Responses to Questions from February 21, 2007 Issues Resolution Workshop

Application for Certification (06-AFC-9) for

COLUSA GENERATING STATION
Colusa County, California

March 23, 2007

Prepared for:

E&L Westcoast, LLC

Prepared by:

URS

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AIR QUALITY

Technical Area: Air Quality
Author: William Walters

WORKSHOP QUESTION

1. Regarding Data Request 11, please clarify the notation of the ammonia correction and provide the calculation noted in the justification.

RESPONSE

Derivation of Ammonia Salts

Sulfur in the gas turbine fuel is converted in the combustion process to SO_2 and SO_3. Some of the SO_2 in the gas turbine exhaust is converted to SO_3 within the HRSG. In addition, sulfur in the duct burner fuel is converted to SO_2 and SO_3. Some of the SO_2 in the flue gas is also converted to SO_3 in the SCR and CO catalyst.

SO_3 reacts with ammonia (NH_3) injected as part of the SCR process in the following two reactions:

$2NH_3 + SO_3 + H_2O \rightarrow (NH_4)_2SO_4$ (ammonium sulfate)

$NH_3 + SO_3 + H_2O \rightarrow (NH_4)HSO_4$ (ammonium bisulfate)

Whether ammonium sulfate or ammonium bisulfate is formed is a function of the mole ratio of NH_3 to SO_3. When the NH_3 to SO_3 mole ratio is 2 or greater, ammonium sulfate is expected to form. Due to the low levels of sulfur in the fuel, this ratio will be well above 2 for this project, and thus ammonium sulfate will form. As can be seen from the first equation above, 1 mole of SO_3 is converted to 1 mole of $(NH_4)_2SO_4$ (which has a molecular weight of 132.1). For the 114^oF fired case, after all the SO_2–to-SO_3 conversions discussed above, there are 0.00887 moles/hr of SO_3 in the flue gas, and thus the ammonium sulfate formation is:

0.00887 moles SO_3/hr × 1 mole $(NH_4)_2SO_4$/mole SO_3 × 132.1 lb $(NH_4)_2SO_4$/mole $(NH_4)_2SO_4$

= 1.17 lb $(NH_4)_2SO_4$/hr

Using 12 lb/hr from the gas turbine and 0.01 lb/mmBTU from the duct burners and a 4 percent margin on the ammonium salt formation, total PM_{10} emissions are:

= 12 lb/hr + 688 mmBTU/hr × 0.01 lb/mmBTU + 1.17 × (1 + 0.04)

= 12 lb/hr + 6.88 lb/hr + 1.22 lb/hr

= 20.1 lb/hr

The above case without the duct burner contribution to PM_{10} or the sulfur in the duct burner fuel to PM_{10} is:

= 12 lb/hr + 1.17 × (1.1/1.5) lb/hr

= 12.9 lb/hr

In the last equation, 1.1 and 1.5 are the estimated SO_2 emissions in lb/hr for the unfired and fired cases, respectively. Their ratio is used to scale the expected ammonia salt formation.

Note that the calculation above supports the PM_{10} emission rates provided in the AFC. The sulfur content allowed in the fuel likely will be increased from the level used in the AFC (see response to Workshop Question 3). A strict application of the above equations using higher fuel sulfur content would produce a slight increase in the PM_{10} emissions. However, the Applicant requests that the PM_{10} emission rates provided in the AFC remain unchanged. Sufficient margin is included in the PM_{10} emission rates in the AFC to accommodate the slight increase in PM_{10} due to the higher fuel sulfur.

WORKSHOP QUESTION

2. Regarding Data Requests 12 and 13, please clarify/justify your previous response, since the numbers in the appendix do not match those presented in Table 8.1-16. Provide the specific operating case that is relevant to the third quarter emissions presented in Table 8.1-16.

RESPONSE

A revised version of Appendix G, Attachment 1, Page 3 of 5 with details of the operating conditions for the 3rd quarter that produces the estimated emissions of PM_{10} and SO_2 that match the 3rd quarter PM_{10} and SO_2 emissions shown in Table 8.1-16 is included below.

Revised Table 8.1-16 (Rev. 1)
Third Quarter Emissions (Jul, Aug, Sep)

	Operating Assumption			**Third Quarter**	**Operating Assumption**	**Turbine Emissions (lb/qtr/CT)**	**Emissions for Both Turbines (ton/qtr/2CT)**
	Base	**Cyclical**		**NO_X**	Cyclical	50,868.70	50.9
Total Hours of Operation	2208	1208		**CO**	Cyclical	106,290.31	106.3
Total Number of Cold Starts	3.5	1.0		**VOC**	Cyclical	11,811.95	11.8
Cold Start Duration (hr)	4.50	4.50		**SO_2**	Base	2,812.26	2.8
Total Number of Warm Starts	0	12		**PM**	Base	35,542.80	35.5
Warm Start Duration (hr)	3.00	3.00					
Total Number of Hot Starts	10.5	60.7					
Hot Start Duration (hr)	1.50	1.50					
Total Number of Shutdowns	14.0	73.7					
Shutdown Duration (hr)	0.50	0.50					
Duct Burner Operation (hr)	1040	1040					
Average Operation (hr)	1130	0					
Half Load Operation (hr)	0.00	0.00					

Notes:

- Duct Burner Emission Rates are based on the maximum duct burner capability scenario (59°F; 100% load; no evaporative cooler; duct burner duty = 598.3 MMBTU/hr)
- Average Operation Emission Rates are based on the average operation scenario (59°F; 100% load; no evaporative cooler).
- Actual average temperatures during this quarter are higher. Therefore, this produces a conservatively high emission estimate.

