A PUBLIC AGENCY
NCPA
NORTHERN CALIFORNIA POWER AGENCY

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Revised Agenda

Date: **July 9, 2014**

Subject: **July 14, 2014 Lodi Energy Center Project Participant Committee Meeting**

Location: **12745 N. Thornton Road, Lodi, CA or via teleconference**

Time: **10:00 A.M.**

***** In compliance with the Brown Act, you may participate in person at the meeting location or via teleconference at one of the locations listed below. In either case, please: (1) post this notice at a publicly accessible location at the participation location at least 72-hours before the call begins, and (2) have a speaker phone available for any member of the public who may wish to attend at your location.**

NCPA 12745 N. Thornton Road Lodi, CA	**NCPA 651 Commerce Drive Roseville, CA**	**CITY OF HEALDSBURG 401 Grove Street Healdsburg, CA**
BAY AREA RAPID TRANSIT 300 Lakeside Drive, 16th Floor Oakland, CA	**CITY OF GRIDLEY 685 Kentucky Street Gridley, CA**	**CITY OF LOMPOC 100 Civic Center Plaza Lompoc, CA**
CITY OF BIGGS 465 “C” Street Biggs, CA	**CITY OF SANTA CLARA 1500 Warburton Avenue Santa Clara, CA**	**CITY OF UKIAH 411 W Clay Street Ukiah, CA**
CALIFORNIA DEPARTMENT OF WATER RESOURCES 3310 El Camino Ave. Room LL93 Sacramento, CA	**POWER & WATER RESOURCES POOLING AUTHORITY 2106 Homewood Way, Suite 100 Carmichael, CA**	**PLUMAS-SIERRA RURAL ELECTRIC COOP 73233 Highway 70 Portola, CA**
MODESTO IRRIGATION DISTRICT 1231 Eleventh Street Modesto, CA		

The Lodi Energy Center Project Participant Committee may take action on any of the items listed on this Agenda regardless of whether the matter appears on the Consent Calendar or is described as an action item, a report, or an information item. If this Agenda is supplemented by staff reports, they are available to the public upon written request. Pursuant to California Government Code Section 54957.5, the following is the location at which the public can view Agendas and other public writings: NCPA, 651 Commerce Drive, Roseville, CA or www.ncpa.com

1. **Call Meeting to Order and Roll Call**

PUBLIC FORUM

Any member of the public who desires to address the Lodi Energy Center Project Participant Committee on any item considered by the Lodi Energy Center Project Participant Committee at this meeting before or during the Lodi Energy Center Project Participant Committee's PPC consideration of that item shall so advise the Chair and shall thereupon be given an opportunity to do so. Any member of the public who desires to address the Lodi Energy Center Project Participant Committee on any item within the jurisdiction of the Lodi Energy Center Project Participant Committee and not listed on the Agenda may do so at this time.

2. **Meeting Minutes** - Approval of PPC meeting minutes for the June 9, 2014 regular meeting

MONTHLY REPORTS

3. **Operational Report for June 2014** - *(Jeremy Lawson)*

4. **Market Data Report for June 2014** – Verbal Report *(Bob Caracristi)*

5. **Monthly Asset Report** – *(Michael DeBortoli)*

CONSENT CALENDAR

All items on the Consent Calendar are considered routine and will be approved without discussion by a single roll call vote. Any Project Participant or member of the public may remove any item from the Consent Calendar. If an item is removed, it will be discussed separately following approval of the remainder of the Consent Calendar. Prior to the roll call vote to approve the Consent Calendar, the Participants will be polled to determine if any Participant wishes to abstain from one or more items on the Consent Calendar.

6. **Treasurer's Report for June 2014 –** Accept by all Participants

7. **Financial Report for June 2014 –** Approve by all Participants

8. **GHG Reports (excerpted from monthly ARB)** - Accept by all Participants

9. **Change Order No. 1 to Siemens Long Term Maintenance Program for LEC** – Staff seeking approval of Change Order No. 1 to document the costs associated with warranty repair of Row 3 diaphragm replacement and to the track the Event, Annual, and Contract limitations. No fiscal impact.

Consent Items pulled for discussion: ______________________________________

BUSINESS ACTION ITEMS

10. **Change Order No. 2 to Siemens Long Term Maintenance Program for LEC** – Staff seeking approval of Change Order No. 2 to (i) add the third Major to the Contract scope including operation on Equivalent Starts, (ii) provide for the installation of CIE hardware (as defined below) at the Period 2 Hot Gas Path Scheduled Outage, (iii) add flex scheduling, (iv) provide additional coverage for access costs for warranty non-conformities and to increase Seller's aggregate financial limitation over the Term for damage to Buyer's property, and (iv) eliminate the requirement for Buyer to provide business continuation insurance, at an additional cost of $28 million over the 18 year life of the agreement.

11. **Planned Maintenance Outage Schedule for Calendar Year 2015** – Staff seeking approval of the planned maintenance outage schedule for 2015 for LEC (*Mike DeBortoli*)

INFORMATIONAL ITEMS

12. **Proposed PG&E Rate Increase –** Staff to provide update regarding the proposed PG&E rate increase, its impacts, NCPA's participation in the Northern California Gas Coalition (NCGC) and its activities regarding gas-related activities and the current natural gas transmission and storage rate case at the CPUC *(Gillian Biedler)*

13. **LEC Project Management and Operations Agreement (PMOA) Schedule 7.00 –** Staff to provide update on development of an amendment to PMOA Schedule 7.00 and discuss the formulas and methodologies contained therein *(James Takehara)*

14. **Nexant Study Analysis and Findings –** Staff to provide update regarding study performed relative to congestion at LEC.

15. **Other New Business**

ADJOURNMENT

Next Meeting: August 11, 2014

11. **Planned Maintenance Outage Schedule for Calendar Year 2015** – Staff seeking approval of the planned maintenance outage schedule for 2015 for LEC (*Mike DeBortoli*)

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15. **Other New Business**

ADJOURNMENT

Next Meeting: August 11, 2014

Lodi Energy Center
Project Participant Committee Meeting
June 9, 2014 - MEETING MINUTES
Location: Lodi Energy Center
12745 N. Thornton Rd, Lodi CA 95242
and by teleconference
10:00 A.M.

1. Call Meeting to Order and Roll Call

The PPC meeting was called to order at 10:03 a.m. by Chairman Mike Werner. He asked that roll be called as listed below.

Particpant	Attendance	Particulars / GES
Azusa - Morrow	Present	2.7857%
BART - Schultz	Absent	6.6000%
Biggs - Sorenson	Present	0.2679%
CDWR - Werner	Present	33.5000%
Gridley - Stiles	Absent	1.9643%
Healdsburg - Crowley	Absent	1.6428%
Lodi - Price	Present	9.5000%
Lompoc - Hostler	Absent	2.0357%
MID - Caballero	Absent	10.7143%
Plumas-Sierra - Brozo	Absent	0.7857%
PWRPA - Palmerton	Present	2.6679%
SVP - Hance	Present	25.7500%
Ukiah - Grandi	Absent	1.7857%
Summary		
Present	6	74.4715%
Absent	7	25.5285%
Quorum by #:	No	
Quorum by GES:	Yes	

Also present were:
Lloyd Rowe (CDWR by telephone)
Ken Speer (NCPA)
Mike DeBortoli (NCPA)
Jeremy Lawson (NCPA)
Linda Stone (NCPA)
Bob Caracristi (NCPA by telephone)
Donna Stevener (NCPA by telephone)
Tom Lee (NCPA by telephone)
Gillian Biedler (NCPA by telephone)
Ruthann Ziegler (Meyers-Nave by telephone)

Chairman Werner noted there is not a quorum based on the number of Participant representatives present. However action may be taken based on there being present a quorum of Participant representatives holding a GES of not less than a majority of the aggregate GES of all non-defaulting participants.

Public Forum

Chairman Werner asked if any members of the public were present in Lodi or at any of the other noticed meeting locations that would like to address the PPC on any agenda items. No members of the public were present.

2. Meeting Minutes

The draft minutes for the May 12, 2014 regular meeting were considered. The LEC PPC considered the following motion:

Date: 6/9/2014

Motion: The PPC approves the minutes of the May 12, 2014 regular meeting, including any edits discussed at today's meeting.

Moved by: **Azusa**

Seconded by: **Lodi**

Discussion: There was no further discussion.

Vote Summary on Motion		
Participant	**Vote**	**Particulars / GES**
Azusa	Yes	2.7857%
BART	Absent	6.6000%
Biggs	Yes	0.2679%
CDWR	Yes	33.5000%
Gridley	Absent	1.9643%
Healdsburg	Absent	1.6428%
Lodi	Yes	9.5000%
Lompoc	Absent	2.0357%
Modesto	Absent	10.7143%
Plumas-Sierra	Absent	0.7857%
PWRPA	Yes	2.6679%
Silicon Valley Power	Yes	25.7500%
Ukiah	Absent	1.7857%
Vote Summary		
Total Ayes	6	74.4715%
Total Noes	0	0.0000%
Total Abstain	0	0.0000%
Total Absent	7	25.5285%
Result:	Motion passed by GES.	

MONTHLY REPORTS

3. Operational Reports for May 2014

Jeremy Lawson presented the monthly written Operational Report including Safety, Notice of Violations, Outage Summaries, Planned Outages, and Generating Unit Statistics for May. There were no OSHA Recordable accidents, no Permit violations and no NERC/WECC violations. The plant completed its planned outages; as a result was out of service for 43.6 hours during the month. An outage occurred on May 31 when an HP economizer header drain developed a crack creating a steam leak in the HRSG forcing LEC offline. A weld repair was done during the weekend and it was returned to service the next day. The report reflected monthly production of 71,206 net MWH, 296 service hours, and equivalent operating availability of 90.89%. The report set forth the Capacity Factor @ 280MW Pmax of 34.23% and @ 302MW Pmax of 31.73%. During the month the plant had 11 hot starts, six warm starts, and one cold start. Jeremy said the overall operation and unit itself is running well.

4. Market Data Report for May 2014

Bob Caracristi discussed the operating and financial settlement results for the month.

Frank Schultz arrived at the meeting on behalf of BART.

5. Monthly Asset Report

Mike DeBortoli presented his updated monthly budget review for FY 14 with actual numbers compared to estimated values for April. He said the unit is performing better than planned. He discussed maintenance costs over budget due primarily to new plant issues, RAC leaks, and long term maintenance costs. He pointed out that the budget numbers are based on 296 MW production output. The long term maintenance is based on fired hours not HW hours. He said when the plant is running we are covering the costs. Ken Speer said there is nothing in our bid strategy for margins. Frank Schultz asked how much the plant is expected to run this summer. Tom Lee said the plant is expected to run at peak with a 50-60% capacity factor. Ken said he expects the plant will also run a lot in the fall when hydro disappears. LEC ran more this spring than last year and he expects that to continue.

Consent Calendar

Chairman Werner asked if any Participant wished to remove any item listed on the Consent Calendar for separate discussion. Hearing none, he then asked if any Participant wished to abstain from one or more items on the Consent Calendar. There were no abstentions. The LEC PPC considered the following motion:

Date: 6/9/2014

Motion: The PPC approves the 6/9/2014 Consent Calendar consisting of agenda items no. 6, 7, 8, 9, 10, and 11.

Moved by: **BART**

Seconded by: **Lodi**

Discussion: There was no further discussion.

Vote Summary on Motion		
Participant	**Vote**	**Particulars / GES**
Azusa	Yes	2.7857%
BART	Yes	6.6000%
Biggs	Yes	0.2679%
CDWR	Yes	33.5000%
Gridley	Absent	1.9643%
Healdsburg	Absent	1.6428%
Lodi	Yes	9.5000%
Lompoc	Absent	2.0357%
Modesto	Absent	10.7143%
Plumas-Sierra	Absent	0.7857%
PWRPA	Yes	2.6679%
Silicon Valley Power	Yes	25.7500%
Ukiah	Absent	1.7857%
Vote Summary		
Total Ayes	7	81.0715%
Total Noes	0	0.0000%
Total Abstain	0	0.0000%
Total Absent	6	18.9285%
Result:	Motion passed.	

BUSINESS ACTION ITEMS

12. Amendment to LEC Long Term Maintenance Program

Mike DeBortoli presented a detailed PowerPoint and explained an amendment to the Long Term Maintenance Program he is discussing with Siemens. LEC purchased the final model FD3 turbine from Siemens in 2008. Siemens is now producing model FD5 and Mike explained the differences. In February 2014 Siemens announced that parts are available to upgrade the FD3 which would be beneficial for LEC. Being a starts based maintenance program, starts would be increased to 1200 from 900 and with the new parts; the need for combustion inspection outages would be eliminated. Mike provided a comparison and details about various components. He also showed how the new parts would extend the inspection intervals; three majors would be covered. Mike summarized the existing terms of the maintenance program agreement and summarized the changed terms being discussed. He presented an economic evaluation which shows a benefit of about $12 million over the life of the agreement. This results in approximately a $4 million benefit over the next five years. Mike said he is presenting this information to gauge the Participants' interest in amending the maintenance program and whether he should continue negotiations with Siemens. Ken Speer said an additional benefit of utilizing the new parts is that fewer parts would need to be stocked in the warehouse. When asked his opinion, Mike DeBortoli said he thinks this is a great deal. It was noted that this would be a commitment to use Siemens for one more maintenance cycle. It was the unanimous opinion of the Participants that staff go forward with negotiations to utilize the new parts and increase equivalent start intervals for hot gas path and major inspections.

The second issue Mike presented relative to the long term maintenance program is consideration of upgrading to a DF5 to possibly gain 30 MW. The work would be done during a major outage, such as in 2022, and would require a much more long term look and the impacts on generation. Discussion was had. Mike said there is extensive engineering to review to determine whether such an upgrade would be feasible from an entire plant aspect. In response to a question from Martin Caballero and regarding calculation of a break-even cost, Mike said staff has not yet looked at the economics. Mike Werner said the issue of emission reduction credits would also need to be included in the analysis.

13. PG&E's Compressed Air Storage Project

Ken Speer followed up his report to the Committee last month. With respect to the two biggest issues for NCPA to allow the project to go forward, Ken presented a draft of language he submitted to Steve Schwabauer to address assurance that sufficient water storage capacity is constructed to ensure daily operation of LEC and STIG; installation and maintenance of any and all transmission improvements necessary to avoid local congestion or deliverability charges imposed by the CAISO due to the project which impacts NCPA's ability to operate or the prices paid for output of either LEC or STIG; and PG&E to pay NCPA for all costs of any such congestion charges imposed by CAISO directly or indirectly related to the new project. Mike Werner noted that any impacts to the switchyard should be included. A deliverability study will be done for the project. Ken said in his opinion based on economics, the odds of the project going forward are slim. Mike Werner also noted that if PG&E pays for upgrades, we may lose local capacity. Staff has not yet looked at this aspect for this possible project. Ken said we will include a provision about the local capacity component. George Morrow commented that if the PPC is able to facilitate this project since it would be good for LEC Participant the City of Lodi, he hopes the PPC can do so.

14. LEC Project Management and Operations Agreement (PMOA) Schedule 1.00

Tony Zimmer presented a memo to provide background and observations regarding LEC bidding strategy – real time market. The new Fifteen Minute Market (FMM) began operating May 1, 2014 and has been operating for one full month. The FMM effectively replaces the Hour Ahead Scheduling Process (HASP) and produces financially binding awards for both Inter-Tie schedules and internal generation for each 15-minute interval during an hour. Tony explained that the FMM design is primarily intended to align pricing between inter-tie schedules and internal generation to reduce RTM settlement neutrality and to reduce RTM price volatility. The PPC considered the following motion. Staff presented a revised PMOA Schedule 1.00 to change the section entitled NCPA Dispatch Operations.

