total Transmission Expense	$ 10,525	$ 10,421	$ (104)

PROJECTED CRSP TRANSMISSION EXPENSE

Table consistantly reviewed and updated. Last review December 2014

Customer	Contract Number	Contract Expiration Date	Unit	2015	2016	2017	2018	2019
APS	14-06-400-3654	6/1/2046	kW	150,000	150,000	150,000	150,000	150,000
			$	$ -	$ -	$ -	$ -	$ -
Black Hills/Colorado Electric Utility Company, LP	13-SLC-0682	9/30/2024	kW	8,000	8,000	8,000	8,000	8,000
			$	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000
Bridger Valley 1/	14-06-400-1011	**9/30/2044 (or upon 3 years notice by either party)**	kW	5,306,912	5,306,912	5,306,912	5,306,912	5,306,912
	9/30/2044	Rates revised yearly on March 1. Rate adjustments are based on operating cost of the transmission system.	$	$ 15,655	$ 15,655	$ 15,655	$ 15,655	$ 15,655
Delta-Montrose 2/	14-06-400-4447	**Expired in March 2003, but continuing on indefinitely, due to the inability to develop an agreeable alternative service plan.**	kW	507	507	507	507	507
		Delta-Montrose transmission charge equals CRSP firm transmission rate currently in effect.	$	$ 6,753	$ 6,753	$ 6,753	$ 6,753	$ 6,753
Deseret G&T 3/ (Exhibit D)	2-07-40-P0716	**6/1/2053, after June 1, 2022, either party can terminate by providing 5 years notice.**	kW	83,000	83,000	83,000	83,000	83,000
	Transmission Cost is variable. Transmission service request is usually for a 3-4 year period. Transmission request is handled in a revision to an Exhibit of this Contract. Revised effective 10/1/2013		$	$ 2,562,974	$ 2,562,974	$ 2,562,974	$ 2,562,974	$ 2,562,974
	Deseret will provide Western w/83MW of trans. & transfrmtn. Deseret will chg. Western their trans. Rate of $30.8792/kW-year & $2.22/kw-year for transformation.							
DSWR (Intertie) **4/**	88-BCA-10149	**9/30/2017. However, CRSP MC can terminate with 30 days notice.**	kW	134,000	134,000	134,000	134,000	134,000
		Transmission charge is as set at the Intertie rate schedule (INT-FT4).	$	$ 2,588,880	$ 2,588,880	$ 2,588,880	$ 2,588,880	$ 2,588,880

PROJECTED CRSP TRANSMISSION EXPENSE

Table consistantly reviewed and updated. Last review December 2014

Customer	Contract Number	Contract Expiration Date	Unit	2015	2016	2017	2018	2019
El Paso Electric	05-SLC-0578	9/30/2024	kW	2,000	2,000	2,000	2,000	2,000
		This is a pass-through for both rev & exp. through Holloman AFB	$	$ -	$ -	$ -	$ -	$ -
Empire Electric	91-SLC-0170	**11/22/2041**	kW	12,000	12,000	12,000	12,000	12,000
		Cost based rate revised yearly. Western pays an annual charge: 1/6 of the total each month from April to September.	$	$ 20,820	$ 20,820	$ 20,820	$ 20,820	$ 20,820
	7-07-40-P0752	5/15/2037	kW	8,000	8,000	8,000	8,000	8,000
		Cost based rate revised yearly. Western pays an annual charge: 1/6 of the total each month from April to September.	$	$ 82,305	$ 82,305	$ 82,305	$ 82,305	$ 82,305
Public Service Company of CO 5/	8-07-40-PO695	**9/30/2030. After 9/30/2010, can be terminated by either party with 3 years notice.**	kW	14,500	14,500	14,500	14,500	14,500
		Rate adjustment occurs upon adjustment to PSCO's published rate schedule for firm transmission.	$	$ 274,920	$ 274,920	$ 274,920	$ 274,920	$ 274,920
Public Service Company of NM 6/	8-07-40-P0695	**Contract expired on 6/1/1987. (Subject to 10 yr ext up to 2047) Western has option of six 10-year extensions. Western provides notice 3 years prior to the expiration of the contracts. This contract has been extended to 2017.**	kW	107,000	107,000	107,000	107,000	107,000
Rate is set in contract at $2.13. Actual rate will be $1.22/kW after various credits are provided for seasonal scheduling diversity and credit for Western providing 50 MW of Intertie transmission. Rate can be changed if PNM files for a rate change. If things really change, the rate goes to $1.71/kWM & the intertie expense will drop by 40% & PTP revs will go up by $1.8m. Currently @ $1.30/KwM with an avg. of 107MW for Winter and 97MW for summer giving an avg. of 99MW.			$ 1.30	$ 1,669,200	$ 1,669,200	$ 1,669,200	$ 1,669,200	$ 1,669,200

PROJECTED CRSP TRANSMISSION EXPENSE

Table consistantly reviewed and updated. Last review December 2014

Customer	Contract Number	Contract Expiration Date	Unit		2015		2016		2017		2018		2019
Pacificorp 7/ - Looked through the last years invoices. Nothing over 330MW.	14-06-400-2436	**Contract expired on 6/1/1987. (Subject to 10 yr ext up to 2047) Western has option of six 10-year extensions. Western provides notice 3 years prior to the expiration of the contracts. This contract has been extended to 2017**											
Flat Charge		$600,000/yr for terminating Cal-Pac agreement. Payments continues through the life of the Contract	$	$	600,000	$	600,000	$	600,000	$	600,000	$	600,000
First Tier		$4.20/kW-year, fixed for term of Contract	kW		230,000		230,000		230,000		230,000		230,000
			$	$	966,000	$	966,000	$	966,000	$	966,000	$	966,000
Second Tier		$15.83year (We do not know when the $14.70 second tier rate will occur. PacifiCorp has let the issue go for now. Continue with the current $11.96 rate). Revised every 3 years, based on complicated rate escalation methodology. The methodology is included as Exhibit C to this contract. Last rate change was April 2001.	kW		100,000		100,000		100,000		100,000		100,000
			$	$	1,583,000	$	1,583,000	$	1,583,000	$	1,583,000	$	1,583,000
Third Tier		OATT rate. Rate changes upon publication of new rate.	kW		0		0		0		0		0
			$	$	-	$	-	$	-	$	-	$	-
Total UP&L			kW		330,000		330,000		330,000		330,000		330,000
			$	$	3,149,000	$	3,149,000	$	3,149,000	$	3,149,000	$	3,149,000
Salt River Project	08-SLC-0615	6/30/2018											
			kW		50,000		50,000		50,000		50,000		50,000
			$	$	-	$	-	$	-	$	-	$	-
Total transmission expense			$	$	10,420,507	$	10,420,507	$	10,420,507	$	10,420,507	$	10,420,507

1/ Bridger Valley wheels power @ $.00227/kWh. Number of kWh in a year varies.
2/ Delta Montrose wheels power to the Montrose Operations Center @ $27.96/kW-year (new rate 10/01/03). Since this line serves both power and transmission operations its costs are allocated between power and transmission on the same basis as O&M is allocated.
3/ Deseret G&T provides Western 22,048 KW to Bonanza @ $2.22/kW-year and 118,510 kW between Bonanza and Vernal and 1,000 kW between Bonanza and UPALCO @ $30.88/kW-year.
4/ 134,000 kW is wheeled between Westwing and Pinnacle Peak for SLCA/IP @ $15.24/kW-year.
5/ PSCO only wheels 13,500 @ $18.96/kW-year for the Collbran Project and 750 kW for Silt; 14,250 kW.
6/ PNM wheels from Four Corners to Albuquerque @ $1.30 per kW/Month.
The 99000 KW represents the average of 107,000kW for the Winter and 91,000kW for the summer @$1.30/kW-month times 12 months.
7/ UP&L principles for amending 2436 in effect 10-1-87 include a flat charge and a three tier rate. The charges are as follows:

a) $600,000 flat charge
b) $4.20/kW-year for the first 230 MW
c) $11.96/kW-year for the next 100 MW
d) $24.30/kW-year for over 330 MW

