12745 N. Thornton Road
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Revised Agenda

Date: September 4, 2014

Subject: **September 8, 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**

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

Persons requiring accommodations in accordance with the Americans with Disabilities Act in order to attend or participant in this meeting are requested to contact the NCPA Secretary at 916.781.3636 in advance of the meeting to arrange for such accommodations.

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 the following PPC meeting minutes:
    - August 11, 2014 regular meeting
    - August 22, 2014 special meeting

MONTHLY REPORTS

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

4. **Market Data Report for August 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 August 2014** - Accept by all Participants

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

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

9. **LEC Project Management and Operations Agreement (PMOA) Schedule 7.00 – Differential Transmission Cost Adjustment** – Staff seeking approval of Schedule 7.00 (*James Takehara*)

Consent Items pulled for discussion: ______________________________

BUSINESS ACTION ITEMS

10. **Update regarding Forced Outage Issues, LEC Start-up, and Bidding Strategies** – Staff to provide updated information about valve issues, repair efforts, startup, and possible alternative bidding strategies

INFORMATIONAL ITEMS

11. **LEC Congestion Study Report – Overview of Findings –** Nexant staff will provide an overview of the study findings which are detailed in its final report. The consultant's analyses of congestion exhibited over the historical study period (April through September, 2012), modeling results under transmission upgrade scenarios, and potential congestion impact mitigation tools will be discussed. *(Gillian Biedler*)

12. **Insurance Policy Review –** Staff will provide an update on the current status of property and casualty insurance for the LEC Project *(Donna Stevener)*

13. **Request for American Flag at LEC** – Staff to provide information about this request *(Michael DeBortoli)*

14. **Other New Business**

ADJOURNMENT

Next Meeting: October 13, 2014

Lodi Energy Center
Project Participant Committee Meeting
August 11, 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.

PPC Meeting Attendance Summary		
Participant	**Attendance**	**Particulars / GES**
Azusa - Morrow	Present	2.7857%
BART - Schultz	Present	6.6000%
Biggs - Sorenson	Present	0.2679%
CDWR - Werner	Present	33.5000%
Gridley - Stiles	Present	1.9643%
Healdsburg - Crowley	Absent	1.6428%
Lodi - Cadek	Present	9.5000%
Lompoc - Hostler	Present	2.0357%
MID - Caballero	Present	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	10	95.7858%
Absent	3	4.2142%
Quorum by #:	Yes	
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)
Ken Goeke (NCPA by telephone)
Donna Stevener (NCPA by telephone)
Tom Lee (NCPA)
Gillian Biedler (NCPA)
Ruthann Ziegler (Meyers-Nave by telephone)

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 July 9, 2014 regular meeting were considered. The LEC PPC considered the following motion:

Date: 8/11/2014

Motion: The PPC approves the minutes of the July 14, 2014 regular PPC committee meeting, including any edits discussed at today's meeting.

Moved by: **Azusa**

Seconded by: **Gridley**

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	Yes	1.9643%
Healdsburg	Absent	1.6428%
Lodi	Yes	9.5000%
Lompoc	Yes	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	10	95.7858%
Total Noes	0	0.0000%
Total Abstain	0	0.0000%
Total Absent	3	4.2142%
Result:	Motion passed.	

MONTHLY REPORTS

3. Operational Reports for July 2014

Jeremy Lawson presented the monthly written Operational Report including Safety, Notice of Violations, Outage Summaries, Planned Outages, and Generating Unit Statistics for July and said it was an excellent month. There were no OSHA Recordable accidents, no Permit violations, no NERC/WECC violations, and no outages during July.

The report reflected monthly production of 118,197 net MWH, 473 service hours, and equivalent operating availability of 100%. The report set forth the Capacity Factor @ 280MW Pmax of 56.81% and @ 302MW Pmax of 52.67%. During the month the plant had 20 hot starts, two warm starts, and zero cold starts. Jeremy said the efficiency remains outstanding.

4. Market Data Report for July 2014

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

5. Monthly Asset Report

Mike DeBortoli presented his updated monthly budget review for FY 14 with actual numbers compared to estimated values for June and through this fiscal year end. He noted costs in the maintenance area are over budget and said the Long Term Maintenance costs are lumped in that category also which calculation is based on the plant running at full output. There were no significant deviations from the projected budget. Frank Schultz inquired as to the cost per MWh for this fiscal year period. Mike DeBortoli said he would obtain that information.

Consent Calendar - July

Various items previously considered at the July 14, 2014 PPC meeting under the consent calendar and business action items were brought back for approval. Ken Speer discussed with the Participants pertinent sections of the Power Sales Agreement pertaining to the Participant Committee, including what constitutes a quorum and the requirements to be met for Participant Committee approval. Ruthann Ziegler, NCPA legal counsel to the committee, and Ken Speer explained that a quorum may be established either by a majority of the Participants or by GES shares of not less than a majority of the shares of all Participants. Once a quorum is established, action may be taken by a majority of the quorum in attendance. In the event, however, a Participant requests that a GES vote be taken, then a higher GES share percentage is required based on the Threshold Amount of the item and according to the formula set forth in the PSA. The calling of a GES share vote at the July meeting invoked a higher percentage required for action on motions which was not possible based on the number of GES shares of Participants in attendance at the meeting.

Chairman Werner asked if any Participant wished to remove any item listed on the Consent Calendar-July 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: 8/11/2014

Motion: The PPC approves the Consent Calendar-July consisting of agenda items no. 6, 7, 8, 9, and 10 as listed on the 8-11-14 agenda.

Moved by: **Azusa**

Seconded by: **BART**

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	Yes	1.9643%
Healdsburg	Absent	1.6428%
Lodi	Yes	9.5000%
Lompoc	Yes	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	10	95.7858%
Total Noes	0	0.0000%
Total Abstain	0	0.0000%
Total Absent	3	4.2142%
Result:	Motion passed.	

The Consent Calendar for August was then considered. Chairman Werner asked if any Participant wished to remove any item listed on the Consent Calendar-August 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: 8/11/2014

Motion: The PPC approves the Consent Calendar for items from the August PPC meeting consisting of agenda items no. 11, 12, 13, 14, 15, and 16.

Moved by: **Gridley**

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	Yes	1.9643%
Healdsburg	Absent	1.6428%
Lodi	Yes	9.5000%
Lompoc	Yes	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	10	95.7858%
Total Noes	0	0.0000%
Total Abstain	0	0.0000%
Total Absent	3	4.2142%
Result:	Motion passed.	

Note regarding Consent item 15: By this motion, the PPC approved the change to Market Charge Code 4560 to reflect the GMC-Market Services Charge 2014 Rate of $.0940. The Total GMC Amount as reflected on the draft Exhibit 5 included with the meeting materials did not update the total. The new Total GMC Amount is $0.383.

BUSINESS ACTION ITEMS

17. Siemens Long Term Maintenance Program for LEC

Mike DeBortoli presented slides to supplement the Staff Report prepared for this item. Mike discussed the final negotiations had with Siemens to extend the sunset date with respect to coverage of three majors under this Amended and Restated Long Term Maintenance Program Agreement. Following a question from Martin Caballero, a discussion was had about Exhibit E, Payment Schedule, and the changes made regarding true up of variable fees. The PPC considered the following motion:

Date: 8/11/2014

Motion: The PPC approves the "Amended and Restated Program Parts, Non-Program Parts, Miscellaneous Hardware, Program Management Services and Scheduled Outage Services Contract" with Siemens Energy, Inc., including upgrade of parts to increase equivalent start intervals for Hot Gas Path and Major Inspections, a contract extension, clarity for open/close warranty parts liability, escalation of the Extra Work Authorization benefit, flexible scheduling, and other revisions, at an additional cost of $28 million over the 18 year life of the agreement, with any non-substantial changes recommended and approved by the NCPA General Counsel, as discussed at today's meeting.