WORKSHOP QUESTION

3. Regarding Data Request 15, internal calculations show that the long-term sulfur content used appears to be different than PG&E's data. We will need to make sure that both CEC and the District do not have conflicting numbers in the emissions limitation and fuel sulfur limitation conditions.

RESPONSE

Data provided to the Applicant after the workshop show that sulfur content in the fuel could be higher than the value used in the AFC. Over about a five-year period, the annual average value was about 0.3 gr/100 SCF and peak readings approach the 1.0 gr/100 SCF tariff limit. The Applicant supports using 0.3 gr/100 SCF annual average as the basis for calculating the annual and quarterly SO_2 emissions limits in the permit for all of the sources fueled by natural gas. Compliance with the permit limits on SO_2 emissions could be the subject of two permit conditions. The first condition would be to periodically measure the sulfur content in the natural gas, and the second would be to calculate actual SO_2 emissions on a periodic basis using fuel flow measurements and the sulfur value from the applicable period. The Applicant suggests a condition stating:

> "The owner/operator shall take monthly samples of the natural gas utilized at the CGS and analyze for the sulfur content using CCAPCD-approved laboratory methods, or shall obtain certified analytical results from the gas supplier."

The Applicant suggests a related permit condition as suggested below to verify SO_2 emissions:

> "To demonstrate compliance, the owner/operator shall calculate and record on a daily basis, Sulfur Dioxide (SO_2) mass emissions from each power train and from the Auxiliary Boiler. The owner/operator shall use the actual Fuel Input Rates calculated, and CEC and CCAPCD-approved emission factors to calculate these emissions."

WORKSHOP QUESTION

4. Regarding Data Request 19, please confirm that the two IC engines would not be operating during turbine startups as modeled for maximum 1-hour NO_X and CO impacts. A condition stating this may need to be included due to the cumulative 1-hour NO_X impacts being just below the 1-hour standard.

RESPONSE

The Applicant stated in the workshop and confirms here that it is acceptable to include a condition to limit testing of either of the two diesel engines to times other than turbine startups.

WORKSHOP QUESTION

5. Regarding Data Request 26, the revised NO_X emission levels as specified in the response may not meet BACT. The overall emission was revised upward in this response from 0.0108 lb/MMBtu to 0.049 lb/MMBtu. A specific NO_X BACT target value in ppm should be provided for the low-NO_X burner for BACT determination and that value should be represented in the calculations.

RESPONSE

Although the specifics of the auxiliary boiler control technologies have not been finalized, the Applicant has revised the emission factors to meet the NO_X BACT target value of 15 ppmv at 3% O_2. Furthermore, the CO and VOC emission factors were also revised. A revised summary of the auxiliary boiler's emissions reflecting the changes above is provided in Revised AFC Table 8.1-19 (Rev. 2).

Revised Table 8.1-19 (Rev. 2)
Auxiliary Boiler Emissions

Pollutant[a]	Emission Factor (lb/MMBtu)	Emissions	
		lb/hr	ton/yr[b]
NO_X controlled to 15 ppmvd @ 3 % O_2	0.018	0.79	1.48
CO controlled to 50 ppmvd @ 3 % O_2	0.037	1.61	3.01
PM_{10}	0.0075	0.33	0.62
SO_2	N/A[c]	0.13	0.07
VOC controlled to 10 ppmvd @ 3 % O_2	0.0042	0.18	0.34

Notes:
[a] Emission factors based on BACT concentrations shown. Emission factor for PM_{10} is from AP-42 Table 1.4-2.
[b] Annual emissions based on 3,744 hours of operation.
[c] SO_2 emissions based on sulfur in fuel of 1.0 grain per 100 standard cubic foot for hourly emissions and 0.30 grains per standard cubic foot for annual emissions.

The proposed quarterly and annual emissions shown in AFC Table 8.1-21 still accurately depict these revisions as well as the emergency diesel firewater pump emission factor revisions, as shown in the response to Workshop Question 6.

WORKSHOP QUESTION

6. Regarding Data Request 28, why would the fire water pump engine be specified as a Tier 2 engine when Tier 3 engines should now be readily available for this engine size (2006 and newer engines)?

RESPONSE

The diesel driven fire water pump will be rated at 300 horsepower and will comply with Tier 3 requirements. The Title 17 CCR CARB ATCM emission limits mandate conformance with Tier 3 emissions levels for 300 HP stationary engines installed in 2009. While these engines are currently under development, specific emission levels from Tier 3 compliant engines for this manufacturer at this size and duty are not available at this date. Therefore, the manufacturer's emission data sheet cannot be provided. For the purposes of air permitting work for Colusa, the Tier 3 emission limits should be used at this time as manufacturers indicate that it will be possible to meet the Tier 3 emissions levels. The Title 17 CCR CARB ATCM Tier 3 emission limits that will be in effect in 2009 are summarized in Table 6-1.

Table 6-1
Tier 3 Emission Limits

Pollutant	Emission Limit (g/HP-hr)
NHMC + NO_X	3.00
CO	2.60
PM	0.15

WORKSHOP QUESTION

7. Regarding Data Request 31, please discuss how and why SO_2 emissions are not directly based on fuel flow, and to a lesser extent, why PM_{10} emissions are not either.

RESPONSE

The Applicant stated in the workshop and confirms here that PM_{10} from the gas turbine is based on GE's guarantee of 12 lb/hr and applies whenever the unit is running regardless of fuel flow. The Applicant stated in the workshop and confirms here that SO_2 emissions are based on estimated fuel flow and the sulfur content in the fuel.