File: SLIP
Date: 5/15/15
Analyst: Henriquez

Participating Integrated Projects

	Dolores							Seedskadee						
Year	Sales	Revenues	Expenses	Interest	Repayment	RR	Surplus	Sales	Revenues	Expenses	Interest	Repayment	RR	Surplus
UNIT---->	MWH	$	$	$	$	$	$	MWH	$	$	$	$	$	$
1988	0	0	0	0	0	0	0	**(357)**	**(3,108)**	306,409	**189,840**	**0**	496,249	-499,357
1989	0	0	0	0	0	0	0	**21,715**	**214,490**	418,752	**241,628**	**0**	660,380	-445,890
1990	0	0	0	0	0	0	0	**54,462**	**430,312**	356,145	**466,981**	**0**	823,126	-392,814
1991	0	0	0	0	0	0	0	**57,634**	**728,922**	430,575	**506,557**	**0**	937,132	-208,210
1992	0	0	0	0	0	0	0	**43,272**	**622,900**	367,510	**527,211**	**0**	894,721	-271,821
1993	0	0	0	0	0	0	0	**49,584**	**240,411**	434,389	**554,059**	**0**	988,448	-748,037
1994	0	0	0	0	0	0	0	**43,322**	**1,406,935**	380,791	**640,033**	**386,111**	1,406,935	0
1995	**11,950**	**1,876,736**	347,666	**1,340,258**	**188,813**	1,876,737	-1	**52,322**	**1,424,991**	504,249	**(438,442)**	**1,360,841**	1,426,648	-1,657
1996	**18,923**	**2,920,220**	426,124	**2,297,879**	**196,217**	2,920,220	0	**66,451**	**1,217,656**	394,596	**538,407**	**13,857**	946,860	270,796
1997	**9,052**	**3,084,638**	426,973	**2,210,948**	**446,717**	3,084,638	0	**66,024**	**1,206,283**	392,247	**536,887**	**277,982**	1,207,116	-833
1998	**17,337**	**2,911,559**	262,491	**2,484,812**	**164,256**	2,911,559	0	**74,063**	**2,248,405**	384,985	**470,580**	**1,392,442**	2,248,007	398
1999	**21,373**	**3,235,465**	238,424	**2,360,057**	**636,984**	3,235,465	0	**70,862**	**1,510,537**	303,630	**234,116**	**887,112**	1,424,858	85,679
2000	**28,127**	**2,894,923**	269,973	**2,269,738**	**355,212**	2,894,923	0	**59,144**	**1,384,025**	413,142	**236,187**	**767,744**	1,417,073	-33,048
2001	**23,456**	**2,766,549**	432,606	**2,449,206**	**0**	2,881,812	-115,263	**27,335**	**937,996**	445,909	**188,663**	**402,868**	1,037,440	-99,444
2002	**5,959**	**2,948,763**	335,235	**2,306,448**	**307,080**	2,948,763	0	**22,579**	**1,301,665**	398,287	**153,559**	**778,599**	1,330,445	-28,780
2003	**6,294**	**2,874,934**	392,962	**2,260,611**	**221,246**	2,874,819	115	**38,252**	**1,124,598**	463,975	**33,965**	**626,659**	1,124,599	-1
2004	**17,885**	**2,988,795**	251,627	**2,237,649**	**499,634**	2,988,910	-115	**42,331**	**1,014,123**	639,547	**1,378**	**373,199**	1,014,124	-1
2005	**20,005**	**2,921,844**	399,570	**2,179,516**	**342,758**	2,921,844	0	**63,356**	**1,154,975**	621,122	**9,269**	**510,308**	1,140,699	14,276
2006	**15,431**	**2,845,475**	213,197	**2,151,507**	**480,771**	2,845,475	0	**47,027**	**1,705,213**	674,556	**(6,636)**	**307,231**	975,151	730,062
2007	**8,249**	**2,959,291**	207,826	**2,096,781**	**654,684**	2,959,291	0	**37,494**	**1,082,246**	702,400	**(3,969)**	**(292,000)**	406,431	675,815
2008	**24,028**	**2,784,627**	539,065	**2,025,898**	**219,664**	2,784,627	0	**45,688**	**1,184,425**	680,755	**3,870**	**26,155**	710,780	473,645
2009	**19,152**	**3,214,372**	446,834	**2,169,152**	**598,386**	3,214,372	0	**55,245**	**(408,852)**	601,098	**(319)**	**(12,790)**	587,989	-996,841
2010	**18,391**	**3,850,995**	800,106	**2,090,005**	**960,884**	3,850,995	0	**34,348**	**929,572**	673,746	**187**	**1,152,596**	1,826,529	-896,957
2011	**21,019**	**3,158,541**	1,010,691	**2,189,874**	**0**	3,200,565	-42,024	**52,076**	**1,389,147**	999,594	**(31,308)**	**41,816**	1,010,102	379,045
2012	**19,660**	**3,328,365**	2,355	**2,019,915**	**1,304,912**	3,327,182	1,183	**53,693**	**455,410**	918,833	**(3,399)**	**(80,979)**	834,455	-379,045
2013	**9,545**	**3,047,401**	862,788	**1,809,897**	**333,875**	3,006,560	40,841	**33,461**	**3,002,908**	931,825	**2,673**	**318,497**	1,252,995	1,749,913
2014	**20,297**	**3,067,909**	416,411	**1,950,259**	**701,239**	3,067,909	0	**55,659**	**1,136,350**	934,423	**184,921**	**345,137**	1,464,481	-328,131
2015	**53,169**	**3,181,648**	672,088	**1,804,710**	**704,851**	3,181,649	-1	**40,871**	**1,891,777**	1,894,916	**(3,140)**	**1**	1,891,777	0
2016	**53,169**	**3,181,648**	724,898	**1,758,219**	**698,531**	3,181,648	0	**40,871**	**1,891,777**	968,146	**17,269**	**805,002**	1,790,417	101,360
2017	**53,169**	**3,181,648**	744,252	**1,712,510**	**724,886**	3,181,648	0	**40,871**	**1,891,777**	997,466	**17,269**	**825,000**	1,839,735	52,042
2018	**53,169**	**3,181,648**	764,798	**1,667,851**	**749,000**	3,181,649	-1	**40,871**	**1,891,777**	1,424,158	**17,332**	**442,000**	1,883,490	8,287
2019	**53,169**	**3,181,648**	785,956	**1,621,704**	**773,989**	3,181,649	-1	**40,871**	**1,891,777**	1,057,740	**27,454**	**806,584**	1,891,778	-1
2020	**53,169**	**3,181,648**	807,746	**1,574,015**	**799,888**	3,181,649	-1	**40,871**	**1,891,777**	1,089,240	**26,975**	**393,416**	1,509,631	382,146
2021	**53,169**	**3,181,648**	807,746	**1,524,047**	**849,855**	3,181,648	0	**40,871**	**1,891,777**	1,089,240	**17,269**	**0**	1,106,509	785,268
2022	**53,169**	**3,181,648**	807,746	**1,470,958**	**902,944**	3,181,648	0	**40,871**	**1,891,777**	1,089,240	**17,269**	**15,581**	1,122,090	769,687
2023	**53,169**	**3,181,648**	807,746	**1,414,553**	**959,349**	3,181,648	0	**40,871**	**1,891,777**	1,089,240	**17,269**	**0**	1,106,509	785,268
2024	**53,169**	**3,181,648**	807,746	**1,354,625**	**1,019,278**	3,181,649	-1	**40,871**	**1,891,777**	1,089,240	**17,269**	**47,185**	1,153,694	738,083
2025	**53,169**	**3,181,648**	807,746	**1,321,640**	**1,052,262**	3,181,648	0	**40,871**	**1,891,777**	1,089,240	**17,269**	**0**	1,106,509	785,268
2026	**53,169**	**3,181,648**	807,746	**1,286,596**	**1,087,307**	3,181,649	-1	**40,871**	**1,891,777**	1,089,240	**17,269**	**0**	1,106,509	785,268
2027	**53,169**	**3,181,648**	807,746	**1,218,674**	**1,155,229**	3,181,649	-1	**40,871**	**1,891,777**	1,089,240	**17,269**	**1,046**	1,107,555	784,222
2028	**53,169**	**3,181,648**	807,746	**1,146,509**	**1,227,394**	3,181,649	-1	**40,871**	**1,891,777**	1,089,240	**17,269**	**0**	1,106,509	785,268
2029	**53,169**	**3,181,648**	807,746	**1,069,836**	**1,304,066**	3,181,648	0	**40,871**	**1,891,777**	1,089,240	**17,269**	**50,933**	1,157,442	734,335

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Participating Integrated Projects

	Dolores							Seedskadee						
Year	**Sales**	**Revenues**	**Expenses**	**Interest**	**Repayment**	**RR**	**Surplus**	**Sales**	**Revenues**	**Expenses**	**Interest**	**Repayment**	**RR**	**Surplus**
UNIT---->	MWH	$	$	$	$	$	$	MWH	$	$	$	$	$	$
2030	**53,169**	**3,181,648**	807,746	**990,504**	**1,383,398**	3,181,648	0	**40,871**	**1,891,777**	1,089,240	**17,269**	**1,451**	1,107,960	783,817
2031	**53,169**	**3,181,648**	807,746	**906,226**	**1,467,677**	3,181,649	-1	**40,871**	**1,891,777**	1,089,240	**17,269**	**0**	1,106,509	785,268
2032	**53,169**	**3,181,648**	807,746	**814,552**	**1,559,350**	3,181,648	0	**40,871**	**1,891,777**	1,089,240	**17,269**	**0**	1,106,509	785,268
2033	**53,169**	**3,181,648**	807,746	**717,143**	**1,656,760**	3,181,649	-1	**40,871**	**1,891,777**	1,089,240	**17,269**	**71,108**	1,177,617	714,160
2034	**53,169**	**3,181,648**	807,746	**613,648**	**1,760,254**	3,181,648	0	**40,871**	**1,891,777**	1,089,240	**17,269**	**0**	1,106,509	785,268
2035	**53,169**	**3,181,648**	807,746	**503,689**	**1,870,214**	3,181,649	-1	**40,871**	**1,891,777**	1,089,240	**17,269**	**0**	1,106,509	785,268
2036	**53,169**	**3,181,648**	807,746	**386,860**	**1,987,042**	3,181,648	0	**40,871**	**1,891,777**	1,089,240	**17,269**	**6,051**	1,112,560	779,217
2037	**53,169**	**3,181,648**	807,746	**265,948**	**2,107,954**	3,181,648	0	**40,871**	**1,891,777**	1,089,240	**17,269**	**0**	1,106,509	785,268
2038	**53,169**	**3,181,648**	807,746	**146,332**	**2,227,570**	3,181,648	0	**40,871**	**1,891,777**	1,089,240	**17,269**	**910**	1,107,419	784,358
2039	**53,169**	**3,181,648**	807,746	**43,834**	**2,330,068**	3,181,648	0	**40,871**	**1,891,777**	1,089,240	**17,269**	**0**	1,106,509	785,268
2040	**53,169**	**3,181,648**	807,746	**481**	**19,488**	827,715	2,353,933	**40,871**	**1,891,777**	1,089,240	**17,269**	**0**	1,106,509	785,268
2041	**53,169**	**3,181,648**	807,746	**0**	**1,472,257**	2,280,003	901,645	**40,871**	**1,891,777**	1,089,240	**17,269**	**20,220**	1,126,729	765,048
2042	**53,169**	**3,181,648**	807,746	**0**	**77,344**	885,090	2,296,558	**40,871**	**1,891,777**	1,089,240	**17,269**	**541,506**	1,648,015	243,762
2043	**53,169**	**3,181,648**	807,746	**0**	**0**	807,746	2,373,902	**40,871**	**1,891,777**	1,089,240	**17,269**	**137,020**	1,243,529	648,248
2044	**53,169**	**3,181,648**	807,746	**0**	**84,303**	892,049	2,289,599	**40,871**	**1,891,777**	1,089,240	**17,269**	**0**	1,106,509	785,268
2045	**53,169**	**3,181,648**	807,746	**0**	**0**	807,746	2,373,902	**40,871**	**1,891,777**	1,089,240	**17,269**	**0**	1,106,509	785,268
2046	**53,169**	**3,181,648**	807,746	**0**	**2,710**	810,456	2,371,192	**40,871**	**1,891,777**	1,089,240	**17,269**	**0**	1,106,509	785,268
2047	**53,169**	**3,181,648**	807,746	**0**	**0**	807,746	2,373,902	**40,871**	**1,891,777**	1,089,240	**17,269**	**18,459**	1,124,968	766,809
2048	**53,169**	**3,181,648**	807,746	**0**	**4,327**	812,073	2,369,575	**40,871**	**1,891,777**	1,089,240	**17,269**	**0**	1,106,509	785,268
2049	**53,169**	**3,181,648**	807,746	**0**	**106,045**	913,791	2,267,857	**40,871**	**1,891,777**	1,089,240	**17,269**	**42,023**	1,148,532	743,245
2050	**53,169**	**3,181,648**	807,746	**0**	**4,711**	812,457	2,369,191	**40,871**	**1,891,777**	1,089,240	**17,269**	**0**	1,106,509	785,268
2051	**53,169**	**3,181,648**	807,746	**0**	**0**	807,746	2,373,902	**40,871**	**1,891,777**	1,089,240	**17,269**	**0**	1,106,509	785,268
2052	**53,169**	**3,181,648**	807,746	**0**	**0**	807,746	2,373,902	**40,871**	**1,891,777**	1,089,240	**17,269**	**0**	1,106,509	785,268
2053	**53,169**	**3,181,648**	807,746	**0**	**0**	807,746	2,373,902	**40,871**	**1,891,777**	1,089,240	**17,269**	**0**	1,106,509	785,268
2054	**53,169**	**3,181,648**	807,746	**0**	**1,101,289**	1,909,035	1,272,613	**40,871**	**1,891,777**	1,089,240	**17,269**	**0**	1,106,509	785,268
2055	**53,169**	**3,181,648**	807,746	**0**	**0**	807,746	2,373,902	**40,871**	**1,891,777**	1,089,240	**17,269**	**177,342**	1,283,851	607,926
2056	**53,169**	**3,181,648**	807,746	**0**	**0**	807,746	2,373,902	**40,871**	**1,891,777**	1,089,240	**17,269**	**0**	1,106,509	785,268
2057	**53,169**	**3,181,648**	807,746	**0**	**0**	807,746	2,373,902	**40,871**	**1,891,777**	1,089,240	**17,269**	**346,941**	1,453,450	438,327
2058	**53,169**	**3,181,648**	807,746	**0**	**0**	807,746	2,373,902	**40,871**	**1,891,777**	1,089,240	**17,269**	**0**	1,106,509	785,268
2059	**53,169**	**3,181,648**	807,746	**0**	**23,921**	831,667	2,349,981	**40,871**	**1,891,777**	1,089,240	**17,269**	**47,185**	1,153,694	738,083
2060	**53,169**	**3,181,648**	807,746	**0**	**34,061**	841,807	2,339,841	**40,871**	**1,891,777**	1,089,240	**17,269**	**5,388**	1,111,897	779,880
2061	**53,169**	**3,181,648**	807,746	**0**	**106,045**	913,791	2,267,857	**40,871**	**1,891,777**	1,089,240	**17,269**	**17,960**	1,124,469	767,308
2062	**53,169**	**3,181,648**	807,746	**0**	**0**	807,746	2,373,902	**40,871**	**1,891,777**	1,089,240	**17,269**	**146**	1,106,655	785,122
2063	**53,169**	**3,181,648**	807,746	**(692)**	**22,813**	829,867	2,351,781	**40,871**	**1,891,777**	1,089,240	**17,269**	**0**	1,106,509	785,268
2064	**53,169**	**3,181,648**	807,746	**0**	**187,128**	994,874	2,186,774	**40,871**	**1,891,777**	1,089,240	**17,269**	**0**	1,106,509	785,268
2065	**53,169**	**3,181,648**	807,746	**0**	**59,903**	867,649	2,313,999	**40,871**	**1,891,777**	1,089,240	**17,269**	**48,300**	1,154,809	736,968
2066	**53,169**	**3,181,648**	807,746	**0**	**358**	808,104	2,373,544	**40,871**	**1,891,777**	1,089,240	**17,269**	**248**	1,106,757	785,020
2067	**53,169**	**3,181,648**	807,746	**0**	**0**	807,746	2,373,902	**40,871**	**1,891,777**	1,089,240	**17,269**	**0**	1,106,509	785,268
2068	**53,169**	**3,181,648**	807,746	**0**	**0**	807,746	2,373,902	**40,871**	**1,891,777**	1,089,240	**17,269**	**0**	1,106,509	785,268
2069	**53,169**	**3,181,648**	807,746	**0**	**0**	807,746	2,373,902	**40,871**	**1,891,777**	1,089,240	**17,269**	**0**	1,106,509	785,268
2070	**53,169**	**3,181,648**	807,746	**0**	**1,237,749**	2,045,495	1,136,153	**40,871**	**1,891,777**	1,089,240	**17,269**	**20,220**	1,126,729	765,048