Date:	6/9/2014
Motion:	The PPC approves revised Schedule 1.00-Scheduling and Dispatch Operations and Economic Criteria, to reflect elimination of Hour Ahead Scheduling Process (HASP) and replacement with the new Fifteen Minute Market (FMM), as part of its existing Real Time Market Process, as discussed at today's meeting.
Moved by:	**BART**
Seconded by:	**Lodi**

Discussion: There was no further discussion.

Vote Summary on Motion		
Participant	**Vote**	**Particulars / GES**
Azusa	Yes	2.7857%
BART	Yes	6.6000%
Biggs	Yes	0.2679%
CDWR	Yes	33.5000%
Gridley	Absent	1.9643%
Healdsburg	Absent	1.6428%
Lodi	Yes	9.5000%
Lompoc	Absent	2.0357%
Modesto	Yes	10.7143%
Plumas-Sierra	Absent	0.7857%
PWRPA	Yes	2.6679%
Silicon Valley Power	Yes	25.7500%
Ukiah	Absent	1.7857%
Vote Summary		
Total Ayes	8	91.7858%
Total Noes	0	0.0000%
Total Abstain	0	0.0000%
Total Absent	5	8.2142%
Result:	Motion passed.	

Tony also explained observations from May and answered questions from the group. Based on those findings, staff wants to make the Participants aware that NCPA intends to begin actively submitting LEC incremental and decremental energy bids into the RTM for the balance of June because staff believes cumulative gains could be yielded on incremental bids and savings realized on decremental bids with this strategy.

INFORMATIONAL ITEMS

15. Remembrance of Former PPC Chairman Steve Hill

In remembrance of former PPC Chairman Steve Hill, staff suggested a display of photographs of all former and current chairpersons of the PPC at the LEC facility. It was the unanimous direction of the Committee that staff carryout this suggestion.

Adjournment

The next regular meeting of the PPC is scheduled for Monday, July 14, 2014. The meeting was adjourned at 11:45 a.m.

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Lodi Energy Center Project Participant Committee

Operational Report

Agenda Item No. 3

Date: 6/9/2014

To: Lodi Energy Center Project Participant Committee

Safety

- OSHA Recordable: 0 Accidents

Notice of Violations

- Permits: 0 Violations
- NERC/WECC: 0 Violations

Outage Summaries:

- **High Pressure Economizer #1 tube leak** – 06/01/2014 – A High Pressure Economizer #1 tube leak developed a crack creating a steam leak in the HRSG. LEC was forced offline during June for 23.3 hours for the weld repair and returned back to service
- **High Pressure Steam Turbine Bearing Drive-End Vibration** – 06/07/2014 – A steam leak near the HP Steam Bearing vibration sensor causing a false vibration spike. The false vibration reading tripped the steam turbine. The Combustion Turbine Generator tripped following the steam turbine trip due both condensate pumps tripping off and not having the capacity to cool full hot reheat steam in bypass mode.

Planned Outage Summaries:

- 2015, May 1st @ 0001 thru May 24th @ 2359 for a Combustion Inspection

Generating Unit Statistics:

Report Date:	
Start Date	6/1/2014
End Date	7/1/2014

1. Monthly Production 51,036 MWH
2. Productivity Factor
   a. Service Hours 217 Hours
   b. Service Factor 30.12 %
   c. Capacity Factor @ 280MW Pmax 25.31 %
   d. Capacity Factor @ 302MW Pmax 23.47 %
3. Equivalent Operating Availability (EOA) 96.41 %
4. Forced Outage Rate (FOR)
   a. Combustion Turbine Generator 10.56 %
   b. Steam Turbine Generator 10.78 %
5. Heat Rate Deviation (HRD)
   a. Fuel Cost (Not Current Market Price) 4.00 $/mmBTU

MW Range		Average HR	PMOA HR	Deviation	Production	Cost
		BTU/kW-Hr	BTU/kW-Hr	%	MWH	$
Seg. 1	296 - 302	6,850	6850	0.00%	0	$0
Seg. 2	284 - 296	6,937	6870	0.97%	4,095	$1,091
Seg. 3	275 - 284	6,947	6971	-0.35%	16,194	-$1,585
Seg. 4	250 - 275	6,977	7081	-1.47%	13,695	-$5,720
Seg. 5	225 - 250	7,032	7130	-1.38%	5,913	-$2,320
Seg. 6	200 - 225	7,131	7315	-2.52%	4,054	-$2,984
Seg. 7	175 - 225	7,292	7711	-5.43%	3,367	-$5,641
Seg. 8	165 - 175	7,578	7856	0.00%	1,288	-$1,433
					48,606	**-$18,593**

6. AGC Control Deviation

MW Range		High Dev	Low Dev	Absolute Dev	Cost
		MWH	MWH	MWH	$
Seg. 1	296 - 302	0	0	0	$0
Seg. 2	284 - 296	12	-1	14	$380
Seg. 3	275 - 284	19	-98	116	$3,232
Seg. 4	250 - 275	49	-62	110	$3,081
Seg. 5	225 - 250	34	-17	51	$1,434
Seg. 6	200 - 225	27	-13	39	$1,124
Seg. 7	175 - 225	19	-10	29	$847
Seg. 8	165 - 175	7	-4	10	$309
		167	-203	370	**$10,407**

7. Starting Reliability

Start Type	**Hot Starts**	**Warm Starts**	**Cold Starts**
Number of Starts	11	0	3
Start Time Benchmark (Minutes)	85	160	235
Start Time Actual (Average Minute)	82.5	160.0	184.3
Start Time Deviation (%)	-3.0%	0.0%	-21.6%
Start Fuel Benchmark PMOA (mmBTU)	1,967	5,200	5,430
Start Fuel Actual (Average mmBTU)	1,453	5,200	3,536
Fuel Deviation	-26.1%	0.0%	-34.9%
Costs of Fuel Deviations ($)	**-$2,057**	**$0**	**-$7,575**

Definitions:

1. Monthly Production = Plant Net MWH's

2. Capacity Factor

   a. Service Hours = In Production or in Service State

   b. Service Factor = SH / PH x 100%

   c. Capacity Factor = Production / 302MW x PH

   d. Capacity Factor = Production / 280MW x PH

3. Monthly Equivalent Availibility Factor (EAF) = (AH – EPDH – EFDH) / PH x 100%

4. Forced Outage Rate = (FOH/(FOH+SH) * 100%

5. Heat Rate Deviation (HRD)

   a. Fuel Cost = Cost of Fuel in $/mmBTU

   b. Average Heat Rate = The Average Heat Rate for the given Range

   c. Heat Rate Deviation = (Heat Rate Average - Heat Rate Expected) / Heat Rate Expected x 100%

   d. Production = The Sum of Production for the given Range

   e. Costs of Heat Rate Deviations = (Average Heat Rate - Expected Heat Rate) x Production x Cost of Fuel

6. AGC Deviation-

   a. MWH’s = AGC Set Point Generation - LEC Actual Generation

   b. Cost of Deviations = Fuel Cost x Heat Rate x Generation

7. Starting Reliability

   a. Number of Starts = Start Count for Hot, Warm, and Cold

   b. Start Time = Average Time from 0 Fuel Flow to Pmin

   c. Start Fuel = Average Fuel Consumption to Pmin

   d. Cost of Fuel Deviation = (Actual Fuel Consumed - Expected Fuel) x Cost of Fuel

Lodi Energy Center
Monthly Budget Analysis

Means Actual or Estimated values
Means Forecasted values

	July	August	September	October	November	December	January	February	March	April	May	May (Estimate)	May (Diff)	May Estimate vs Actual (Diff %)	Apr-May Actual vs Actual (Diff %)	June	Year End Projection	FY2014 Budget	Percent Used	Comments
VOM	4,510,911	3,441,771	3,527,417	3,559,665	3,829,061	5,841,427	5,859,348	9,204,955	5,722,081	2,564,099	2,142,420	3,773,424	1,631,004	43%	-20%	4,127,189	54,374,812	48,880,350	111.2%	
Capacity Factor	59%	45%	46%	47%	52%	66%	66%	83%	58%	27%	24%	50%	26%	53%	-17%	50%	52%	54%		
Fuel Consumed (mmBTU, estimated)	879,771	674,758	658,848	688,301	742,102	968,742	956,882	1,095,418	861,414	393,436	341,351	717,551	376,200	52%	-15%	690,691	8,951,713	9,349,196	95.7%	
Avg Fuel Cost ($/mmBTU)	4.26	4.21	4.43	4.44	4.32	5.22	5.32	7.59	5.84	5.57	5.59	5.54	-0.05	-1%	0%	5.54	5.19	4.38		
Power Produced (MWHr, estimated)	122,486	94,610	92,090	98,738	105,077	138,065	136,604	156,088	120,488	55,376	47,484	103,993	56,509	54%	-17%	100,100	1,267,206	1,354,956	93.5%	
Avg Power Price ($/MWHr)	46.91	42.48	46.99	41.03	42.09	54.14	48.14	65.20	52.62	52.88	54.41	47.70	-6.71	-14%	3%	47.70	49.55	53.60		
Operations	43,003	96,234	127,333	26,495	108,825	124,300	95,063	126,143	92,987	100,341	44,467	108,395	63,928	59%	-126%	108,395	1,093,586	1,300,738	84.1%	
Fuel (estimated)	3,752,183	2,838,640	2,921,836	3,055,256	3,208,112	5,061,023	5,085,936	8,309,024	5,031,464	2,190,537	1,909,037	3,513,129	1,604,092	46%	-15%	3,688,288	47,051,336	41,400,588	113.6%	
AB32 GHG Offset (estimated)	665,425	470,249	440,345	439,427	466,509	601,037	622,287	706,677	548,537	250,531	213,573	107,833	-105,740	-98%	-17%	286,439	5,711,037	5,650,224	101.1%	
CA ISO Charges (estimated)	50,300	36,648	37,902	38,488	45,615	55,066	56,062	63,111	49,093	22,690	19,811	44,067	24,256	55%	-15%	44,067	518,853	528,800	98.1%	
Routine O&M (Fixed)	825,352	705,626	781,796	836,116	1,541,610	1,660,100	1,459,604	703,908	667,353	1,864,026	1,968,125	1,004,313	-963,812	-96%	5%	1,417,376	14,430,992	12,360,283	116.8%	
Maintenance	122,856	103,896	138,361	205,464	804,406	282,058	856,754	124,522	97,799	1,151,111	437,243	308,000	-129,243	-42%	-163%	721,063	5,045,533	3,752,752	134.4%	
Administration	176,051	14,591	100,092	101,797	96,024	100,085	99,312	109,722	111,409	97,241	100,343	101,221	878	1%	3%	101,221	1,207,888	1,214,657	99.4%	
Mandatory Costs	54,223	33,816	75,781	40,651	44,151	27,705	32,310	52,601	27,343	70,140	12,497	38,000	25,503	67%	-461%	38,000	509,218	456,000	111.7%	
Inventory Stock	0	0	0	0	0	14,393	40,196	0	11,593	37,507	48,728	86,352	37,624	44%	23%	86,352	238,769	400,000	59.7%	
Labor	362,071	347,160	363,503	379,492	492,969	347,638	322,319	313,003	319,642	403,967	487,987	352,258	-135,729	-39%	17%	352,258	4,492,009	4,227,098	106.3%	
Insurance	110,151	206,163	104,059	108,712	104,060	888,221	108,713	104,060	99,567	104,060	881,327	118,481	-762,846	-644%	88%	118,481	2,937,574	2,309,776	127.2%	
Power Management & Settlements										0	0		0							
Other Costs										0	0		0							
Projects	33,104	33,104	33,105	33,104	82,515	48,100	34,184	34,711	33,104	179,700	63,281	558,104	494,823	89%	-184%	33,104	641,117	1,115,250	57.5%	
Maintenance Reserve	33,104	33,104	33,105	33,104	33,104	33,104	33,104	33,104	33,104	33,104	33,104	33,104	0	0%	0%	33,104	397,250	397,250	100.0%	
Operations & Maintenance Projects	0	0	0	0	49,411	14,996	1,080	1,607	0	146,596	30,177	0	-30,177	#DIV/0!	-386%	0	243,867	168,000	145.2%	
Capital Projects	0	0	0	0	0	0	0	0	0	0	0	525,000	525,000	100%	#DIV/0!	0	0	550,000	0.0%	
A&G	93,845	93,845	143,178	116,185	146,921	144,534	111,394	197,482	127,236	131,936	161,551	188,459	26,908	14%	18%	188,459	1,656,566	2,261,509	73.3%	
Administrative & General (Allocated)	76,204	76,204	110,033	93,660	119,853	120,763	88,473	176,496	102,680	110,501	130,556	145,900	15,344	11%	15%	145,900	1,351,323	1,750,798	77.2%	
Generation Services Shared	17,641	17,641	33,145	22,525	27,068	23,771	22,921	20,986	24,556	21,435	30,995	42,559	11,564	27%	31%	42,559	305,243	510,711	59.8%	
Total O&M Cost	5,463,212	4,274,346	4,485,496	4,545,070	5,600,107	7,694,161	7,464,530	10,141,056	6,549,774	4,739,761	4,335,377	5,524,300	1,188,922	22%	-9%	5,766,128	71,103,486	64,617,392	110.0%	
Debt Service	2,211,514	2,211,516	2,211,511	2,211,516	1,652,233	2,211,513	2,211,514	2,211,514	2,211,514	2,211,514	1,652,233	2,163,002	510,769	24%	-34%	2,163,002	25,371,094	25,956,029	97.7%	
Revenues	5,746,023	4,019,075	4,330,249	4,051,388	4,422,375	7,475,000	7,354,210	10,177,669	6,340,241	2,928,400	2,583,515	4,632,883	2,049,368	44%	-13%	4,954,955	64,383,100	55,613,202	115.8%	
ISO Energy Sales (estimated)	5,746,023	4,019,075	4,327,698	4,051,388	4,422,375	7,475,000	6,575,721	10,177,669	6,340,241	2,928,400	2,583,515	4,632,883	2,049,368	44%	-13%	4,954,955	63,602,060	55,539,944		
Other Income	0	0	2,551	0	0	0	778,489	0	0%	0	0	0	0	0%	0%	0	781,040	73,258		
Net	($1,928,703)	($2,466,787)	($2,366,758)	($2,705,199)	($2,829,966)	($2,430,674)	($2,321,834)	($2,174,900)	($2,421,048)	($4,022,875)	($3,404,095)	($3,054,419)	$349,676	-11%	-32%	($2,974,175)	($32,091,480)	($34,960,219)		

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LEC Treasurer's Report

AGENDA ITEM NO.:______

Date: July 9, 2014

To: LEC Project Participant Committee

Subject: Treasurer's Report for the Month Ended June 30, 2014

In compliance with NCPA policy and State of California Government Code Sections 53601 and 53646(b), the following monthly report is submitted for your information and acceptance.

Cash - At month end cash totaled $0.

The cash balance held at U.S. Bank includes outstanding checks that have not yet cleared.

Investments - The carrying value of the LEC's investment portfolio totaled $24,675,998 at month end. The current market value of the portfolio totaled $24,647,793.

The overall portfolio had a combined weighted average interest rate of 0.460% with a bond equivalent yield (yield to maturity) of 0.406%. Investments with a maturity greater than one year totaled $11,351,000. June maturities totaled $24 million and during the month $5 million was invested.

Funds not required to meet annual cash flow are reinvested and separately reported as they occur.

Interest Rates - During the month, rates on 90 day T-Bills stayed the same (at 0.04%) and rates on one year T-Bills increased 1 basis points (from 0.10% to 0.11%).