WORKSHOP QUESTION

8. Regarding Data Request 11 and similar to Workshop Question 1, please clarify/justify the notation of the ammonia correction to the PM_{10} emissions.

RESPONSE

See response to Workshop Question 1.

WORKSHOP QUESTION

9. Regarding Data Request 35, please discuss how/why SO_2 emissions are not directly based on fuel flow, and to a lesser extent, why PM_{10} emissions are not either.

RESPONSE

See response to Workshop Question 7.

WORKSHOP QUESTION

10. Regarding Data Request 36, please clarify the reference noted. It is unclear how the gasoline equipment values were obtained.

RESPONSE

Construction equipment emissions were calculated using the South Coast Air Quality Management District's (SCAQMD) table "Off-road Mobile Source Emission Factors (Scenario Years 2006-2020)" posted on their website.[1] No other source of emission factors was used. However, during a review of the work done it was noticed that some of the SCAQMD factors had been copied incorrectly and that the fuel was improperly called out as "gasoline" when in fact diesel fuel emission factors were presented. We have revised the calculations using the updated emissions factors as shown in Appendix A1.

Appendix A2 presents the modified Appendix G.2, Tables G.2-4 through G.2-8, based on the corrected emission factors. The emissions of CO, VOC, SO_2 and PM_{10} all decreased based on the corrected emission factors while the emissions of NO_X increased by about 1.5 percent.

[1] http://www.aqmd.gov/ceqa/handbook/offroad/offroad.html

WORKSHOP QUESTION

11. Regarding Data Request 39, the emission factors for the first three months cannot be reproduced without adding some sort of control factor for the unpaved roads, and the loading factor determination cannot be matched. Please discuss the calculations that support the emission values given in Table G.2-2.

RESPONSE

The equation for fugitive dust emissions from heavy-duty vehicle travel on unpaved roads appears in AP 42 Section 13.2.2 in the following form:

$$E = k\ (s/12)^a\ (W/3)^b$$

However, on page 4-22 of the background document for this section, the recommended form of the equation is:

$$E = k\ (s/12)^a\ (W/3)^b/(M/0.2)^c$$

This equation is repeated on page 4-33 of the background document (which may be found at www.epa.gov/ttn/chief/ap42/ch13/bgdocs/b13s0202.html—click on the bullet titled “Background Document – Emission Factor Documentation for AP-42 Section 13.2.2 Unpaved Roads”). The background study for the new equation found that soil moisture content was a fundamental measure of the emission factor, and should be included in the new emission factor equation. This is inconsistent with the previous AP 42 emission factor, which ignored moisture. Consequently, we believe that the equation printed in AP 42 Section 13.2.2 has mistakenly left off the denominator.

Fugitive dust calculations for truck hauling on unpaved roads using 28.35 tons as the average truck weight results in 16.22 lb/hr without using the denominator and 4.21 lb/hr when using the denominator.

WORKSHOP QUESTION

12. What is the status of the Federal Prevention of Significant Deterioration of Air Quality (PSD) permit application that the Applicant filed with the Environmental Protection Agency's regional office in San Francisco?

RESPONSE

The U.S. EPA has sent a letter indicating that the PSD application is complete. This letter is provided in Appendix B.

BIOLOGICAL RESOURCES

Technical Area: Biological Resources
Author: John Mathias

WORKSHOP QUESTION

13. Provide updated tables showing impacts to wetlands.

The revised jurisdictional delineation report and Individual Permit application for impacts to wetlands and other potential waters of the United States will be submitted to the U.S. Army Corps of Engineers within the next two weeks. Table 13-1 provides the updated table showing impacts to wetlands and other potential waters of the United States that will be reflected in the revised wetland delineation report. Once the permit application is received by the Corps, formal consultation will be initiated with the U.S. Fish and Wildlife Service.

Table 13-1
Impacts and Proposed Mitigation for Potential Jurisdictional Waters of the United States

Habitat Impacted	Area of Impact (acres)	Proposed Mitigation Ratio	Proposed Mitigation Acreage	Type of Mitigation
Potential Jurisdictional Wetlands				
Permanent Impacts				
PG&E Access Road Alignment and Glenn-Colusa Bridge Sites – Freshwater Marsh	0.112	3:1	0.336	Offsite compensatory mitigation.[1]
Glenn-Colusa Bridge Replacement – Rice Field Wetland	0.323	1:1	0.323	Offsite compensatory mitigation.[1]
Temporary Impacts				
PG&E Access Road Alignment and Glenn-Colusa Bridge Sites – Freshwater Marsh	0.146	1:1	0.146	Onsite restoration of affected area.
PG&E Access Road Alignment and Glenn-Colusa Bridge Sites – Seasonal Wetland	0.052	1:1	0.052	Onsite restoration of affected area.
Teresa Creek Bridge Replacement – Seasonal Wetland	0.023	1:1	0.023	Onsite restoration of affected area.
Potential Jurisdictional Non-Wetland Waters of the United States				
Permanent Impacts				
PG&E Access Road Alignment and Glenn-Colusa Bridge Sites – Agricultural Ditch	0.161	1:1	0.161	Onsite, in-kind replacement.[1, 2]
Teresa Creek Bridge Replacement – Perennial Stream	0.014	1:1	0.014	Onsite, in-kind replacement.[1, 2]

Table 13-1
Impacts and Proposed Mitigation for Potential Jurisdictional Waters of the United States

Habitat Impacted	Area of Impact (acres)	Proposed Mitigation Ratio	Proposed Mitigation Acreage	Type of Mitigation
Temporary Impacts				
PG&E Access Road Alignment and Glenn-Colusa Bridge Sites – Agricultural Ditch	1.032	1:1	1.032	Onsite restoration of affected area.[1]
Teresa Creek Bridge Replacement – Temporary Culverts Placed in Stream	0.04	1:1	0.04	Onsite restoration of affected area.[1]

Notes:

1 Resulting mitigation will be the greater amount for either impacts to giant garter snake habitat or jurisdictional wetlands, but not both. Mitigation would be provided that is consistent with the USFWS Programmatic Consultation for the giant garter snake (USFWS, 1997).

