Responses to Sierra Club Data Requests: Nos. 1 through 97

Amended Application for Certification for HYDROGEN ENERGY CALIFORNIA (08-AFC-8A) Kern County, California

Prepared for:
Hydrogen Energy California LLC

hydrogen energy california

Submitted to:

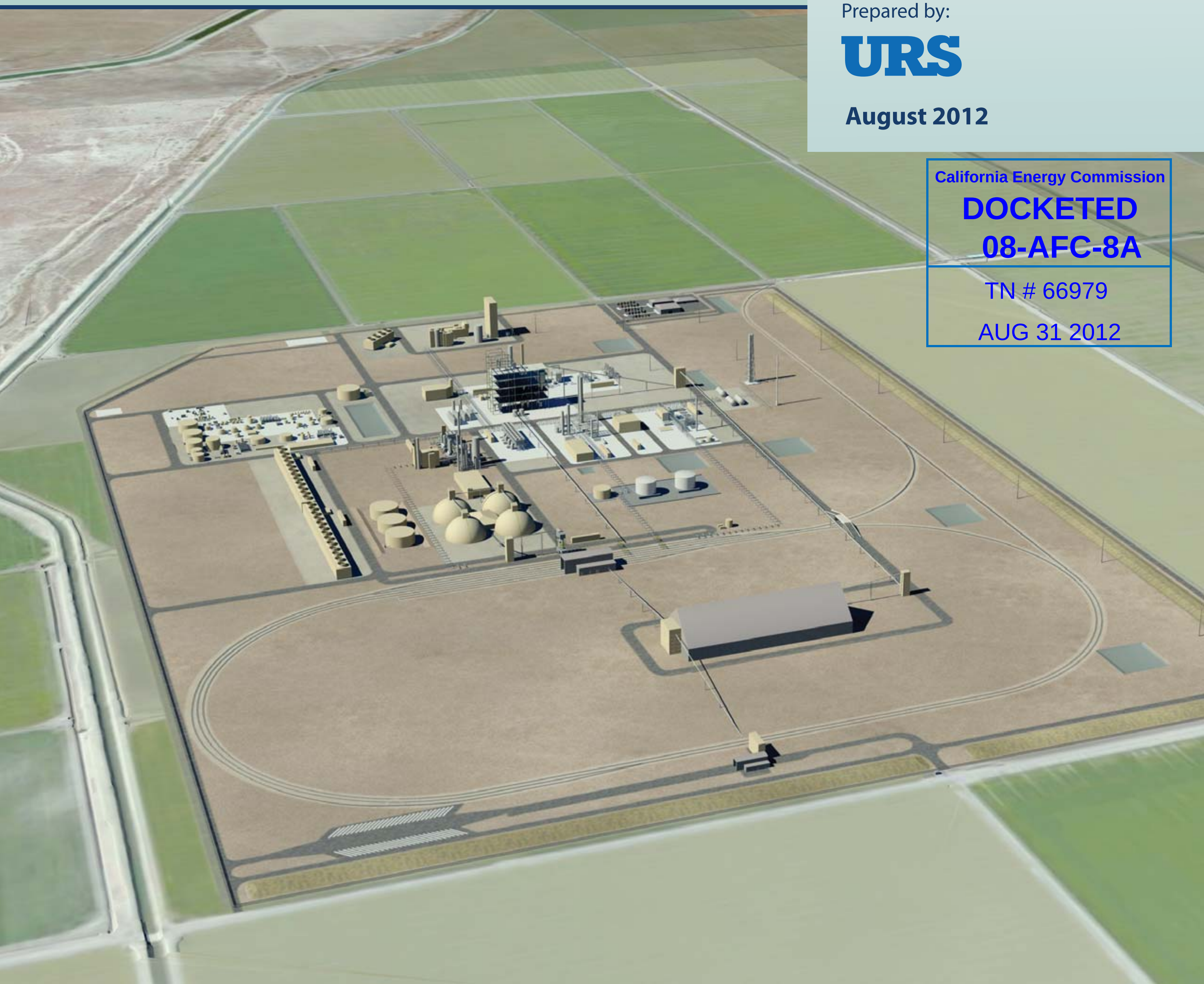
California Energy Commission

U.S Department of Energy

Prepared by:

URS

August 2012



**RESPONSES TO DATA REQUESTS 1 THROUGH 97
FROM SIERRA CLUB**

TABLE OF CONTENTS

TABLES

FIGURES

ATTACHMENTS

LIST OF ACRONYMS AND ABBREVIATIONS USED IN RESPONSES

ACC	air-cooled condenser
AFC	Application for Certification
BACT	Best Available Control Technology
BP	British Petroleum
Btu	British thermal unit
BVWSD	Buena Vista Water Storage District
CEC	California Energy Commission
CEQA	California Environmental Quality Act of 1970
CO	carbon monoxide
CO_2	carbon dioxide
COC	Condition of Certification
CPUC	California Public Utilities Commission
DOE	Department of Energy
DPM	Diesel Particulate Matter
EDR	Environmental Data Resources, Inc.
EPA	Environmental Protection Agency (see USEPA)
ERCs	Emission Reduction Credits
GAC	Granular-activated carbon
HAP	Hazardous Air Pollutant
HECA	Hydrogen Energy California
HRSG	heat recovery steam generator
IGCC	Integrated Gasification Combined Cycle
LTPP	Long-Term Procurement Plan
MMBtu	million British thermal units
NO_X	oxides of nitrogen
Petcoke	petroleum coke
PLA	Project Labor Agreement
PM	particulate matter
PM_{10}	particulate matter 10 microns in diameter or less
$PM_{2.5}$	particulate matter 2.5 microns in diameter or less
PSA	Preliminary Staff Assessment
SCAQMD	South Coast Air Quality Management District
SCR	selective catalytic reduction
SJVAPCD	San Joaquin Valley Air Pollution Control District
SO_2	Sulfur dioxide
SOCMI	Synthetic Organic Chemical Manufacturing Industry
SO_X	oxides of sulfur
stpy	short tons per year
Syngas	synthesis gas
TAC	Toxic Air Contaminant
USEPA	United States Environmental Protection Agency
VOC	volatile organic compound

BACKGROUND: DEMAND FOR GENERATION CAPACITY IN CALIFORNIA

The AFC, p. 1-15, defines one of the Project objectives as providing "dependable low-carbon electricity to help meet future power needs and "back-up" intermittent renewable power sources, such as wind and solar, to support a reliable power grid. The AFC, p. 6-3, claims that the combination of continued population growth in California (at a rate of just over one percent until 2030) and long-term economic prosperity will result in robust growth in energy demand. The AFC provides no support for these claims.