Moved by: **MID**

Second by: **CDWR**

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	Yes	1.9643%
Healdsburg	Absent	1.6428%
Lodi	Yes	9.5000%
Lompoc	Yes	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	10	95.7858%
Total Noes	0	0.0000%
Total Abstain	0	0.0000%
Total Absent	3	4.2142%
Result:	Motion passed.	

INFORMATIONAL ITEMS

18. August Forced Outage

Mike DeBortoli introduced this item and reported that a forced outage occurred on August 5 as a result of problems with the High Pressure Steam Turbine Control Valve (HPCV). A cool down period of five days transpired before repairs could begin. Mike presented a diagram of the valve arrangement as a visual aid to the discussion and introduced Ryan Johnson, lead operator at LEC, who led a discussion with the Participants about what went wrong. Referring to the diagram, Ryan explained the workings of the valve, which must be completely closed and sealed in order to have enough pressure to open. Tests were done in April on the valves and at that time some leaking by was detected. Last month CT specialist tests showed the IP and HP valves had some leaking by. Photographs were shown of the HPCV actuator, disk, seat, stem, and the Butterfly valve and seal where it is broken. Work is being done to resurface the area to obtain a new reseat. The concern is that replacement parts are not on hand for the HPCV issue so hopefully the resurfacing goes well. If new parts are required there is an eight week delivery time for new valves. In the future some new pressure indicators will be added in the cavity between the valves.

Jeremy Lawson spoke about further work being done on the RAC to take advantage of this forced outage. 15 new tubes have been plugged, bringing the total to 70. Jeremy reminded the group that based on Siemens limits a total of 94 tubes may be plugged and that Siemens took responsibility for the RAC replacement cost under the warranty. Pictures were displayed on the screen of this work in progress. The new RAC is on order and delivery is expected mid-October. The plan continues to be that replacement of the RAC will occur during the planned outage in May 2015.

19. LEC Project Management and Operations Agreement (PMOA) Schedule 7.00

As a follow up to the information presented at last month's meeting, James Takehara presented an update. Two takeaways from the July meeting were that James will send a spreadsheet to the Participants providing explanation and requesting that any questions be submitted; and that he bring back the terms of Article 7 of the PMOA to refresh the group's recall. Article 7, Differential Transmission Cost Adjustment, was provided and James revisited his July presentation to discuss the methodology used to draft Schedule 7.00. Discussion was had about MID's load in the Balancing Authority of Northern California and MID's options to export energy out; the difference in incremental costs when making exports; calculation methodology; and agreement to cooperate regarding mitigation of the expected amount and incidence of the differential transmission cost adjustment. It was noted that MID has not yet done any exports. James said he thinks the draft of the Schedule 7.00 accurately reflects what is intended by the terms of the PMOA. Mike Werner noted that Section 7.1.6 of Article 7 of the PMOA provides for review of the differential transmission cost adjustment at least annually. The Schedule 7.00 will be brought back to the Committee next month for approval.

20. Other New Business

Owen Stiles made a suggestion that a large American Flag be flown at the LEC location. Mike DeBortoli said he would check into the terms of the plant's license and any other regulations which may apply and report back to the Committee.

Adjournment

The next regular meeting of the PPC is scheduled for Monday, September 8, 2014. The meeting was adjourned at 11:55 a.m.

Lodi Energy Center
Project Participant Committee SPECIAL Meeting
August 22, 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 special meeting was called to order at 10:00 a.m. by Chairman Mike Werner. He asked that roll be called as listed below.

PPC Meeting Attendance Summary		
Participant	**Attendance**	**Particulars / GES**
Azusa - Morrow	Absent	2.7857%
BART - Lloyd	Present	6.6000%
Biggs - Sorenson	Absent	0.2679%
CDWR - Werner	Present	33.5000%
Gridley - Stiles	Present	1.9643%
Healdsburg - Crowley	Absent	1.6428%
Lodi - Cadek	Absent	9.5000%
Lompoc - Hostler	Absent	2.0357%
MID - Caballero	Absent	10.7143%
Plumas-Sierra - Brozo	Absent	0.7857%
PWRPA - Palmerton	Absent	2.6679%
SVP - Hance	Absent	25.7500%
Ukiah - Grandi	Absent	1.7857%
Summary		
Present	3	42.0643%
Absent	10	57.9357%
Quorum by #:	No	
Quorum by GES:	No	

This meeting is informational only; no action is being sought. A quorum is not necessary to proceed.

Public Forum

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

2. August Forced Outages

Mike DeBortoli updated the Committee since the report given at the August 11 regular meeting. On August 5 a forced outage occurred when the emergency stop valve would not open. The failure occurred within the High Pressure Steam Turbine Control Valve (HPCV) and the High

Pressure Steam Turbine Emergency Stop Valve (HP ESV) assembly. Excessive steam leak-by around the HPCV caused an excessive differential pressure around the HP-ESV which did not allow it to open. Staff has been working with Siemens to expedite the fabrication of new HPCV and HP-ESV parts to rebuild each valve. A test was reported successful on August 16 but then it failed again on August 17. On August 20 a short term work-around solution was implemented. Generally it involved making adjustments so the unit could start at a lower pressure. So far the work-around continues to be successful.

Marty Hostler from Lompoc and Martin Caballero from MID joined the meeting.

Mike's update included a PowerPoint presentation which showed the technical workings of the valve components, photographs of test findings, and details of the testing and other checks performed. It also outlined three possible outcomes and included costs associated with those scenarios. Mike was asked if any damage could result when starting at a lower pressure, to which he replied "no", but said that the unit will be closely monitored to make sure no water gets into the steam turbine. Siemens has not seen this issue before. The theory continues to be that the seat is leaking. A complete check takes between three to five weeks and it is hoped that the unit will make it to the scheduled outage. Ken Speer said he has seen the lower pressure work-around before but not on a unit that starts and stops as much as this unit. Never letting an outage go to waste, Mike outlined the other work done while the unit was down.

Bob Caracristi discussed the market results as a product of this outage. Dave Dockham discussed CAISO Reliability requirements citing to the Monthly Availability Standards for Compliance Year 2014 and the Business Practice Manual for Reliability Requirements. He also discussed how penalties are calculated and projected the estimated penalty as a result of this outage. Tony Zimmer offered comments about Resource Adequacy and noted that for situations where there are expectations of an impending outage, Participants can go out and replace RA; however he noted that it must be provided to the CAISO before an outage is declared. This is a tool to hedge this issue as energy losses appear to be much less than replacement capacity. Tony said RA has been claimed through September and October, but said November will be claimed in a couple of weeks so let him know by mid-September for that month. More operating data will be available at the next regular PPC meeting.

Ken Speer summarized the situation saying the good news is that a work-around for the valve issues has been identified and implemented; the bad news is that the cause of the problems remains a theory until testing can be completed.

<u>Adjournment.</u>

Chairman Werner adjourned the special meeting at 10:45 a.m.