To the best of my knowledge and belief, all securities held by LEC as of July 14, 2014, are in compliance with the Agency's investment policy. There are adequate cash flow and investment maturities to meet next month's cash requirements.

Environmental Analysis
The Treasurer's report will not result in a direct or reasonably foreseeable indirect change in the physical environment and is therefore not a "project" for purposes of Section 21065 of the California Environmental Quality Act. No environmental review is necessary.

Respectfully submitted,

Donna Stevener

DONNA STEVENER
Assistant General Manager/CFO
Administrative Services/Finance

Prepared by:

K W Wallace

KEVIN W. WALLACE
Treasurer-Controller

Attachments

LODI ENERGY CENTER

TREASURER'S REPORT

JUNE 30, 2014

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Northern California Power Agency/Lodi Energy Center
Treasurer's Report
Cash & Investment Balance
June 30, 2014

	CASH	INVESTMENTS	TOTAL	PERCENT	INVESTMENTS at MARKET
MANDATORY FUNDS					
Construction Revolving	$ -	$ 3,356	$ 3,356	0.014%	$ 3,356
Debt Service Account	-	2,211,630	2,211,630	8.963%	2,211,625
Debt Service Reserve	-	11,748,570	11,748,570	47.611%	11,716,191
O & M Reserve	-	10,641,654	10,641,654	43.126%	10,645,833
	-	24,605,211	24,605,211	99.713%	24,577,005
ADDITIONAL PROJECT FUNDS					
GHG Cash Account	-	70,788	70,788	0.287%	70,788
	$ -	$ 24,675,998	$ 24,675,998	100.000%	$ 24,647,793

NOTE A -Investment amounts shown at book carrying value.

Northern California Power Agency/Lodi Energy Center
Treasurer's Report
Cash Activity Summary
June 30, 2014

	RECEIPTS			EXPENDITURES			CASH
	OPS/CONSTR	INTEREST (NOTE B)	INVESTMENTS (NOTE A)	OPS/CONSTR	INVESTMENTS (NOTE B)	INTER-COMPANY/ FUND TRANSFERS	INCREASE / (DECREASE)
MANDATORY FUNDS							
Construction Revolving	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Debt Service Account	-	91	20,638,103	(20,643,689)	(2,209,321)	2,214,817	0
Debt Service Reserve	-	107	-	-	(107)	-	-
O & M Reserve	-	7,500	3,003,000	-	(3,010,500)	-	-
	-	7,697	23,641,103	(20,643,689)	(5,219,928)	2,214,817	0
ADDITIONAL PROJECT FUNDS							
GHG Cash Account	-	-	(110)	-	-	110	-
TOTAL	$ -	$ 7,697	$ 23,640,993	$ (20,643,689)	$ (5,219,928)	$ 2,214,927	$ 0

NOTE A -Investment amounts shown at book carrying value.

NOTE B -Net of accrued interest purchased on investments.

Northern California Power Agency/Lodi Energy Center
Treasurer's Report
Investment Activity Summary
May 31, 2014

	PURCHASED	SOLD OR MATURED	(NON-CASH) DISC/(PREM) AMORT	(NON-CASH) GAIN/(LOSS) ON SALE	INVESTMENTS TRANSFERS	INVESTMENTS INCREASE / (DECREASE)
MANDATORY FUNDS						
Construction Revolving		$ -	$ -	$ -	$ -	$ -
Debt Service Account	2,209,321	(20,638,103)	35	-	-	(18,428,747)
Debt Service Reserve	107	-	(159)	-		(53)
O & M Reserve	3,010,500	(3,003,000)	(1,003)	-		6,497
	5,219,928	(23,641,103)	(1,127)	-	-	(18,422,303)
ADDITIONAL PROJECT FUNDS						
GHG Cash Account		110	-	-		110
TOTAL	$ 5,219,928	$ (23,640,993)	$ (1,127)	$ -	$ -	$ (18,422,193)

Less Non- Cash Activity	
Disc/(Prem) Amortization & Gain/(Loss) on Sale	1,127
Net Change in Investment --Before Non-Cash Activity	$ (18,421,065)

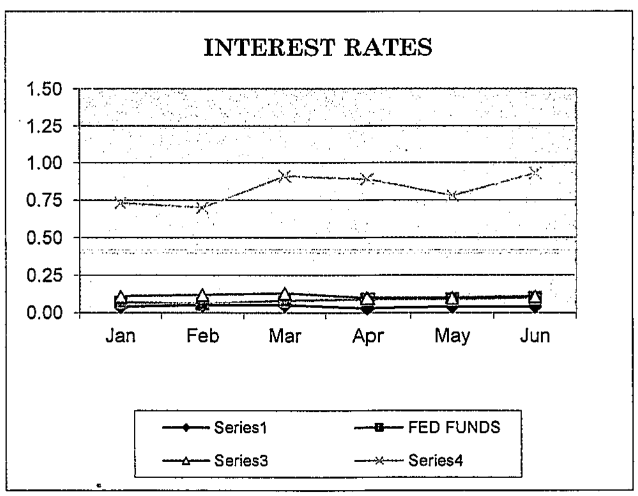
NOTE A -Investment amounts shown at book carrying value.

NORTHERN CALIFORNIA POWER AGENCY
LODI ENERGY CENTER
INTEREST RATE/YIELD ANALYSIS
JUNE 30, 2014

	WEIGHTED AVERAGE INTEREST RATE	BOND EQUIVALENT YIELD
OVERALL COMBINED	0.460%	0.406%
Construction Revolving Acct	0.235%	0.235%
Funds:		
Debt Service Account	0.070%	0.071%
Debt Service Reserve	0.546%	0.571%
O & M Reserve	0.448%	0.295%
GHG Cash Account	0.235%	0.235%

KEY INTEREST RATES

	CURRENT	PRIOR YEAR
Fed Fds (Ovrnight)	0.10%	0.10%
T-Bills (90da.)	0.04%	0.06%
Agency Disc (90da.)	0.04%	0.05%
T-Bills (1yr.)	0.11%	0.02%
Agency Disc (1yr.)	0.14%	0.16%
T-Notes (3yr.)	0.93%	0.70%



Lodi Energy Center
Total Portfolio
Investment Maturities Analysis
June 30, 2014

Type	0-7 Days	8-90 Days	91-180 Days	181-270 Days	271-360 Days	1-5 Years	5-10 Years	Total	Percent
US Government Agencies		$2,980	$2,842		$0	$11,351	$0	$17,173	69.60%
US Bank Trust Money Market	3,395							3,395	13.76%
Investment Trusts (LAIF)	4,105							4,105	16.64%
U.S.Treasury Market Acct. *	0							0	0.00%
U.S.Treasury Bill								0	0.00%
Certificates of Deposit	0							0	0.00%
Total Dollars	$7,500	$2,980	$2,842	$0	$0	$11,351	$0	$24,673	100.00%
Total Percents	30.40%	12.08%	11.52%	0.00%	0.00%	46.01%	0.00%	100.00%	

Investment are shown at Face Value, in thousands.

* The cash balance held at US Bank includes outstanding checks that have not yet cleared. This cash balance is invested nightly in a fully collateralized (U.S. Government Securities) repurchase agreement.

** Cash held by Union Bank of California is invested nightly in fully collateralized U.S. Treasury Securities.

NORTHERN CALIFORNIA POWER AGENCY

Detail Report Of Investments

APPENDIX

Note: **This appendix has been prepared to comply with Government Code section 53646.**

Northern California Power Agency
Treasurer's Report
06/30/2014

LEC Construction Revolving

Issuer	Trustee / Custodian	Stated Value	Interest Rate	Purchase Date	Purchased Price	Maturity Date	Days to Maturity	Bond* Equiv Yield	Market Value	CUSIP	Investment #	Carrying Value
Local Agency Investm		3,356	0.235		3,356		1	0.235	3,356	SYS70040	70040	3,356
	Fund Total and Average	**$ 3,356**	0.235		**$ 3,356**		**1**	**0.235**	**$ 3,356**			**$ 3,356**
	GRAND TOTALS:	**$ 3,356**	0.235		**$ 3,356**		**1**	**0.235**	**$ 3,356.**			**$ 3,356**

*Bond Equivalent Yield to Maturity is shown based on a 365 day year to provide a basis for comparison between all types. Investments with less than 6 months to maturity use an approximate method, all others use an exact method.

Current Market Value is based on prices from Trustee/ Custodian Statements or bid prices from the Wall Street Journal as of 06/30/2014

NCPA NORTHERN CALIFORNIA POWER AGENCY

Northern California Power Agency
Treasurer's Report
06/30/2014

LEC Issue#1 2010A DS Fund

Issuer	Trustee / Custodian	Stated Value	Interest Rate	Purchase Date	Purchased Price	Maturity Date	Days to Maturity	Bond* Equiv Yield	Market Value	CUSIP	Investment #	Carrying Value
US Bank Trust	USB	369	0.100		369		1	0.100	369	SYS79003	79003	369
Federal National Mtg	USB	693,000	0.069	06/26/2014	692,787	12/01/2014	153	0.070	692,792	313589R54	26138	692,794
	Fund Total and Average	**$ 693,369**	0.070		**$ 693,156**		**153**	**0.071**	**$ 693,161**			**$ 693,163**

LEC Issue #1 2010B DS Fund

Issuer	Trustee / Custodian	Stated Value	Interest Rate	Purchase Date	Purchased Price	Maturity Date	Days to Maturity	Bond* Equiv Yield	Market Value	CUSIP	Investment #	Carrying Value
US Bank Trust	USB	500	0.100		500		1	0.100	500	SYS79004	79004	500
Federal National Mtg	USB	732,000	0.070	06/26/2014	731,775	12/01/2014	153	0.070	731,780	313589R54	26139	731,782
	Fund Total and Average	**$ 732,500**	0.070		**$ 732,275**		**153**	**0.071**	**$ 732,280**			**$ 732,282**

LEC Issue #2 2010A DS Fund

Issuer	Trustee / Custodian	Stated Value	Interest Rate	Purchase Date	Purchased Price	Maturity Date	Days to Maturity	Bond* Equiv Yield	Market Value	CUSIP	Investment #	Carrying Value
US Bank Trust	USB	436	0.100		436		1	0.100	436	SYS79011	79011	436
Federal National Mtg	USB	434,000	0.069	06/26/2014	433,867	12/01/2014	153	0.070	433,870	313589R54	26140	433,871
	Fund Total and Average	**$ 434,436**	0.070		**$ 434,303**		**153**	**0.071**	**$ 434,306**			**$ 434,307**

LEC Issue #2 2010B DS Fund

Issuer	Trustee / Custodian	Stated Value	Interest Rate	Purchase Date	Purchased Price	Maturity Date	Days to Maturity	Bond* Equiv Yield	Market Value	CUSIP	Investment #	Carrying Value
US Bank Trust	USB	983	0.100		983		1	0.100	983	SYS79012	79012	983
Federal National Mtg	USB	351,000	0.069	06/26/2014	350,892	12/01/2014	153	0.070	350,895	313589R54	26141	350,896
	Fund Total and Average	**$ 351,983**	0.070		**$ 351,875**		**153**	**0.071**	**$ 351,878**			**$ 351,879**
	GRAND TOTALS:	**$ 2,212,288**	0.070		**$ 2,211,609**		**153**	**0.071**	**$ 2,211,625.**			**$ 2,211,631**

***Bond Equivalent Yield to Maturity is shown based on a 365 day year to provide a basis for comparison between all types. Investments with less than 6 months to maturity use an approximate method, all others use an exact method.**

Current Market Value is based on prices from Trustee/ Custodian Statements or bid prices from the Wall Street Journal as of 06/30/2014

Northern California Power Agency

Treasurer's Report

06/30/2014

Issuer	Trustee / Custodian	Stated Value	Interest Rate	Purchase Date	Purchased Price	Maturity Date	Days to Maturity	Bond* Equiv Yield	Market Value	CUSIP	Investment #	Carrying Value
LEC Issue #1 2010 DSR Fund												
US Bank Trust	USB	46,093	0.100		46,093		1	0.100	46,093	SYS79005	79005	46,093
Federal Home Loan Mt	USB	4,181,000	0.580	05/30/2014	4,183,927	08/26/2016	787	0.548	4,176,485	3134G56B6	26135	4,183,814
Federal National Mtg	USB	4,170,000	0.875	05/30/2014	4,171,960	08/28/2017	1,154	0.977	4,146,857	3135GOMZ3	26136	4,171,908
	Fund Total and Average	$ 8,397,093	0.724		$ 8,401,980		965	0.759	$ 8,369,435			$ 8,401,815
LEC Iss#1 2010B BABS Subs Resv												
US Bank Trust	USB	2,260,521	0.100		2,260,521		1	0.100	2,260,521	SYS79006	79006	2,260,521
	Fund Total and Average	$ 2,260,521	0.100		$ 2,260,521		1	0.100	$ 2,260,521			$ 2,260,521
LEC Issue #1 2010 COI Acct												
US Bank Trust	USB	2	0.100		2		1	0.100	2	SYS79008	79008	2
	Fund Total and Average	$ 2	0.100		$ 2		1	0.100	$ 2			$ 2
LEC Issue #2 2010B DSR BABS												
US Bank Trust	USB	1,086,233	0.100		1,086,233		1	0.100	1,086,233	SYS79013	79013	1,086,233
	Fund Total and Average	$ 1,086,233	0.100		$ 1,086,233		1	0.100	$ 1,086,233			$ 1,086,233
LEC Issue#2 2010 COI Acct												
US Bank Trust	USB	0	0.100		0		1	0.100	0	SYS79015	79015	0
	Fund Total and Average	$ 0	0.100		$ 0		1	0.100	$ 0			$ 0
	GRAND TOTALS:	$ 11,743,849	0.546		$ 11,748,736		690	0.571	$ 11,716,191.			$ 11,748,571

*Bond Equivalent Yield to Maturity is shown based on a 365 day year to provide a basis for comparison between all types.
Investments with less than 6 months to maturity use an approximate method, all others use an exact method.

Current Market Value is based on prices from Trustee/ Custodian Statements or bid prices from the Wall Street Journal as of 06/30/2014

Investment # 26135 - FNMA Structured Note .58% thru 11/26/14; Callable anytime

Northern California Power Agency
Treasurer's Report
06/30/2014

LEC O & M Reserve

Issuer	Trustee / Custodian	Stated Value	Interest Rate	Purchase Date	Purchased Price	Maturity Date	Days to Maturity	Bond* Equiv Yield	Market Value	CUSIP	Investment #	Carrying Value
Local Agency Investm		4,030,964	0.235		4,030,964		1	0.235	4,030,964	SYS70047	70047	4,030,964
Union Bank of Califo	UBOC	0	0.002	07/18/2013	0		1	0.002	0	SYS70041	70041	0
Federal Home Loan Mt	UBOC	2,980,000	0.750	02/19/2014	2,991,264	09/22/2014	83	0.110	2,984,500	3134G2WG3	26099	2,984,284
Federal Home Loan Mt	UBOC	632,000	0.140	10/31/2013	631,127	10/21/2014	112	0.142	631,899	313397L41	26066	631,725
Federal Home Loan Mt	UBOC	3,000,000	0.500	10/25/2013	2,992,800	06/06/2016	706	0.592	2,998,470	3134G46A1	26052	2,994,682
	Fund Total and Average	**$ 10,642,964**	0.448		**$ 10,646,155**		**229**	**0.295**	**$ 10,645,833**			**$ 10,641,655**
	GRAND TOTALS:	**$ 10,642,964**	0.448		**$ 10,646,155**		**229**	**0.295**	**$ 10,645,833.**			**$ 10,641,655**

***Bond Equivalent Yield to Maturity is shown based on a 365 day year to provide a basis for comparison between all types.**
Investments with less than 6 months to maturity use an approximate method, all others use an exact method.