To the contrary, recent studies have shown that California's population is now projected to grow more slowly than anticipated (slightly less than 1% per year until 2030 and slowing down to 0.6% by 2050.)[1] Even without factoring in these recent findings with respect to population growth, the California Public Utilities Commission ("CPUC") recently found clear evidence that "additional generation is not needed by 2020" and ruled to defer any new procurement of fossil fuel generation. This ruling establishes for most of the state, that California's long-term energy needs do not require building more fossil fuel infrastructure. The ruling further explains that "[w]hile the focus of this proceeding extends out to 2020, it is important to note that the record similarly does not support a finding of need for additional generation beyond 2020." Accordingly, the agency found that "it is also reasonable to defer procurement of generation for any estimated need after 2020."[2]

At present, excess generation capacity exists in California. For example, Calpine Corporation's 572-MW natural-gas fired Sutter Energy Center combined cycle power plant recently faced imminent retirement. Only intervention by the CPUC, which ordered Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric to enter negotiations with the Sutter Energy Center's owner, Calpine Corporation, to offer a contract to keep the plant online in 2012, averted shutdown of the plant.[3]

---

1 John Pitkin and Dowell Meyers, California Demographic Futures, Generational Projections of the California Population by Nativity and Year of Immigrant Arrival, April 2012; http://www.usc.edu/schools/price/futures/pdf/2012_Pitkin-Myers_CA-Pop-Projections.pdf.

2 California Public Utilities Commission, Decision on System Track I and Rules Track III of The Long-Term Procurement Plan Proceeding and Approving Settlement, Rulemaking 10-05-006, filed May 6, 2010; http://docs.cpuc.ca.gov/PUBLISHED/AGENDA_DECISION/164031.htm#P27_410.

3 California Public Utilities Commission, Energy Division Resolution E-4471, March 22, 2012; http://docs.cpuc.ca.gov/published/Final_resolution/162985.htm.

DATA REQUEST

1. Please explain why the Applicant proposes to build a new fossil fuel-fired baseload plant when there does not appear to be any demand for additional generation capacity in the state until at least 2020.

RESPONSE

Hydrogen Energy California (HECA) respectfully disagrees with the notion that "there does not appear to be any demand for additional generation capacity in the state until at least 2020," and maintains its position that the project will provide dependable, low-carbon electricity to help meet future power needs, and to help "back-up" intermittent renewable power sources, such as wind and solar, to support a reliable power grid (AFC, 2012[1]). The Intervenor bases their proposition on a recent California Public Utilities Commission (CPUC) proposed decision[2]. However, the proposed decision settlement was inconclusive with respect to future demand of energy resources for the Long-Term Procurement Plan (LTPP) cycle (2012–2020).

The proposed decision concludes that "the Settling Parties agree that: The resource planning analyses presented in this proceeding do not conclusively demonstrate whether or not there is need to add capacity for renewable integration purposes through the year 2020, the period to be addressed during the current LTPP cycle. The Settling Parties have differing views on the input assumptions used in, and conclusions to be drawn from the modeling. There is general agreement that further analysis is needed before any renewable integration resource need determination is made [...] (Settlement Agreement at 4-5.)"

---

1 Amended Application for Certification for HYDROGEN ENERGY CALIFORNIA (08-AFC-8) Kern County, California. Volume 1. Pg. 1-15. May 2012. http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/amended_afc/Vol-I/

2 California Public Utilities Commission, Decision on System Track I and Rules Track III of The Long-Term Procurement Plan Proceeding and Approving Settlement, Rulemaking 10-05-006, filed May 6, 2010. http://docs.cpuc.ca.gov/PUBLISHED/AGENDA_DECISION/164031.htm#P27_410.

DATA REQUEST

2. Please discuss whether the Applicant is in discussions for a power purchase agreement with any utilities. If yes, please indicate which utilities and produce documents related to those discussions.

RESPONSE

As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1,* docketed on August 22, 2012, the Applicant objects to this Data Request.

DATA REQUEST

3. Please indicate the anticipated price of electricity that would be generated by the Project and compare to the price of electricity generated by natural gas-fired combined-cycle facilities in California.

RESPONSE

As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1,* docketed on August 22, 2012, the Applicant objects to this Data Request.

BACKGROUND: PROJECT FUNDING BY THE DEPARTMENT OF ENERGY

The U.S. Department of Energy (“DoE”) is proposing to provide financial assistance to HECA for project definition, design and construction, and demonstration of the Project under the Clean Coal Power Initiative (“CCPI”) program, Round 3. (AFC, Appx. B, p. B-3.) The AFC states that the purpose and need for DOE action— providing limited financial assistance to the Project—is “to advance the CCPI program by funding projects that have the best chance of achieving the program’s objectives as established by Congress: The commercialization of clean coal technologies that advance efficiency, environmental performance, and cost competitiveness well beyond the level of technologies that are currently in commercial service.” (AFC, Appx. B, p. B-1.)

DOE’s financial assistance (or “cost share”) would be limited to $408 million, which is approximately 10 percent of the HECA Project’s total cost. DOE would share the costs of the gasifier, syngas cleanup systems, a combustion turbine, a heat recovery steam generator, a steam turbine, supporting facilities and infrastructure, and a demonstration phase in which the HECA Project would use at least 75 percent coal (calculated on a fuel thermal input basis) to generate low-carbon electricity and low-carbon nitrogen-based products and would capture carbon dioxide (“CO_2“) for use in enhanced oil recovery (“EOR”) and sequestration. (AFC, Appx. B, pp. B-2 – B-4.) So far, the DOE has invested $54 million in the Project.[4] Funding would be fully or partially appropriated by the American Recovery and Reinvestment Act of 2009.