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Lodi Energy Center Project Participant Committee

Operational Report

Agenda Item No. 3

Date: 9/8/2014

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 Steam Turbine Control Valve and Emergency Stop Valve – (362 Hours, 8/5/2014 – 8/20/2014)** LEC experienced a failure within the High Pressure Steam Turbine Control Valve (HPCV) and the High Pressure Steam Turbine Emergency Stop Valve (HP ESV) assembly. Excessive steam leak-by around the HPCV caused an excessive differential pressure around the HP-ESV disallowing the HP-ESV to open. Staff has been working with Siemens to expedite the fabrication of new HPCV and HP-ESV parts to rebuild each valve. Short term corrections included using a local valve shop to re-lap and improve the seating surface of the HPCV.

Planned Outage Summaries:

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

Generating Unit Statistics: LEC

Report Date:	
Start Date	8/1/2014
End Date	8/31/2014

1. Monthly Production 68,997 MWH
2. Productivity Factor
   a. Service Hours 282 Hours
   b. Service Factor 37.97 %
   c. Capacity Factor @ 280MW Pmax 33.16 %
   d. Capacity Factor @ 302MW Pmax 30.75 %
3. Equivalent Operating Availability (EOA) 51.22 %
4. Forced Outage Rate (FOR)
   a. Combustion Turbine Generator 0.00 %
   b. Steam Turbine Generator 56.23 %
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	6,916	6870	0.67%	133	$24
Seg. 3	275 - 284	6,905	6971	-0.95%	41,499	-$10,991
Seg. 4	250 - 275	6,934	7081	-2.07%	14,493	-$8,514
Seg. 5	225 - 250	7,005	7130	-1.75%	4,775	-$2,380
Seg. 6	200 - 225	7,099	7315	-2.95%	2,806	-$2,426
Seg. 7	175 - 225	7,236	7711	-6.16%	1,904	-$3,616
Seg. 8	165 - 175	7,555	7856	-3.83%	573	-$691
					66,182	**-$28,593**

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	1	0	1	$26
Seg. 3	275 - 284	108	-80	188	$5,205
Seg. 4	250 - 275	50	-72	122	$3,372
Seg. 5	225 - 250	27	-12	39	$1,088
Seg. 6	200 - 225	19	-10	29	$836
Seg. 7	175 - 225	11	-6	17	$482
Seg. 8	165 - 175	14	-1	15	$440
		229	-181	410	**$11,448**

7. Starting Reliability

Start Type	**Hot Starts**	**Warm Starts**	**Cold Starts**
Number of Starts	12	3	1
Start Time Benchmark (Minutes)	85	160	235
Start Time Actual (Average Minute)	103.2	187.7	187.0
Start Time Deviation (%)	21.4%	17.3%	-20.4%
Start Fuel Benchmark PMOA (mmBTU)	1,967	5,200	5,430
Start Fuel Actual (Average mmBTU)	1,858	3,421	3,578
Fuel Deviation	-5.6%	-34.2%	-34.1%
Costs of Fuel Deviations ($)	**-$437**	**-$7,118**	**-$7,408**

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

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LEC Treasurer's Report

AGENDA ITEM NO.:______

Date: September 3, 2014

To: LEC Project Participant Committee

Subject: Treasurer's Report for the Month Ended August 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 $29,121,337 at month end. The current market value of the portfolio totaled $29,087,328.

The overall portfolio had a combined weighted average interest rate of 0.396% with a bond equivalent yield (yield to maturity) of 0.351%. Investments with a maturity greater than one year totaled $11,351,000. During the month $2 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 0.03%) and rates on one year T-Bills decreased 1 basis point (from 0.12% to 0.11%).

To the best of my knowledge and belief, all securities held by LEC as of September 8, 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:

KEVIN W. WALLACE
Treasurer-Controller

Attachments

LODI ENERGY CENTER

TREASURER'S REPORT

AUGUST 31, 2014

TABLE OF CONTENTS

Northern California Power Agency/Lodi Energy Center
Treasurer's Report
Cash & Investment Balance
August 31, 2014

		CASH		INVESTMENTS		TOTAL	PERCENT		INVESTMENTS at MARKET
MANDATORY FUNDS									
Construction Revolving	$	-	$	3,441	$	3,441	0.012%	$	3,441
Debt Service Account		-		6,634,937		6,634,937	22.784%		6,635,148
Debt Service Reserve		-		11,772,458		11,772,458	40.426%		11,737,214
O & M Reserve		-		10,639,676		10,639,676	36.536%		10,640,700
		-		29,050,512		29,050,512	99.757%		29,016,503
ADDITIONAL PROJECT FUNDS									
GHG Cash Account		-		70,825		70,825	0.243%		70,825
	$	-	$	29,121,337	$	29,121,337	100.000%	$	29,087,328

NOTE A -Investment amounts shown at book carrying value.

Northern California Power Agency/Lodi Energy Center
Treasurer's Report
Cash Activity Summary
August 31, 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	-	0	1,345	-	(2,212,699)	2,211,354	-
Debt Service Reserve	-	24,123	-	-	(24,123)	-	-
O & M Reserve	-	-	-	-	-	-	-
	-	24,123	1,345	-	(2,236,822)	2,211,354	-
ADDITIONAL PROJECT FUNDS							
GHG Cash Account	-	-	-	-	-	-	-
TOTAL	$ -	$ 24,123	$ 1,345	$ -	$ (2,236,822)	$ 2,211,354	$ -

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
August 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	2,212,699	(1,345)	269	-	-	2,211,623
Debt Service Reserve	24,123	-	(159)	-		23,964
O & M Reserve	-	-	(1,281)	-		(1,281)
	2,236,822	(1,345)	(1,171)	-	-	2,234,306
ADDITIONAL PROJECT FUNDS						
GHG Cash Account		-	-	-		-
TOTAL	$ 2,236,822	$ (1,345)	$ (1,171)	$ -	$ -	$ 2,234,306

Less Non- Cash Activity	
Disc/(Prem) Amortization & Gain/(Loss) on Sale	1,171
Net Change in Investment --Before Non-Cash Activity	$ 2,235,477

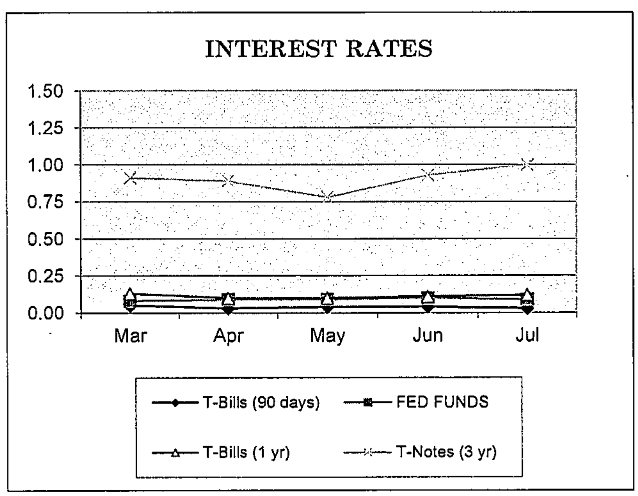
NOTE A -Investment amounts shown at book carrying value.