Current Market Value is based on prices from Trustee/ Custodian Statements or bid prices from the Wall Street Journal as of 06/30/2014
Investment # 26052 - FHLMC Structured Note .50%; Callable on 06/06/14 Quarterly thereafter.

Northern California Power Agency
Treasurer's Report
06/30/2014

LEC GHG Auction Acct

Issuer	Trustee / Custodian	Stated Value	Interest Rate	Purchase Date	Purchased Price	Maturity Date	Days to Maturity	Bond* Equiv Yield	Market Value	CUSIP	Investment #	Carrying Value
Local Agency Investm		70,788	0.235		70,788		1	0.235	70,788	SYS70046	70046	70,788
	Fund Total and Average	**$ 70,788**	0.235		**$ 70,788**		**1**	**0.235**	**$ 70,788**			**$ 70,788**
	GRAND TOTALS:	**$ 70,788**	0.235		**$ 70,788**		**1**	**0.235**	**$ 70,788.**			**$ 70,788**

*Bond Equivalent Yield to Maturity is shown based on a 365 day year to provide a basis for comparison between all types.
Investments with less than 6 months to maturity use an approximate method, all others use an exact method.

Current Market Value is based on prices from Trustee/ Custodian Statements or bid prices from the Wall Street Journal as of 06/30/2014

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LEC Financial Reports

AGENDA ITEM NO.: ____

Date: July 9, 2014

Subject: June 30, 2014 Financial Reports (Unaudited)

NORTHERN CALIFORNIA POWER AGENCY
LODI ENERGY CENTER
STATEMENT OF NET POSITION
UNAUDITED

ASSETS	June 30 2014	2013 (Note A)
CURRENT ASSETS		
Cash and cash equivalents	$ 70,788	$ 86,359
Accounts receivable		
Others	-	1,551,216
Interest receivable	11,947	3,917
Inventory and supplies - at average cost	1,171,357	990,780
Prepaid insurance	294,862	359,039
Due from (to) Agency, net	14,287,993	7,458,196
TOTAL CURRENT ASSETS	15,836,947	10,449,507
RESTRICTED ASSETS		
Cash and cash equivalents	11,914,356	17,745,913
Investments	13,595,285	10,560,080
Interest receivable	12,633	5,760
TOTAL RESTRICTED ASSETS	25,522,274	28,311,753
ELECTRIC PLANT		
Electric plant in service	423,359,226	423,354,890
Less: accumulated depreciation	(21,917,781)	(8,535,874)
TOTAL ELECTRIC PLANT	401,441,445	414,819,016
OTHER ASSETS		
Regulatory assets	14,774,261	10,352,111
TOTAL OTHER ASSETS	14,774,261	10,352,111
TOTAL ASSETS	$ 457,574,927	$ 463,932,387

Note A:
Commercial operation began November 27, 2012. Prior to commercial operation, all costs of construction, test start-up and financing were capitalized.

NORTHERN CALIFORNIA POWER AGENCY
LODI ENERGY CENTER
STATEMENT OF NET POSITION
UNAUDITED

	June 30	
	2014	2013 (Note A)
LIABILITIES & NET POSITION		
CURRENT LIABILITES		
Accounts and retentions payable	$ 2,161,416	$ 4,690,934
Operating reserves	11,395,584	10,951,042
Current portion of long-term debt	9,025,000	8,640,000
Accrued interest payable	1,451,050	2,000,616
TOTAL CURRENT LIABILITIES	24,033,050	26,282,592
NON-CURRENT LIABILITIES		
Operating reserves and other deposits	70,654	86,392
Regulatory liability	45,404,582	49,148,706
Long-term debt, net	372,818,011	382,935,703
TOTAL NON-CURRENT LIABILITIES	418,293,247	432,170,801
TOTAL LIABILITIES	442,326,297	458,453,393
NET POSITION		
Invested in capital assets, net of related debt	(1,543,728)	(9,743,935)
Restricted	14,512,411	11,126,152
Unrestricted	2,279,947	4,096,777
TOTAL NET POSITION	15,248,630	5,478,994
TOTAL LIABILITIES AND NET POSITION	$ 457,574,927	$ 463,932,387

Note A:
Commercial operation began November 27, 2012. Prior to commercial operation, all costs of construction, test start-up and financing were capitalized.

NORTHERN CALIFORNIA POWER AGENCY
LODI ENERGY CENTER
STATEMENT OF REVENUES, EXPENSES
& CHANGES IN NET POSITION
UNAUDITED

	Year Ended June 30 2014	2013 (Note A)
SALES FOR RESALE		
Participants	$ 36,219,478	$ 36,097,132
Other	62,068,460	26,007,358
TOTAL SALES FOR RESALE	98,287,938	62,104,490
OPERATING EXPENSES		
Operations	47,778,441	25,081,830
Depreciation	13,381,907	8,535,874
Maintenance expenses	9,045,689	6,707,633
Administrative and general	5,253,969	1,854,517
Transmission	1,166,932	1,003,997
Intercompany (sales) purchases	384,219	165,709
TOTAL OPERATING EXPENSES	77,011,157	43,349,560
NET OPERATING REVENUES	21,276,781	18,754,930
OTHER REVENUES (EXPENSES)		
Interest expense	(16,155,569)	(16,646,760)
Interest income	89,264	143,898
Capitalized Interest	-	6,319,827
Amortization	(76,259)	(37,204)
Other	1,322,604	103,612
TOTAL OTHER REVENUES (EXPENSES)	(14,819,960)	(10,116,627)
FUTURE RECOVERABLE AMOUNTS	4,498,409	(2,977,286)
REFUNDS TO PARTICIPANTS	(1,185,594)	(182,023)
INCREASE IN NET POSITION	9,769,636	5,478,994
NET POSITION		
Beginning of year	5,478,994	
End of period	$ 15,248,630	$ 5,478,994
	-	-

Note A:
Commercial operation began November 27, 2012. Prior to commercial operation, all costs of construction, test start-up and financing were capitalized.

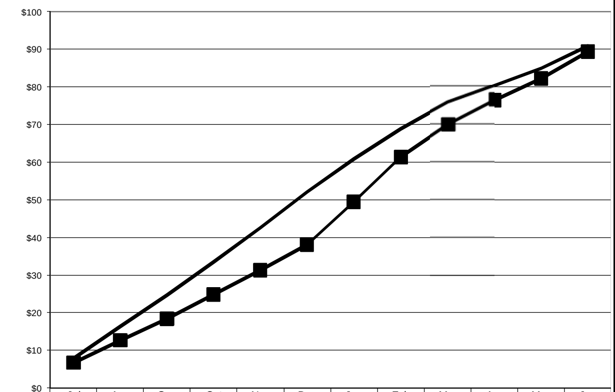
Lodi Energy Center
FY 2014 Operating Costs
As of June 30, 2014

	Annual Budget	Actual	Remaining	YTD % Remaining	Notes
Routine O&M Costs					
Operations	$ 1,300,738	$ 1,086,163	$ 214,575	16%	
Maintenance	3,752,752	4,565,382	(812,630)	-22%	**A**
Administration	1,214,657	1,209,935	4,722	0%	
Mandatory Costs	456,000	491,953	(35,953)	-8%	**B**
Inventory Stock	400,000	180,577	219,423	55%	
Routine O&M Costs without Labor	7,124,147	7,534,010	(409,863)	-6%	
Labor	4,227,098	4,464,047	(236,949)	-6%	
Total Routine O&M Cost	11,351,245	11,998,057	(646,812)	-6%	
Other Costs					
Fuel	41,400,588	45,005,490	(3,604,902)	-9%	**E**
AB32 GHG Offset	5,650,224	-	5,650,224	100%	**C**
CA ISO Charges	528,800	1,166,932	(638,132)	-121%	**D**
Debt Service	25,956,029	25,920,344	35,685	0%	
Other Costs	2,309,776	2,133,890	175,886	8%	
Administrative & General (Allocated)	1,750,798	1,315,422	435,376	25%	
Generation Services Shared	510,711	285,682	225,029	44%	
Maintenance Reserve	397,250	397,250	-	0%	
Total O&M Cost	89,855,421	88,223,067	1,632,354	2%	
Projects					
Operations & Maintenance	168,000	298,012	(130,012)	-77%	**G**
Capital	961,000	915,336	45,664	5%	
Total Capital Budget	1,129,000	1,213,348	(84,348)	-7%	
Annual Cost	90,984,421	89,436,415	1,548,006	2%	
Less: Third Party Revenue					
Interest Income	73,258	38,386	34,872	48%	
ISO Energy Sales	53,249,904	60,608,973	(7,359,069)	-14%	
Ancillary Services Sales	2,290,040	1,459,487	830,553	36%	
ERCS Sale	-	788,059	(788,059)	N/A	**F**
	55,613,202	62,894,905	(7,281,703)	-13%	
Net Annnual Cost to Participants	$ 35,371,219	$ 26,541,510	$ 8,829,709	25%	

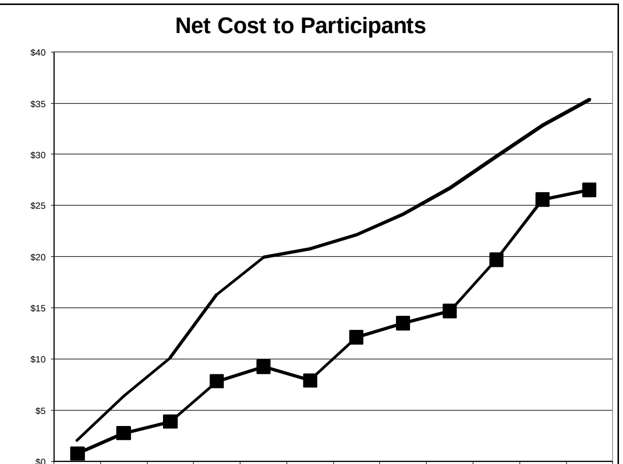
Net Cumulative Generation (MWh)	1,354,957	1,241,892
Total O&M Cost Per MWh	$ 66.32	$ 71.04
Net Annual Cost Per MWh	$ 26.11	$ 21.37

Footnotes:

A - Higher costs resulting from increase maintenance under Siemens LTSA.
B - Payments for hazardous waste fee and air resources board fee were higher than budgeted.
C - The project did not purchase any GHG Allowances as participants have delivered sufficient allowances through June 30, 2014.
D - CA ISO Charges are greater than anticipated primarily due to unplanned Regulation Energy and Resource Adequacy Standard Capacity charges.
E - Fuel costs are higher than anticipated due to higher natural gas prices per MMBTU during the year.
F - Proceeds from the Sale of ERCS
G - Amount includes unanticipated project to Clean Injection Well.



	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
FY 14 Budget (in mil)	$7.90	$16.26	$24.73	$33.51	$42.42	$51.95	$60.86	$68.76	$75.71	$80.43	$84.95	$90.98
FY 14 Actual (in mil)	$6.59	$12.64	$18.41	$24.79	$31.30	$38.03	$49.40	$61.30	$69.91	$76.39	$82.28	$89.44

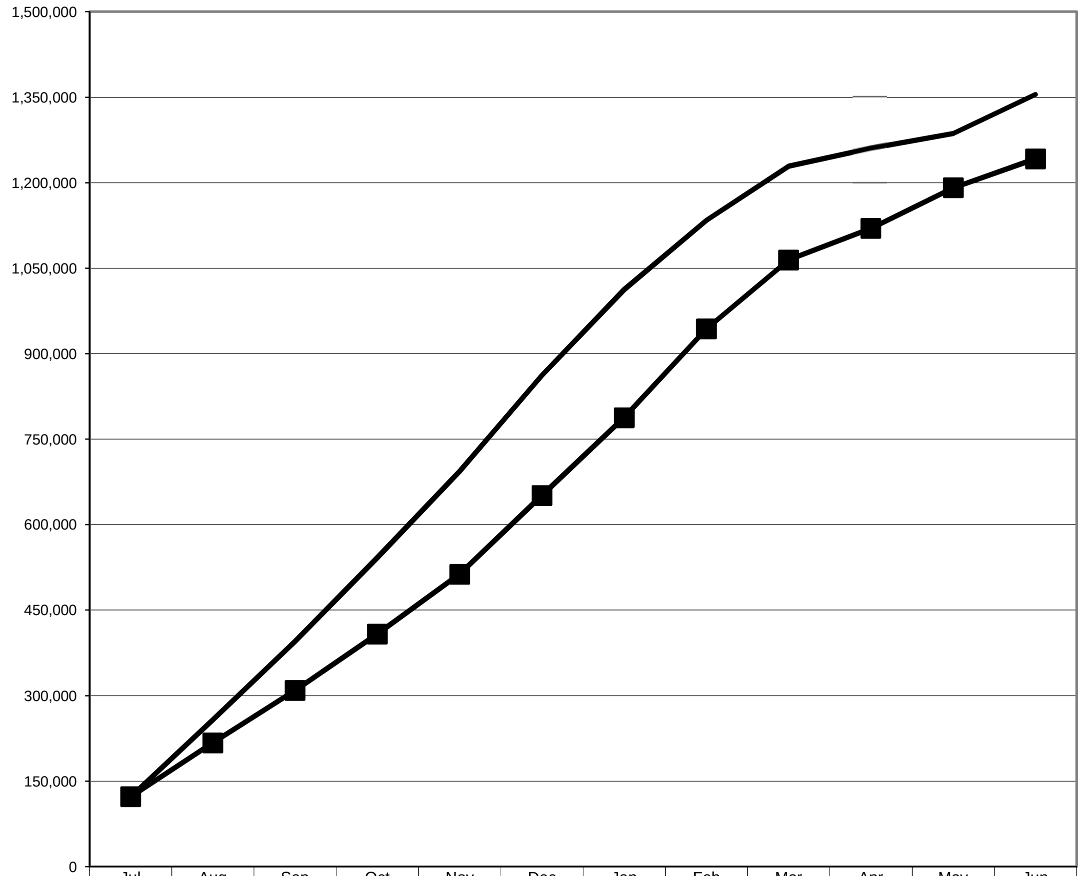


	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
FY 14 Budget (in mil)	$2.02	$6.37	$10.15	$16.29	$19.92	$20.76	$22.17	$24.12	$26.68	$29.80	$32.81	$35.37
FY 14 Actual (in mil)	$0.75	$2.74	$3.86	$7.80	$9.24	$7.90	$12.10	$13.51	$14.72	$19.68	$25.58	$26.54

Annual Budget
LEC Generation Analysis
Planned vs. Actual
FY 2014

In MWh

Lodi Energy Center



	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
FY 14 Planned	121,978	256,984	395,231	542,229	693,104	861,565	1,012,066	1,134,115	1,229,069	1,260,406	1,286,266	1,354,957
FY 14 Actual	122,492	217,106	309,196	407,944	513,022	651,089	787,692	943,780	1,064,26	1,119,64	1,190,85	1,241,89