Source: Dolores FY2015 Preliminary PRS 05_15_2015

Source: Seedskadee FY2015 Preliminary PRS 05_15_2015

COLORADO RIVER BASIN SALINITY CONTROL PROGRAM TITLE II

Upper Colorado River Basin Fund

As of 9/30/2014

A	B	C	D	E	F	G	H	I	J
	Up-front Cost Sharing								
Fiscal Year	Paradox Valley O&M	Grand Valley O&M	McElmo Creek (Dolores) O&M	Lower Gunnison O&M	Basinwide SCP	USDA NRCS BSP	**Total Transfer to UC Region**	**Total Repayment Transfer to Treasury**	**Total Annual Requirement**
1987								6,918	6,918
1988								90,088	90,088
1989								110,531	110,531
1990								156,936	156,936
1991								200,047	200,047
1992								301,475	301,475
1993								451,325	451,325
1994								357,687	357,687
1995								1,934,454	1,934,454
1996								2,750,148	2,750,148
1997					222,505	(254,648)	0	285,643	253,500
1998	65,752	126,103	$26,036	25,622	487,341	131,146	862,000	135,666	997,666
1999	80,561	50,013	21,423	17,195	803,533	244,275	1,217,000	87,604	1,304,604
2000	122,523	42,997	17,817	20,513	773,201	1,611,949	2,589,000	0	2,589,000
2001	104,192	25,425	19,707	20,202	693,579	(863,105)	0	0	0
2002	97,249	49,402	14,879	11,045	738,660	318,765	1,230,000	0	1,230,000
2003	73,375	42,882	23,278	(161)	549,268	271,358	960,000	0	960,000
2004	88,788	37,100	21,859	(89)	613,687	1,200,655	1,962,000	0	1,962,000
2005	95,089	32,359	27,996		529,948	1,256,756	1,942,148	0	1,942,148
2006	90,822	45,863	33,206		544,650	1,469,355	2,183,896	0	2,183,896
2007	98,721	50,252	18,809		574,676 1/	3,274,556	4,017,014 2/	0	4,017,014
2008	135,786	42,183	25,118		513,236	(2,541,323)	(1,825,000)	0	(1,825,000)
2009	117,029	65,919	27,105		1,110,870	4,725,077	6,046,000	0	6,046,000
2010	141,167	38,278	30,396		430,984	1,289,302	1,930,127	0	1,930,127
2011	137,250	51,500	22,114		545,989	801,982	1,558,835	0	1,558,835
2012	121,350	48,336	21,592		533,448	861,682	1,586,408	0	1,586,408
2013	117,199	56,644	25,341		557,908	930,508	1,687,600	0	1,687,600
2014	131,600	70,700	21,536		450,964	1,603,400	2,278,200	0	2,278,200
Subtotal	1,818,453	875,956	398,212	94,327	10,674,447	16,331,690	30,193,085	6,868,522	37,061,607
2015	135,500	75,000	21,536		470,186	1,116,964	1,819,186	0	1,819,186
2016	195,500	90,000	21,536		500,000	1,215,643	2,022,679	0	2,022,679
2017	135,500	90,000	21,536		500,000	1,146,327	1,893,363	0	1,893,363
2018	138,540	90,000	21,536		500,000	771,000	1,521,076	0	1,521,076
2019	138,540	90,000	21,536		500,000	707,000	1,457,076	0	1,457,076
2020	138,540	90,000	21,536		500,000	643,000	1,393,076	0	1,393,076
2021	138,540	90,000	21,536		500,000	643,000	1,393,076	0	1,393,076
2022	138,540	90,000	21,536		500,000	643,000	1,393,076	0	1,393,076
2023	138,540	90,000	21,536		500,000	643,000	1,393,076	0	1,393,076
2024	138,540	90,000	21,536		500,000	643,000	1,393,076	0	1,393,076
2025	138,540	90,000	21,536		500,000	643,000	1,393,076	0	1,393,076
2026	138,540	90,000	21,536		500,000	643,000	1,393,076	1,384,314	2,777,390
2027	138,540	90,000	21,536		500,000	643,000	1,393,076	0	1,393,076
2028	138,540	90,000	21,536		500,000	643,000	1,393,076	0	1,393,076
2029	138,540	90,000	21,536		500,000	643,000	1,393,076	0	1,393,076
2030	138,540	90,000	21,536		500,000	643,000	1,393,076	0	1,393,076
2031	138,540	90,000	21,536		500,000	643,000	1,393,076	0	1,393,076
2032	138,540	90,000	21,536		500,000	643,000	1,393,076	0	1,393,076
2033	138,540	90,000	21,536		500,000	643,000	1,393,076	0	1,393,076
2034	138,540	90,000	21,536		500,000	643,000	1,393,076	0	1,393,076
2035	138,540	90,000	21,536		500,000	643,000	1,393,076	0	1,393,076
2036	138,540	90,000	21,536		500,000	643,000	1,393,076	0	1,393,076
2037	138,540	90,000	21,536		500,000	643,000	1,393,076	0	1,393,076
2038	138,540	90,000	21,536		500,000	643,000	1,393,076	0	1,393,076
2039	138,540	90,000	21,536		500,000	643,000	1,393,076	3,200,008	4,593,084
2040	138,540	90,000	21,536		500,000	643,000	1,393,076	64,747	1,457,823
2041	138,540	90,000	21,536		500,000	643,000	1,393,076	0	1,393,076
2042	138,540	90,000	21,536		500,000	643,000	1,393,076	347,605	1,740,681
2043	138,540	90,000	21,536		500,000	643,000	1,393,076	158,454	1,551,530
2044	138,540	90,000	21,536		500,000	643,000	1,393,076	0	1,393,076
2045	138,540	90,000	21,536		500,000	643,000	1,393,076	0	1,393,076
2046	138,540	90,000	21,536		500,000	643,000	1,393,076	1,071,189	2,464,265
2047	138,540	90,000	21,536		500,000	643,000	1,393,076	1,919,584	3,312,660
2048	138,540	90,000	21,536		500,000	643,000	1,393,076	0	1,393,076
Total	6,579,693	3,920,956	1,130,436	94,327	27,644,633	39,935,624	79,305,669	15,014,423	94,320,092

1/ In FY2003 $1,103,000 was transferred from the Upper Basin Fund, but was not transferred into the Salinity Program until FY 2007. The total amount was accounted for in the Basinwide Program portion.

2/ The actual amount transferred from the Upper Basin Fund to the UC Region for the Salinity Program was $2,038,000, of which $573,000 was for the Basinwide Program. Please see footnote 1/ for the explanation of the difference.

Unfunded Benefits

CRSP

	FERS				CSRS				TOTAL
	JJCR	GGCR	LLCR	FERS TOTAL	JJCR	GGCR	LLCR	CSRS TOTAL	(FERS+CSRS)
2010	202,892	53,843	59,689	316,424	356,713	106,199	138,766	601,678	**918,102**
2011	133,612	50,658	44,354	228,624	268,390	112,946	112,849	494,185	**722,809**
2012	105,572	47,284	38,591	191,447	219,125	98,178	110,926	428,229	**619,676**
2013	99,807	44,369	39,062	183,238	179,272	82,306	104,690	366,268	**549,506**
2014	180,385	61,364	70,598	312,346	132,029	46,837	77,101	255,967	**568,313**
5YR AVG	**144,454**	**51,503**	**50,459**	**246,416**	**231,106**	**89,293**	**108,866**	**429,265**	**675,681**

Other Integrated and Participating Projects

	Collbran			Dolores			Rio Grande			Seedskadee		
	FERS	CSRS	Total	FERS	CSRS	Total	FERS	CSRS	Total	FERS	CSRS	Total
2010	19.84	165.13	184.97	19.84	165.13	184.97	19.84	165.13	184.97	27.77	231.19	258.96
2011	81.50	189.47	270.97	81.50	189.47	270.97	81.50	189.47	270.97	114.10	265.25	379.35
2012	62.19	158.23	220.42	62.19	158.23	220.42	62.19	158.23	220.42	87.06	221.48	308.54
2013	44.19	127.03	171.22	44.19	127.03	171.22	44.19	127.03	171.22	61.87	177.85	239.72
2014	82.74	90.37	173.11	82.74	90.37	173.11	82.74	90.37	173.11	115.84	126.51	242.35
5YR AVG	**58.09**	**146.05**	**204.14**	**58.09**	**146.05**	**204.14**	**58.09**	**146.05**	**204.14**	**81.33**	**204.46**	**285.78**

Aid to Irrigation data for the FY 2014 CRSP PRS

	Aid to irrigation 1/	
Irrigation allocation		107,965,744
Less other credits:		
	Contributions	257,691
	CRDF	118,265
	Non-reimbursable	
Due from surplus power & M&I for 2014		107,589,788
Due from surplus power & M&I for 2013		110,931,255
Increase for FY 2014 (goes in PRS IFI)		(3,341,467)
M&I payments through 2014		17,134,339
M&I payments through 2013		16,784,433
FY14 Increase to Surplus M&I Revenues for PRS		349,906
Anticipated power repayment		90,455,449

	Aid to Part Proj Irr	
Construction	2/	778,430,000
Apportionment	3/	316,630,000
Total	FY 2014	1,095,061,070
	FY 2013	1,093,183,000
	FY 2014 increase for PRS	1,878,070
	Total Non-power (2014) for SOR	
	2014	1,185,516,519
	2013 /4	1,187,329,823
	Increase	(1,813,304)

1/ Based on the 2013 SPCCR.
2/ Based on the USBR FY 2013 (56th Annual Report)revenues required by Basin States for irrigation assistance. From Mike Loring (Malcolm Wilson)
3/ Based on the apportionment table.
4/ Based on the 2013 SOR.

ENTERED IN PRS

ENTERED IN SOR

Colorado River Storage Project (Initial Units) Irrigation

SPCCR for FY 2013

		0622	0591	0557	0594	0711	0864	
	Schedule	Aspinall	Flaming	Glen	O&M	Navajo	Trans	Total
Costs								
Multipurpose Land and Rights (SGL 1711)	A	1,415,126	2,730,057	2,940,104		3,855,993		10,941,280
Plant in Service (SGL 1740)	A	1,744,469	13,283,899	49,620,899		26,691,559		91,340,826
Property Transfers	B	18,779	1,728,356	2,249,103				3,996,238
Expensed	B					52,429		52,429
Non-reimbursable	B							-
Retirements and Abandoned Plant	B		18,510	1,599,722		16,739		1,634,971
Transfer to Western	B							-
IDC Multipurpose	D							-
IDC Power	D							-
IDC Transferred to Western	D							-
Total Costs		3,178,374	17,760,822	56,409,828	-	30,616,720	-	107,965,744
Repayment								-
Contributions	E	3,451	142,562	111,678				257,691
CRDF	E	9,305	34,398	18,842		55,720		118,265
Western	E							-
Surplus M&I Applied to Repayment	E		17,134,339					17,134,339
Future Power Repayment	F	3,169,447	1,153,085	58,831,426		30,813,404		93,967,362
Total Repayment		3,182,203	18,464,384	58,961,946	-	30,869,124	-	111,477,657

Salt Lake City Area Integrated Projects

Irrigation Cumulative Repayment Obligations Comparisons

Unit: $1,000

Item		Step 2 Rate	FY 2013 Preliminary		Difference
Aid to Main-stem Irrigation		110,928	110,931	2/	3
Aid to Participating Projects Irrigation: 1/					
	Construction	765,762	777,762		12,000
	Apportionment	661,675	315,421		(346,254)
Total aid to Participating Projects		1,427,437	1,093,183	2/	(334,254)

1/ Includes only projects meeting the criteria of the 1983 CREDA agreement. Increase in construction mostly due to revision to cost allocations for Utah's Bonneville Unit. Decrease in apportionment due to MOA between BOR, WAPA, Upper Basin States & CREDA.