The AFC does not adequately demonstrate that the Project’s technology components and their integration would adequately advance the CCPI’s objectives to justify funding by the DOE.

---

4 Hydrogen Energy California, SCS Energy Agrees to Take Over HECA and to Move Project Forward, May 23, 2011; http://hydrogenenergycalifornia.com/uncategorized/scs-energy-agrees-to-take-over-heca-and-to-move-project-forward.

DATA REQUEST

4. Gasification of petroleum coke (“petcoke”) and coal has long been demonstrated successfully on a commercial scale and numerous gasification plants operate around the world including several in the U.S. Here, the Project would use Mitsubishi Heavy Industries (“MHI”) gasification technology. This technology has been demonstrated on a variety of coal and other feedstocks in pilot facilities, demonstration plants and on a commercial scale at the 250-MW integrated gasification combined cycle (“IGCC”) Facility in Nakoso, Japan, which has been in operation since 2008. (AFC, p. 2-74.) Please explain why the use of the MHI gasification technology for the Project is novel and qualifies for CCPI funding.

RESPONSE

As described in *Applicant’s Objections and Requests for Additional Time to Respond to Sierra Club’s Data Requests Set 1,* docketed on August 22, 2012, the Applicant objects to this Data Request.

DATA REQUEST

5. When the DOE selected the HECA project as one of the projects for demonstration and funding under DOE's CCPI Round 3, the Project was proposed with gasification technology and combustion and steam turbine generators developed and manufactured by the U.S. firm General Electric ("GE"). The Project design has since undergone significant design changes and now proposes to use gasification technology and combustion and steam turbine generators developed and manufactured by the Japanese firm MHI.

a) Please discuss in detail why the Applicant decided not to use GE gasification and turbine technology and instead to use MHI technologies.

b) Has the DOE been apprised of the changes in the technological configuration and commercial issues of the Project?

c) Please explain whether DOE can legally invest in Japanese technology with funds that are partially or fully appropriated by the American Recovery and Reinvestment Act.

d) Please discuss the economics for the Project.

e) Would the Project be able to go forward if the Applicant does not receive funding from DOE?

RESPONSE

a. As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1*, docketed on August 22, 2012, the Applicant is requesting additional time to address this Data Request.

b. Yes, the U.S. Department of Energy (DOE) has been apprised of the changes in the technological configuration and commercial issues associated with the Project.

c. As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1,* docketed on August 22, 2012, the Applicant objects to this Data Request.

d. As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1,* docketed on August 22, 2012, the Applicant objects to this Data Request.

e. As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1,* docketed on August 22, 2012, the Applicant objects to this Data Request.

DATA REQUEST

6. The AFC, p. 2-8, recognizes that the Project's key technologies – integrated gasification combined cycle, carbon capture and storage ("CCS"), and EOR – have long been used separately and safely. However, the AFC, p. 2-73, states that while "both gasification and gas purification with carbon capture are proven technologies, operating at commercial scale within the United States and around the world," "integration of these technologies with sequestration has not yet been performed on a commercial scale."

a) Please discuss technological and other problems associated with integrating gasification and gas purification technologies with carbon capture and sequestration on a commercial scale. Please discuss issues that would be specifically addressed and "proven" by the Project.

b) Since 2000, CO_2 captured at the Dakota Gasification Company's coal gasification plant near Beulah, North Dakota, is compressed and transported via pipeline about 200 miles north to southeast Saskatchewan, Canada, for use in EOR and sequestration. The Weyburn-Midale CO_2 Project has been injecting about 7,700 and 2,000 short tons per day ("stpd") at Cenovus's Weyburn and Apache's Midale oil fields, respectively, since 2006. (See http://www.ptrc.ca/weyburn_history.php and http://www.ptrc.ca/weyburn_final.php.) The annual CO_2 injection, about 3.5 million short tons per year ("stpy")[5], is on the same order of magnitude as the proposed CO_2 injection for the Project of 3 million stpy. (AFC, p. 1-2.)

i. Please discuss why the Weyburn-Midale CO_2 Project does not constitute commercial demonstration of integrating large-scale injection of pipeline CO_2 from gasification and carbon capture for purposes of EOR.

ii. Please discuss any differences with respect to the integration of CO_2 capture and subsequent transportation and injection for purposes of EOR and sequestration between a) the Weyburn/Midale CO_2 Project and b) the planned CO_2 capture at HECA and subsequent transportation to and injection of CO_2 at Elk Hills Oil Field.

---

5 Estimated from: (Weyburn: 7,000 tonnes/year + Midale: 1,800 tonnes/year) × (1.1 short tons/tonne) × (365 days/year) = 3.54 million stpy.

RESPONSE

As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1*, docketed on August 22, 2012, the Applicant is requesting additional time to address this Data Request.

7. DOE states that its overarching goal for CCPI Round 3 projects was to demonstrate technologies at commercial scale in a commercial setting that would: (1) operate at 90 percent capture efficiency for CO_2; (2) make progress towards capture and sequestration at less than a 10 percent increase in the cost of electricity for gasification systems and a less than 35 percent increase for systems; and (3) make progress toward capture and sequestration of 50 percent of the facility's CO_2 output at a scale sufficient to evaluate the full impacts of carbon capture technology on a generating plant's operations, economics and performance. Please provide a detailed discussion how the Project would meet each of these objectives. Please document your assumptions.

RESPONSE

As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1,* docketed on August 22, 2012, the Applicant objects to this Data Request.