NORTHERN CALIFORNIA POWER AGENCY
LODI ENERGY CENTER
INTEREST RATE/YIELD ANALYSIS
August 31, 2014

	WEIGHTED AVERAGE INTEREST RATE	BOND EQUIVALENT YIELD
OVERALL COMBINED	0.396%	0.351%
Construction Revolving Acct	0.221%	0.221%
Funds:		
Debt Service Account	0.060%	0.061%
Debt Service Reserve	0.545%	0.571%
O & M Reserve	0.443%	0.290%
GHG Cash Account	0.221%	0.221%

KEY INTEREST RATES

	CURRENT	PRIOR YEAR
Fed Fds (Ovrnight)	0.09%	0.09%
T-Bills (90da.)	0.03%	0.03%
Agency Disc (90da.)	0.05%	0.03%
T-Bills (1yr.)	0.11%	0.11%
Agency Disc (1yr.)	0.16%	0.14%
T-Notes (3yr.)	0.97%	0.61%



Lodi Energy Center
Total Portfolio
Investment Maturities Analysis
July 31, 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		$10,246				$11,351		$21,597	74.16%
US Bank Trust Money Market	3,419							3,419	11.74%
Investment Trusts (LAIF)	4,106							4,106	14.10%
U.S.Treasury Market Acct. *								0	0.00%
U.S.Treasury Bill								0	0.00%
Certificates of Deposit								0	0.00%
Total Dollars	$7,525	$10,246	$0	$0	$0	$11,351	$0	$29,122	100.00%
Total Percents	25.84%	35.18%	0.00%	0.00%	0.00%	38.98%	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

08/31/2014

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		3,441	0.221	07/01/2013	3,441		1	0.221	3,441	SYS70040	70040	3,441
	Fund Total and Average	**$ 3,441**	0.221		**$ 3,441**		**1**	**0.221**	**$ 3,441**			**$ 3,441**
	GRAND TOTALS:	**$ 3,441**	0.221		**$ 3,441**		**1**	**0.221**	**$ 3,441.**			**$ 3,441**

***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 08/31/2014

Northern California Power Agency

Treasurer's Report

08/31/2014

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	644	0.100	07/01/2013	644		1	0.100	644	SYS79003	79003	644
Federal Home Loan Ba	USBT	694,000	0.050	08/25/2014	693,906	12/01/2014	91	0.050	693,917	313385R57	26153	693,912
Federal National Mtg	USB	693,000	0.069	06/26/2014	692,787	12/01/2014	91	0.070	692,917	313589R54	26138	692,877
Federal National Mtg	USBT	693,000	0.060	07/25/2014	692,851	12/01/2014	91	0.060	692,917	313589R54	26142	692,895
	Fund Total and Average	$ 2,080,644	0.060		$ 2,080,188		91	0.061	$ 2,080,395			$ 2,080,328

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	154	0.100	07/01/2013	154		1	0.100	154	SYS79004	79004	154
Federal Home Loan Ba	USBT	733,000	0.050	08/25/2014	732,900	12/01/2014	91	0.050	732,912	313385R57	26154	732,907
Federal National Mtg	USB	732,000	0.070	06/26/2014	731,775	12/01/2014	91	0.070	731,912	313589R54	26139	731,870
Federal National Mtg	USBT	732,000	0.060	07/25/2014	731,843	12/01/2014	91	0.060	731,912	313589R54	26143	731,889
	Fund Total and Average	$ 2,197,154	0.060		$ 2,196,672		91	0.061	$ 2,196,890			$ 2,196,820

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	361	0.100	07/01/2013	361		1	0.100	361	SYS79011	79011	361
Federal Home Loan Ba	USBT	434,000	0.050	08/25/2014	433,941	12/01/2014	91	0.050	433,948	313385R57	26155	433,945
Federal National Mtg	USB	434,000	0.069	06/26/2014	433,867	12/01/2014	91	0.070	433,948	313589R54	26140	433,923
Federal National Mtg	USBT	434,000	0.060	07/25/2014	433,907	12/01/2014	91	0.060	433,948	313589R54	26144	433,934
	Fund Total and Average	$ 1,302,361	0.060		$ 1,302,076		91	0.061	$ 1,302,205			$ 1,302,163

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	784	0.100	07/01/2013	784		1	0.100	784	SYS79012	79012	784
Federal Home Loan Ba	USBT	352,000	0.050	08/25/2014	351,952	12/01/2014	91	0.050	351,958	313385R57	26156	351,956
Federal National Mtg	USB	351,000	0.069	06/26/2014	350,892	12/01/2014	91	0.070	350,958	313589R54	26141	350,938
Federal National Mtg	USBT	352,000	0.060	07/25/2014	351,924	12/01/2014	91	0.060	351,958	313589R54	26145	351,947
	Fund Total and Average	$ 1,055,784	0.060		$ 1,055,552		91	0.061	$ 1,055,658			$ 1,055,625

GRAND TOTALS:	$ 6,635,943	0.060	$ 6,634,488	91	0.061	$ 6,635,148.	$ 6,634,936

*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 08/31/2014

Northern California Power Agency

Treasurer's Report

08/31/2014

LEC Issue #1 2010 DSR 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	70,132	0.100	07/01/2013	70,132		1	0.100	70,132	SYS79005	79005	70,132
Federal Home Loan Mt	USB	4,181,000	0.580	05/30/2014	4,183,927	08/26/2016	725	0.548	4,170,757	3134G56B6	26135	4,183,596
Federal National Mtg	USB	4,170,000	0.875	05/30/2014	4,171,960	08/28/2017	1,092	0.977	4,149,400	3135GOMZ3	26136	4,171,807
	Fund Total and Average	**$ 8,421,132**	0.722		**$ 8,426,019**		**901**	**0.757**	**$ 8,390,289**			**$ 8,425,535**

LEC Iss#1 2010B BABS Subs Resv

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	2,260,635	0.100	07/01/2013	2,260,635		1	0.100	2,260,635	SYS79006	79006	2,260,635
	Fund Total and Average	**$ 2,260,635**	0.100		**$ 2,260,635**		**1**	**0.100**	**$ 2,260,635**			**$ 2,260,635**

LEC Issue #1 2010 COI 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
US Bank Trust	USB	2	0.100	07/01/2013	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

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	1,086,288	0.100	07/01/2013	1,086,288		1	0.100	1,086,288	SYS79013	79013	1,086,288
	Fund Total and Average	**$ 1,086,288**	0.100		**$ 1,086,288**		**1**	**0.100**	**$ 1,086,288**			**$ 1,086,288**

LEC Issue#2 2010 COI 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
US Bank Trust	USB	0	0.100	07/01/2013	0		1	0.100	0	SYS79015	79015	0
	Fund Total and Average	**$ 0**	0.100		**$ 0**		**1**	**0.100**	**$ 0**			**$ 0**
	GRAND TOTALS:	**$ 11,768,057**	0.545		**$ 11,772,944**		**645**	**0.571**	**$ 11,737,214.**			**$ 11,772,460**

***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 08/31/2014

Investment # 26135 – FHLMC Note .58% thru 8/26/16,; Callable 11/26/14, semi-annually thereafter.

NCPA
NORTHERN CALIFORNIA POWER AGENCY

Northern California Power Agency
Treasurer's Report
08/31/2014

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		4,031,547	0.221	07/01/2013	4,031,547		1	0.221	4,031,547	SYS70047	70047	4,031,547
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	21	0.110	2,981,132	3134G2WG3	26099	2,981,111
Federal Home Loan Mt	UBOC	632,000	0.140	10/31/2013	631,127	10/21/2014	50	0.142	631,981	313397L41	26066	631,877
Federal Home Loan Mt	UBOC	3,000,000	0.500	10/25/2013	2,992,800	06/06/2016	644	0.592	2,996,040	3134G46A1	26052	2,995,141
	Fund Total and Average	**$ 10,643,547**	0.443		**$ 10,646,738**		**191**	**0.290**	**$ 10,640,700**			**$ 10,639,676**
	GRAND TOTALS:	**$ 10,643,547**	0.443		**$ 10,646,738**		**191**	**0.290**	**$ 10,640,700.**			**$ 10,639,676**

***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 08/31/2014

Investment # 26052 - FHLMC Structured Note .50%; Callable on 09/06/14 Quarterly thereafter.