2/ Totals are equal to Historical Subtotals for Principle Payment plus Unpiad Balance in the Executive Summary

Colorado River Storage Project

Aid to Participating Projects Irrigation Repayment Obligations and Apportioned Revenues Applied

FY 2014 PRS

Unit: $ 1,000

	Colorado 46%				New Mexico 17%				Utah 21.5%				Wyoming 15.5%				Total			
	Incremental		Cumulative		Incremental		Cumulative		Incremental		Cumulative		Incremental		Cumulative		Incremental		Cumulative	
year	Obligation	Available W/Appor	Obligation	Available W/Appor	Obligation	Available W/Appor	Obligation	Available W/Appor	Obligation	Available W/Appor	Obligation	Available W/Appor	Obligation	Available W/Appor	Obligation	Available W/Appor	Obligation	Available W/Appor	Obligation	Available W/Appor
2015	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2016	-	3,961	-	3,961	-	1,464	-	1,464	8,610	1,851	8,610	1,851	-	1,335	-	1,335	8,610	8,610	8,610	8,610
2017	3,194	2,018	3,194	5,978	-	746	-	2,209	-	943	8,610	2,794	1,192	680	1,192	2,014	4,386	4,386	12,996	12,996
2018	-	-	3,194	5,978	-	-	-	2,209	-	-	8,610	2,794	-	-	1,192	2,014	-	-	12,996	12,996
2019	-	-	3,194	5,978	-	-	-	2,209	-	-	8,610	2,794	-	-	1,192	2,014	-	-	12,996	12,996
2020	-	2,941	3,194	8,919	-	1,087	-	3,296	6,393	1,374	15,003	4,169	-	991	1,192	3,005	6,393	6,393	19,389	19,389
2021	13,650	6,279	16,844	15,198	-	2,321	-	5,617	-	2,935	15,003	7,103	-	2,116	1,192	5,121	13,650	13,650	33,039	33,039
2022	-	-	16,844	15,198	-	-	-	5,617	-	-	15,003	7,103	-	-	1,192	5,121	-	-	33,039	33,039
2023	-	10,965	16,844	26,163	23,836	4,052	23,836	9,669	-	5,125	15,003	12,228	-	3,695	1,192	8,816	23,836	23,836	56,875	56,875
2024	-	-	16,844	26,163	-	-	23,836	9,669	-	-	15,003	12,228	-	-	1,192	8,816	-	-	56,875	56,875
2025	-	47,521	16,844	73,684	-	17,562	23,836	27,231	103,307	22,211	118,310	34,439	-	16,013	1,192	24,828	103,307	103,307	160,182	160,182
2026	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160,182	160,182
2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160,182	160,182
2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160,182	160,182
2029	5,483	37,031	5,483	37,031	-	13,686	-	13,686	-	17,308	-	17,308	12,478	12,478	12,478	12,478	17,961	80,503	178,143	240,685
2030	-	-	5,483	37,031	-	-	-	13,686	-	-	-	17,308	-	-	12,478	12,478	-	-	178,143	240,685
2031	-	-	5,483	37,031	-	-	-	13,686	-	-	-	17,308	-	-	12,478	12,478	-	-	178,143	240,685
2032	-	-	5,483	37,031	7,665	-	7,665	13,686	-	-	-	17,308	-	-	12,478	12,478	7,665	-	185,808	240,685
2033	-	-	5,483	37,031	-	-	7,665	13,686	-	-	-	17,308	-	-	12,478	12,478	-	-	185,808	240,685
2034	-	-	5,483	37,031	-	-	7,665	13,686	5,005	-	5,005	17,308	-	-	12,478	12,478	5,005	-	190,813	240,685
2035	-	70,415	5,483	107,447	-	26,023	7,665	39,709	-	32,912	5,005	50,220	23,727	23,727	36,205	36,205	23,727	153,077	214,540	393,762
2036	-	-	5,483	107,447	-	-	7,665	39,709	-	-	5,005	50,220	-	-	36,205	36,205	-	-	214,540	393,762
2037	-	-	5,483	107,447	-	-	7,665	39,709	-	-	5,005	50,220	-	-	36,205	36,205	-	-	214,540	393,762
2038	50,534	-	56,017	107,447	-	-	7,665	39,709	-	-	5,005	50,220	-	-	36,205	36,205	50,534	-	265,074	393,762
2039	-	-	56,017	107,447	-	-	7,665	39,709	-	-	5,005	50,220	-	-	36,205	36,205	-	-	265,074	393,762
2040	5,164	-	61,181	107,447	-	-	7,665	39,709	-	-	5,005	50,220	-	-	36,205	36,205	5,164	-	270,238	393,762
2041	-	-	61,181	107,447	-	-	7,665	39,709	-	-	5,005	50,220	-	-	36,205	36,205	-	-	270,238	393,762
2042	4,736	-	65,917	107,447	-	-	7,665	39,709	-	-	5,005	50,220	-	-	36,205	36,205	4,736	-	274,974	393,762
2043	-	-	65,917	107,447	-	-	7,665	39,709	-	-	5,005	50,220	-	-	36,205	36,205	-	-	274,974	393,762
2044	-	-	65,917	107,447	-	-	7,665	39,709	-	-	5,005	50,220	-	-	36,205	36,205	-	-	274,974	393,762
2045	101,967	60,438	167,884	167,884	-	22,336	7,665	62,044	-	28,248	5,005	78,468	-	20,365	36,205	56,570	101,967	131,386	376,941	525,148
2046	-	-	167,884	167,884	-	-	7,665	62,044	-	-	5,005	78,468	-	-	36,205	56,570	-	-	376,941	525,148
2047	-	-	167,884	167,884	-	-	7,665	62,044	-	-	5,005	78,468	-	-	36,205	56,570	-	-	376,941	525,148
2048	78,644	78,644	246,528	246,528	-	29,064	7,665	91,108	-	36,757	5,005	115,225	-	26,500	36,205	83,069	78,644	170,965	455,585	696,113
2049	23,301	23,301	269,829	269,829	-	8,611	7,665	99,719	-	10,891	5,005	126,116	-	7,851	36,205	90,921	23,301	50,654	478,886	746,767
2050	-	-	269,829	269,829	-	-	7,665	99,719	72,894	-	77,899	126,116	-	-	36,205	90,921	72,894	-	551,780	746,767
2051	-	-	269,829	269,829	-	-	7,665	99,719	-	-	77,899	126,116	-	-	36,205	90,921	-	-	551,780	746,767
2052	80,847	80,847	350,676	350,676	-	29,878	7,665	129,598	-	37,787	77,899	163,903	-	27,242	36,205	118,163	80,847	175,754	632,627	922,521
2053	-	-	350,676	350,676	-	-	7,665	129,598	-	-	77,899	163,903	-	-	36,205	118,163	-	-	632,627	922,521
2054	-	22,561	350,676	373,237	-	8,338	7,665	137,935	96,549	10,545	174,448	174,448	-	7,602	36,205	125,765	96,549	49,045	729,176	971,566
2055	-	30,986	350,676	404,223	-	11,451	7,665	149,387	14,482	14,483	188,930	188,930	-	10,441	36,205	136,205	14,482	67,361	743,658	1,038,927
2056	-	-	350,676	404,223	-	-	7,665	149,387	-	-	188,930	188,930	-	-	36,205	136,205	-	-	743,658	1,038,927
2057	22,703	25,821	373,379	430,044	-	9,543	7,665	158,929	12,069	12,069	200,999	200,999	-	8,701	36,205	144,906	34,772	56,133	778,430	1,095,060
2058	-	-	373,379	430,044	-	-	7,665	158,929	-	-	200,999	200,999	-	-	36,205	144,906	-	-	778,430	1,095,060
2059	-	-	373,379	430,044	-	-	7,665	158,929	-	-	200,999	200,999	-	-	36,205	144,906	-	-	778,430	1,095,060
2060	-	-	373,379	430,044	-	-	7,665	158,929	-	-	200,999	200,999	-	-	36,205	144,906	-	-	778,430	1,095,060
Total	390,223	503,728			31,501	186,160			319,309	235,438			37,397	169,734			778,430	1,095,060		

Note: Boxed yellow amounts trigger apportionment. Boxed green amounts indicate total available with apportionment. Boxed blue amounts indicate apportionment under MOA agreement

REVENUES REQUIRED BY THE UPPER COLORADO RIVER BASIN STATES
FOR IRRIGATION ASSISTANCE OF PARTICIPATING PROJECTS
USING FULL 50-YEAR REPAYMENT PERIOD FOR EACH BLOCK

Fiscal Year 2013 - 57th Annual Report
(Units = $1,000)

	Colorado		New Mexico		Utah		Wyoming		
Fiscal Year	*Project or Block*	*Amount Required*	*Project or Block*	*Amount Required*	*Project or Block*	*Amount Required*	*Project or Block*	*Amount Required*	*Total of Four States*
2016					Vernal Unit	8,610			8,610
2017	Smith Fork	3,194					Seedskadee	1,192	4,386
2020					Emery County	6,393			6,393
2021	Florida	7,709							7,709
2021	Silt	5,941							5,941
2023			San Juan-Chama 1	23,836					23,836
2025					Duchesne	103,307			103,307
2029	Bostwick Park	5,483					Eden	12,478	17,961
2032			San Juan-Chama 2	1,028					1,028
2032			Hammond	6,637					6,637
2034					Jensen Unit	5,005			5,005
2035							Lyman	23,727	23,727
2038	Dolores 1	50,534							50,534
2040	Paonia	5,164							5,164
2042	Dallas Creek	4,736							4,736
2045	Dolores 4	101,967							101,967
2048	Dolores 6	78,644							78,644
2049	Dolores 7	23,301							23,301
2050					Heber-Francis	72,894			72,894
2052	Dolores 8	80,847							80,847
2054					Utah County	96,549			96,549
2055					Starvation Reservoir	14,482			14,482
2057	Animas-La Plata 1/	22,703			UBRP	12,069			34,772
SUBTOTAL:		390,223		31,501		319,309		37,397	778,430
2110	Fruitland Mesa				Uintah Unit		Savery-Pot Hook		
2110	West Divide				Upalco Unit		LaBarge		
2110	San Miguel								
2110	Savery-Pot Hook								
SUBTOTAL: 2/		0		0		0		0	0
TOTAL:		390,223		31,501		319,309		37,397	778,430

1/ Legal waiver of assistance for irrigation investigation costs still not available. Timing dated 50 years from construction completion estimated at year 2007.
2/ Apportioned revenues associated with those projects indefinitely deferred pursuant to the 1983 CREDA Agreement.