2013 NCPA All Resources Bill LEC GHG Compliance Instrument Detail Report for the Lodi Energy Center														
	Actual													Compliance Year 2013
IDENTIFIER	DECEMBER	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	Total
Energy (MWh)	0	82,787	101,925	128,167	134,284	32,545	80,153	122,492	94,615	92,091	98,739	105,078	138,068	1,210,944
Gas Schedule (MMBtu)	0	593,484	723,038	894,657	952,529	229,724	579,650	870,331	673,965	650,250	692,396	738,008	965,292	8,563,324
Emissions Factor (MT/MMBtu)	0	0.053	0.053	0.053	0.053	0.053	0.053	0.053	0.053	0.053	0.053	0.053	0.053	
Monthly MT Emissions (MT)	0	31,455	38,321	47,417	50,484	12,175	30,721	46,128	35,720	34,463	36,697	39,114	51,160	453,856
Cumulative MT Obligation (MT)	0	31,455	69,776	117,193	167,677	179,852	210,573	256,701	292,421	326,884	363,581	402,696	453,856	453,856
Compliance Instrument Participant Transfers (to LEC)														
Auction Allowances	92,695	5,350	0	13,644	105,000	50,632	30,628	1,600	102,200	12,594	0	0	46,290	460,633
Secondary Market Allowances	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reserve Sale Allowances	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Offsets	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Compliance Instrument Participant Transfers (MT)	92,695	5,350	0	13,644	105,000	50,632	30,628	1,600	102,200	12,594	0	0	46,290	460,633
NCPA Compliance Instrument Purchases (for LEC)														
Auction Purchases	47,000	0	0	0	0	0	0	0	0	0	0	0	0	47,000
Secondary Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reserve Sale Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Offset Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total NCPA Compliance Instrument Purchases (MT)	47,000	0	0	0	0	0	0	0	0	0	0	0	0	47,000
Compliance Instruments Surrendered to CARB (MT)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Monthly Activity (MT)	139,695	5,350	0	13,644	105,000	50,632	30,628	1,600	102,200	12,594	0	0	46,290	507,633
Cumulative MT Account Balance [MTA] (MT)	139,695	145,045	145,045	158,689	263,689	314,321	344,949	346,549	448,749	461,343	461,343	461,343	507,633	507,633
MTA Shortfall (MT)	(139,695)	(113,590)	(75,269)	(41,496)	(96,012)	(134,469)	(134,376)	(89,848)	(156,328)	(134,459)	(97,762)	(58,647)	(53,777)	(53,777)

2013 NCPA All Resources Bill LEC GHG Compliance Instrument Detail Report for the Lodi Energy Center	2014 NCPA All Resources Bill LEC GHG Compliance Instrument Detail Report for the Lodi Energy Center															
	Actual						Estimated						Compliance Year 2014	Cumulative Totals		
IDENTIFIER	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	Total	Total	Charge Code	Source
Energy (MWh)	136,604	156,089	120,489	55,378	71,210	100,100	103,992	103,992	100,100	107,885	96,207	103,992	1,256,038	2,466,982		Forecast/Meter
Gas Schedule (MMBtu)	951,700	1,092,730	858,805	391,272	512,068	700,697	727,946	727,946	700,697	755,195	673,447	727,946	8,820,450	17,383,774		Forecast/Meter
Emissions Factor (MT/MMBtu)	0.053	0.053	0.053	0.053	0.053	0.053	0.053	0.053	0.053	0.053	0.053	0.053				MARS
Monthly MT Emissions (MT)	50,440	57,915	45,517	20,737	27,140	37,137	38,581	38,581	37,137	40,025	35,693	38,581	467,484	921,340		derived
Cumulative MT Obligation (MT)	504,296	562,211	607,728	628,465	655,605	692,742	731,323	769,904	807,041	847,066	882,759	921,340		921,340		derived
Compliance Instrument Participant Transfers (to LEC)																
Auction Allowances	102,347	50,000	48,066	25,000	1,290	0	0	0	0	0	0	0	226,703	687,336		CITSS
Secondary Market Allowances	0	0	0	0	0	0	0	0	0	0	0	0	0	0		CITSS
Reserve Sale Allowances	0	0	0	0	0	0	0	0	0	0	0	0	0	0		CITSS
Offsets	0	0	0	0	0	0	0	0	0	0	0	0	0	0		CITSS
Total Compliance Instrument Participant Transfers (MT)	102,347	50,000	48,066	25,000	1,290	0	0	0	0	0	0	0	226,703	687,336		
NCPA Compliance Instrument Purchases (for LEC)																
Auction Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	47,000		CITSS
Secondary Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0		CITSS
Reserve Sale Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0		CITSS
Offset Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0		CITSS
Total NCPA Compliance Instrument Purchases (MT)	0	0	0	0	0	0	0	0	0	0	0	0	0	47,000		
Compliance Instruments Surrendered to CARB (MT)	0	0	0	0	0	0	0	0	0	0	0	0	0	0		CITSS
Total Monthly Activity (MT)	102,347	50,000	48,066	25,000	1,290	0	0	0	0	0	0	0	226,703	734,336		derived
Cumulative MT Account Balance [MTA] (MT)	609,980	659,980	708,046	733,046	734,336	734,336	734,336	734,336	734,336	734,336	734,336	734,336		734,336		derived
MTA Shortfall (MT)	(105,684)	(97,769)	(100,318)	(104,581)	(78,731)	(41,594)	(3,013)	35,568	72,705	112,730	148,423	187,004		187,004	MTA SHORTFALL	derived

Forecast for July-December 2014 has been updated.

NCPA All Resources Bill LEC GHG Obligation Detail Report (Cumulative)
July 2014

IDENTIFIER	AZUSA	BART	BIG	CDWR	GRI	HEA	LOD	LOM	MID	PLU	PWRPA	SNCL	UKI	TOTAL	Charge Code	Source
Allocation Percentages																
Generation Entitlement Share %	2.7857%	6.6000%	0.2679%	33.5000%	1.9643%	1.6428%	9.5000%	2.0357%	10.7143%	0.7857%	2.6679%	25.7500%	1.7857%	100%		MARS
Obligation Accounts																
Current MT Compliance Obligation (MTO) Balance (MT)	20,372	48,267	1,959	244,993	14,365	12,014	69,476	14,888	78,356	5,746	19,511	188,316	13,059	731,323		derived
Current MT Compliance Instrument Account (MTA) Balance (MT)	26,000	102,200	2,329	325,000	17,059	13,104	75,578	24,200	95,000	5,900	24,787	220,000	14,140	945,297		derived
MTA Shortfall (MT)	(5,628)	(53,933)	(370)	(80,007)	(2,694)	(1,090)	(6,102)	(9,313)	(16,644)	(154)	(5,276)	(31,684)	(1,081)	(213,975)	MTA SHORTFALL	Derived
Monthly GHG Price $/MT	11.78	11.78	11.78	11.78	11.78	11.78	11.78	11.78	11.78	11.78	11.78	11.78	11.78	11.78	MTA SHORTFALL	ICE Index
GHG Minimum Cash Compliance Obligation ($)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	MTA SHORTFALL	Derived
Current Month CCA Balance ($)*	60,991	0	143	0	1,103	4,780	755	0	0	0	0	0	2,652	70,424	CCA BALANCE	Accounting
Net GHG Obligation ($)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	NET GHG OBLIG	Derived

* The Current Month CCA Balance ($) consists of the current cash balance plus any outstanding balance of Net GHG Obligation ($) billed but not yet received.

Lodi Energy Center Project Participant Committee

Staff Report

AGENDA ITEM NO.: 9

Date: July 10, 2014

To: Lodi Energy Center Project Participant Committee

Subject: Siemens Energy, Inc. – Change Order No. 1 to Long Term Maintenance Program Agreement for LEC

Proposal

Approve Change Order No. 1 to the Long Term Maintenance Program Agreement with Siemens Energy, Inc. (Siemens) for the Lodi Energy Center facility.

Background

On September 13, 2010, NCPA entered into an agreement with Siemens for not-to exceed $50,000,000.00, for the long term maintenance program for the Lodi Energy Center.

During the May 2014 outage, a bore scope inspection revealed internal damage to the components. The components were determined to be under warranty. Under the terms of the Long Term Agreement, Siemens is responsible to bear the costs associated with the repair of a warranty item up to the financial limitations as outlined in the contract. The limitations are set out in section 5.4.1 and define that Siemens is responsible for $1,000,000 per event, and $2,000,000 per year. NCPA would be responsible for any excess costs beyond these limits. The Contract has a lifetime limit of $6,000,000.

Fiscal Impact

This Change Order No. 1 is created to document the costs associated with this warranty repair and track the Event, Annual and Contract limitations.

Prior to the start of the outage, The Contract financial limit was still at the full $6,000,000 obligation. The cost of the warranty repair was $359,487.09. Siemens remaining financial obligations for warranty repair are $5,640,512.91

Environmental Analysis

This activity would not result in a direct or reasonably foreseeable indirect change in the physical environment and is therefore not a “project” for purposes of Section 21065 the California Environmental Quality Act. No environmental review is necessary.

Recommendation

Staff recommends that the PPC approve Change Order No. 1 to the Long Term Maintenance Program Agreement with Siemens Energy, Inc. with any non-substantial changes recommended and approved by the NCPA General Counsel, and authorizes the General Manager to execute the Change Order No. 1. Change Order No. 1 documents the costs associated with warranty repair of Row 3 diaphragm replacement and tracks the Event, Annual, and Contract limitations of the Agreement.

Prepared by:

Ken Speer

KEN SPEER
Assistant General Manager
Generation Services

Attachments: (1)

- Change Order No. 1 to Long Term Maintenance Program Agreement with Siemens Energy, Inc.

CHANGE ORDER NO. 1

Contract: Program Parts, Non-Program Parts, Miscellaneous Hardware, Program Management Services and Scheduled Outage Services Contract, dated September 13, 2010

Effective Date: June 1, 2014

Buyer: Northern California Power Agency

Seller: Siemens Energy, Inc.

1. **Introduction**. This Change Order No.1 (this "Change Order") is agreed to pursuant to that certain Program Parts, Non-Program Parts, Miscellaneous Hardware, Program Management Services and Scheduled Outage Services Contract, dated September 13, 2010 (the "Contract") by and between Siemens Energy, Inc. ("Seller") and Northern California Power Agency ("Buyer"). Capitalized terms used but not defined herein shall have the meaning given them in the Contract. This Change Order as submitted by one Party to the other shall constitute a request for a Change Order. Upon its countersignature in the space provided below, this Change Order shall constitute a Change Order within the meaning of the Contract.

2. **Scope of Change**. This Change Order documents the Row 3 diaphragm replaced by Seller during the April 2014 Unscheduled Outage.

   Pursuant to Section 5.4, Seller has applied a credit of the total amount listed in Table 1 below for the work performed. This credit has been applied against Seller's financial limitation for damage to Buyer's property for both Calendar Year 2014 (see Table 2) and the Term aggregate (see Table 3), each as provided in Section 5.4.

Table 1	
Work Performed under Section 5.4	**Amount**
Field service	$ 306,366.70
Insulation	$ 22,075.40
Forklift and Crane	$ 31,044.99
Total	**$ 359,487.09**

Table 2	
2014 Property Damage Financial Limitation	**Amount**
Initial Financial Limitation	$ 2,000,000.00
(Less) Table 1 Total	($ 359,487.09)
Remaining 2014 Property Damage Financial Limitation	**$ 1,640,512.91**

Table 3	
Term Aggregate Property Damage Financial Limitation	**Amount**
Initial Term Aggregate Financial Limitation	$ 6,000,000.00
(Less) Table 1 Total	($ 359,487.09)
Remaining Term Aggregate Property Damage Financial Limitation	**$ 5,640,512.91**

3. **Timing**. This Change Order will be in effect as of the Effective Date first written above.

DRAFT

4. **Payment and Term**. The value of this Change Order is zero dollars zero cents (**$0.00**).

5. **Other Terms and Conditions**. Except as otherwise specifically provided in this Change Order, all other terms and conditions of the Contract shall remain in full force and effect.

IN WITNESS WHEREOF, the Parties, intending to be legally bound, have caused this Change Order to be executed by their duly authorized representatives to be effective as of the date first above written.

Siemens Energy, Inc.	**Northern California Power Agency**
____________________________	____________________________
By: __________________________	By: __________________________
Name:	Name
Title:	Title:
Date:	Date:

DRAFT

Lodi Energy Center Project Participant Committee

Staff Report

AGENDA ITEM NO.: 10

Date: July 10, 2014

To: Lodi Energy Center Project Participant Committee

Subject: Siemens Energy, Inc. – Change Order No. 2 to Long Term Maintenance Program Agreement for LEC

Proposal

Approve Change Order No. 2 to the Long Term Maintenance Program Agreement with Siemens Energy, Inc. (Siemens) for Lodi Energy Center to take advantage of new technology and parts to extend the time between outages. This Change Order would include upgrading combustion turbine parts to increase equivalent start intervals for Hot Gas Path (HGP) and Major Inspections (MI). In addition the proposed revisions include a contract extension, contract clarity for "open/close" warranty parts liability, an increase to property damage limits, the removal of the business interruption insurance requirement, escalation of the Extra Work Authorization benefit, flexible scheduling and Bulletin 6 inspections.

Background

In 2008, NCPA procured from Siemens the second to last FD3 model turbine being produced. Since that time, Siemens has gone on to produce the FD4 and FD5 models. Some of the features of the FD5 include increased mass flow, higher combustion temperatures, more power, greater efficiency and extended life on the components. Subsequent to the procurement of the turbine, NCPA and Siemens entered into a Long Term Maintenance Program (LTMP) on September 13, 2010. The LTMP outlines the responsibilities between NCPA and Siemens for minor and major maintenance for the combustion and steam turbine. The program also outlines the intervals of inspection by equivalent base hours (EBH) or equivalent starts (ES), whichever comes first. However, pricing of the contract was based on the EBH intervals being attained. Since LEC was commissioned, the operation profile of LEC has triggered the equivalent start based maintenance scenario. Due to this mode of operation, the contract requires a true-up, which is in effect, an early maintenance penalty. The order of magnitude of this penalty is about \$3.8mm. Generally speaking, with the components installed, there is no option to extend the maintenance beyond the 900 ES.

In February 2014, Siemens announced that the new advanced parts developed for the FD5 are available for retrofit into the FD3. These new components can extend the equivalent start based maintenance interval or major inspections and eliminate the smaller Combustion Inspections (CI). Because the new parts allow 1200 ES between maintenance intervals, it is expected that they could reduce the LEC true-up cost by a significant amount.

Because the new parts affect the maintenance intervals, modifications to the contract must be made to allow for the revised intervals. Also, because of the negotiated proposal, Siemens would require a contract extension to offset costs. Modifications to the LTMP to address the extended duration are also addressed. Finally, there have been several other minor issues related to the contract that will be cleaned up and clarified. In summary, the contract terms to change are:

1) Modify the billing so that under periods of heavy starts and low hours, starts based maintenance penalties are paid early in smaller amounts, reducing the final penalty at the time of the significant outage
2) Extend the term of the contract to cover 3 majors (this includes the steam turbine as well). The term of the contract is currently set to expire at the conclusion of the 2nd major. However, if 3 majors have not been accomplished, the contract will expire 18 years from 2010 execution, unless both parties agree to continue.
3) Continue the Extra Work Authorization Allowances benefit into the extended term and calculate a new escalated benefit at the conclusion of the second major.
4) Increase property damage limit by $3mm to account for the extended term
5) Include Bore Scope inspections
6) Eliminate Combustion Inspections
7) Extend the 900 ES requirement to 1200 ES
8) Clarify language that Siemens will be responsible for the cost of Open/Close on warranty repairs
9) Remove language requiring Business Interruption Insurance
10) Allow for Flexible Scheduling and Scope

The Change Order would take effect on November 1, 2014.

Fiscal Impact

The capital cost of the project is $0. Siemens would install the components at the next schedule maintenance interval. The project will be paid for through the continued payment of equivalent base hours as well as a contract extension. This project was not included in the current fiscal year budget. Additional funds beyond what are already budgeted are not required to fund this project. The contract extension period amounts to 50,000 hours of operation, under the base rate of $521 / equivalent base hours (EBH) (escalation factor not applied), the cost of this extension will be $26,050,000. Because of the calculation change, funds paid into the maintenance reserve accounts for the purpose of the starts based penalty may be used earlier than anticipated, as the costs of early maintenance will be spread over a longer duration.