NCPA NORTHERN CALIFORNIA POWER AGENCY

Northern California Power Agency
Treasurer's Report
08/31/2014

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		70,825	0.221	07/01/2013	70,825		1	0.221	70,825	SYS70046	70046	70,825
	Fund Total and Average	**$ 70,825**	0.221		**$ 70,825**		**1**	**0.221**	**$ 70,825**			**$ 70,825**
	GRAND TOTALS:	**$ 70,825**	0.221		**$ 70,825**		**1**	**0.221**	**$ 70,825.**			**$ 70,825**

*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 08/31/2014

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LEC Financial Reports

AGENDA ITEM NO.: ____

Date: September 3, 2014

Subject: August 30, 2014 Financial Reports (Unaudited)

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

	August 31	
ASSETS	**2014**	**2013**
CURRENT ASSETS		
Cash and cash equivalents	$ 70,825	$ 86,392
Interest receivable	10,986	1,745
Inventory and supplies - at average cost	1,263,331	990,780
Due from (to) Agency, net	16,577,566	15,611,006
TOTAL CURRENT ASSETS	17,922,708	16,689,923
RESTRICTED ASSETS		
Cash and cash equivalents	8,317,475	2,260,084
Investments	21,621,120	28,951,035
Interest receivable	20,064	7,806
TOTAL RESTRICTED ASSETS	29,958,659	31,218,925
ELECTRIC PLANT		
Electric plant in service	423,372,867	423,354,890
Less: accumulated depreciation	(25,567,466)	(10,956,865)
TOTAL ELECTRIC PLANT	397,805,401	412,398,025
OTHER ASSETS		
Regulatory assets	13,003,930	12,561,646
TOTAL OTHER ASSETS	13,003,930	12,561,646
TOTAL ASSETS	$ 458,690,698	$ 472,868,519

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

	August 31	
	2014	2013
LIABILITIES & NET POSITION		
CURRENT LIABILITES		
Accounts and retentions payable	$ 2,549,373	$ 4,539,661
Operating reserves	11,724,923	11,017,250
Current portion of long-term debt	9,025,000	8,640,000
Accrued interest payable	4,346,880	4,978,297
TOTAL CURRENT LIABILITIES	27,646,176	29,175,208
NON-CURRENT LIABILITIES		
Operating reserves and other deposits	981,859	86,392
Regulatory liability	45,618,145	49,148,706
Long-term debt, net	372,666,989	382,753,588
TOTAL NON-CURRENT LIABILITIES	419,266,993	431,988,686
TOTAL LIABILITIES	446,913,169	461,163,894
NET POSITION		
Invested in capital assets, net of related debt	(4,752,067)	(3,868,495)
Restricted	12,881,184	14,440,108
Unrestricted	3,648,412	1,133,012
TOTAL NET POSITION	11,777,529	11,704,625
TOTAL LIABILITIES AND NET POSITION	$ 458,690,698	$ 472,868,519

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

	Two Months Ended August 31	
	2014	2013
SALES FOR RESALE		
Participants	$ 7,314,211	$ 7,391,094
Other	8,633,137	9,896,516
TOTAL SALES FOR RESALE	15,947,348	17,287,610
OPERATING EXPENSES		
Operations	7,207,051	6,614,111
Depreciation	2,433,111	2,420,991
Maintenance expenses	525,963	929,641
Administrative and general	655,289	867,198
Intercompany (sales) purchases	18,043	17,641
TOTAL OPERATING EXPENSES	10,839,457	10,849,582
NET OPERATING REVENUES	5,107,891	6,438,028
OTHER REVENUES (EXPENSES)		
Interest expense	(2,744,808)	(2,795,566)
Interest income	37,630	6,292
Amortization	-	(12,710)
Other	(629,593)	367,342
TOTAL OTHER REVENUES (EXPENSES)	(3,336,771)	(2,434,642)
FUTURE RECOVERABLE AMOUNTS	385,783	413,472
INCREASE IN NET POSITION	2,156,903	4,416,858
NET POSITION		
Beginning of year	9,620,626	7,287,767
End of period	$ 11,777,529	$ 11,704,625
	-	-

Lodi Energy Center
FY 2015 Operating Costs
As of August 31, 2014

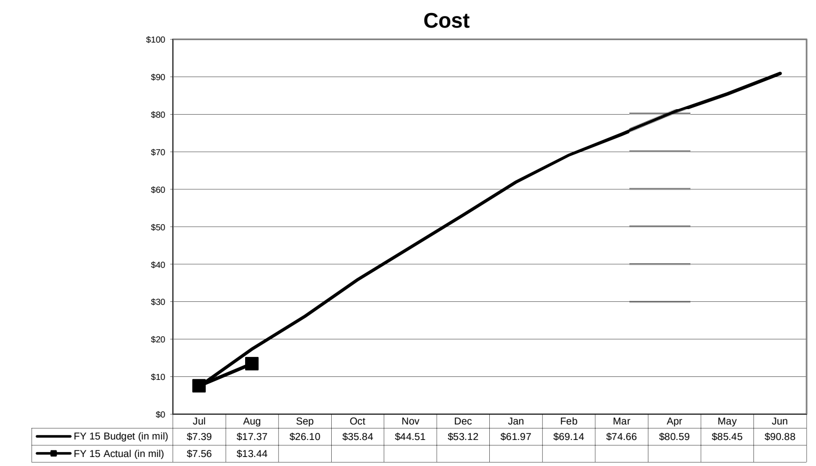
	Annual Budget	Actual	Remaining	YTD % Remaining	Notes
Routine O&M Costs					
Variable	$ 3,651,332	$ 176,528	$ 3,474,804	95%	
Fixed	1,765,358	203,045	1,562,313	88%	
Administration	1,250,914	193,715	1,057,199	85%	
Mandatory Costs	220,000	37,348	182,652	83%	
Inventory Stock	400,000	91,974	308,026	77%	
Routine O&M Costs without Labor	7,287,604	702,610	6,584,994	90%	
Labor	4,299,182	702,402	3,596,780	84%	
Total Routine O&M Cost	11,586,786	1,405,012	10,181,774	88%	
Other Costs					
Fuel	41,167,130	6,881,322	34,285,808	83%	
CA ISO Charges	489,050	-	489,050	100%	
Debt Service	26,437,890	4,406,316	22,031,574	83%	
Insurance	1,000,425	-	1,000,425	100%	**A**
Other Costs	51,781	20,063	31,718	61%	**B**
Generation Services Shared	437,453	38,043	399,410	91%	
Administrative & General (Allocated)	1,728,654	186,419	1,542,235	89%	
Power Management Allocated Costs	1,187,916	197,986	989,930	83%	
Total O&M Cost	84,087,085	13,135,161	70,951,924	84%	
Projects					
Operations & Maintenance	332,500	-	332,500	100%	
Capital	4,658,760	5,088	4,653,672	100%	
Maintenance Reserve	1,800,000	300,000	1,500,000	83%	
Total Projects	6,791,260	305,088	6,486,172	96%	
Annual Cost	90,878,345	13,440,249	77,438,096	85%	
Less: Third Party Revenue					
Interest Income	44,489	4,072	40,417	91%	
ISO Energy Sales	54,517,593	8,411,800	46,105,793	85%	
Ancillary Services Sales	1,420,431	221,337	1,199,094	84%	
Other Income	-	587	(587)	N/A	
	55,982,513	8,637,796	47,344,717	85%	
Net Annnual Cost to Participants	$ 34,895,832	$ 4,802,453	$ 30,093,379	86%	