BACKGROUND: PROJECT FUNDING BY THE CALIFORNIA PUBLIC UTILITIES COMMISSION

In 2009, the Applicant received authorization from CPUC to recover up to $30 million in costs stemming from the Applicant's co-funding of the HECA feasibility study ($17 million in funding for Phase I assessing initial feasibility and $13 million for the Phase II Front End Engineering Design ("FEED") study). The $30 million of funding constitutes approximately 20 percent of the $152 million budgeted for Phase I and II studies. [6] The CPUC's decision, in part, relied upon the finding that the Project would not be so duplicative of the reports the Applicant was producing in its feasibility study for the Clean Hydrogen Power Generation ("CHPG") project in Utah or of efforts by BP, Rio Tinto, and Edison Mission Group for the Carson Project in Southern California that the feasibility studies would fail to produce benefits that make it reasonable to authorize recovery of costs in rates. One argument for demonstrating the difference between the CHPG and the HECA project for Phase II costs was that "CHPG is a coal fed project, while HECA uses petroleum coke."

6 California Public Utilities Commission, Application of Southern California Edison Company (U338E) For Authorization to Recover Costs Necessary to Co-Fund a Feasibility Study of a California IGCC with Carbon Capture and Storage, Application 09-04-008, filed April 3, 2009, Decision 09-12-014, December 3, 2009, issued: December 9, 2009; http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/110973.htm.

DATA REQUEST

8. Has the Applicant spent the entire $30 million approved by the CPUC for reports produced for the feasibility study of the previously proposed HECA project? Please provide a breakdown of costs for Phase I and Phase II.

RESPONSE

Yes, the $30 million was spent before the current owners acquired the HECA Project.

The breakdown of costs for Phase I and II can be found on page 10 of the SCE Testimony in Support of Application for Authorization to Recover Costs Necessary to Co-Fund a Feasibility Study of a California Integrated Gasification Combined Cycle (IGCC) with Carbon Capture and Storage, which can be found on the CPUC website at http://www3.sce.com/sscc/law/dis/dbattach7.nsf/0/2A85B596280D04328825758D0078A926/$FILE/A0904XXX+HECA+-+SCE+Testimony+in+Support+of+Application.pdf.

DATA REQUEST

9. Please provide a list of all reports produced for the feasibility study for the previously proposed HECA project separately for Phase I and Phase II. Please provide a copy of the reports.

RESPONSE

Exhibit A of the HECA Study Agreement provides a list of the reports produced for the feasibility study. The Study Agreement can be found on the CPUC website at http://www3.sce.com/sscc/law/dis/dbattach7.nsf/0/2A85B596280D04328825758D0078A926/$FILE/A0904XXX+HECA+-+SCE+Testimony+in+Support+of+Application.pdf. (The Study Agreement is Attachment 4 of the document.) In addition, copies of the reports are available on the CPUC website.

DATA REQUEST

10. The technological configuration and commercial issues for the Project have changed considerably since the Applicant received authorization from CPUC for cost recovery for a feasibility study. For example, the Project is now designed with one instead of two gasifiers which use different technology, would use a 75%/25% coal/petcoke blend instead of 100% petcoke, and would include a fertilizer manufacturing facility.

a) Please discuss which reports produced for the feasibility study authorized by the CPUC apply to the current Project configuration without changes and which require changes.

b) Please describe or provide the additional reports that must be conducted for determining the feasibility of the current Project configuration.

c) Has the CPUC been apprised of the changes in the technological configuration and commercial issues of the Project?

d) Will the Applicant apply with the CPUC for authorization of additional cost recovery for reports produced for determining the feasibility of the current Project configuration?

RESPONSE

a. The reports produced for the feasibility study pertained to the former project configuration. The Applicant does not anticipate making any changes to these reports, because they are no longer applicable.

b. No new reports are anticipated at this time. The reports produced under the feasibility study were to help establish the feasibility of the former Project design, and were a requirement of the Study Agreement and receipt of the $30 million. No new reports are required.

c. Yes, the CPUC has been apprised of the changes in the technological configuration and commercial aspects of the Project.

d. The Applicant does not anticipate applying to the CPUC for additional cost recovery for feasibility study reports at this time.

BACKGROUND: REFERENCES

The AFC cites to a number of references to support its assumptions that are not readily available in the public domain and are not provided in the current record.

DATA REQUEST

11. Please provide a copy of the following references:

a) HECA (Hydrogen Energy California) Project Team, 2008. Field work and observations. (AFC, Section 5.8.)

b) Sierra Scientific Services, 2009. An Evaluation of the Geology, Hydrology, Well Placements and Potential Impacts of the Buena Vista Water Storage District's proposed Brackish Groundwater Remediation Project. (AFC, Section 5.14.)

c) Boyle Engineering Corporation, 2002. Groundwater Status and Management Plan for Buena Vista Water Storage District. (AFC, Section 5.14.)

d) Buena Vista Water Storage District, 2009. Personal communication with URS. May. (AFC, Section 5.14.)

e) Environmental Data Resources, Inc. (EDR), 2009. Data Map Well Search Report, April 3, 2009. (AFC, Section 5.14.)

f) ESA, 2010. Groundwater Banking Project Environmental Impact Report. Prepared for West Kern Water District. March. (AFC, Section 5.14.)

g) Sierra Scientific Services, 2003. Determination of Aquifer Storage Capacity for the Rosedale-Rio Bravo Water Storage District, Bakersfield, California. January 20. (AFC, Section 5.14.)

h Sierra Scientific Services, 2004. An Evaluation of Well Placements and Potential Impacts of the ID4/Kern Tulare/Rosedale—Rio Bravo Aquifer Storage and Recovery Project. July 20. (AFC, Section 5.14.)

i) Sierra Scientific Services, 2007a. A Water Quality Evaluation of the Strand Ranch Aquifer Storage and Recovery Project, Kern County, CA., in: Rosedale—Rio Bravo Water Storage District Strand Ranch Integrated Banking Project Environmental Impact Report, January, 2008, prepared by ESA, Los Angeles, California. December 19. (AFC, Section 5.14.)

j) Sierra Scientific Services, 2007b. An Evaluation of Well Placements and Potential Impacts of the proposed Strand Ranch Well Field, Kern County, California. In "Rosedale—Rio Bravo Water Storage District Strand Ranch Integrated Banking Project Environmental Impact Report," January 2008, prepared by ESA, Los Angeles, California. December 20. (AFC, Section 5.14.)

k) Sierra Scientific Services, 2009. An Evaluation of the Geology, Hydrology, Well Placements and Potential Impacts of the Buena Vista Water Storage