Environmental Analysis

The combustion components being replaced are upgraded in materials and coatings for improved life and reliability. There were no design changes to the combustion itself or the emissions, fuel input or power output.

This activity would not result in a direct or reasonably foreseeable indirect change in the physical environment and is therefore not a “project” for purposes of Section 21065 the California Environmental Quality Act. No environmental review is necessary.

Recommendation

NCPA staff recommends that the PPC approve Change Order No. 2 modifying the Long Term Maintenance Program Agreement with Siemens Energy, Inc. as outlined above, with any non-substantial changes recommended and approved by the NCPA General Counsel, and authorizes the General Manager to execute the Change Order No. 2. Change Order No. 2 includes upgrading combustion turbine parts to increase equivalent start intervals for Hot Gas

Path (HGP) and Major Inspections (MI). In addition the proposed revisions include a contract extension, contract clarity for "open/close" warranty parts liability, an increase to property damage limits, the removal of the business interruption insurance requirement, escalation of the Extra Work Authorization benefit, flexible scheduling and Bulletin 6 inspections.

Prepared by:

Ken Speer

KEN SPEER
Assistant General Manager
Generation Services

Attachments: (1)

- Change Order No. 2 to Long Term Maintenance Program Agreement with Siemens Energy, Inc.

SUBJECT TO MANAGEMENT APPROVAL

CHANGE ORDER NO.2

Contract: Program Parts, Non-Program Parts, Miscellaneous Hardware, Program Management Services and Scheduled Outage Services Contract, dated September 13, 2010

CHANGE ORDER Date: October 1, 2014

Buyer: Northern California Power Agency

Seller: Siemens Energy, Inc.

1. **Introduction**. This Change Order No.2 (this "Change Order") is agreed to pursuant to that certain Program Parts, Non-Program Parts, Miscellaneous Hardware, Program Management Services and Scheduled Outage Services Contract, dated September 13, 2010 (the "Contract") by and between Siemens Energy, Inc. ("Seller") and Northern California Power Agency ("Buyer"). Capitalized terms used but not defined herein shall have the meaning given them in the Contract. This Change Order as submitted by one Party to the other shall constitute a request for a Change Order. Upon its countersignature in the space provided below, this Change Order shall constitute a Change Order within the meaning of the Contract.

2. **Scope of Change**. The purpose of this Change Order is to (i) add the third Major to the Contract scope including operation on Equivalent Starts, (ii) provide for the installation of CIE hardware (as defined below) at the Period 2 Hot Gas Path Scheduled Outage, (iii) add flex scheduling, (iv) provide additional coverage for access costs for warranty non-conformities and to increase Seller's aggregate financial limitation over the Term for damage to Buyer's property, and (iv) eliminate the requirement for Buyer to provide business continuation insurance, each as described below.

   2.1 Extension of the Contract Scope.

   A. Section 5.1 of the Contract is hereby deleted in its entirety and replaced with the following:

   "5.1 Term. The Term of the Contract shall commence on the Effective Date and unless terminated early pursuant to Article 12, shall expire upon the earlier of:

   (i) the date the Combustion Turbine completes the third Major Scheduled Outage under the Contract, or

   (ii) the date that is eighteen (18) years after the Contract's Effective Date ("Sunset Date");

   provided that, no later than three (3) years prior to the Sunset Date, the Parties agree to review and, if the Term is anticipated to reach its Sunset Date prior to the performance of the third Major Inspection Schedule Outage, the Parties may extend the Term for a period of time reasonably necessary to perform such final Major Inspection Scheduled Outage. During such extension period, the applicable portions of the Contract shall be governed by the same terms and conditions. Buyer shall continue to pay the Fixed Annual Fee and the Variable Fee (based upon the Combustion Turbine's predominant mode of operation) as set forth in Exhibit E, Payment Schedule, through the date of completion of the Scheduled Outage Services associated with such final Scheduled Outage.

B. Exhibit E titled "Payment Schedule" is hereby amended hereto as set for the below.

The following is hereby added to the end of Exhibit E of the Contract.

"**Variable Fee after Period 2 Hot Gas Path Scheduled Outage**

1. Variable Fee After Period 2 Hot Gas Path Scheduled Outage.

   Beginning upon completion of installation of the CIE hardware at the Period 2 Hot Gas Path Scheduled Outage, Seller shall invoice Buyer and Buyer shall pay to Seller a Variable Fee (subject to escalation as provided above in this Exhibit E) of five hundred twenty-one Dollars per Equivalent Base Hour (US $521/EBH) or ten thousand eight hundred fifty-four Dollars and seventeen cents per Equivalent Start (US $10,854.17/ES), depending on the actual mode of operation, as described below.

   The "Variable Fee" is calculated and invoiced based upon the Equivalent Base Hours (EBH) or Equivalent Starts (ES) accumulated by the Combustion Turbine during each calendar quarter. Commencing as of the Period 2 Hot Gas Path Scheduled Outage, at the end of each calendar quarter thereafter (or at the time of a Scheduled Outage), Seller shall invoice Buyer for the Variable Fee (per above), based on the actual operation during such calendar quarter (or during such calendar quarter up to the commencement of the next Scheduled Outage).

   For invoicing purposes, the mode of operation is based on the most recent completed calendar quarter. A ratio is calculated by taking the total EBH accumulated over the previous calendar quarter divided by the total ES accumulated over the same time period. If the EBH/ES ratio exceeds 21, Seller will invoice based on EBH. If the EBH/ES ratio is equal to or below 21, Seller will invoice based on ES.

   The Variable Fee will be calculated in accordance with the following:

   Where:
   X = Ratio of accumulated EBH to accumulated ES
   Y = U.S. $521/EBH
   Z = U.S. $10,854.17/ES

   Calculation of the Variable Fee:

   When X is > 21, then the Variable Fee shall equal the amount of EBH accrued in that calendar quarter multiplied by Y.

When X is ≤ 21, then the Variable Fee shall equal the amount of ES accrued in that calendar quarter multiplied by Z.

Example calculation of the Variable Fee for different values of X:

(i)

X = EBH/ES = 32
EBH accrued in that calendar quarter = 1,800
ES accrued in that calendar quarter = 56
Variable Fee = (1,800)*($521) = $937,800

(ii)

X = EBH/ES = 20
EBH accrued in that calendar quarter = 1,400
ES accrued in that calendar quarter = 70
Variable Fee = (70)*($10,854.17) = $759,791.90

2. True Up of Variable Fees after Period 2 Hot Gas Path Scheduled Outage.

a. If the Hot Gas Path or Major Scheduled Outage is scheduled based on ES per Exhibit C~~Addendum 1A, of Exhibit A~~, at the commencement of each Hot Gas Path or Major Scheduled Outage, Seller, notwithstanding other amounts invoiced under this Contract, will invoice Buyer from the Period 2 Hot Gas Path Scheduled Outage or from the prior Hot Gas Path or Major Inspection, each as applicable, to the commencement of the Hot Gas Path or Major Scheduled Outage, the ES Variable Fee multiplied by the greater of the total ES accumulated or 1,200 ES, and credit to Buyer any Variable Fees that have been paid by Buyer since the last Hot Gas Path Scheduled Outage or Major Scheduled Outage.

b. If the Hot Gas Path or Major Scheduled Outage is scheduled based on EBH per Exhibit C~~Addendum 1A, of Exhibit A~~, at the commencement of each Hot Gas Path or Major Scheduled Outage, Seller, notwithstanding other amounts invoiced under this Contract, will invoice Buyer from the Period 2 Hot Gas Path Scheduled Outage or from the prior Hot Gas Path or Major Inspection, each as applicable, to the commencement of the Hot Gas Path or Major Scheduled Outage, the EBH Variable Fee multiplied by the greater of the total EBH accumulated or 25,000 EBH, and credit to Buyer any Variable Fees that have been paid by Buyer since the last Hot Gas Path Scheduled Outage or Major Scheduled Outage."

2.2 Combustion Turbine Interval Extension Hardware.

The Parties agree that Combustion Turbine Interval Extension Program Parts are to be supplied and delivered by Seller for installation during the Period 2 Hot Gas Path Scheduled Outage.

A. Section 1.1 Defined Terms is amended as follows:

The following defined terms are hereby added to Section 1.1 Defined Terms and defined as follows:

"BASELINE 12.5k Program Parts" means those Program Parts in Exhibit B of the type listed in the table titled "BASELINE 12.5k Program Parts Table.

"Combustion Turbine Interval Extension Program Parts" or "CIE" means those Program Parts in Exhibit B of the type listed in the table titled "Combustion Turbine Interval Extension Program Parts Table.

B. Addendum 1A of Exhibit A titled "Combustion Turbine Scheduled Outage Services Description" is hereby amended hereto as follows:

The following is hereby added to the beginning of Addendum 1A of Exhibit A:

"The following paragraphs become effective upon installation of the CIE hardware at the Period 2 Hot Gas Path Scheduled Outage.

The Parties agree that this Contract is designed to accommodate modifications to the operating interval and scope as technologies, techniques and procedures evolve over the Term. As such, Seller shall have the right to request modifications during the Term to the (i) Basis Interval, which as of the Effective Date is not less than the earlier of 25,000 EBH or 1,200 ES ("Basis Interval") and (ii) the scope within the Basis Scope, which as of the Period 2 Hot Gas Path Scheduled Outage is the scope of work defined below ("Basis Scope").

Whenever Seller desires to modify the Basis Interval (such modification referred to as "Flex Interval") or Basis scope (such modification referred to as "Flex Scope"), then Seller must present such requested modification via the Scheduled Outage planning set forth in Exhibit A, Section 4.2. As part of such application, Seller must provide and present information to support the requested change(s) to Buyer. Such presentation may include Seller's methodology, evaluation criteria and assessment process used to define both the interval and/or scope, as applicable. Buyer shall review such request(s) in a timely manner~~ and shall not unreasonably withhold its approval for such modification~~. If Buyer desires to review specific technical information in connection with such Flex Interval or Flex Scope modification, then Seller shall make its relevant resources and documents that are approved for external distribution available to Buyer in a timely manner (to include hosting a review of documents at Seller's facility, if necessary), subject to the provisions of Section 16.1.1.

Similarly, if Buyer desires for Seller to make modifications to extend the Basis Interval, subject Section 6.5 of the Contract, then Buyer shall present such request to Seller also via the Scheduled Outage planning process. Seller shall review such request(s) in a timely manner~~ and shall not unreasonably withhold its approval for such modification.~~.

In no instance shall either Party knowingly request or implement modifications which would adversely affect the operation and performance of the Combustion

Turbines. Adverse effects would include adverse impacts to safety, operation and/or emissions or dynamics. Further, the Parties agree to work cooperatively to mitigate effects of such modifications to outage scheduling and implementation. The Parties agree to work together to reach mutual agreement on whether, and to what extent, a Flex Interval and/or a Flex Scope or modifications to extend the Base Interval shall be implemented. Under no circumstances will a Flex Interval, Flex Scope or modifications to extend the Base Interval be unilaterally implemented.

For clarity, each type of Scheduled Outage is subject to revision pursuant to the application and modification procedure set forth herein. Other than the modification process described above, all other requested changes shall be implemented pursuant to Article 6.

Basis Scope
All disassembly, inspections and assembly to be performed by Seller will be performed per the applicable Seller field service procedures. The following Scheduled Outage work scope description, defined as the "Basis Scope," illustrates a typical Scheduled Outage but may not reflect the actual work scope performed which may vary from this description; however, Seller will complete Seller's workscope using the level of effort necessary in accordance with prudent engineering practices. Components which have reached their repair or replacement interval or were deemed not fit for continued service through the inspection process will be replaced as specified by the Contract."

C. Exhibit B titled "Combustion Turbine Program Parts List" is hereby amended in its entirety and replaced with the Exhibit B, Rev.1, attached hereto as Attachment 1.

D. Exhibit C titled "Projected Scheduled Outage Plan" is hereby amended in its entirety and replaced with the Exhibit C, Rev.1, attached hereto as Attachment 2.

E. Exhibit D titled "Service Bulletin 55004" is hereby amended in its entirety and replaced with the Exhibit D, Rev. 1, titled "Service Bulletin" attached hereto as Attachment 3.

F. Exhibit G titled "Cancellation Amount" is hereby amended in its entirety and replaced with the Exhibit G, Rev. 1, attached hereto as Attachment 4.

2.3 Flex Scheduling.

The following defined terms are hereby added to Section 1.1 Defined Terms and defined as follows:

"Basis Interval" has the meaning set forth in Exhibit A, Addendum 1A.

"Basis Scope" has the meaning set forth in Exhibit A, Addendum 1A.

"Flex Interval" has the meaning set forth in Exhibit A, Addendum 1A.

"Flex Scope" has the meaning set forth in Exhibit A, Addendum 1A.

2.4 Access to Warranty Non-Conformities.

A. The title to Section 5.4 of the Contract is hereby deleted in its entirety and replaced with the following:

"5.4 Seller's Responsibility for Access to Warranty Non-Conformities and Damage to Buyer's Property.

B. Section 5.4.1 of the Contract is hereby deleted in its entirety and replaced with the following:

5.4.1 Subject to the provisions stated in this Section 5.4 below, if a Program Part, an item of Miscellaneous Hardware or a Service provided by Seller pursuant to this Contract fails to conform to the corresponding Program Parts Term Warranty stated in Section 8.1, the Miscellaneous Hardware and Non-Program Part Warranty stated in Section 8.2 or the Services Warranty stated in Section 8.3, then for each such event Seller shall credit Buyer for the actual direct costs incurred by Buyer for the following:

(i) Seller's uncovering, gaining access to, removing and replacing the Program Part, Miscellaneous Hardware or Service, including disassembly and reassembly of the Combustion Turbine or Steam Turbine that does not conform to its respective warranty as set forth in Section 8, Warranties, to the extent that Seller provided such uncovering, gaining access to, removal and replacement of the non-conforming Program Part, item of Miscellaneous Hardware or such Services hereunder, and

(ii) sudden and accidental damage to Buyer's property to the extent that such property damage was caused by the failure of a Program Part, an item of Miscellaneous Hardware or a Service to conform to its respective warranty as set forth in Article 8, Warranties.

Seller's obligations under this Section 5.4 shall be limited on a per event basis to the lesser of:

(a) the actual direct cost incurred by Buyer to repair the property damage including uncovering, gaining access to, removal and replacement costs, to be substantiated to the reasonable satisfaction of Seller, or

(b) an amount of one million Dollars (U.S. $1,000,000).

Seller's obligations under this Section 5.4 shall be limited to an aggregate financial limitation of two million Dollars (U.S. $2,000,000) for all such events occurring within each Calendar Year and a total aggregate financial limitation of nine million Dollars ($9,000,000) for all such events occurring during the Contract's Term.

C. Section 5.4.2 of the Contract is hereby deleted in its entirety and replaced with the following:

5.4.2 As a condition precedent to Seller's performance of its obligations under this Section 5.4, (i) Buyer will be responsible for performing the obligations equivalent to that which would be required of Buyer pursuant to Exhibit A, Addendum 2A, Combustion Turbine Scheduled Outage Division of Responsibilities and Addendum 2B, Steam Turbine Scheduled Outage Division of Responsibilities, and (ii) the Parties shall enter into a Change Order pursuant to which Buyer shall purchase and Seller shall provide all labor, parts, repairs and materials required for the repair of the related property damage necessary to return the applicable Combustion Turbine or Steam Turbine to an operable condition. Seller's obligations under Section 5.4, shall not apply to any liabilities arising out of or related to events or circumstances occurring after either the expiration of the Contract's Term or the termination of the Contract, whichever occurs first. In case of any conflict or inconsistency between the duties and related payments under Section 5.4.2 (i) and (ii), Section 5.4.2 (ii) shall control.