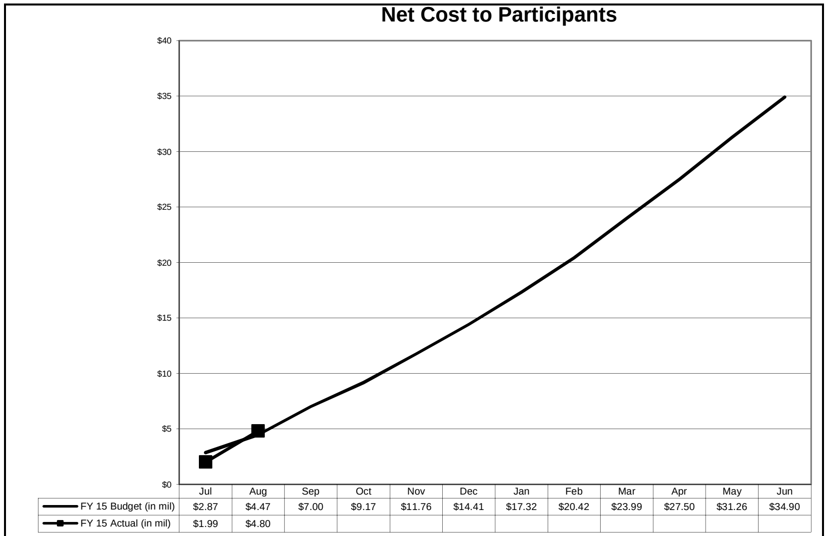
Total Variable Costs	45,307,512	7,057,850	38,249,662
Total Fixed Costs	45,570,833	6,382,399	39,188,434
	$ 90,878,345	$ 13,440,249	$ 77,438,096

Net Cumulative Generation (MWh)	1,207,542	187,481
Total O&M Cost Per MWh	$ 69.63	$ 70.06
Net Annual Cost Per MWh	$ 28.90	$ 25.62

Footnotes:

A - Insurance is paid annually in November.
B - Payments for annual bank trust fees.





Annual Budget
LEC Generation Analysis
Planned vs. Actual
FY 2015

In MWh

Lodi Energy Center

	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
FY 15 Planned	97,285	263,628	393,482	553,897	688,758	817,382	946,527	1,034,640	1,080,058	1,136,945	1,164,072	1,207,542
FY 15 Actual	118,471	187,481										

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)

	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	51,037	118,473	103,992	100,100	107,885	96,207	103,992	1,221,456	2,432,400		Forecast/Meter
Gas Schedule (MMBtu)	951,700	1,092,730	858,805	391,272	512,068	371,695	836,762	727,946	700,697	755,195	673,447	727,946	8,600,264	17,163,588		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	19,700	44,348	38,581	37,137	40,025	35,693	38,581	455,814	909,670		derived
Cumulative MT Obligation (MT)	504,296	562,211	607,728	628,465	655,605	675,304	719,653	758,234	795,371	835,396	871,089	909,670		909,670		derived
Compliance Instrument Participant Transfers (to LEC)																
Auction Allowances	102,347	50,000	48,066	25,000	1,290	138,448	0	0	0	0	0	0	365,151	825,784		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	138,448	0	0	0	0	0	0	365,151	825,784		
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	138,448	0	0	0	0	0	0	365,151	872,784		derived
Cumulative MT Account Balance [MTA] (MT)	609,980	659,980	708,046	733,046	734,336	872,784	872,784	872,784	872,784	872,784	872,784	872,784		872,784		derived
MTA Shortfall (MT)	(105,684)	(97,769)	(100,318)	(104,581)	(78,731)	(197,480)	(153,131)	(114,550)	(77,413)	(37,388)	(1,695)	36,886		36,886	MTA SHORTFALL	derived

Forecast for July-December 2014 has been updated.

NCPA All Resources Bill LEC GHG Obligation Detail Report (Cumulative) September 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)	22,157	52,494	2,131	266,449	15,623	13,066	75,560	16,191	85,218	6,249	21,220	204,808	14,203	795,371		derived
Current MT Compliance Instrument Account (MTA) Balance (MT)	26,000	82,200	2,257	325,000	16,547	12,676	75,578	24,200	95,000	6,700	24,787	220,000	14,140	925,085		derived
MTA Shortfall (MT)	(3,843)	(29,706)	(126)	(58,551)	(924)	390	(18)	(8,009)	(9,782)	(451)	(3,567)	(15,192)	63	(129,714)	MTA SHORTFALL	Derived
Monthly GHG Price $/MT	11.79	11.79	11.79	11.79	11.79	11.79	11.79	11.79	11.79	11.79	11.79	11.79	11.79	11.79	MTA SHORTFALL	ICE Index
GHG Minimum Cash Compliance Obligation ($)	0	0	0	0	0	4,602	0	0	0	0	0	0	742	5,344	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.

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Lodi Energy Center Project Participant Committee

Staff Report

AGENDA ITEM NO.: 9

Date: September 2, 2014

To: Lodi Energy Center Project Participant Committee

Subject: Approval of Amendment 1 to Project Management and Operations Agreement (PMOA), Schedule 7.00

Background

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

1. *[T]he 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 (Section 7.1),*
2. *All Parties agree to cooperate as reasonably required to establish such Project protocols and guidelines that reduce the expected amount and incidence of the differential transmission cost adjustment (Section 7.1.3), and*
3. *Any differential transmission cost adjustment approved for implementation by the PPC will be billed according to the procedures approved by the PPC in Agreement Schedule 7.00 and shall be allocated to all Participants in proportion to their respective GES.*

At the time the PMOA was adopted and executed by the LEC Project Participants, Schedule 7.00 was attached in a draft form.

The attached proposal was first introduced to this Committee as an informational item at the July PPC meeting and included a detailed staff report that addressed the proposal particulars and a detailed presentation. Following the request of the PPC, staff deferred seeking approval of Amendment 1 to Schedule 7.00 to allow Project Participant staff to review the proposal and ask questions during the intervening month. Staff returned to this Committee at the August PPC meeting to provide a briefing on the issues and questions that were raised by Project Participant staff. There were several questions raised by various Participant staff, but these questions did not lead to any revisions in the proposal.

Since the commercial operation date of the LEC, no Participants have exported LEC energy from the CAISO Balancing Authority Area to serve its native load.

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.

Recommendation

NCPA staff recommends the PPC pass a motion approving Amendment 1 to PMOA, Schedule 7.00, effective September 1, 2014, including any non-substantive changes authorized by NCPA General Counsel.

Prepared by:

/s/
JAMES TAKEHARA
Energy Resource Analyst

Attachment: (4)

- Proposed Amendment 1 to PMOA, Schedule 7.00
- Staff Report, "Update on Development of Amendment to PMOA, Schedule 7.00" (July 10, 2014)
- Attachment A to July 10 Staff Report
- Presentation to PPC, July 14, 2014

SR: get from Linda

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.

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

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

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.