District's proposed Brackish Groundwater Remediation Project. In prep. (AFC, Section 5.14.)

l) ***URS, 2009a. Preliminary Geotechnical Investigation for Proposed Hydrogen Energy California Project (HECA), Kern County, California. (AFC, Section 5.14.)***

m) ***URS 2010b. Draft Addendum to the Draft Hydrogeologic Data Acquisition Report for Proposed Hydrogen Energy California Project (HECA), Kern County, California. April 2010. (AFC, Section 5.14.)***

n) ***URS 2010c. Linear Modifications to the Revised Application for Certification for Hydrogen Energy California, Kern County, California. August 2010. (AFC, Section 5.14.)***

RESPONSE

The majority of these documents were previously docketed with the California Energy Commission (CEC). Table 11-1 provides a cross-reference for these documents. Only one document is new (i.e., requested document 11f); this document will be submitted to the CEC separately on a disk.

Table 11-1
HECA Reference Documents

Requested Reference Document	Location of Document
11a. HECA (Hydrogen Energy California) Project Team, 2008. Field work and observations. (Application for Certification [AFC], Section 5.8.)	We found no such citation in the 2012 Amended AFC, Section 5.8; nevertheless, this type of citation would be a reference to field work, not a document.
11b. Sierra Scientific Services, 2009. *An Evaluation of the Geology, Hydrology, Well Placements and Potential Impacts of the Buena Vista Water Storage District's proposed Brackish Groundwater Remediation Project*. (AFC, Section 5.14.)	As previously indicated in Applicant's response to the April 12, 2010 CEC Data Response and Issues Resolution Workshop Data Request 16, this document is under preparation and is not available.
11c. Boyle Engineering Corporation, 2002. *Groundwater Status and Management Plan for Buena Vista Water Storage District*. (AFC, Section 5.14.)	Document is cited in BVWSD's *Final Environmental Impact Report for the Buena Vista Water Storage District Buena Vista Water Management Program* (Docket # 55029), and is not in Applicant's possession.
11d. Buena Vista Water Storage District, 2009. Personal communication with URS. May. (AFC Buena, Section 5.14.)	Citation is personal communication. There is no additional information than that presented in the cited text.
11e. Environmental Data Resources, Inc. (EDR), 2009. *Data Map Well Search Report*, April 3, 2009. (AFC, Section 5.14.)	Please see 2009 Revised AFC, Appendix M – Phase I ESA, Appendix D (part of Docket # 51735 dated May 28, 2009).
11f. ESA, 2010. *Groundwater Banking Project Environmental Impact Report*. Prepared for West Kern Water District. March. (AFC, Section 5.14.)	As stated in the response, this document will be submitted to the CEC separately on a disk.

Table 11-1
HECA Reference Documents (Continued)

Requested Reference Document	Location of Document
11g. Sierra Scientific Services, 2003. Determination of Aquifer Storage Capacity for the Rosedale–Rio Bravo Water Storage District, Bakersfield, California. January 20. (AFC, Section 5.14.)	Document was docketed with the CEC on June 10, 2010 as part of the Responses to the April 12, 2010 CEC Data Response and Issues Resolution Workshop. This document was provided in response to Workshop Data Request No. 16a. (Docket # 57101).
11h. Sierra Scientific Services, 2004. An Evaluation of Well Placements and Potential Impacts of the ID4/Kern Tulare/Rosedale—Rio Bravo Aquifer Storage and Recovery Project. July 20. (AFC, Section 5.14.)	Document was docketed with the CEC on June 10, 2010 as part of the Responses to the April 12, 2010 CEC Data Response and Issues Resolution Workshop. This document was provided in response to Workshop Data Request No. 16b. (Docket # 57101).
11i. Sierra Scientific Services, 2007a. A Water Quality Evaluation of the Strand Ranch Aquifer Storage and Recovery Project, Kern County, CA., in: *Rosedale—Rio Bravo Water Storage District Strand Ranch Integrated Banking Project Environmental Impact Report, January, 2008*, prepared by ESA, Los Angeles, California. December 19. (AFC, Section 5.14.)	Document was docketed with the CEC on June 10, 2010 as part of the Responses to the April 12, 2010 CEC Data Response and Issues Resolution Workshop. This document was provided in response to Workshop Data Request No. 16c. (Docket # 57101).
11j. Sierra Scientific Services, 2007b. An Evaluation of Well Placements and Potential Impacts of the proposed Strand Ranch Well Field, Kern County, California. In *Rosedale—Rio Bravo Water Storage District Strand Ranch Integrated Banking Project Environmental Impact Report*, January 2008, prepared by ESA, Los Angeles, California. December 20. (AFC, Section 5.14.)	Document was docketed with the CEC on June 10, 2010 as part of the Responses to the April 12, 2010 CEC Data Response and Issues Resolution Workshop. This document was provided in response to Workshop Data Request No. 16d. (Docket # 57101).
11k. Sierra Scientific Services, 2009. An Evaluation of the Geology, Hydrology, Well Placements and Potential Impacts of the Buena Vista Water Storage District's proposed Brackish Groundwater Remediation Project. In prep. (AFC, Section 5.14.)	This is the same document as 11b. This document is under preparation and is not available.
11l. URS, 2009a. *Preliminary Geotechnical Investigation for Proposed Hydrogen Energy California Project (HECA), Kern County, California*. (AFC, Section 5.14.)	See Appendix P in the 2009 Revised AFC (part of Docket # 51735 dated May 28, 2009).
11m. URS 2010b. *Draft Addendum to the Draft Hydrogeologic Data Acquisition Report for Proposed Hydrogen Energy California Project (HECA), Kern County, California*. April 2010. (AFC, Section 5.14.)	This addendum was docketed with the main report on April 29, 2010 (Docket #56563).
11n. URS 2010c. *Linear Modifications to the Revised Application for Certification for Hydrogen Energy California, Kern County, California. August 2010*. (AFC, Section 5.14.)	This document was docketed on August 27, 2010 (Docket # 58261) and was filed confidentially.