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2.5 Business Interruption/Extra Expense Insurance.

Buyer will no longer be required to maintain business interruption/extra expense insurance. This requirement is hereby deleted from Section 11.2.1(a) of the Contract. The remaining requirements of Section 11.2 shall continue to apply.

2.6 Allowance for Certain Extra Work.

The following language is hereby added to the end of Section 6.6 titled "Allowance for Certain Extra Work":

"After completion of the second Major Scheduled Outage, for each subsequent Scheduled Outage remaining during the Term of the Contract, such amounts will be escalated from the completion date of the second Major Scheduled Outage, calculated that same as the Escalation Factor but using the completion date of the second Major Scheduled Outage as the base value."

3. **Timing**. This Change Order will be in effect as of the Change Order Date first written above.

4. **Payment and Term**. Payment terms will be pursuant to the Contract as amended by this Change Order. Payments shall be made per Section 4.4 of the Contract.

5. **Other Terms and Conditions**. Except as otherwise specifically provided in this Change Order, all other terms and conditions of the Contract shall remain in full force and effect.

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SUBJECT TO MANAGEMENT APPROVAL

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SUBJECT TO MANAGEMENT APPROVAL

IN WITNESS WHEREOF, the Parties, intending to be legally bound, have caused this Change Order No. 2 to be executed by their duly authorized representatives to be effective as of the date first above written.

Siemens Energy, Inc.	**Northern California Power Agency**
______________________________	______________________________
By: ______________________________	By: ______________________________
Name:	Name
Title:	Title:
Date:	Date:

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SUBJECT TO MANAGEMENT APPROVAL

Attachment 1

Exhibit B, Rev.1
Combustion Turbine Program Parts List

BASELINE 12.5k Program Parts Table

BASELINE Program Parts
Combustor Baskets
Fuel Nozzles
Transitions
Transition Seals
Ring Segments – Row 1
Ring Segments – Row 2
Ring Segments – Row 3
Ring Segments – Row 4
Row 1 Blade
Row 1 Vane
Row 2 Blade
Row 2 Vane
Row 3 Blade
Row 3 Vane
Row 4 Blade
Row 4 Vane
Compressor Blades
Compressor Diaphragms
Diaphragm Seals

Combustion Turbine Program Parts to be changed for 25k EBH/ 1200 ES Basis intervals (Combustion Turbine Interval Extension Program Parts)

CIE Program Parts
Baskets
Pilot Nozzles
Support Housing
Transitions
Transition Seals

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SUBJECT TO MANAGEMENT APPROVAL

Attachment 2

Exhibit C, Rev. 1
Projected Scheduled Outage Plan

The projected Scheduled Outage plan below is based on the current revision of the Service Bulletins as provided in Exhibit D, Rev.1. Combustion Turbine Scheduled Outages will be performed as required by the Contact, subject to the application and modification process set forth in Exhibit A, Addendum 1, Rev. 1.

Combustion Turbine	
Period	**Scheduled Outage Type**
1	CI
2	HGP*
3	
4	Major
5	
6	HGP
7	
8	Major
9	
10	HGP
11	
12	Major

* Installation of Combustion Turbine Interval Extension Program Parts at Period 2 HGP

Steam Turbine Scheduled Outages will be performed in conjunction with the corresponding Combustion Turbine Scheduled Outage as set forth below; should a change to the Service Bulletin adversely affect the Buyer, the Parties will negotiate changes to the Contract in good faith.

Steam Turbine	
Period	**Scheduled Outage Type**
1	ASI
2	LO
3	ASI
4	MO
5	ASI
6	LO
7	ASI
8	MO
9	ASI
10	LO
11	ASI
12	MO

Outage Definitions:

CI – Combustor Scheduled Outage
HGP – Hot Gas Path Scheduled Outage
Major – Major Scheduled Outage
ASI – Steam Turbine Annual Safety Inspection
LO – Steam Turbine Limited Overhaul
MO – Steam Turbine Major Overhaul

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SUBJECT TO MANAGEMENT APPROVAL

Attachment 3

Exhibit D, Rev. 1
Service Bulletin

Service Bulletin 55004

Prior to installation of Combustion Turbine Interval Extension Program Parts, the current Service Bulletin for the Combustion Turbine is Service Bulletin 55004. Service Bulletin 55004 is attached separately.

Service Bulletin SB4-11-0018-GT-EN-01

Upon installation of Combustion Turbine Interval Extension Program Parts into the Combustion Turbine the applicable Service Bulletin will be Service Bulletin SB4-11-0018-GT-EN-01.

Service Bulletin SB4-11-0018-GT-EN-01 is attached separately and is modified by the following:

Exhibit D Addendum 1: Service Program Inspection Intervals (Basis Intervals)

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SUBJECT TO MANAGEMENT APPROVAL

Attachment 3 (continued)

Exhibit D
Addendum 1

Service Program Inspection Intervals

This Addendum 1 to Exhibit D provides recommendations for gas turbine inspection intervals for certain SGT6-5000F and 501F units. The inspection intervals provided herein are particular to Buyer's Combustion Turbine and are to be used in lieu of the minimum interval requirements outlined in Exhibit SB4-11-0018-GT-EN. Calculation methodology and inspection scope recommendations are as provided in such SB SB4-11-0018-GT-EN.

Table 1. Inspection Interval Summary (to be applied in place of the inspection intervals provided in SB4-11-0018-GT-EN).

Inspection Type	Interval
Hot Gas Path (includes the Combustor Inspection workscope)	25,000 EBH or 1200 ES
Major	50,000 EBH or 2400 ES
Rotor Assessment	See Note 2 below.

Notes

1.) EBH and ES are to be calculated using the service counter calculation parameters/counters/methods provided per in SB4-11-0018-GT-EN.

2.) Specific Rotor scope and interval will be based on rotor design and application. Consult your Siemens Service representative for details.

SUBJECT TO MANAGEMENT APPROVAL

Attachment 4

Exhibit G, Rev. 1
Cancellation Schedule

The cancellation amount owed by Buyer to Seller, pursuant to Section 12.6 of the Contract, shall be equal to twelve percent (12%) of the remaining Fees that Buyer would have owed to Seller if the third Major had been performed on the Combustion Turbine based on the predominant mode of operation. Such cancellation amount will be calculated from the date of termination of the Contract.

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NORTHERN CALIFORNIA POWER AGENCY
CALENDAR YEAR 2015
PLANNED MAINTENANCE OUTAGE SCHEDULE

Lodi Energy Center: **May 1 – 24, 2014**

DRAFT prepared 7-9-14 las

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Lodi Energy Center Project Participant Committee

Staff Report

AGENDA ITEM NO.: 13

Date: July 10, 2014

To: Lodi Energy Center Project Participant Committee

Subject: Update on Development of Amendment to Project Management and Operations Agreement, Schedule 7.00

Introduction

This memorandum provides a status update on the development of an amendment to Project Management and Operations Agreement ("PMOA"), Schedule 7.00. Further, it describes the formulas, methodologies, and context under which the "Differential Transmission Cost Adjustment" ("DTCA") would be implemented, tracked, and settled. Staff will bring the amendments to the PPC and NCPA Commission for approval and authorization at a later date.

Background

All LEC Project Participants are signatories to the PMOA, which became effective August 1, 2010. PMOA Article 7 stipulates that the:

> *PPC is authorized to establish, approve, implement, administer and revise from time to time a differential transmission cost adjustment to mitigate or partially mitigate additional or duplicative Balancing Authority Area charges applicable to affected Exporting Participant(s) when Project Energy is delivered to such Exporting Participant(s)' load.*

Article 7 further stipulates that the differential transmission cost adjustment would follow the methodology described in PMOA Schedule 7.00, which was attached in draft form at the time the PMOA was approved and executed. This proposal represents the finalization of Schedule 7.00.

Representatives from MID and CDWR met six times over a one-year period to analyze the draft Schedule 7.00 in discussions facilitated by NCPA staff. In this effort, the representatives analyzed the applicability of concepts and figures contained within the draft; identified, discussed, and determined the applicability of other factors that were absent from the draft Schedule 7.00; and ultimately produced the following proposal. Several concepts or particular details have a number of viable options or were consciously removed from consideration throughout this process; an itemized list of options, with a brief explanation for each, is provided as "Attachment A".

Proposal Particulars

The proposal follows the original framework of Schedule 7.00. The DTCA is calculated in three segments: (1) CAISO Costs, (2) Western Area Power Administration ("WAPA") Cost, and (3) Other Benefit Adjustments.

Since the LEC is connected to the CAISO Balancing Authority Area (BAA) and MID's loads are located in the BANC BAA, CAISO Costs (Differential Transmission Cost Summary Table, Item 1) will include an export component when MID exports LEC energy to supply its loads. If LEC had been connected to the BANC BAA, MID would not have to pay CAISO export costs when it used LEC's energy for its loads. However, MID would still pay WAPA Costs (Item 2) and other adjustments (Item 3). As contemplated in Article 7 of the PMOA, the DTCA is the calculated difference between actual CAISO costs incurred to export energy (Item 1) and the estimated WAPA applicable costs, had LEC been interconnected to the BANC BAA (Items 2 & 3).

CAISO costs (Item 1) are based on costs invoiced by the CAISO for LEC energy that is exported to serve MID load. Item 2 and 3 are incremental costs otherwise avoided by MID by interconnecting LEC to the CAISO BAA. Thus, these are generally treated as "benefits" to MID. Item 2 & 3 benefits are generally treated as a hurdle that MID costs must exceed before DTCA payments are made by other LEC Participants. This process involves keeping track of cumulative DTCAs by using a "balancing account" methodology, which was the original framework of Schedule 7.00. Under this proposal, NCPA will perform this service.

CAISO costs (Item 1) are comprised of Grid Management Charges ("GMC") and Wheeling Access Charges ("WAC"). GMC is the CAISO administrative fee and is comprised of multiple Charge Codes. Only those that pertain to exports are applicable. Item 1 costs are primarily volumetric. Therefore, these costs are proportional to the amount of energy MID exports. The more energy MID exports, the higher these costs are. If MID exports no energy, Item 1 costs are zero.

The WAC is the transmission rate that is charged to all loads and exports. It is based on the wheeling rates and voltage level at the particular scheduled load or export point. The proposal is based on the high-voltage rate, only, since there are no low-voltage points contemplated for use at this time. If exports are made at low-voltage points, the methodology would need to be updated. Further, the GMC and WAC rates change periodically.

This proposal requests authority from the PPC to use the CAISO rates in effect at the time an export is made, including prior-period adjustments, and that the CAISO's current rates preempt the figures contained in Schedule 7.00. The figures in Schedule 7.00 will be maintained through the required annual review and updated pursuant to Article 7.

WAPA costs (Item 2) are comprised of 3 elements, (a) WAPA transmission rates, (b) WAPA Operating Reserves ("OR"), and (c) differential in capital costs. Item 2 costs are loosely labeled "benefits". These costs represent estimated costs MID would have incurred if LEC was connected to the BANC BAA and MID used LEC energy for its loads. Western transmission (a) and WAPA Operating Reserve costs (b) are rate based. Therefore these costs are proportional to the amount of energy MID exports. The more energy MID exports, the higher these costs are. If MID exports no energy, costs for (a) and (b) are zero. Differential capital costs (c) are based on estimated fixed costs and represent the extra capital cost had LEC been connected to the BANC BAA.

Western operates three transmission projects and maintains rates specific to each. The applicable transmission project for this proposal is known as "CVP Transmission" and utilizes the published point-to-point transmission rate ($/MWh).

The OR requirement for the BANC BAA is based on the WECC methodology that utilizes the Most Severe Single Contingency ("MSSC") within the BAA. The MSSC is allocated between

SMUD and WAPA according to their own respective MSSC. WAPA further allocates its share of the MSSC to each LSE within WAPA's operational boundaries based on a pro rata share of the annual load of the preceding calendar year. LEC would have little potential to be the MSSC for the BANC BAA. However, it would have the potential to impact the allocation between SMUD and WAPA, and thus increase the OR requirement for all LSEs that operate in BANC's operational boundaries, including the Exporting Participant. The figures in the proposal reflect this incremental impact.

The differential of capital costs for a BANC interconnection is an estimate that is based on an engineering study prepared by Navigant at the request of MID in March 2009. This study found that system reinforcements would be necessary if the LEC were interconnected directly to the WAPA transmission system (part of the BANC BAA) and would cost approximately $15.75 million. The total estimated cost of connecting LEC to the CAISO BAA was $2.55 million. This produces a net differential of $13.2 million. This proposal first allocates the $13.2 million differential to each Project Participant based on Generation Entitlement Shares (GES) to isolate the amount that would be allocated to MID, which equals $1.4 million. This $1.4 million is treated as a "benefit" to MID under a cost-avoidance basis. This cost is amortized at 4% over a 30 year period and amounts to approximately $2.454 million. The proposal treats this as an accumulated front-loaded "Interconnection Benefit Threshold" to MID. Its role is described further under the Fiscal Impact section below.

Item 3, Other Benefits Adjustments captures any benefits and costs not identified in Item 1 or 2. At the time the PMOA was adopted, this item showed a benefit to the Project Participants in the amount of $857,000, annually, if the plant were interconnected to the CAISO BAA. This figure represented the value of Regulation Up and Regulation Down capacity and energy that would be sold into the CAISO markets. At the time, the CAISO did not permit any imports of Regulation capacity from external balancing authorities, nor was there a similar market opportunity available within BANC. However, the CAISO modified its operating protocols in November, 2012 and now allows for imports of all Ancillary Service. Therefore, this item shows a net benefit-cost differential of $0 between interconnection choices with respect to the sale of Regulation Reserves. Staff recommends retaining this section as a placeholder and to remove all associated line items since none are used at this time.

To the extent MID receives excess DTCA payments from other LEC Participants, MID is required to refund the excess amount. Under low to zero export scenarios, Item 2 benefits (avoided WAPA costs) may exceed Item 1 costs (incurred CAISO costs). Under these scenarios, MID would not need to refund the difference, nor would the difference be recognized in the balancing account, since the Item 2 benefits are not based on actual exchanges of funds.

Fiscal Impact

To the extent LEC generation is exported from the CAISO BAA, the proposal has the potential to distribute to all Project Participants transmission related costs associated with such exports in proportion to GES. No increase in costs associated with this proposal would be passed through to CAISO-based Project Participants until the $2.454 million "Interconnection Benefit Threshold" associated with the transmission interconnection cost differential is extinguished. MID estimates show that if LEC is operating at an 80% capacity factor and 10% of MID's GES energy is exported, the Interconnection Benefit Threshold would be extinguished in approximately 20 years.