2 Additional offsite compensation is proposed for giant garter snake impacts.

Reference

USFWS (U.S. Fish and Wildlife Service), 1997. Programmatic Formal Consultation for U.S. Army Corps of Engineers 404 Permitted Projects with Relatively Small Effects on the Giant Garter Snake within Butte, Colusa, Glenn, Fresno, Merced, Sacramento, San Joaquin, Solano, Stanislaus, Sutter and Yolo Counties, California. November 13, 1997.

WORKSHOP QUESTION

14. Identify the California Department of Fish and Game contact for the project.

RESPONSE

The California Department of Fish and Game has indicated that a contact will be determined upon submittal of the Streambed Alteration Agreement (Section 1600). The Agreement is expected to be submitted to the CDFG within the next two months. A copy of the Agreement will be forwarded to the CEC upon completion. At this time, we understand that the contact will be either Gary Hobgood or Dale Watkin.

WORKSHOP QUESTION

15. Provide assurance that the resource agencies find the Biological Assessment complete.

RESPONSE

URS has submitted the draft BA directly to U.S. Fish and Wildlife Service (USFWS) and National Oceanic and Atmospheric Administration (NOAA) Fisheries. The contacts are Michelle Tovar at USFWS and John Baker at NOAA Fisheries. URS will continue to work with these agencies to provide requested information prior to the initiation of formal consultation. USFWS has requested additional information regarding the hydrology of the alkali grassland habitat areas. To address this question, a field visit was conducted in mid-March, timed to coincide with the optimal period for observing wetland hydrology. USFWS also requested that URS submit information regarding the duration of inundation at sites that could be utilized by breeding California tiger salamanders. To address this question, URS conducted site visits in late March and will conduct additional site visits in spring 2007 to evaluate the duration of inundation at stock ponds in the project vicinity.

WORKSHOP QUESTION

16. Steve Hackney of Colusa County Department of Planning and Building indicated that Senate Bill (SB) 1535 should be considered.

RESPONSE

Senate Bill 1535 (2006) increases certain of the filing fees that a project applicant must pay for California Department of Fish and Game actions taken pursuant to the California Environmental Quality Act (CEQA). It eliminates the exemption from paying a filing fee that formerly applied if a project had a *de minimis* effect on fish and wildlife, and instead provides an exemption if "[t]he project has <u>no</u> effect on fish and wildlife." It states that "no project shall be operative, vested, or final, nor shall local government permits for the project be valid, until the filing fees required pursuant to this section are paid." In addition, the bill allows the Fish and Game to hire staff, including an executive officer, to assist the Commission. SB 1535 did not increase the fee assessed for projects that are reviewed pursuant to a certified regulatory program such as that of the California Energy Commission. This fee remains at $850 and is routinely assessed upon project certification. SB 1535 is not expected to affect the project's permitting process.

SOCIOECONOMICS

Technical Area: Socioeconomics
Author: Shaelyn Strattan

WORKSHOP QUESTION

17. Regarding Data Request 89, please discuss the availability of trained onsite or on-call Colusa Generating Station support personnel, during both construction and operational phases, to conduct a primary emergency response. Identify any equipment or personnel deficiencies in local fire and emergency response agencies that would be addressed and compensated for with onsite personnel or facilities.

RESPONSE

Construction Staffing

During the work day (normally 7:00 a.m. to 7:00 p.m., Monday through Friday) the following personnel will be available.

1. Site Manager
2. Construction Manager
3. Project Manager
4. Field Superintendent
5. Project Field Engineer
6. Project Safety Supervisor
7. Project Environmental Coordinator
8. Construction Environmental Coordinator
9. Project Personnel Manager
10. Contract Administrator

These personnel will be notified of all incidents in the order listed. A list of critical personnel and their contact phone numbers will be kept current. The Site Manager, or Construction Manager in his stead, will form a response team of onsite individuals who are needed based on the type of incident.

During construction off hours (other than normal working times above) the Guard Shift Supervisor or local police will notify the personnel identified above, depending on the type of emergency. Off duty response will be as determined by the Site Manager, or Construction Manager in his stead, who will form a response team of on-call individuals who are needed based on the type of incident.

Operations Staffing

The Emergency Action Plan will identify the responsibilities of plant employees, the response and notification process, and the response procedures in the event of an emergency. Operations will require up to 31 full-time permanent personnel, with up to 16 staff on site during the day shift and approximately 2 to 3 staff on site during the night and weekend shifts. If additional staffing resources are required in an emergency, offsite full-time staff will be called. Those with a higher level of emergency training would be called first. Since all full-time permanent personnel will be trained in emergency response, up to 31 total staff will be available for either onsite or on-call emergency response throughout the day.

Chief Wells of the Maxwell Fire District was concerned that a potential event requiring an emergency response would create a strain on his agency. He expressed this at the Issue Resolution Workshop. The Applicant has discussed this with the Maxwell Fire Department and has hired a local consultant, selected by the fire department. The consultant is working on a report identifying potential deficiencies as well as the necessary measures required to address these deficiencies.