BACKGROUND: MATERIAL MASS BALANCES

The AFC does not provide adequate material mass balances necessary to understand the facility's various technologies, e.g., gasification and fertilizer manufacturing process, and associated emission sources. Further, the information provided on product flows is inconsistent.

DATA REQUEST

12. Please provide material mass balances for the facility including water, carbon, sulfur, nitrogen, methanol, volatile organic compounds ("VOCs"), hazardous air pollutants ("HAPs") and toxic air contaminants ("TACs"), and inert solids. These mass balances should clearly identify all individual process streams and the respective compound streams and emission points.

RESPONSE

Please see the Applicant's responses to CEC Data Requests A14, A15, and A16, docketed on August 22, 2012.

13. The overall component balances provided in AFC, Figure 2-13 for sulfur, carbon, and inert solids are inconsistent with the maximum amounts of products shown in AFC, Tables 2-10 and 2-11: For sulfur, Table 2-11 indicates a total production of 150 stpd of sulfur; in contrast, Table 2-10 and Figure 2-13 indicate a total production of 8,370 lb/hr of sulfur (Process Stream #4) or 100 stpd of sulfur.[7] For carbon, Tables 2-10 and 2-11 indicate a total flow rate of 9,200 stpd CO_2 for EOR; in contrast, Figure 2-13 indicates a total flow rate of 207,655 lb/hr carbon (Process Stream #5) or 9,137 stpd CO_2.[8] For inert solids from gasification, Tables 2-10 and 2-11 indicate a flow rate of 850 stpd; Figure 2-13 indicates a total flow rate of 69,925 lb/hr or 839 stpd.[9] Please discuss these discrepancies.

---

7 (8,370 lb/hr) × (24 hours/day) / (2,000 lb/ton) = 100.44 short tons per day (stpd).

8 (207,655 lb/hr) × (24 hours/day) / (2,000 lb/ton) × (44 g/mol CO_2/12 g/mol C) = 9,136.82 stpd CO_2.

9 (39,925 lb/hr) × (24 hours/day) / (2,000 lb/ton) = 839.1 stpd.

RESPONSE

For sulfur, 150 stpd represents the maximum processing capability of the sulfur degassing process; 100 stpd represents the design capacity of the sulfur recovery unit. For carbon dioxide for EOR, 9,200 stpd is a value showing two significant figures which encompasses 9,137 stpd. For inert solids from gasification 850 stpd is a value showing two significant figures which encompasses 839 stpd.

BACKGROUND: FEEDSTOCK SUPPLY, DEMAND, AND SPECIFICATIONS

The Project would gasify a blend of 75% western sub-bituminous coal and 25% California petcoke based on thermal input to the gasifier higher heating value ("HHV"). (AFC, p. 2-1.) The AFC provides inconsistent and inadequate information for these feedstocks.

DATA REQUEST

14. The AFC, pp. 2-15 and 2-16, states that the Project would require 4,580 sptd of coal and 1,140 stpd of petcoke for a total of 5,720 stpd. Elsewhere, the AFC indicates that the Project would require a total of 5,800 stpd of feedstock (as received). (AFC, Table 2-10, p. 2-84, Table 2-11, p. 2-85.) Please discuss this apparent discrepancy.

RESPONSE

The Project will use 4,580 short tons per day (stpd) of coal and 1,140 stpd of petroleum coke (petcoke), for a total of 5,720 stpd. Differences in total solid feedstock volumes reported in the 2012 Amended AFC are due to rounding.

DATA REQUEST

15. The AFC, p. 2-16, states that the Project would be able to accept a variety of petcoke and coal feedstocks and shows typical analyses for both petcoke and coal (Tables 2-4 and 2-5). Please discuss the ranges of petcoke and coal feedstock specifications (e.g., ultimate analysis, moisture content, gross heating value, sulfur content, chloride content, bulk density, mercury content, ash mineral analysis) that would meet the Project's technology requirements.

RESPONSE

The plant is designed to have sufficient flexibility to gasify coal and petcoke blends that are within Mitsubishi Heavy Industries' (MHI's) gasification experience base, and within specific plant process and equipment capabilities. The project will purchase coal and petcoke under commercial agreements with specific suppliers, and has obtained representative samples of these feedstocks for evaluation of the feedstock properties. This evaluation comes in multiple parts, with the first part having been completed by the Nagasaki Research and Development Center. The center conducted a Sizing, Proximate, Ultimate, Mineral, and Ash Fusion analysis, and has found the intended feedstock to be within the plant design capabilities and experience base of MHI.

DATA REQUEST

16. In the prior AFC for the Project, the Applicant proposed to gasify 100% petcoke with the flexibility to operate with up to 75% thermal input western bituminous coal in a GE gasifier. (See, e.g., 08-AFC-08, p. 2-1.) In the initial public workshop, the Applicant indicated that MHI only guarantees a 25% petcoke/75% coal feedstock for the gasifier.

a) Please discuss why the Applicant has decided to switch to MHI gasification technology.

b) Please discuss in detail why the gasifier developed by GE is able to operate on 100% petcoke but not the gasifier developed by MHI.

c) Please discuss whether the Applicant has investigated other gasifier technologies.

d) Please provide the vendor guarantee for the MHI gasifier.

e) Please discuss whether the Applicant requested a vendor guarantee from MHI for gasifying any feedstock blend other than 25% petcoke/75% coal. If yes, please discuss the response and include any relevant documents. If not, then please discuss why not.

f) Please discuss whether the MHI gasifier could operate on any other feedstock blend besides 25% petcoke/75% coal, including 50%/50%, 75% coal/25%petcoke, and/or 100% petcoke.

RESPONSE

As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1*, docketed on August 22, 2012, the Applicant is requesting additional time to address this Data Request.