Update PMOA Schedule 7.00
July 10, 2014

Prepared by:

JAMES TAKEHARA
Energy Resource Analyst

Attachments: (2)

- PMOA Schedule 7.00 DRAFT
- PMOA Schedule 7.00 Attachment Excel Spreadsheet

Agreement Schedule 7.00

Differential Transmission Cost Adjustment

Differential Transmission Cost Adjustment for Exporting Participant:

The Differential Transmission Cost Adjustment ("DTCA") reimburses the Exporting Participant for their export costs. It is the net sum of actual costs incurred by the Exporting Participant for exporting energy from the CAISO Balancing Authority Area ("BAA") to the Balancing Authority of Northern California ("BANC") BAA minus BANC costs if LEC was connected to the BANC BAA. The BANC costs are considered "benefits" and are therefore subtracted because the Exporting Participant avoided paying this cost. The reimbursement amount is based on the following information and calculations:

1. ***CAISO Costs*:**

The CAISO currently has over 160 different charge codes associated with different types of transactions and services. Certain costs are based on pre-determined rates, while others are market-based and are subject to variation due to market or system conditions. Only a subset of the CAISO costs apply to the DTCA, specifically those that are assessed incrementally on exports of energy from the CAISO BAA. The costs included in this Agreement Schedule 7.00 shall be from the actual CAISO invoices received, including all prior period adjustments.

The CAISO posts online its currently applicable and historical Grid Management Charge (GMC) and Wheeling Access Charge (WAC), found under Transmission Access Charge (TAC), at the following website location:

- http://www.caiso.com/docs/2005/03/20/2005032013150120093.html

Table of Applicable Charge Codes

The following Charge Codes will be used to calculate the CAISO Cost component of the DTCA. GMC and WAC will each be aggregated and tracked in their own line item and all remaining Charge Codes will be aggregated under "Other Applicable CAISO Costs". To the extent there are inconsistencies between the rates and/or formulas listed in (a) this Schedule 7.00 and (b) the CAISO Tariff and/or the CAISO Business Practice Manuals (BPM) the CAISO Tariff and BPMs will apply.

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Table S7-1: Table of Applicable CAISO Charge Codes

	LINE ITEM	CHARGE CODE DESCRIPTION	CHARGE CODE
1	Grid Management Charge	Market Service Charge	4560
2		System Operation Charge	4561
3	Wheeling Access Charge	High Voltage Wheeling Allocation	382
4	Other Applicable CAISO Costs	FERC Fee Settlement (monthly, annually)	550, 551
5		NERC/WECC Reliability Charge	6490
6		Emissions Cost Recovery	591
7		Long Term Voltage Support Allocation	1302
8		Ancillary Service Upward Neutrality Allocation	6090
9		Spinning Reserve Neutrality Allocation	6196
10		Non-Spinning Reserve Neutrality Allocation	6296
11		Real Time Imbalance Energy Offset	6477
12		Excess Cost Neutrality Allocation	6480
13		IFM Bid Cost Recovery Tier 2 Allocation	6637
14		Real Time Bid Cost Recovery Allocation	6678
15		Real Time Congestion Offset	6774
16		CRR Balancing Account (surplus/deficit allocation)	6790
17		IFM Marginal Losses Surplus Credit Allocation	6947
18		Flexible Ramp Up Cost Allocation	7056

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NOTE: NCPA staff validating this information

2. ***Western Area Power Administration (WAPA) Benefits, Costs, and Other Factors*:**

The following volumetric costs will be deducted from the CAISO Costs incurred by the Exporting Participant in order to determine the DTCA:

- Western's point-to-point Central Valley Project ("CVP") transmission service rate (see Rate Schedule CV-T3),
- Estimated incremental impact to Operating Reserve Requirements in WAPA's Sub-Balancing Authority,
- Other applicable factors

Western's transmission service costs are known and available in advance of the settlement period and are currently displayed at the following website:

– http://www.wapa.gov/sn/marketing/rates/

The incremental impacts to Operating Reserve Requirements in WAPA's Sub-Balancing Authority are estimated using the Spinning Reserve Service and Supplemental Reserve Services (i.e. non-spinning reserves) Rate Schedules CV-SPR4 and Rate Schedule CV-SUR4, respectively. Interconnection of LEC to BANC transmission BAA are estimated to increase WAPA's allocated share of BANC Operating Reserve requirements by 19 MWs in all operating hours. The Exporting Participant would be allocated its proportion of costs based on a load ratio share, according to WAPA allocation methodologies. The price is the arithmetic average price of the Spinning and Supplemental Reserve prices, which are based on market prices in the CAISO Day-Ahead Market for Spinning and Non-Spinning Reserve, NP15 Region.

Other applicable factors included in the DTCA calculation are estimates for alternative interconnection related costs (i.e. the additional cost and/or debt service burden had the LEC Project been interconnected to the BANC BAA instead of the CAISO BAA). Estimates associated with the differences in these capital costs will be applied as a separate benefit threshold, with respect to cumulative balancing accounts discussed in Section 4.

3. *Other Benefit Factors*:

The DTCA will also reflect adjustments to account for other elements of value which can be identified as a function of plant location in either the CAISO or BANC Balancing Authority Areas. There are currently no line items that fall into this category.

4. Cumulative Balancing Accounts:

NCPA will track the benefit threshold associated with the alternative interconnection related cost ("Interconnection Benefit Threshold") and two cumulative balancing accounts for each Exporting Participant. The first balancing account is the cumulative costs and benefits (i.e. cumulative DTCA) for an Exporting Participant. The second balancing account is the cumulative net payments made by the Project to an Exporting Participant.

The Interconnection Benefit Threshold is the Exporting Participant's GES portion of the non-refundable differential interconnection cost plus cumulative interest (4%) paid on this amount over 30 years. The initial Interconnection Benefit Threshold is $2.454 million. Refer to the summary table below for details.

If the Exporting Participant exports in a Fiscal Year, then the calculated DTCT for that year will be subtracted from the Interconnection Benefit Threshold. If the Interconnection Benefit Threshold is extinguished and cumulative DTCA still exist, the Exporting Participant will be reimbursed the net amount by the Project and all Project Participants will be billed based upon their GES, including the Exporting Participant.

If the Exporting Participant does not export in a Fiscal Year, then the DTCA for that year will be zero and the Interconnection Benefit Threshold will remain the same.

The Interconnection Benefit Threshold balance will begin upon the effective date of this Schedule 7.00 and will be eliminated when the cumulative DTCAs exceed the beginning Interconnection Benefit Threshold balance. The Interconnection Benefit Threshold balance does not expire and does not increase over time. For each Exporting Participant, the PPC shall review the cumulative costs and benefits and make a determination of when payments shall be reimbursed to avoid large accumulation of obligations.

Example Differential Transmission Cost Summary Table

The material below illustrates how the DTCS is calculated.

Key Assumptions:

The following are inputs or intermediate calculations used to derive costs and benefits.

Assumptions/Model Inputs		
1	LEC Capacity	280
2	MID Capacity	30
3	MID GES	10.7143%
4	LEC Capacity Factor	80%
5	MID GES Share of LEC Generation	210,240
6	Portion of GES Share Exported by MID	5%
7	MID Exported Energy out of CAISO	11,442
8	Western Reserve Sharing Requirement for Capacity (MW)	6
9	Reserve Pricing from CAISO ($/MWh)	$ 2.06
10	Proxy Western Reserves Impact	$ 79,545
11	Additional Capital Costs of Connecting to Western	$ 13,200,000
12	MID GES Share of Annualized Additional Capital Cost of Western Interconnection	$ 81,788
13	Net Behind the Meter / Energy Swaps	
14	Net Ancillary Services Revenue from CAISO	$ 8,000,000
15	Estimated Ancillary Services Revenue from Western	$ 8,000,000
16	CAISO GMC	$ 0.487
17	CAISO TAC	$ 8.8593
18	Western Transmission Rate	$ 1.82

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Table S7-2: Example Differential Transmission Cost Summary

Example Differential Transmission Cost Summary Table						
Item	**Particulars**	**Estimated Rate**	**Benefits**	**Charges**	**Cumulative Charges - Benefits Account Balance**	**Cumulative adjustments paid by the Project to the Exporting Participant**
1	**CAISO Charges**					
1.1	GMC (export & load)	$ (0.49)		$ (5,572)		
1.2	CAISO TAC (HV, $/MWh)	$ (8.86)		$ (101,370)		
1.3	Other Applicable CAISO Charges ($/MWh)			$ -		
1.4	**Total CAISO Charges ($/MWh)**	**$ (9.35)**		**$ (106,942)**		
2	**Western Charges**					
2.1	Western CVP X-mission Rate ($/MWh)	$ 1.82	$ 20,825			
2.2	Proxy Western Reserves Impact ($/MWh)	$ 0.38	$ 4,329			
2.3	Differential of Capital Cost for a Western Interconnect vs CAISO ($/MWh)				$2.454 million	
2.4	Other Applicable Western Charges ($/MWh)					
2.5	**Total Western Charges ($/MWh)**	**$ 2.20**	**$ 25,154**			
3	**Other Benefit Adjustments**					
3.1	**Total Adjustments ($/MWh)**		**$ -**	**$ -**		
4	**Net Effect on MID**					
4.1	Calculated Cost Differential		($81,788)			
4.2	MID Share of Cost Differential		($8,763)			
4.3	Net MID Cost Differential		($73,025)			
5	**Reimbursement Calculations**					
5.1	PPC Approved Credit toward Benefits		$73,025			
5.2	PPC Approved Reimbursement to MID		$0			
5.3	PPC Approved Reimbursement from MID		$0			
6	**Cumulative Balance Accounts**					
6.1	Beginning Cumulative (Charges - Benefits)		$ 2,453,652			
6.2	Beginning Cumulative Reimbursement to MID		$ -			
6.3	Ending Cumulative (Charges - Benefits)		$ 2,380,627			
6.4	Ending Cumulative Reimbursement to MID		$ -			

Notes:

- Item 1 represent actual costs invoiced by the CAISO to Exporting Participants Scheduling Coordinator for exports associated with LEC generation.
- Items 2.1 and 2.2 represent estimated costs that Exporting Participant would have paid if LEC were interconnected to the BANC BAA. These costs are avoided by Exporting Participant since the plant was interconnected to the CAISO BAA.
- Item 4.1 is equal to the sum of 1.4 and 2.5. This represents the net variable transmission and administrative costs incurred by Exporting Participant in exporting LEC energy from the CAISO BAA to serve Exporting Participant's load.
- Item 4.2 represents Exporting Participant's share of the cost differential described in item 4.1.
- Item 4.3 represents the net variable cost that all other LEC Participants would pay as the Differential Transmission Cost Adjustment.
    - The DTCA is first applied to item 2.3, the "Differential of Capital Cost for a Western Interconnect vs. CAISO".
    - Other LEC Participants would make no payments to Exporting Party until this line item is extinguished.
    - This activity will be tracked under item 6.

Schedule 7 Discussion Matrix

1	CAISO Charges	
	GMC (export)	**Recommendation:** Include GMC Charge Codes that are assessed on exports. Do not include Charge Codes that are based on SC registration or schedule counts (immaterial). Use applicable rates based on operating date, including impacts from prior period adjustments.
		All parties agree to GMC applicability for those Charge Codes assess on export energy.
		Little to no discussion or exploration to alternatives or options.
	CAISO TAC (HV, $/MWh)	**Recommendation:** Include High Voltage TAC rate that are assessed on exports. If exports are scheduled at Low Voltage points, this portion would need to be modified. Use applicable rates at based on operating date, including impacts from prior period adjustments.
		Determine probable take-out points. TAC is a function of the voltage level at the take-out point.
		MID would likely schedule exports at the Tesla-Westley (230 kV), which would be assessed a high-voltage TAC charge.
		If Tesla-Westley were not available, MID would likely use Tracy (230 kV) as a scheduling point, which would also be assessed a HV TAC charge.
		No plausible Low Voltage take-out locations were identified.
	Other Applicable CAISO Charges	**OPERATING RESERVES**
		Recommendation: Include Spin & Non-Spinning charges based on scheduled export quantities and prevailing market rates, as applied by CAISO settlements.
		ISO assess charges for Spinning and Non-Spinning reserve charges on a pro-rata basis for all loads and exports.
		MISCELLANEOUS CHARGE CODES
		Recommendation: Include various Charge Codes assessed on exports, using applicable rates and prior period adjustments.
		The group did not discuss these in great detail, but there are a number of Charge Codes that are assessed on exports. The group agreed that the intent of this Schedule is to mimic CAISO Settlements as closely as practical. Many of these are neutrality adjustments and can be charges or credits.

2 Western Charges

Western CVP X-mission Rate ($/MW)	**Recommendation:** Use Western's Point-to-Point hourly CVP transmission rate as a proxy for the incremental transmission costs that MID would incur to move LEC generation to MID load, if LEC were constructed in BANC. This rate is published on the WAPA SNR website, published effective 10/1 of each year and subject to a mid-year adjustment effective 4/1 of each year.
	If LEC were interconnected to the Western CVP transmission grid, MID would need to subscribe to transmission service to wheel the power to its load, since it does not have existing rights to that specific location.
	The parties explored the use of a NITS (network integrated transmission service) cost structure but determined this was unworkable because, in part, such costs are allocated on pro-rata load based on the CVP transmission system coincident peak. Since the Point to Point rate and NITS revenue requirements are based on the same revenue requirement, and for ease of implementation, the point to point transmission rate is used as a proxy.
Proxy Western Reserves Impact ($/MW)	**Recommendation:** Include LEC's incremental impact to Western Operating Reserve Requirement (ORR) as a benefit (i.e. avoided cost). The avoided cost is approximately 6 MW multiplied by the average of the applicable Spinning and Non-Spinning Reserve price in the CAISO.
	LEC is unlikely to set a new ORR in the BANC, which is based on the single largest contingency in the balancing authority area. However, it has the potential to increase the proportion of the ORR placed on the Western Sub-BA, and thus the allocated cost to MID.
	MID estimated the increase to the sub-BA would be 19 MW, and MID's allocated share would be approximately 6 MW applied 7x24.
	The parties explored whether applying this method 7x24 was appropriate, since it would only apply on days where LEC were scheduled. After deliberation, the parties found the difference to be immaterial and agreed to the 7x24 application.

2	**Western Charges (continued)**
Differential of Capital Cost for a Western Interconnect vs. CAISO ($)	**Recommendation:** Apply MID's estimated share of the differential in capital costs, amortized over 30 years at 4%, as a cost threshold; costs associated with MID scheduled exports would reduce this cost threshold. Other LEC Participants would not reimburse MID for their GES share of MID export costs until this threshold is exhausted.
	The parties discussed whether this component is appropriate for this Schedule. The interconnection costs are gross estimates and are not associated with any actual, physical project. Ultimately, the parties agreed that some recognition for the differential in capital costs is acceptable for Schedule 7.00. The parties explored several configurations that utilized a volumetric rate for this component, and determined that such rate is inappropriate since interconnection costs would traditionally be treated as a fixed cost. Conversion to a variable cost would artificially inflate the per-unit export cost to MID, discouraging exports.
	The parties discussed whether this component should be subject to refund if, after some period of time, the threshold was not extinguished. After brief discussion, the parties agreed this is not appropriate for refund and would be out of scope of Article 7.
Other Applicable Western Charges	**Recommendation:** Include no other Western Charges at this time.
	The parties explored whether Western would increase MID share of Regulation and Frequency Response charges if LEC were interconnected to BANC. Based on discussions with Western operations staff, it was determined that Western would not change is level of Regulation/FR under this scenario.
3	**Other Benefit Adjustments**
Other Applicable Adjustments	**Recommendation:** Include no other adjustments at this time. Delete three line items used in sample Schedule 7.00 since they are not used.
	The sample Schedule 7.00 included an entry of approximately $857,000 under "Net A/S Obligations and Sales Value" to recognize that LEC would be precluded, by rule, from selling Regulation Reserves into the CAISO market if it were interconnected to the BANC transmission system. In November 2012, the CAISO changed its policy on this matter and LEC would now be able to sell Regulation Reserves into the CAISO markets as a BANC resource. The group explored if imports of Regulation are limited, but found no such constraints. Thus, the group decided to effectively delete this line item by including an equal double entry of costs/benefits netting to $0.