SOIL AND WATER RESOURCES

Technical Area: Soil and Water Resources
Author: Richard Latteri

WORKSHOP QUESTION

18. Regarding Data Request 91a, please provide further discussion about why the Will Serve letter provides for 400 acre-feet of water per year, whereas the project will only require an estimated 126 acre-feet of water per year.

As indicated in the workshop, the Applicant first initiated discussions with the Glenn-Colusa Irrigation District (GCID) when wet cooling technology was being pursued for the power plant. A wet-cooled power plant was estimated to require approximately 4,000 acre-feet of water per year. The GCID issued a Will Serve letter for this amount, and this letter was approved by their Board of Supervisors. Subsequent to discussions with the CEC, the Applicant opted to switch to dry cooling technology, which decreased the water usage. The initial estimates for dry cooling technology was that it would require approximately 10 percent of the water required for wet cooling technology (or 400 acre-feet of water per year). The GCID then issued another Will Serve letter for 400 acre-feet per year based on this estimate. Upon further design of a dry-cooled power plant, the water use was refined to 126-acre feet per year. Since the existing Will Serve letter adequately covers the project's water requirements, the Applicant did not want to burden the GCID and its Board by requesting another Will Serve letter.

The draft Agreement with the GCID provides 130 acre-feet of water per year. This Agreement is discussed further in the response to Workshop Question 19. This Agreement will be subject to Board approval, shortly. The agreement will be submitted to the CEC upon approval.

WORKSHOP QUESTION

19. Explain the status of the water supply.

To supply the water demand of 126 acre-feet per year, a three-way agreement will be executed between E&L Westcoast (E&L), GCID, and the County of Colusa (County). (The Agreement has been rounded up to 130 acre-feet per year.) The Agreement specifically allows PG&E to be assigned E&L's rights and obligations under the Agreement, once PG&E takes its ownership interest in the project. Specifics of the Agreement and a summary of implementation steps follow. The contract will be submitted to the CEC once it has been approved by the Board of Supervisors.

Agreement Terms – The agreement to supply surface water to the project will consist of GCID delivering 130 acre-feet of water through the Tehama-Colusa Canal (TCC), then delivery to the County at the project diversion point at mile post 63.273L, then the County will immediately deliver the water to the project at that location. GCID and the TCC Authority have an existing wheeling agreement in place that allows GCID to divert its water at TCC Authority's Red Bluff facilities and use the TCC for delivery to the County, for which the TCC Authority receives a wheeling fee. In addition, since the County is a TCC Authority Member Agency, it has the right to use the TCC.

Water to Be Transferred – GCID expects to transfer to the County 130 acre-feet of its U.S. Bureau of Reclamation (USBR) Project Water.[2] Both GCID and the County are USBR contractors, and transfers such as this are allowable and routine, but must receive approval from the USBR. The County can then supply the project, as the project is within the County's service area. In order to enhance the project's reliability, the Agreement has a provision requiring GCID to supply the project from another of its vast array of water sources in the event it cannot deliver the USBR project water.

Initial Diversion Point – The GCID water will be diverted at the existing TCC facilities at Red Bluff, under existing environmental clearances and restraints. The TCC Authority has confirmed that even under the environmental restraints in place due to anadromous fisheries, the low volume of water needed to supply the project can easily be accommodated under existing diversion practices and environmental permits.

Project Diversion Point – After GCID water is diverted into the TCC, it will be conveyed in the TCC by GCID under its existing wheeling agreement with the TCC Authority and delivered to the County at milepost 63.273L of the TCC. At that point, the County will take possession of the water and immediately transfer it to E&L. E&L will divert the water out of the TCC at that location and transport it to the plant via a raw water pipeline. The diversion structure in the TCC requires a permit from the USBR. A meter will be installed and read by GCID/TCC Authority at this diversion point.

Term – The Agreement has an initial term of 30 years. Two successive 10-year renewal terms are available at E&L's option.

Reliability Provision – Although there is no reason to suspect that GCID's USBR contract water will not be available for the duration of the project life, the Agreement contains provisions

[2] "Contract Between the United States and Glenn-Colusa Irrigation District, Diverter of Water From Sacramento River Sources, Settling Water Rights Disputes and Providing for Project Water Service" (Contract No. 14-06-200-855A-R-1), as executed on February 28, 2005.

requiring GCID (with E&L's input) to develop an alternative source of water and deliver that to the project throughout the term of the Agreement, including any extensions, to insure the viability of the water supply for the project.

Agreement Approval Process – GCID and E&L (with PG&E's assistance) have been negotiating the final terms of the Agreement and expect to reach agreement in the immediate future. The County is also reviewing the Agreement. Since the County's role in regard to water deliveries is minor, acceptance of the terms by the County is expected. Approval by the three parties will occur shortly after the terms are approved, and is exempt from CEQA under California Public Resources Code Section 21080 (b)(6).

USBR Approval of the Agreement – Under the terms of GCID's USBR contract, the USBR has up to 90 days to review and approve the Agreement. The approval requires NEPA compliance, which is routinely done through a Finding of No Significant Impact ("FONSI"). Approval may be granted by the USBR field office in Willows.

WORKSHOP QUESTION

20. Provide further details on the water intake and explain how the water will be metered.

RESPONSE

The new intake will consist of a screened perforated pipe placed over the bank, requiring minimal disturbance to the canal embankment. The intake pipe will be laid down on the slope of the canal embankment and will lead to a submersible pump. The intake pipe will be anchored on the embankment, and a short section of the intake pipe will be buried under the maintenance road within the canal.