DATA REQUEST

17. The AFC, pp. 2-15 and 2-16, indicates that several mines have been identified that can supply western sub-bituminous coal meeting Project technology requirements in terms of ash composition and other characteristics. At the June 20, 2012 workshop, the Applicant indicated that it would contract with Peabody Energy for supply of sub-bituminous coal from the Lee Ranch Mine in New Mexico. Peabody Energy's Lee Ranch Mine produced about 1.7 million stpy in 2010 and currently supplies coal to the Western Fuels Association and Tucson Electric Power under long-term contracts that run through 2014 and 2010, respectively.[10] The Project would consume about 1.6 million stpy, i.e., 94% of the mine's current production. (AFC, p. 2-15.)

a) Please identify the mines the Applicant has identified that would meet the Project's technology requirements.

b) Please discuss whether the Applicant has procured a contract with Peabody Energy and discuss the specified duration and costs.

c) Please quantify the percentage of the annual coal supply for the Project that would be sourced from Peabody Energy's Lee Ranch Mine in New Mexico. If not 100 percent, please discuss the source(s) of the remainder.

d) Please discuss whether Peabody Energy's Lee Ranch Mine would increase its annual production of coal to accommodate Project demand.

e) Please discuss whether or not Lee Ranch Mine is currently in compliance with all federal and state regulations and describe and detail any litigation the mine has been involved in for the last ten years.

f) Please provide fuel specifications for coal from the Lee Ranch Mine and any other mines under consideration, including heat content; ash content; sulfur, mercury, hydrogen chloride, and heavy metal content; etc.

g) Please identify the rail carrier(s) that would transport coal from the Lee Ranch Mine in New Mexico to California. Please provide any procurement contracts or documents of discussions with the respective rail carrier(s).

---

10 Peabody Energy, Fact Sheets, Lee Ranch Mine; http://www.peabodyenergy.com/content/278/Publications/Fact-Sheets/Lee-Ranch-Mine.

RESPONSE

a. Peabody Energy will supply the coal from their portfolio of mines, including, but not limited to, Lee Ranch; and more likely, El Segundo.

b. As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1,* docketed on August 22, 2012, the Applicant objects to this Data Request.

c. All of the coal will be supplied from the portfolio of Peabody Energy mines. Please refer to the response to Data Request 17a.

d. The Applicant is not privy to Peabody Energy's production intentions. Nonetheless, we note that Peabody Energy has more than enough capacity in its El Segundo and other mines to meet HECA's needs.

e. As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1,* docketed on August 22, 2012, the Applicant objects to this Data Request.

f. Please refer to Attachment 17-1 for the El Segundo Five-year Plan Typical Analysis.

g. BNSF is the rail carrier that will transport the coal from New Mexico to California. As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1,* docketed on August 22, 2012, the Applicant objects to the second sentence of this Data Request that calls for confidential business information.

ATTACHMENT 17-1
EL SEGUNDO FIVE-YEAR PLAN TYPICAL ANALYSIS

EL SEGUNDO

5 Year Plan
Typical Analysis

Raw Basis | **Report Data 2/16/09**
State of New Mexico

Proximate Analysis	**As Received**	**Dry**
Moisture	18.1	
Ash	14.7	17.9
Volatile Matter	33.4	40.8
Fixed Carbon	33.8	41.3
BTU	9180	11209
Sulfur	1.06	1.29
MAFBTU	13653	
Lb. SO2/MMBTU	2.30	
Lb. S/MMBTU	1.15	

Ultimate Analysis	
Carbon	63.2
Hydrogen	4.7
Nitrogen	1.0
Chlorine	0.01
Sulfur	1.29
Ash	17.9
Oxygen	11.90

Sulfur Forms	
Pyritic	0.48
Sulfate	0.02
Organic	0.79

Water Soluble Alkalies	
Sodium Oxide	0.063
Potassium Oxide	0.004

Equilibrium Moisture	17.4
Free Swelling Index	0.0
Hardgrove Grindability Index @ production moisture	55
Mercury Hg ppm (Dry Whole Coal Basis)	0.12
lbs.Hg / trillion Btu's	10.71

Ash Fusion	
Reducing Atmosphere	
Initial Deformation (I.D.)	2370
Softening (H=W)	2460
Hemispherical (H=1/2W)	2525
Fluid	2590
Oxidizing Atmosphere	
Initial Deformation (I.D.)	2500
Softening (H=W)	2560
Hemispherical (H=1/2W)	2620
Fluid	2700

Mineral Analysis Of Ash (Ignited Basis)	
Silica (SiO2)	57.4
Alumina (Al2O3)	23.0
Titania (TiO2)	1.0
Ferric Oxide (Fe2O3)	7.4
Lime (CaO)	4.2
Magnesia (MgO)	1.2
Potassium Oxide (K2O)	0.9
Sodium Oxide (Na2O)	0.8
Phosphorous Pentoxide (P2O5)	0.1
Sulfur Trioxide (SO3)	3.6
Strontium Oxide (SrO)	0.1
Barium Oxide (BaO)	0.2
Manganese Dioxide (MnO2)	0.1

Alkalies As Na2O	0.25
Base/Acid Ratio	0.18
Silica Value	81.77
Slag Viscosity @ T250	2815
Lb. Ash/MMBTU	16.0
Lb. Na2O/MMBTU	0.13

All analyses are subject to revision due to additional coring, conditions specified in the coal supply agreement, actual operating conditions at time of mining, type of preparation at time of mining, or federal and state regulations. Analysis intended for informational purposes only.

Source Of Information	*Proximate analysis based on mine model provided by M. Flatcher & M. Shetley with 4" of floor added. Remainder of analysis based on cores and production data*

Prepared by W.B. Emke

DATA REQUEST

18. The AFC, p. 2-16, states that the Project would consume about 400,000 stpy of fuel-grade petcoke which is about 7% of the total 6.0 million stpy petcoke produced in-state by six major California refineries in Los Angeles area and central California.

a) Please provide a discussion of the total annual petcoke production in California from all sources and the current annual demand for and fate of petcoke from California (e.g., shipment overseas).

b) Has the Applicant procured contracts or discussed contractual terms with any petcoke manufacturers? Please produce associated documents including phone logs, correspondence, contracts, etc.

RESPONSE

a. As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1,* docketed on August 22, 2012, the Applicant objects to this Data Request.

b. As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1,* docketed on August 22, 2012, the Applicant objects to this Data Request.