Salt Lake City Integrated Projects

unit: 1,000

Average Annual Transmission Revenue Comparison

Item	Step 2 Rate	FY 2015 Preliminary	Difference
Total Transmission Revenue	$ 16,718	$ 16,326	$ (392)

PROJECTED CRSP FIRM AND NON-FIRM WHEELING AND EXCHANGE REVENUE

Table consistantly reviewed and updated. Last review December 2014

Customer	Contract Number	Contract Expiration Date	R--> Unit	1.27	2015 $1.11	2016	2017	2018	2019
Firm Wheeling Contracts									
APS		6/1/2046	kW		150,000	150,000	150,000	150,000	150,000
	14-06-400-3654		$		~~$ -~~	~~$ -~~	~~$ -~~	~~$ -~~	~~$ -~~
APS	09-SLC-0628	12/31/2020	kW		56,732	56,732	56,732	56,732	56,732
This is a Network Contract-effective 1/2011			$	varies	$ 778,452	$ 778,452	$ 778,452	$ 778,452	$ 778,452
Basin Electric Power Cooperation	14-RMR-2601	10/31/2015	kW		20,000	20,000	20,000	20,000	20,000
			$	1.27	$ 266,400	$ 304,800	$ 304,800	$ 304,800	$ 304,800
Black Hills/Colorado Electric Utility Company, LP	11-SLC-0661	12/31/2022	kW		14,420	14,420	14,420	14,420	14,420
			$	varies	$ -	$ -	$ -	$ -	$ -
CRSP Energy Mngt. & Mktg Office (EMMO)	07-SLC-0610 - 1507 MW	9/30/2024	kW		3,513,000	3,513,000	3,513,000	3,513,000	3,513,000
	98-SLC-0372 - 130MW 00-SLC-0439 - 440MW 11-SLC-0659 - 1436MW	9/30/2024	$	1.27	$ -	$ -	$ -	$ -	$ -
Delta Montrose Electric Assoc.	99-SLC-0407	3/31/2008	kW		20	20	20	20	20
			$	1.27	$ 266	$ 305	$ 305	$ 305	$ 305
Deseret G&T **(Exhibit B)**	2-07-40-P0716 New Exibit - Rev. 8 effec.	6/1/2022	kW		123,000	123,000	123,000	123,000	123,000
	10/1/13 thru 9/30/16	Can be terminated w/5yrs prior notice	$	1.27	$ 1,638,360	$ 1,874,520	$ 1,874,520	$ 1,874,520	$ 1,874,520
Farmington, NM			kW		100,000	100,000	100,000	100,000	100,000
	3-07-40-P0715	6/30/2022	Per Yr Charg $	1.975	$ 197,500	$ 197,500	$ 197,500	$ 197,500	$ 197,500
Fredonia, AZ 3/ **(Estimate) - Take the avg.of each for the past FY - See Avgs. Sprdsh -**	08-SLC-0620	9/30/2028	kW		1,829	1,829	1,829	1,829	1,829
		When it can be terminated w/5yrs prior notice	$	varies	$ 25,476	$ 25,476	$ 25,476	$ 25,476	$ 25,476
Holloman Air Force Base 2/	05-SLC-0578	9/30/2024	kW		2,000	2,000	2,000	2,000	2,000
$2.42/kWh = $2.31 + .07Ans. Svs + .04 Sch. 2 Chg.			$	-	$ -	$ -	$ -	$ -	$ -
Los Alamos County	14-RMR-2495	9/30/2024	kW		10,000	10,000	10,000	10,000	10,000
			$	1.27	$ 133,200	$ 152,400	$ 152,400	$ 152,400	$ 152,400

PROJECTED CRSP FIRM AND NON-FIRM WHEELING AND EXCHANGE REVENUE

Table consistantly reviewed and updated. Last review December 2014

Customer	Contract Number	Contract Expiration Date	R--> Unit	1.27	2015 $1.11	2016	2017	2018	2019
Municipal Energy Agency of NE 3/ **(Estimate) - Take the avg.of each for the past FY - See Avgs. Sprdsh**	12-RMR-2321	9/30/2022	kW		19,000	19,000	19,000	19,000	19,000
			$	varies	$ 71,013	$ 71,013	$ 71,013	$ 71,013	$ 71,013
Municipal Energy Agency of NE	13-RMR-2411	5/1/2019	kW		2,000	2,000	2,000	2,000	2,000
			$	1.27	$ 26,640	$ 30,480	$ 30,480	$ 30,480	$ 30,480
Navajo Tribal Utility Authority 4/	14-06-400-4537	6/1/2023	kW		0	0	0	0	0
			$	1.27	$ -	$ -	$ -	$ -	$ -
PacifiCorp/APS	94-SLC-0276	5/31/2022	kW		250,000	250,000	250,000	250,000	250,000
			$	1.27	$ 3,330,000	$ 3,810,000	$ 3,810,000	$ 3,810,000	$ 3,810,000
Page, City of 3/ (Estimate) - Take the avg.of each for the past FY - See Avgs. Sprdsh	12-DSR-12368	12/31/2022	kW		20,000	20,000	20,000	20,000	20,000
			$	varies	$ 98,785	$ 98,785	$ 98,785	$ 98,785	$ 98,785
Public Service Company of New Mexico 1/ (Rate established by Farmington's Transformation)	06-SLC-0586	6/30/2016	Per Yr Chg		10,000	10,000	10,000	10,000	10,000
				1.975	$ 19,750	$ 19,750	$ 19,750	$ 19,750	$ 19,750
Salt River Project (OATT)	09-SLC-0641	12/31/2015	kW		9,000	9,000	9,000	9,000	9,000
			$	1.27	$ 119,880	$ 137,160	$ 137,160	$ 137,160	$ 137,160
Tri-State G&T	03-SLC-0503	10/28/2037	kW		100,000	100,000	100,000	100,000	100,000
			$	1.27	$ 1,332,000	$ 1,524,000	$ 1,524,000	$ 1,524,000	$ 1,524,000
Tri-State G&T (Colorado-Ute)	91-SLC-0178	9/30/2053	kW		100,000	100,000	100,000	100,000	100,000
			$	1.27	$ 1,332,000	$ 1,524,000	$ 1,524,000	$ 1,524,000	$ 1,524,000
Deseret	12-RMR-2324	12/31/2017	kW		6,000	6,000	6,000	6,000	6,000
			$	1.27	$ 79,920	$ 91,440	$ 91,440	$ 91,440	$ 91,440
Williams Energy Services 1/	95-SLC-0280	1/31/2016	Per Yr		62,000	62,000	62,000	62,000	62,000
			Chg	1.629	$ 100,998	$ 100,998	$ 33,666	$ 33,666	$ 33,666
Total Firm Wheeling Revenues			kW		4,578,001	4,578,001	4,578,001	4,578,001	4,578,001
			$	1.27	$ 9,550,640	$ 10,741,079	$ 10,673,747	$ 10,673,747	$ 10,673,747

PROJECTED CRSP FIRM AND NON-FIRM WHEELING AND EXCHANGE REVENUE

Table consistantly reviewed and updated. Last review December 2014

Customer	Contract Number	Contract Expiration Date	R--> Unit	1.27	2015 $1.11	2016	2017	2018	2019
Exchange Contracts									
Salt River Project	14-06-400-2468	9/30/2024	kW		250,000	250,000	250,000	250,000	250,000
			$	Set	$ 4,432,500	$ 4,432,500	$ 4,432,500	$ 4,432,500	$ 4,432,500
			kW		0	0	0	0	0
			$	1.27	$ -	$ -	$ -	$ -	$ -
Salt River Project	08-SLC-0615	6/30/2018	kW		25,000	25,000	25,000	25,000	25,000
			$		$ -	$ -	$ -	$ -	$ -
Navajo Tribal Utility Authority	14-06-400-4537	6/1/2023	kW		30,000	30,000	30,000	30,000	30,000
			$		$ -	$ -	$ -	$ -	$ -
Public Service Company of New Mexico	14-06-400-2425	6/1/2047	kW		84,000	84,000	84,000	84,000	84,000
	8-07-40-P0695				50,000	50,000	50,000	50,000	50,000
			kW						
			$		$ -	$ -	$ -	$ -	$ -
			$		$ 4,432,500	$ 4,432,500	$ 4,432,500	$ 4,432,500	$ 4,432,500
Palo Verde Nuclear Generating Station Shutdown Power & Blackstart Services	**09-DSR-12008**	**12/31/2018**	$		$ 232,800	$ 232,800	$ 232,800	$ 232,800	$ 232,800
Provo River Project (UAMPS, UMPA & Heber)*	**94-SLC-0253 & 0254, 07-SLC-0601**	**9/30/2024**	$		$ 29,788	$ 29,788	$ 29,788	$ 29,788	$ 29,788
***This is phase shifter revenue, assumed to be 1/2 of past average annual revenue until 2017 due to the failure of the Waterflow Phase Shifting Transformer (PSTS). Assume replacement Waterflow PSTS will not be in service until FY 2017.**									
Western Systems Coordination Council			$		$ 500,000	$ 500,000	$ 1,000,000	$ 1,000,000	$ 1,000,000
Total Firm Transmission Revenue					$ 14,745,728	$ 15,936,167	$ 16,368,835	$ 16,368,835	$ 16,368,835
***Revenue CRSP charges UAMPS and UMPA to wheel PRP power, which is marketed separately from Integrated Projects Power.**									

1/ Farmington, NM, PNM, and Williams Energy Services all use the Shiprock Transformer. These contracts are listed on the PO&M under Firm Transmission.
2/ This contract is a pass-through expense - through El Paso Electric
3/ Avg. 12-CP for the past 12mos.

4/ Because NTUA received additional CROD capacity in the Post-2004 allocation process and additional capacity from the native American Power Pool/Benefit Crediting, they have no need for transmission capacity under this contract for the time being. Per Brent 7/26/05

Salt Lake City Area Integrated Projects

Offsetting Revenues Projections Comparisons

Unit: $1,000

Revenue		Step 2 Rate		FY 2015 Preliminary		Difference
Firm Transmission	$	16,718	$	16,326	$	(392)
Non-firm Transmission	$	1,327	$	3,240	$	1,913
Resale Energy 1/	$	6,896	$	7,737	$	841
Transaction fees 1/	$	1,412	$	2,181	$	769
Other 2/	$	7,687	$	5,118	$	(2,569)
Total	**$**	**34,040**	**$**	**34,602**	**$**	**562**

1/ Merchant function.

2/ Includes revenues from ancillary services, auxiliary services, spinning reserves, admin charges for WRP and CDP transactions, facility use, energy imbalance, and other misc. revenues.

CRSP Offsetting Revenues Projections

as of May 2015

Year	Transmission Revenues			Merchant Function Revenue			Other	Total Offsetting
	Firm 1/	Non-firm 2/	Total	Resale 3/	Transaction Fee 4/	Total	Revenues 5/	Revenues
2011		2,876,694		15,475,107	2,136,665	17,611,772	5,189,775	
2012		2,341,214		8,242,461	2,150,078	10,392,539	4,746,016	
2013		3,835,128		4,263,741	2,111,987	6,375,728	5,409,049	
2014		4,115,659		3,484,655	2,357,883	5,842,538	4,493,975	
2015		3,030,620		7,218,323	2,150,042	9,368,365	5,751,635	
5-yr AVG	**16,325,568**	**3,239,863**	**19,565,431**	**7,736,857**	**2,181,331**	**9,918,188**	**5,118,090**	**34,601,709**
		6/				**7/**	**8/**	

1/ Based on average-firm transmission contracts in the PRS, from 2015 through the "pinchpoint"

2/ Non-firm transmission revenues are taken off of the PO&M 60's

3/ Resale revenue is the difference between monthly sales and purchases. Does not include WRP sales or purchases.

4/ Transaction fees reflect the cost of real time merchant services, management and energy accounting support, and information technology costs.

5/ Includes revenues from ancillary services, auxiliary services, spinning reserves, admin charges for WRP and CDP transactions, facility use, energy imbalance, and other misc. revenues.