Due to the low intake quantity (less than 150 gpm), the pump will be submersible and will be located within the intake pipe. The pipe will be lowered into the canal down the existing embankment, with a Johnson-type screened intake end (a perforated tee pipe) to prevent debris from entering the pipe. This pipe will be attached to the existing embankment, and will end at the top of the canal to connect to the underground pipeline leading to the power plant. The plant will have a calibrated water meter to record the quantity of water extracted. The electrical power cable will terminate in a controller box located on the canal embankment, and this equipment will be enclosed in a protective fence. A canal turnout is not needed due to the low quantity of water required and the very large quantity of water the canal can deliver.

WORKSHOP QUESTION

21. Regarding Data Request 94, provide a discussion of the Colusa County Department of Environmental Health's requirements and permitting process for septic systems.

To obtain a septic permit from Colusa County Environmental Health Services (EHS), the applicant must first submit an application (Appendix C1) along with a $113 fee for a site evaluation to determine the suitability of the soil for a septic system. The Applicant must prepare a hole 10 feet long, 8 feet deep, and 3 feet wide, with one side stepped off, prior to EHS's arrival. A site may be found not to be suitable for a septic system due to:

- Lack of suitable soil depths, impervious soil, or saturated soil conditions;
- Steep slopes (i.e., greater than 30 percent);
- History of failures in the area;
- Other factors.

Upon EHS's determination that the site is suitable, the Applicant must submit a permit application (Appendix C2) along with the fee, which is $225 for a commercial/industrial permit, and a plot plan to scale. If the application is for a specially designed septic system, the Applicant also should include justification for the design, such as unusual features of geology, hydrology, terrain, or use. The application will be approved or disapproved by the EHS director. If the application is disapproved, the Applicant will be notified in writing of the reason.

Septic Tanks

EHS recommends certain sizes for different sizes of residential units, but does not provide recommendations for other nonresidential uses. Concrete tanks are allowed; other prefabricated tanks must be approved and installed according to instructions. The septic tank must be at least 10 feet from a house (it is not clear whether an industrial structure is also included in this minimum distance) and at least 50 feet from a water well; 100 feet is recommended. The septic tank must be 10 feet from the property line, 50 feet from a stream (100 feet recommended), and 50 feet from irrigation ditches (100 feet recommended).

Leach Fields

The size of the leach field depends on the soil conditions; a site inspection and soil profile analysis is required for all planned systems. The leach field cannot be covered by permanent structures.

Leach Lines

The length, width, and depth of the leach lines will be determined after the inspection and analysis. Leach lines must be at least 10 feet from a house (and possibly industrial structure) and at least 100 feet from a water well. Leach lines must be 10 feet from the property line, 50 feet from a stream (100 feet recommended), and 50 feet from irrigation ditches (100 feet recommended). The maximum slope for leach lines is 3 inches per 100 feet, with a suggested slope of level. The minimum slope of sewer lines is 0.25 inch per 1 foot. Rock used should be 0.75- to 2.5-inch washed rock.

WORKSHOP QUESTION

22. Regarding Data Request 95, provide a draft DESCP containing elements A through I below outlining site management activities and erosion/sediment control BMPs to be implemented during site mobilization, excavation/demolition, construction, and post-construction activities. The level of detail in the draft DESCP should be commensurate with the current level of planning for site grading and drainage. Please provide all conceptual erosion control information for those phases of construction and post-construction that have been developed or provide a statement about when such information will be available.

A. Vicinity Map – A map(s) at a minimum scale of 1" = 100' will be provided indicating the location of all project elements (construction site, laydown area, pipelines, etc.) with depictions of all significant geographic features including swales, storm drains, and sensitive areas.

B. Site Delineation – All areas subject to soil disturbance for the CGS (project site, laydown area, all linear facilities, landscaping areas, and any other project elements) shall be delineated showing boundary lines of all construction/demolition areas and the location of all existing and proposed structures, pipelines, roads, and drainage facilities.

C. Watercourses and Critical Areas – The DESCP shall show the location of all nearby watercourses including swales, storm drains, and drainage ditches. Indicate the proximity of those features to the CGS construction, laydown, and landscape areas and all transmission and pipeline construction corridors.

D. Drainage Map – The DESCP shall provide a topographic site map(s) at a minimum scale of 1" = 100' showing all existing, interim and proposed drainage systems and drainage area boundaries. On the map, spot elevations are required where relatively flat conditions exist. The spot elevations and contours shall be extended off site for a minimum distance of 100 feet in flat terrain.

E. Drainage of Project Site Narrative – The DESCP shall include a narrative of the drainage measures to be taken to protect the site and downstream facilities. The narrative should include the summary pages from the hydraulic analysis prepared by a professional engineer/erosion control specialist. The narrative shall state the watershed size(s) in acres that was used in the calculation of drainage measures. The hydraulic analysis should be used to support the selection of BMPs and structural controls to divert offsite and onsite drainage around or through the CGS construction and laydown areas.

F. Clearing and Grading Plans – The DESCP shall provide a delineation of all areas to be cleared of vegetation and areas to be preserved. The plan shall provide elevations, slopes, locations, and extent of all proposed grading as shown by contours, cross sections or other means. The locations of any disposal areas, fills, or other special features will also be shown. Illustrate existing and proposed topography, tying in proposed contours with existing topography.

G. Clearing and Grading Narrative – The DESCP shall include a table with the quantities of material excavated or filled for the site and all project elements of

the CGS project (project site, laydown area, transmission corridors, and pipeline corridors) whether such excavations or fill are temporary or permanent, and the amount of such material to be imported or exported.