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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

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.

Status Update
Amendment to PMOA, Schedule 7.00

LEC PPC

July 14, 2014

Background

- PMOA, Article 7
  - *PPC is authorized to establish, approve, implement, administer and revise,*
  - *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*

Background

- Article 7 establishes policy
- Schedule 7.00
  - Provides details for calculation
  - Sample attached to PMOA
  - To be finalized before Commercial Operation Date

- Current Draft Development: CDWR, MID, & NCPA
- Builds off example Schedule 7.00
- Explored other costs/benefits

Today's Objectives

- Brief PPC on development status
- Review concepts of current draft proposal
- Review methodology, formulas
- Discuss next steps

Development Status

- CDWR, MID, & NCPA met 7 times over 12 months
- Current draft ready for review by other Participants
- Exploring & testing scheduling mechanics

Differential Transmission Cost Adjustment (DTCA)

CONCEPTS & FORMULAS

General Methodology

Item	Particulars	Estimated Rate	Benefits	Charges	Cumulative Charges - Benefits Account Balance
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		$ -		

(1) Determine actual CAISO transmission-related costs for MID Exports

(2) Estimate Western transmission-related costs avoided by MID

(3) Determine net costs for MID export (Parts 1 + 2)

(4) Apply credits to “differential capital cost threshold”.

Numeric Example

- The following slides assumes 11,442 MWhs exported by MID in a given month

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

Item 1: CAISO Charges

Item	Particulars	Estimated Rate	Benefits	Charges	Cumulative Charges - Benefits Account Balance
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		$ -		

CAISO Export Costs

Item	Particulars	Estimated Rate	Benefits	Charges
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)**

- Based on exports to BAA where Exporting Participant has load
- Applicable CAISO Charge Codes
  - (e.g. Wheeling Access Charge, GMC, Neutrality, etc.)
  - Use CAISO rates in effect at time of export, plus prior period adjustments
- Source: CAISO Invoices

CAISO Export Costs

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

NOTE: NCPA staff validating this information

Item 2: Western Charges/ Benefits

Item	Particulars	Estimated Rate	Benefits	Charges	Cumulative Charges - Benefits Account Balance
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		$ -		

WAPA Avoided Costs (i.e. Benefits)

Item	Particulars	Estimated Rate	Benefits
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 ($/MWh)		
2.4	Other Applicable Western Charges ($/MWh)		
2.5	**Total Western Charges ($/MWh)**	**$ 2.20**	**$ 25,154**

- Based on LEC quantities exported to BAA
- Estimates (i.e. no charges actually accrue)
- Would be assessed on MID if LEC interconnected to BANC

Item 3: Other Benefit Adjustments

Item	Particulars	Estimated Rate	Benefits	Charges	Cumulative Charges - Benefits Account Balance
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		$ -		

Item 3: Other Benefit Adjustments

Item	Particulars	Estimated Rate	Benefits	Charges
3	Other Benefit Adjustments			
3.1	Total Adjustments ($/MWh)		$ -	$ -

- Sample Schedule 7.00 includes $800,000+ revenue for Ancillary Service sales
  - Exclusive to CAISO Interconnection
- CAISO changes policy on imports of Regulation
- Equal access to CAISO markets
- No net benefit

Item 4: Net Effect on MID

Item	Particulars	Estimated Rate	Benefits	Charges	Cumulative Charges - Benefits Account Balance
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		$ -		

$(106,942)	CAISO
+ $25,154	Western

Net Export Costs

Item	Particulars	Estimated Rate	Benefits	Charges
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)	

(CAISO Charges)
\+ Estimated Western Avoided Charges
= Calculated Cost Differential (Entire Plant)

- All participants pay based on GES (including MID)
- CAISO-Based LEC Participants allocated $73,025 in this example

Item 2.3: Differential of Capital Costs

Item	Particulars	Estimated Rate	Benefits	Charges	Cumulative Charges - Benefits Account Balance
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		$ -		

Differential of Capital Costs

Item	Particulars	Estimated Rate	Benefits	Charges	Cumulative Charges - Benefits Account Balance
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**		

Differential of Capital Costs

- Interconnection costs to BANC $13.2 million more expensive than CAISO Interconnection
- Would be paid by all participants
- MID Share = $1,414,288

- Amortized over 30 years @ 4%
  - PMT = $81,788 per year
  - Principle = $1,414,288
  - Interest = $1,039,364
  - **TOTAL AVOIDED COST = $2,453,652**

General Methodology

Item	Particulars	Estimated Rate	Benefits	Charges	Cumulative Charges - Benefits Account Balance
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		$ -		

Interconnection Benefit Threshold (IBT)

Item	Particulars	Estimated Rate	Benefits	Charges
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		$ -	

Interconnection Benefit Threshold

- MID credited $73,025 in this example
- Credit first applied to IBT
- IBT ending balance $2.38 million carried over to following billing period

Future Iterations

- Credits applied to IBT until extinguished
- No cash payments to MID until IBT extinguished
- IBT not refundable to other LEC participants

- At 80% capacity factor, IBT extinguished in:
  - Nearly 40 years if 5% of MID GES exported
  - Approx. 4 years if 50% of MID GES exported
  - (scalable)

Next Steps

- Please Review:
  - Proposed amendment to Schedule 7.00 included in today's PPC meeting materials
  - Staff report provides additional explanations
  - Attachment A to staff report lists options discussed during development of Amendment 1 to Schedule 7.00
- NCPA to distribute DTCA spreadsheet to LEC Participants to aid in review process

- Workshops?
- PPC Approval: August?