6/ Entered as Non-Firm Transmission column (S) in PRS

7/ Entered in Merchant Function column (U) in PRS

8/ Entered in Other Revs column (V) in PRS

CRSP STORAGE UNITS - HISTORIC AND PROJECT NET REVENUES FROM M&I WATER SALES - FY2014
(After Paying OM&R Costs -- Units = $1,000)

	Blue Mesa Reservoir		*Navajo Reservoir*		*Glen Canyon Reservoir*		*Flaming Gorge Reservoir*		*CRSP Total*		
Year	Acre-Feet	Revenue	Acre-Feet	Revenue	Acre-Feet	Revenue	Acre-Feet	Revenue	Acre-Feet	Revenue	Year
1974										291.0	1974
1975										492.5	1975
1976										560.6	1976
1977										560.0	1977
1978										838.8	1978
1979										733.0	1979
1980										721.9	1980
1981										638.7	1981
1982				HISTORIC NET REVENUES						903.2	1982
1983				(Totals Only)						676.8	1983
1984										808.9	1984
1985										677.8	1985
1986										1,110.1	1986
1987										1,018.1	1987
1988										1,168.8	1988
1989										1,024.9	1989
1990										1,004.7	1990
1991										866.3	1991
1992										1,183.9	1992
1993										1,399.6	1993
1994										458.0	1994
1995										418.5	1995
1996										423.2	1996
1997										430.3	1997
1998										311.8	1998
1999										402.3	1999
2000										348.4	2000
2001										307.6	2001
2002										382.1	2002
2003										360.2	2003
2004										313.7	2004
2005										334.3	2005
2006										279.2	2006
2007										217.5	2007
2008										216.6	2008
2009										217.0	2009
2010										379.1	2010
2011										257.4	2011
2012										245.9	2012
2013										350.0	2013
2014										2,549.0	2014
2015	986	56.2	50	0.9	47,628	3,400.0	112	5.0	48,776	3,462.0	2015
2016	1,024	59.5	50	0.9	43,690	3,465.9	112	5.1	44,876	3,531.5	2016
2017	1,069	63.5	50	0.9	43,690	3,533.2	112	5.2	44,921	3,602.8	2017
2018	1,120	67.9	50	0.9	43,690	3,601.8	112	5.3	44,972	3,675.9	2018
2019	1,180	73.1	50	0.9	43,690	3,692.3	112	5.4	45,032	3,771.8	2019
2020	1,223	77.3	50	1.0	43,690	3,771.6	112	5.5	45,075	3,855.4	2020
2021	1,221	78.8	50	1.0	43,690	3,844.6	112	5.7	45,073	3,930.0	2021
2022	1,190	79.0	50	1.0	43,690	3,919.1	112	5.8	45,042	4,004.9	2022
2023	1,186	80.4	50	1.0	43,690	3,995.1	112	5.9	45,038	4,082.4	2023
2024	1,181	81.7	50	1.0	43,690	4,097.4	112	6.0	45,033	4,186.1	2024
2025	1,181	83.4	50	1.1	43,690	4,204.3	112	6.1	45,033	4,294.9	2025
2026	1,151	83.3	50	1.1	43,690	4,285.9	112	6.2	45,003	4,376.5	2026
2027	1,151	85.0	50	1.1	43,690	4,369.0	112	6.4	45,003	4,461.5	2027
2028	1,151	86.7	0	0.0	43,690	4,453.8	112	6.5	44,953	4,547.0	2028
2029	1,151	88.4	0	0.0	43,690	4,570.1	112	6.6	44,953	4,665.1	2029
2030	1,053	86.2	0	0.0	43,690	4,679.4	112	6.8	44,855	4,772.3	2030
2031	1,053	87.9	0	0.0	43,690	4,770.1	112	6.9	44,855	4,864.9	2031
2032	1,053	89.7	0	0.0	43,690	4,862.6	112	7.0	44,855	4,959.3	2032
2033	1,053	91.5	0	0.0	43,690	4,957.0	112	7.2	44,855	5,055.7	2033
2034	1,053	93.3	0	0.0	43,690	5,089.0	112	7.3	44,855	5,189.6	2034
2035	1,053	95.2	0	0.0	43,690	5,199.7	112	7.5	44,855	5,302.3	2035
2036	1,053	97.1	0	0.0	43,690	5,300.3	112	7.6	44,855	5,405.0	2036
2037	1,053	99.0	0	0.0	43,690	5,403.0	112	7.8	44,855	5,509.8	2037
2038	1,053	101.0	0	0.0	43,690	5,507.8	112	7.9	44,855	5,616.7	2038
2039	1,053	103.0	0	0.0	43,690	5,657.4	112	8.1	44,855	5,768.5	2039
2040	1,053	105.1	0	0.0	43,690	5,766.5	112	8.2	44,855	5,879.8	2040
2041	1,053	107.2	0	0.0	43,690	5,892.3	112	8.4	44,855	6,007.9	2041
2042	1,053	109.3	0	0.0	43,690	6,006.3	112	8.6	44,855	6,124.2	2042
2043	1,030	109.5	0	0.0	43,690	6,122.6	112	8.7	44,832	6,240.8	2043
2044	1,005	109.4	0	0.0	43,690	6,292.6	112	8.9	44,807	6,410.9	2044
2045	402	48.4	0	0.0	43,690	6,413.6	112	9.1	44,204	6,471.1	2045
2046	251	33.3	0	0.0	43,690	6,554.1	112	9.3	44,053	6,596.7	2046
2047	251	34.0	0	0.0	43,690	6,680.7	112	9.5	44,053	6,724.1	2047
2048	241	33.4	0	0.0	43,690	6,809.9	112	9.6	44,043	6,852.9	2048
2049	241	34.1	0	0.0	43,690	7,003.2	112	9.8	44,043	7,047.2	2049
2050	241	34.8	0	0.0	43,690	7,137.7	112	10.0	44,043	7,182.5	2050
2051	241	35.5	0	0.0	43,690	7,274.9	112	10.2	44,043	7,320.7	2051
2052	241	36.2	0	0.0	43,690	7,218.2	112	10.4	44,043	7,264.8	2052
2053	98	14.2	0	0.0	43,690	7,355.1	112	10.7	43,900	7,380.0	2053
2054	98	14.4	0	0.0	43,690	7,568.7	112	10.9	43,900	7,594.0	2054
2055	98	14.7	0	0.0	43,690	7,711.2	112	11.1	43,900	7,737.1	2055
2056	98	15.0	0	0.0	43,690	7,856.6	112	11.3	43,900	7,882.9	2056
2057	98	15.3	0	0.0	43,690	8,004.9	112	11.5	43,900	8,031.7	2057
2058	98	15.6	0	0.0	43,690	8,156.1	112	11.8	43,900	8,183.5	2058
2059	98	15.9	0	0.0	43,690	8,399.0	112	12.0	43,900	8,426.9	2059
2060	98	16.3	0	0.0	43,690	8,556.3	112	12.2	43,900	8,584.8	2060

FY 2015 Project Use Summary

	MW								GWH			
	Summer			Winter			Average					
Year	Total	Unassigned	Used	Total	Unassigned	Used	Used		Summer Use	Winter Use	Total	Total Used
2015	187	121.78	65.22	187	167.08	19.92	42,571		101.06	21.56	122.62	122,620
2016	187	121.78	65.22	187	167.08	19.92	42,571		101.06	21.52	122.58	122,580
2017	187	121.31	65.69	187	167.08	19.92	42,806		101.68	21.52	123.2	123,200
2018	187	121.31	65.69	187	167.08	19.92	42,806		101.68	21.52	123.2	123,200
2019	187	117.73	69.27	187	166.38	20.62	44,946		102.88	22.32	125.2	125,200
2020	187	117.73	69.27	187	166.38	20.62	44,946		102.88	22.32	125.2	125,200
2021	187	112.98	74.02	187	161.63	25.37	49,696		105.38	7.12	112.5	112,500
2022	187	112.52	74.48	187	161.63	25.37	49,926		106.02	7.12	113.14	113,140
2023	187	111.97	75.03	187	161.63	25.37	50,201		107.32	7.02	114.34	114,340
2024	187	108.97	78.03	187	161.63	25.37	51,701		113.32	7.02	120.34	120,340
2025	187	108.97	78.03	187	161.63	25.37	51,701		113.32	7.02	120.34	120,340
2026	187	104.22	82.78	187	156.88	30.12	56,451		115.92	7.02	122.94	122,940
2027	187	103.28	83.72	187	156.50	30.5	57,111		117.64	7.51	125.15	125,150
2028	187	103.28	83.72	187	156.50	30.5	57,111		117.64	7.51	125.15	125,150
2029	187	113.78	73.22	187	156.50	30.5	51,861		117.64	7.51	125.15	125,150

FY 2015 Project Use Summary

	MW								GWH			
	Summer			Winter			Average					
Year	Total	Unassigned	Used	Total	Unassigned	Used	Used		Summer Use	Winter Use	Total	Total Used
2015	187	121.78	65.22	187	167.08	19.92	42,571		101.06	21.56	122.62	122,620
2016	187	121.78	65.22	187	167.08	19.92	42,571		101.06	21.52	122.58	122,580
2017	187	121.31	65.69	187	167.08	19.92	42,806		101.68	21.52	123.2	123,200
2018	187	121.31	65.69	187	167.08	19.92	42,806		101.68	21.52	123.2	123,200
2019	187	117.73	69.27	187	166.38	20.62	44,946		102.88	22.32	125.2	125,200
2020	187	117.73	69.27	187	166.38	20.62	44,946		102.88	22.32	125.2	125,200
2021	187	112.98	74.02	187	161.63	25.37	49,696		105.38	7.12	112.5	112,500
2022	187	112.52	74.48	187	161.63	25.37	49,926		106.02	7.12	113.14	113,140
2023	187	111.97	75.03	187	161.63	25.37	50,201		107.32	7.02	114.34	114,340
2024	187	108.97	78.03	187	161.63	25.37	51,701		113.32	7.02	120.34	120,340
2025	187	108.97	78.03	187	161.63	25.37	51,701		113.32	7.02	120.34	120,340
2026	187	104.22	82.78	187	156.88	30.12	56,451		115.92	7.02	122.94	122,940
2027	187	103.28	83.72	187	156.50	30.5	57,111		117.64	7.51	125.15	125,150
2028	187	103.28	83.72	187	156.50	30.5	57,111		117.64	7.51	125.15	125,150
2029	187	113.78	73.22	187	156.50	30.5	51,861		117.64	7.51	125.15	125,150

United States Department of the Interior

BUREAU OF RECLAMATION
Upper Colorado Region
Power Office
125 South State Street, Room 8100
Salt Lake City, Utah 84138-1102

IN REPLY REFER TO:
UC-620
PRJ-17.00

March 4, 2015

VIA ELECTRONIC MAIL ONLY

Ms. Lynn Jeka
CRSP Manager
Western Area Power Administration
150 E. Social Hall Avenue, Suite 300
Salt Lake City, UT 84111
jeka@wapa.gov

Subject: Estimates of Project Use Power Requirements

Dear Ms. Jeka:

Enclosed are tables showing our latest estimates of project use power requirements for the Colorado River Storage Project and Participating Projects. These tables have been updated starting with the year 2015.

If you have any questions, please contact Mr. Blaine Anderson at 801-524-3626.

Sincerely,

/s/

Jane C. Blair
Manager, Power Office

Enclosures - 3

Continued on the next page.