H. Best Management Practices Plan – The DESCP shall identify on the topographic site map(s) the location of the site-specific BMPs to be employed during each phase of construction (initial grading/demolition, project element excavation and construction, and final grading/stabilization). BMPs shall include measures designed to prevent wind and water erosion.

I. Best Management Practices Narrative – The DESCP shall show the location (as identified in H above), timing, and maintenance schedule of all erosion and sediment control BMPs to be used prior to initial grading, during all project element (site, pipelines, etc.) excavations and construction, final grading/stabilization, and post-construction. Separate BMP implementation schedules shall be provided for each project element for each phase of construction. The maintenance schedule should include post-construction maintenance of structural control BMPs, or a statement provided when such information will be available.

RESPONSE

The DESCP is included as Appendix D. The CD of the DESCP will be submitted under separate cover and will also contain the hydrographic calculations database.

TRANSMISSION SYSTEM ENGINEERING

Technical Area: Transmission System Engineering
Author: Ajoy Guha, PE, Sudath Arachchige, and Mark Hesters

WORKSHOP QUESTION

23. Regarding Data Request 98, provide ratings for the Generator Breaker (isophase bus breaker) kV and ampere rating and Generator Step-up Transformer (GSU) MVA rating, for all three transformers.

RESPONSE

The preliminary electrical equipment ratings are as follows:

- STG GCB/Isophase rating = 14,000A minimum, 18 kV nominal
- STG GSUT MVA rating = 222/296/370MVA ONAN/ONAF/ONAF nominal
- CTG GCB/Isophase rating = 7,000A minimum, 18 kV nominal
- STG GSUT MVA rating = 114/152/190MVA ONAN/ONAF/ONAF nominal

All other required information is identified on AFC Figures 3.4-7 and 3.4-8, as follows:

- Switchyard breakers are all SF6 gas insulated, rated 2,000 amp, 40,000 amp short circuit
- Switchyard disconnect switches are all rated 2,000 amp
- Switchyard buses are rated 2,000 amp

WORKSHOP QUESTION

24. Regarding Data Request 107, forward reports or letters from the respective transmission owners including PG&E, Western, SMUD and City of Roseville showing that the mitigation measure(s) selected in their system will effectively offset overload violations and be implemented on a timely basis before the on-line date of the CGC.

The System Impact Study (SIS) for the Colusa Generating Station was prepared in close coordination with PG&E and the ISO and numerous discussions were held with Western and SMUD relative to mitigation of overloads on their systems. Because the SIS did not indicate any negative impacts on the City of Roseville's system, discussions were not held with them. The following summarizes the actions taken to obtain the input and concurrence of PG&E, Western, and SMUD with the results of the SIS and the mitigation activities outlined therein:

- The final SIS for the Colusa Project was sent to PG&E and the ISO in mid-September 2005. The SIS noted that the addition of the project tended to exacerbate pre-existing overloads on certain facilities owned by PG&E and on the following transmission facilities owned (or operated) by Western and SMUD:

  1. O'Banion-Elverta 230-kV lines (Western)
  2. Flanagan-Shasta and Flanagan-Keswick 230-kV lines (Western)
  3. Hurley-Carmichael 230-kV line (SMUD)
  4. Olinda 500/230-kV transformer (operated by Western)

  The SIS also noted that the addition of the project resulted in new overloads on Western's Olinda-Keswick 230-kV line.

- At the time the SIS was completed, discussions had not been held with Western or SMUD relative to the proposed mitigation activities discussed in the SIS. So as to facilitate such discussions, a copy of the SIS was sent to Western and SMUD by the ISO in early October 2005.

- Subsequent to the above, discussions occurred between Navigant Consulting, Inc. (NCI) and SMUD during which certain questions that arose from SMUD's review of the SIS were discussed.

- As a result of the above discussions, on October 12, 2005, SMUD forwarded data files to NCI containing the information required to add the proposed O'Banion-Elverta/Natomas Project and the Folsom Loop Project to the powerflow model (provided as Appendix E1).

- On October 19, 2005, NCI sent an email (provided as Appendix E2) to Western, SMUD, PG&E, and the ISO outlining the results of studies which modeled the system changes suggested by SMUD on October 12.

- On October 19, 2005, representatives of the ISO, Western, SMUD, and NCI met and discussed steps that could be taken to mitigate the new and increased overloads noted in the SIS and as discussed in NCI's October 19, 2005 email discussed above. As indicated in the notes from this meeting (Attachment 102-2 in previous responses to Data Requests), the parties agreed that:

1. The proposed transmission projects would, if they are built, mitigate the pre- and post-project overloads noted on the O'Banion-Elverta lines, the Hurley-Carmichael line, and the Elverta tie. If the transmission projects are not in service prior to the CPV Colusa Project, the project would have to devise other methods to reduce the post-project overloads to the pre-project levels. The parties also agreed that there may be steps the project could take that would facilitate development of these two projects.

2. The overloads on the Olinda transformer (one Category B and one Category C) could be mitigated by the use of a special protection scheme (SPS) that would drop the project generation for the critical outages.

3. Mitigation of the overloads on the Shasta-Flanagan and Flanagan-Keswick lines would require that they be reconductored.

- On January 11, 2006, the ISO sent a letter to PG&E which stated that based on the information in the project SIS, the ISO was granting preliminary approval to connect the Colusa Generating Station with the ISO-controlled grid (provided as Appendix E3). In this document, the ISO discusses the October 19, 2005 meeting mentioned above and expresses the expectation that the actions discussed above would mitigate CGS-related impacts on the Western and SMUD systems.