Questions and Discussion

QUESTIONS

September 8, 2014

Lodi Energy Center Northern California Power Agency

Operational Insurance Program Overview

Lodi Energy Center
Operating Insurance Programs

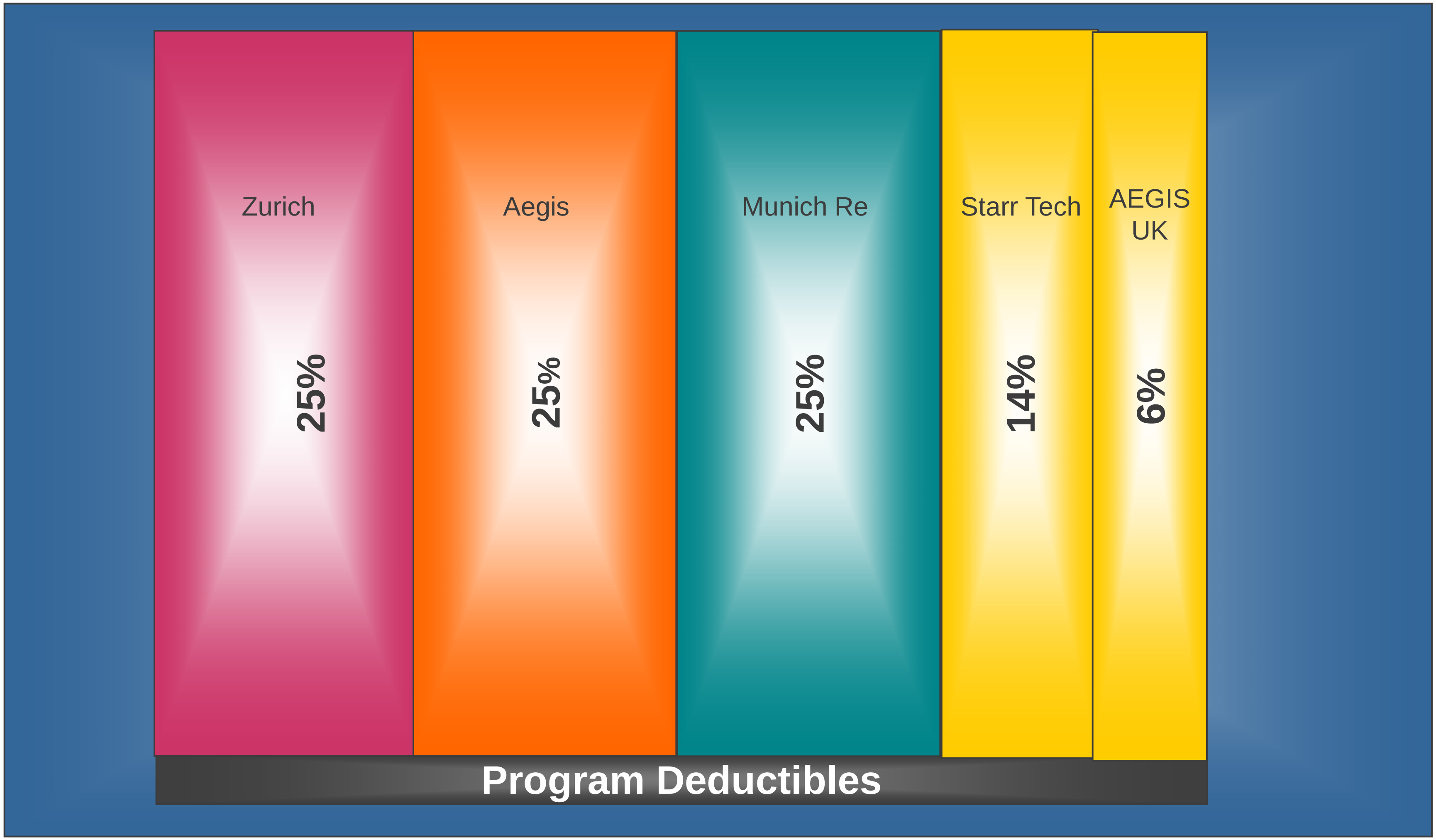
Lodi Energy Center Insurance Summary
November 2013 to 2014

NCPA - Lodi Energy Center
Insurance Coverage Overview

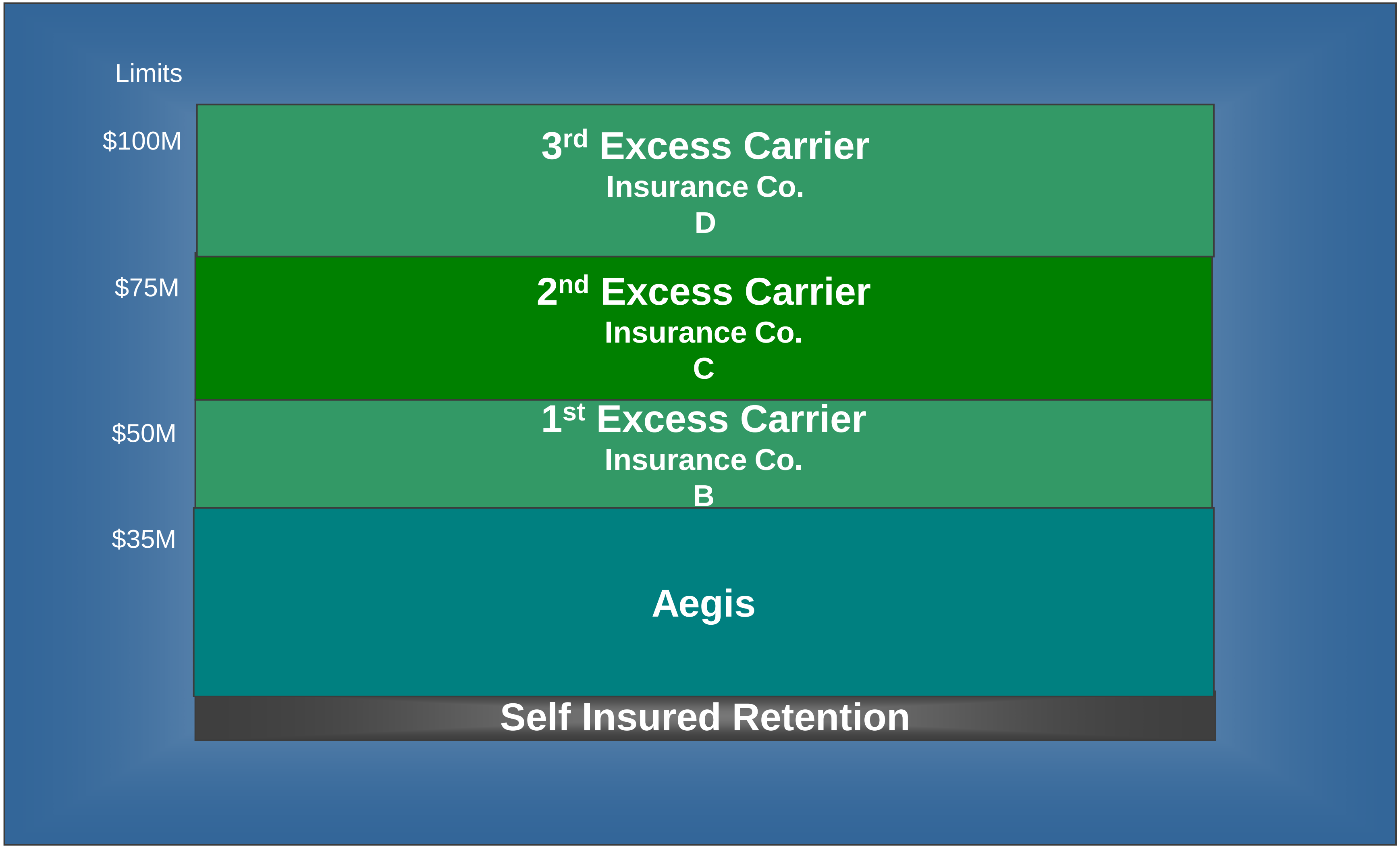
Insurance Coverage: November 20, 2013 - November 19, 2014

Insurance Type	Status	Insured Value	Sublimits	Deductible	2014 Premium
"All Risk" Property Damage	In place	$ 325,000,000		All risk $ 500,000	$ 582,452 (.172 per $100 insured value)
Earth Movement			$ 25,000,000	earthquake 5% or $250,000 (greater of)	
Flood			$ 25,000,000	flood $ 100,000	
Boiler & Machinery			None	turbine generator $ 1,000,000	
Terrorism	Opt out	N/A			Opt Out
Extra Expense/Replacement Power	Opt out	$ 22,452,675			Opt Out
Casualty	In place	$ 35,000,000		$ 200,000	$ 92,969
General Liability, pollution, auto, employer's liability, employment practices					
Optional Coverage		$ 50,000,000			Opt out
Optional Coverage		$ 75,000,000			Opt out
Optional Coverage		$ 100,000,000			Opt out

Lodi Energy Center
Operating Insurance
Property Program Structure



Lodi Energy Center
Operating Insurance
Casualty Program Structure



Next Steps

- September 8 – Marsh to submit specifications to market
- September TBD – Underwriter visits
- September 26 - Quotes due from markets
- October 13 – Proposal to NCPA
- November 3 - PPC Review of Quotes & Approval
- November 20 – Renewal occurs