Subject: Estimates of Project Use Power Requirements

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(w/encl. to each)

COLORADO RIVER STORAGE PROJECT
Participating Projects
Estimated Project Power Requirements (1)
Table 1

Summer Peak Demands (MW) typcially from April to September (but may vary from contract to contract)

Year	Silt	Navajo	NTUA	Paradox	CUP Jensen	(4) CUP Bonneville	(3) Dolores	Dutch John	(2) Animas-LaPlata		Unassigned (MW)	Total (MW)
2015	0.75	35	12	0.70	0.93	3.24	10.5 *	0.2328	1.87	(2)	121.78	187
2016	0.75	35	12	0.70	0.93	3.24	10.5	0.2328	1.87	(2)	121.78	187
2017	0.75	35	12	0.70	1.4	3.24	10.5	0.2328	1.87	(2)	121.31	187
2018	0.75	35	12	0.70	1.4	3.24	10.5	0.2328	1.87	(2)	121.31	187
2019	0.75	38	12	0.70	1.4	3.24	10.5	0.2328	2.45	(2)	117.73	187
2020	0.75	38	12	0.70	1.4	3.24	10.5	0.2328	2.45	(2)	117.73	187
2021	0.75	38	12	0.70	1.4	7.99	10.5	0.2328	2.45	(2)	112.98	187
2022	0.75	38	12	0.70	1.86	7.99	10.5	0.2328	2.45	(2)	112.52	187
2023	0.75	38	12	0.70	1.86	7.99	10.5	0.2328	3.00	(2)	111.97	187
2024	0.75	41	12	0.70	1.86	7.99	10.5	0.2328	3.00	(2)	108.97	187
2025	0.75	41	12	0.70	1.86	7.99	10.5	0.2328	3.00	(2)	108.97	187
2026	0.75	41	12	0.70	1.86	12.74	10.5	0.2328	3.00	(2)	104.22	187
2027	0.75	41	12	0.70	2.3	12.74	10.5	0.2328	3.50	(2)	103.28	187
2028	0.75	41	12	0.70	2.3	12.74	10.5	0.2328	3.50	(2)	103.28	187
2029	0.75	41	12	0.70	2.3	12.74		0.2328	3.50	(2)	113.78	187

Summer Energy Use (GWH)

Year	Silt	Navajo	NTUA *5	Paradox	CUP Jensen	(4) CUP Bonneville	Dolores	Dutch John	(2) Animas-LaPlata		Total (GWH)
2015	1.5	30	42	2.2	1.26	13.6	6	0.5	4.00	(2)	101.06
2016	1.5	30	42	2.2	1.26	13.6	6	0.5	4.00	(2)	101.06
2017	1.5	30	42	2.2	1.88	13.6	6	0.5	4.00	(2)	101.68
2018	1.5	30	42	2.2	1.88	13.6	6	0.5	4.00	(2)	101.68
2019	1.5	30	42	2.2	1.88	13.6	6	0.5	5.20	(2)	102.88
2020	1.5	30	42	2.2	1.88	13.6	6	0.5	5.20	(2)	102.88
2021	1.5	30	42	2.2	1.88	16.1	6	0.5	5.20	(2)	105.38
2022	1.5	30	42	2.2	2.52	16.1	6	0.5	5.20	(2)	106.02
2023	1.5	30	42	2.2	2.52	16.1	6	0.5	6.50	(2)	107.32
2024	1.5	36	42	2.2	2.52	16.1	6	0.5	6.50	(2)	113.32
2025	1.5	36	42	2.2	2.52	16.1	6	0.5	6.50	(2)	113.32
2026	1.5	36	42	2.2	2.52	18.7	6	0.5	6.50	(2)	115.92
2027	1.5	36	42	2.2	3.14	18.7	6	0.5	7.60	(2)	117.64
2028	1.5	36	42	2.2	3.14	18.7	6	0.5	7.60	(2)	117.64
2029	1.5	36	42	2.2	3.14	18.7	6	0.5	7.60	(2)	117.64

(1) Estimates do not include losses.

(2) Power requirements will be updated as project proponents refine their water development. Current projections assume full non-Ute Indian development by 2030. Full prject development (Indian + Non-Indian) would require a Summer Peak demand of 17.0 MW and a Summer use of 42.0 GWH. Summer season now at two months.

(3) The capacity for the Dolores Project includes 1.5 MW for the Ute Mt Utes.
The normal Dolores summer demand is 9 mw and add the 1.5 mw for Mt Ute results in 10.5 mw forecasted above.

(4) The major projects for CUP's use of CRSP power are in the early planning stages.

(5) energy for NTUA computed on bases of 8 months (March 1 to Oct 31) at 60% load factor.

COLORADO RIVER STORAGE PROJECT
Participating Projects
Estimated Project Power Requirements (1)
Table 2

Winter Peak Demands (MW) typcically from October to March (but may vary from contract to contract)

Year	Silt	Navajo	NTUA *5	Paradox	CUP Jensen	(4) CUP Bonneville	(3) Dolores	Dutch John	(2) Animas LaPlata		(MW)	(MW)
2015	0	10	0	0.70	0.09	5.71	3 *	0.22	0.20	(2)	167.08	187
2016	0	10	0	0.70	0.09	5.71	3	0.22	0.20	(2)	167.08	187
2017	0	10	0	0.70	0.09	5.71	3	0.22	0.20	(2)	167.08	187
2018	0	10	0	0.70	0.09	5.71	3	0.22	0.20	(2)	167.08	187
2019	0	10	0	0.70	0.09	5.71	3	0.22	0.90	(2)	166.38	187
2020	0	10	0	0.70	0.09	5.71	3	0.22	0.90	(2)	166.38	187
2021	0	10	0	0.70	0.09	10.46	3	0.22	0.90	(2)	161.63	187
2022	0	10	0	0.70	0.09	10.46	3	0.22	0.90	(2)	161.63	187
2023	0	10	0	0.70	0.09	10.46	3	0.22	0.90	(2)	161.63	187
2024	0	10	0	0.70	0.09	10.46	3	0.22	0.90	(2)	161.63	187
2025	0	10	0	0.70	0.09	10.46	3	0.22	0.90	(2)	161.63	187
2026	0	10	0	0.70	0.09	15.21	3	0.22	0.90	(2)	156.88	187
2027	0	10	0	0.70	0.47	15.21	3	0.22	0.90	(2)	156.50	187
2028	0	10	0	0.70	0.47	15.21	3	0.22	0.90	(2)	156.50	187
2029	0	10	0	0.70	0.47	15.21	3	0.22	0.90	(2)	156.50	187

Winter Energy Use (GWH)

Year	Silt	Navajo	NTUA	Paradox	CUP Jensen	(4) CUP Bonneville	Dolores	Dutch John	(2) Animas LaPlata		Total (GWH)
2015	0	2.0	0.0	2.2	0.04	15.2	0.58	0.5	1.00	(2)	21.56
2016	0	2.0	0.0	2.2	0.04	15.2	0.58	0.5	1.00	(2)	21.52
2017	0	2.0	0.0	2.2	0.04	15.2	0.58	0.5	1.00	(2)	21.52
2018	0	2.0	0.0	2.2	0.04	15.2	0.58	0.5	1.00	(2)	21.52
2019	0	2.0	0.0	2.2	0.04	15.2	0.58	0.5	1.80	(2)	22.32
2020	0	2.0	0.0	2.2	0.04	15.2	0.58	0.5	1.80	(2)	22.32
2021	0	2.0	0.0	2.2	0.04	17.7	0.58	0.5	1.80	(2)	7.12
2022	0	2.0	0.0	2.2	0.04	17.7	0.58	0.5	1.80	(2)	7.12
2023	0	2.0	0.0	2.2	0.04	17.7	0.58	0.5	1.70	(2)	7.02
2024	0	2.0	0.0	2.2	0.04	17.7	0.58	0.5	1.70	(2)	7.02
2025	0	2.0	0.0	2.2	0.04	17.7	0.58	0.5	1.70	(2)	7.02
2026	0	2.0	0.0	2.2	0.04	20.2	0.58	0.5	1.70	(2)	7.02
2027	0	2.0	0.0	2.2	0.63	20.2	0.58	0.5	1.60	(2)	7.51
2028	0	2.0	0.0	2.2	0.63	20.2	0.58	0.5	1.60	(2)	7.51
2029	0	2.0	0.0	2.2	0.63	20.2	0.58	0.5	1.60	(2)	7.51

(1) Estimates do not include losses.

(2) Power requirements will be updated as project proponents refine their water development. Current projections assume full non-Ute Indian development by **2030**. Full project development (Indian + Non-Indian) will require a Winter Peak Demand of 10.0 MW and a Winter use of 17.0 GWH. Winter season now at 10 months.

(3) The capacity for the Dolores Project includes 1.5 MW for the Ute Mt Utes.
The normal Dolores winter demand is 1.5 mw and add the 1.5 mw for the Ute Mt Utes results in 3.0 mw forecasted above.

(4) The major projects for CUP's use of CRSP power are in the early planning stages.

(5) 12 MW transferred from NIIP to Western for NTUA under amendment 5 to 87-SLC-0013 is only from March 1 to October 31 (an 8 month period), therefore 0 demand and 0 energy is shown here for the winter season.

Colorado River Storage
Participating Projects
Estimated Project Power Requirements (1)
Table 3

Below are forecasted Pumping Plant Schedules and loads (3)

CUP - Bonneville Unit (4)

Plant/Project Name	In Service	Capacity MW
Deer Creek/Jordanelle exch.	June 1995	1.80
Wasatch County	April 2001	3.00
Starvation Collection System	1970s	0.24
Envir. Commit. (SL Aqueduct)	Use Varies	0.67
Conjunctive Use (50%)	2020	3.50
Conjunctive Use (50%)	2025	3.50
CUPCA Water Cons. Programs (50%)	2020	1.25
CUPCA Water Cons. Programs (50%)	2025	1.25
	Total	15.21

Navajo Tibubal Utility Authority (NTUA) (5)
(transfer from Navajo Agricultural Products Industry) Total 12

Plant Name Navajo Indian Irrigation Project (NIIP)	In Service (5)	Max. Capacity MW
Blocks 4, 5, 6, 7 and Kutz Pumping Plant	In service	23.80
Block 8 (Schedule 1 & 2)	Aug. 2001	0.45
Gallegos Pumping Pl. (7%)	Aug. 2001	1.42
Block 8, Schedule 3 & 4	Apr. 2001	2.20
Gallegos Pumping Plant (21%)	Apr. 2001	4.25
Block 1 (part. Gas to elect.)	Apr. 2002	0.62
Block 9, Stage 1 (B2.9L)	Apr. 2010	0.15
Gallegos Pumping Plant (0.7%)	Apr. 2010	0.15
Blk9 STG1 (B2.9L)	2013	0.36
Blk9 STG1 (B1.0L)	2014	0.56
Blk9 STG1	2015	0.77
Block 9, Stage 2	Aug. 2020	1.50
~~Gallegos Pumping Plant (9%)~~	~~Aug. 2015~~	~~2.75~~
Block 9, Stage 3	Aug. 2024	1.45
Gallegos Pumping Plant (18%)	Aug. 2024	5.31
Moncisco Pumping Pl. (60%)	Aug. 2029	4.74
Block 10	Aug. 2029	1.74
Gallegos Pumping Plant (28%)	Aug. 2029	8.27
Block 11	Aug. 2034	1.87
Gallegos Pumping Plant (19%)	Aug. 2034	5.61
Moncisco Pumping Pl. (40%)	Aug. 2034	3.16
	Total	68.38
	(Round to)	69

Paradox: the current injection well is showing signs of deterioration. Reclamation is currently investigating alternatives to deep well injection for disposal of the brine, so future project power estimates are in question. New power estimates will be available when a preferred alternative has been selected for Paradox.

Navajo-Gallup Water Supply Project (see note 6)		
San Juan Interim demand	Sept. 2014	0.078
San Juan 2020 demand	Sept. 2023	9.00
Cutter 2020 demand	Dec. 2015	1.72
Cutter + San Juan 2040 demand	2040	27.437
	----------------	------------

(1) The estimates do not include losses.

(2) Deleted note #2 (not used) which was Animas LaPlata and is now online

(3) In service dates are subject to change due to funding.

(4) The major projects for CRSP power are in the early planning stages. See Central Utah Project Completion Program, Supplement to 1988 Definite Plan, Power Appendix, Chapter 5, reference 1.B.02.029.B0.133, Bonneville Unit

(5) Total maximum capacity reserved for NIIP is 87 MW which includes 12 MW currently utilized by NTUA pursuant to contract 87-SLC-0014 as amended.

(6) Authorization for the Navajo-Gallup Water Supply Project (Project) was included in the (Omnibus Public Land Management Act (Act) of 2009, Title X, Part III (Public Law 111-11, March 30, 2009). The Act provides in Section 10602 (e), that: "The Secretary shall reserve, from existing reservations of Colorado River Storage Project power for Bureau of Reclamation projects, up to 26 megawatts of power for use by the Project". While current estimates exceed the amount of power reserved in the legislation, design refinements continue which will result in changes to the estimated total power needs.