- On April 26, 2006, project representatives met with staff members of Western and SMUD. During this meeting, Western/SMUD briefed the project representatives on the status of the O'Banion-Elverta/Natomas and Folsom Loop Projects. The parties also discussed the use of Remedial Action Scheme (RAS) to mitigate the overloads on the Olinda transformer and reconductoring of the Shasta-Flanagan-Keswick lines to mitigate overloads on these lines. In a followup letter to both Western and SMUD, the Applicant requested that Western initiate the activities required to reconductor the Shasta-Flanagan-Keswick lines and to modify/expand existing RAS schemes to run-back CGS generation to mitigate the impacts on the Olinda transformer.

- On July 10, 2006, the ISO notified PG&E that the ISO agreed with the information and recommendations in the Colusa Generating Station Facility Study prepared by PG&E in February 2006 as such information and recommendations relate to the PG&E system. A copy of the ISO's letter is provided as Appendix E3.

- The Applicant continues to work with Western on the Shasta-Flanagan-Keswick reconductoring effort and project representatives continue to have ongoing discussions with Western and SMUD regarding the status of activities on both the O'Banion-Elverta/Natomas project and on the Folsom Loop project.

- The Applicant met with Western at the end of 2006 to establish contractual arrangements for scoping of the project. Upon scoping the project, Western determined that an Environmental Assessment (EA) should be prepared for National Environmental Policy Act (NEPA) compliance. On February 16, 2007, Western provided a Letter of Agreement Determination that establishes a protocol and outlines requirements for the EA. We are scheduled to meet with

Steve Tuggle, Western's Environmental Coordinator, on March 28, 2007, to continue developing the EA.

- The following are the contacts for Western and SMUD:

  Miriam Mirzadeh at Western
  Email: MIRZADEH@wapa.gov
  Telephone: (916) 353-4552

  Don Deberry at SMUD
  Email: DDeberr@smud.org
  Telephone: (916) 732-5358

WORKSHOP QUESTION

25. Provide a Letter of Approval from CAISO.

RESPONSE

The Preliminary Interconnection Approval Letter is provided as Appendix E3. See response to Workshop Question 24 for further details.

WORKER SAFETY AND FIRE PROTECTION

Technical Area: Worker Safety and Fire Protection
Author: Rick Tyler

WORKSHOP QUESTION

26. Regarding Data Request 114, provide information on how the proposed project might resolve the concerns expressed by the MFPD to reduce the impacts to the district to a less-than-significant level as a direct result of the development of the CGS.

See response to Workshop Question 17.

WORKSHOP QUESTION

27. Is there an emergency access point other than the bridge over the Glenn-Colusa Canal bridge.

RESPONSE

As indicated in response to Workshop Question 17, the Applicant will hire a local consultant selected by the Fire Department to address their requirements related to the proposed project. The Applicant will address this issue during this process.

CULTURAL RESOURCES

Technical Area: Cultural Resources
Author: Cindy Baker

WORKSHOP QUESTION

28. Steve Hackney of Colusa County Department of Planning and Building indicated that SB 18 should be considered.

RESPONSE

Because the project will require a General Plan Amendment, it triggers certain provisions of SB 18 (Burton 2004) that are codified in scattered sections of the Government Code. The intent of SB 18 is to allow participation of California Native American tribes in local land use planning decisions at an early stage by providing opportunities for their involvement through public hearings and other appropriate means, such as consultations between local agencies and tribes.

Specifically, SB 18 requires that the County Planning Department, before amendment of the General Plan, refer the proposed General Plan Amendment to California Native American tribes that have traditional lands within the County's jurisdiction, as well as to multiple other agencies and entities. In addition, before approving the General Plan Amendment, the County must conduct consultations with California Native American tribes to preserve or mitigate impacts to religious or ceremonial places, features, and objects located within the County's jurisdiction. Presumably, the County Planning Department will issue a letter describing the project to tribes, which then have 90 days from receipt of the letter to request a consultation with the County. There is no statutory limit on the duration of consultation. SB 18 also requires the County to provide notice of a public hearing regarding a General Plan Amendment to tribes.

Because SB 18 places obligations on the County to refer the proposed General Plan Amendment to tribes, to consult with tribes, and to provide notice of public hearings to tribes, it is the Applicant's understanding that the County will act in accordance with SB 18 by fulfilling these obligations before approving the Applicant's General Plan Amendment application, which was initially submitted to the County in November 2006 before being revised and re-submitted in February 2007.

In addition to these requirements imposed on the County by SB 18, the Applicant and the CEC are required by regulations implementing the Warren-Alquist State Energy Resources Conservation and Development Act to involve and to consult with tribes.

THE FOLLOWING DO NOT REPRESENT WORKSHOP QUESTIONS, BUT PROVIDE ADDITIONAL RESPONSES TO JANUARY 11, 2007 DATA REQUESTS.

PREVIOUS DATA REQUEST 64

29. Please provide copies of all responses to the letters sent to individuals and groups listed by the NAHC.

To date, no written responses to the information letters sent to groups and individuals whose names were provided by the NAHC have been received.

PREVIOUS DATA REQUEST 65

30. Please make one telephone call to Native American individuals or groups listed by the NAHC who have not responded within two weeks to ensure that they have received the correspondence and gather any information they may have regarding cultural resources in the project area. Please provide documentation for each call, and note any comments regarding the project area provided by the Native Americans.

RESPONSE

On March 7, 2007 telephone calls were made to each of the groups and individuals on the list provided by the NAHC. When the individual was not available, a detailed voicemail was left describing the project, detailing the name and contact information of URS archaeologists. Telecon logs of each conversation are provided in Appendix F.