Colorado River Storage Project
Bureau of Reclamation and Western Area Power Administration
Glen Canyon Environmental Studies and Other Environmental Costs

Last Revised: May 6, 2015

				Other Environmental Costs								Total in PRS		
				Reclamation 1/							Western 2/			
	Glen Canyon Environmental Costs			Environmental Studies			Recovery Implementation Program (RIP)							
	Non-Reimbursable													
Year	Western	Reclamation	Total	Flaming Gorge	Aspinall	Navajo	Base Program	Capital 5/	Consumptive Use 6/	Water Quality 6/	Misc Non-Reimbursable	Western	Reclamation	Total
1983	-	876,950	876,950	-	-	-	1,167,482	-	1,122,159	2,275,011	-	-	5,441,602	5,441,602
1984	-	1,013,434	1,013,434	-	-	-	142,781	-	103,593	250,085	-	-	1,509,893	1,509,893
1985	(94,762)	1,404,765	1,310,003	-	-	-	185,189	-	170,642	262,514	377	(94,385)	2,023,110	1,928,725
1986	390,789	2,385,455	2,776,244	-	-	-	246,606	-	108,981	232,844	609	391,398	2,973,886	3,365,284
1987	10,785	1,709,058	1,719,843	-	-	-	330,780	-	117,713	256,638	134,900	145,685	2,414,189	2,559,874
1988	-	966,780	966,780	-	-	-	400,959	-	99,160	330,562	171,435	171,435	1,797,461	1,968,896
1989	-	1,407,719	1,407,719	-	-	-	888,587	-	108,565	124,909	382,630	382,630	2,529,780	2,912,410
1990	1,885,019	4,632,949	6,517,968	-	-	-	(52,519)	-	201,295	173,458	681,645	2,566,664	4,955,184	7,521,848
1991	3,921,978	11,689,135	15,611,113	-	-	-	543,386	-	191,381	206,635	1,076,716	4,998,694	12,630,537	17,629,231
1992	4,245,939	13,043,929	17,289,868	-	-	-	1,235,641	-	160,351	204,299	655,849	4,901,788	14,644,220	19,546,008
3/	10,359,748	39,130,174	49,489,922	-	-	-	5,088,892	-	2,383,840	4,316,955	3,104,161	13,463,909	50,919,862	64,383,771
			4/									-	-	-
1993	2,733,998	-	2,733,998	-	-	-	2,210,511	-	255,814	233,678	254,913	2,988,911	2,700,003	5,688,914
1994	6,292,442	12,392,105	18,684,547	209,483	149,335	-	5,663,621	-	301,640	161,975	523,401	6,815,843	18,519,341	25,335,184
1995	1,473,893	8,391,015	9,864,908	48,410	51,945	-	2,379,586	-	311,533	340,722	69,419	1,543,312	11,422,857	12,966,169
1996	3,155,770	13,032,177	16,187,947	28,157	64,982	-	(2,419,491)	-	281,453	179,236	112,444	3,268,214	11,073,375	14,341,589
1997	1,429,879	6,367,002	7,796,881	54,245	125,779	217,407	1,988,136	-	327,836	317,097	303,075	1,732,954	9,000,071	10,733,025
Sub	15,085,982	40,182,299	55,268,281	340,295	392,041	217,407	9,822,363	-	1,478,278	1,232,708	1,263,252	16,349,234	52,715,647	69,064,881
												-	-	-
1998	130,000	4,352,747	4,482,747	122,000	171,764	535,508	2,259,778	-	243,970	252,856	201,199	331,199	7,109,351	7,440,550
1999	-	1,012,060	1,012,060	286,946	182,201	382,274	3,228,244	-	275,967	302,492	396,008	396,008	4,818,763	5,214,771
2000	-	4,939,719	4,939,719	618,257	213,726	663,719	2,056,559	-	265,736	546,476	508,440	508,440	7,808,491	8,316,931
2001	26,390,000	12,026,703	38,416,703	236,000	303,000	642,000	2,534,979	-	252,125	684,909	515,183	26,905,183	15,498,716	42,403,899
2002	30,000	13,431,462	13,461,462	-	-	-	4,555,228	-	266,796	667,745	603,073	633,073	18,921,232	19,554,305
2003	-	(1,033,336)	(1,033,336)	-	-	-	5,900,957	5,500,000	294,027	406,073	2,202,391	2,202,391	5,567,721	7,770,112
2004	-	10,790,208	10,790,208	30,000	344,000	120,000	6,322,649	-	151,389	994,295	756,803	756,803	18,258,541	19,015,344
2005	1,010,000	7,703,773	8,713,773	30,000	347,000	120,000	5,736,388	5,938,800	275,242	742,726	925,217	1,935,217	14,458,129	16,393,346
2006	-	9,072,369	9,072,369	-	327,000	64,000	7,820,465	-	(1,324,602)	737,622	734,361	734,361	16,305,855	17,040,216
2007	-	9,248,741	9,248,741	3,253	340,746	413	6,923,453	-	248,832	797,608	670,773	670,773	17,218,634	17,889,407
2008	3,830,000	8,831,479	12,661,479	-	767,721	-	7,667,499	-	308,443	599,174	1,673,955	5,503,955	17,406,595	22,910,550
2009	480,000	8,965,727	9,445,727				7,371,302	-	237,027	806,716	781,851	1,261,851	17,380,773	18,642,624
2010	510,000	10,010,181	10,520,181				7,260,131	-	222,256	848,399	1,039,791	1,549,791	18,340,967	19,890,758
2011	-	10,598,156	10,598,156				7,706,099	-	280,380	638,225	995,352	995,352	19,222,860	20,218,212
2012	622,000	4,236,682	4,858,682				10,579,096	-	201,572	846,893	1,741,284	2,363,284	15,864,243	18,227,527
2013	375,000	7,499,314	7,874,314				7,825,157	-	255,613	703,030	1,850,596	2,225,596	16,283,114	18,508,710
2014	1,918,000	13,137,932	15,055,932				7,887,889	-	305,788	755,340	3,529,837	5,447,837	22,086,949	27,534,786
Sub	35,295,000	134,823,917	170,118,917	1,326,457	2,997,158	2,527,914	103,635,873	11,438,800	2,760,561	11,330,580	19,126,114	54,421,114	252,550,931	306,972,045
Total	60,740,730	214,136,390	274,877,120	1,666,752	3,389,199	2,745,321	118,547,128	11,438,800	6,622,679	16,880,243	23,493,527	84,234,257	356,186,440	440,420,697

1/ Costs of RIP program became non-reimbursable beginning in FY 1993 per memo from UC Regional Director on Feb 2, 1993, and further by PL 106-392--October 30, 2000.
Environmental costs at Flaming Gorge, Aspinall, and Navajo are considered reimbursable but may be reclassified in the future.

2/ These costs are related to misc "non-compliance" environmental costs. Some costs are related to the Argonne contract for RIP and are considered non-reimbursable.
Beginning in 2001 portions of Resources and Environmental staff hours were deemed non-reimbursable and included with Argonne in this column.

3/ Title 18, Section 1804, PL 102-575 declared all expenses incurred through FY 1992 as "non-reimbursable". Prior to the Act, Western had considered $51,216,926
of the $52,680,022 as reimbursable by power. This amount ($51,216,926) was adjusted out of Western's power repayment study in 1993.

4/ For FY 1993-1997 as determined by the Commissioner's Office (USBR) and sent to Western on Feb 2, 2000. Costs were prorated to each agency based on each agency's
proportionate share of total costs.

5/ RIP Loans thru the State of Colorado.

6/ Data for 1983 is the cumulative total for 1979-1983.

Department of Energy
Western Area Power Administration
150 East Social Hall Avenue, Suite 300
Salt Lake City, UT 84111-1580

APR 23 2015

Sent via E-mail

Dear Salt Lake City Area Integrated Projects Customer:

Under your firm electric service contract, Western assesses energy and demand charges as set forth in Rate Schedule SLIP-F9. Additionally, under this rate schedule, a Cost Recovery Charge (CRC) may also be assessed if Western determines it is necessary.

Western is required to notify its customers by May 1, 2015, if a CRC is needed in the next fiscal year. We have reviewed our financial situation compared to the anticipated hydropower generation levels and determined there will be no CRC for FY 2016. Because there is no CRC, there is no need for action on your part.

Had the CRC been necessary, each customer would have been provided with two sets of energy numbers for the next fiscal year. One set would have shown the full Sustainable Hydropower (SHP) energy allocation, and the other set would have shown a lower SHP allocation. Under this scenario, each customer would then decide whether to accept or decline the CRC. Customers accepting the CRC would receive the full SHP allocation and be charged the additional expense of the CRC. Those customers declining the CRC would avoid the charge, but receive less energy from Western in the next fiscal year.

Since a CRC is not necessary for FY 2016, Western will not be providing alternative energy and capacity allocations. Western will proceed as normal and provide your Winter Season attachment later this summer. Again, no action is needed on your part.

If there are any questions, please telephone me at (801) 524-4007.

Sincerely,

Rodney G. Bailey
Vice President of Power Marketing
CRSP Management Center

Enclosure

APR 23 2015

FY 2016 CRC Calculation

April 2015

			FY 2016	
Step 1	BFBB	Basin Fund Beginning Balance ($)	$86,899,000	Projected beginning balance for FY2016 per financial cash flow analysis (FY2016 Beginning Bal * 1000)
	BFTB	Basin Fund Target Balance	$35,843,250	Basin Fund Target Balance = 15% *PAE
	PAR	Projected Annual Revenue ($) w/o CRC	$232,780,000	Per financial cash flow analysis, (=TOTAL REV *1000)
	PAE	Projected Annual Expense ($)	$238,955,000	Per financial cash flow analysis, (=TOTAL EXP *1000)
	NR	Net Revenue ($)	($6,175,000)	=PAR-PAE
	NB	Net Balance ($)	$80,724,000	=BFBB + NR
Step 2	EA	SHP Energy Allocation (GWh)	4,951.79	FY '16 SHP energy allocation excluding project use (=SHP DELIVERIES / 1MIL)
	HE	Forecasted Hydro Energy (GWH)	4,560.25	Projected generation from the most current 24-month study, does not include project use (=NET GEN / 1MIL)
	FE	Forecasted Energy Purchase (GWh)	779	Forecasted Energy Purchase (GWh) from the most current 24-month study (=FIRMING PURCHASES / 1MIL)
	Price	Average price per MWh for purchased power	$26.39	Average price = 60% onpeak + 40% offpeak (=COMP PRICE)
	FX	Forecasted Energy Purchase Expense ($)	$20,572,276	Estimated purchased power costs based upon most current 24-month study (= PURCHASE COST)
Step 3	FA1	Basin Fund Balance Factor ($)	$20,572,276	If NB is greater than BFTB then use FA1=FX, if NB is less than BFTB then use FX-(BFTB-NB) Formula is: -IF(NB>BFTB,FX,FX-(BFTB-NB))
	FA2	Revenue Factor ($)	$20,572,276	If NR is greater than -25% of BFBB then FX, if NR is less than -25% of BFBB then, FX+(NR+(25%*BFBB)) Formula is: =IF(NR>-(0.25*BFBB),FX,FX+(NR+(0.25*BFBB)))
	FA	Funds Available ($) (Lesser of FA1 or FA2)	$20,572,276	Formula is: =IF(NR>-(0.25*BFBB),FX,FX+(NR+(0.25*BFBB)))
	FARR	Additional Revenue to be Recovered (FX-FA)	$0	=FX-FA
Step 4	WL	**Waiver Level (GWH)**	**5,340**	**Equals the lesser of SHP or HE + (FE * (FA / FX))**
	WLP	Waiver level percentage of full SHP	**108%**	Percent of waiver level to full SHP
	CRCE	CRC Energy GWh (EA-WL)	0	= EA-WL (Does not include losses projected at 7.81%)
	CRCEP	CRC level percentage of full SHP	0%	Percent of CRCE to full SHP or CRCE/EA
	CRC	**Cost Recovery Charge (mills/kWh)**	-	**=FARR / (EA * 1000)**

Note: Cash flow projections from the: April 2015, 24-month study