BACKGROUND: VOLUNTARY AIR QUALITY IMPROVEMENT AGREEMENT

According to CEC staff's preliminary determination of compliance ("PDOC") for the previously proposed version of the HECA project, the Applicant "has entered into a voluntary Air Quality Improvement Agreement with the district to fund air quality improvements within Kern County. The funding includes an initial fee of over $680,000 and a potential additional fee depending on whether the district's target NOx emission level is met during a two year demonstration period that starts with commercial operation. This agreement specifies that the initial fee will be paid at the time of commercial operation, unless waived by HECA, and that the additional fee, if necessary, will be paid within 180 days after the completion of the demonstration period. The additional fee is based on an agreed calculation procedure that is not to exceed the equivalent ERC cost for NOx credits. The funds obtained by the district under this agreement are to be used to fund emission reduction projects within the San Joaquin Valley Air Basin, preferentially in Kern County, that will focus on replacing older high emitting agricultural equipment in order to provide quantifiable air quality benefits within Kern County."[11] The AFC contains no discussion of this agreement.

---

11 08-AFC-08, California Energy Commission, August 2010 Preliminary Determination of Compliance, pp. 4.1-42/4.1-43.

DATA REQUEST

19. Please provide a copy of the Voluntary Air Quality Improvement Agreement ("Agreement") between HECA and the SJVAPCD, if necessary under confidential cover.

RESPONSE

The Voluntary Air Quality Improvement Agreement for the previous HECA Project is available at this website: http://www.valleyair.org/Board_meetings/GB/agenda_minutes/Agenda/2010/August/Agenda%20Item_08_Aug_19_2010.pdf.

The 2010 agreement is provided as Attachment 19-1.

ATTACHMENT 19-1
HECA AIR QUALITY IMPROVEMENT AGREEMENT
AUGUST 19, 2010

Northern Region Office
4800 Enterprise Way
Modesto, CA 95356-8718
(209) 557-6400 • FAX (209) 557-6475

Central Region Office
1990 East Gettysburg Avenue
Fresno, CA 93726-0244
(559) 230-6000 • FAX (559) 230-6061

Southern Region Office
34946 Flyover Court
Bakersfield, CA 93308-9725
(661) 392-5500 • FAX (661) 392-5585

www.valleyair.org

DATE: August 19, 2010

TO: SJVUAPCD Governing Board

FROM: Seyed Sadredin, Executive Director/APCO
Project Coordinator: Dave Warner

RE: **APPROVE AND AUTHORIZE CHAIR TO SIGN AIR QUALITY IMPROVEMENT AGREEMENT WITH HYDROGEN ENERGY CALIFORNIA LLC**

RECOMMENDATION:

Authorize the Chair to sign the attached air quality improvement agreement with Hydrogen Energy California LLC to accept funds in the amount of six hundred eighty-one thousand two hundred sixty two dollars and thirty-one cents ($681,262.31), with the possibility of receiving additional funds following the first two years of commercial operation, to provide voluntary mitigation of emissions associated with the operation of a proposed integrated gasification combined cycle (IGCC) power plant in Kern County.

BACKGROUND:

Hydrogen Energy California LLC is seeking approval from the California Energy Commission (CEC) to construct and operate the Hydrogen Energy California Power Plant. This proposed project will gasify petroleum coke, or blends of petroleum coke and coal as needed, to produce hydrogen to fuel a combustion turbine operating in combined cycle mode to produce a nominal 390 gross megawatts. The net nominal output will be 250 megawatts of baseload power. The proposed project will also capture approximately 90 percent of the carbon from the raw synthesis gas, which will be transported to a neighboring oil field for enhanced oil recovery and carbon sequestration. On-site construction of the project is expected to take place from December 2011 to December 2014, a total of about 36 months. Commercial operation is planned by the third quarter of 2015. The proposed power plant will be located on a 473-acre parcel in western Kern County, approximately 7 miles west of the outermost edge of the City of Bakersfield and 1.5 miles northwest of the unincorporated community of Tupman.

The proposed power plant is a first of its kind project, with an integrated gasification combined cycle (IGCC) plant and the use of NOx reduction technologies that have not been demonstrated on hydrogen fired turbines. Due to this, the equipment suppliers will not guarantee that nitrogen oxide (NOx) emissions will be below 4 parts per million, by volume (ppmv), while a typical new natural gas fired combined cycle power plant is limited to 2 ppmv NOx. The District recognizes that this power plant is an important opportunity to test and demonstrate IGCC technology and the resulting ability to sequester carbon dioxide emissions. In addition, the proposal has been found to be in compliance with all District rules and regulations, as proposed.

However, in consideration of the importance of NOx emissions to the ability of the San Joaquin Valley to achieve attainment of ozone and particulate ambient air quality standards, the District has expressed concern that the plant will have higher NOx emissions than a new natural gas fired baseload power plant with a similar power output.

Hydrogen Energy California LLC has been very receptive to the District's concerns and has exhibited great willingness to address the District's concerns as well those of Valley residents in the area of the proposed project. Towards that end, Hydrogen Energy California LLC and District staff have negotiated the attached Air Quality Improvement Agreement that will provide funding for additional mitigation of NOx emissions from this project, above and beyond the mitigation required by District regulation.

DISCUSSION:

The District has determined that Hydrogen Energy California LLC's proposal to construct this project, including the hydrogen fired turbine, complies with all District regulations, including requirements for Best Available Control Technology and emissions offsets. The District's Best Available Control Technology determination is that NOx emissions cannot exceed the 4 ppmv level that the equipment suppliers will guarantee, but that the facility must work to achieve a target rate of 2 ppmv. The facility will have a two year initial demonstration period to reach the target level, which they believe they can meet. At the end of the initial demonstration period the District will review source test reports, the operating history of the facility, and any other information or reports gathered over the initial two-year period of operation, to determine if the turbine can operate at 2 ppmv NOx, or if not, to determine the appropriate permit limit that can be achieved, to a maximum of 4 ppmv.

As Hydrogen Energy California LLC has requested the ability to operate above 2 ppmv during the initial demonstration period, and possibly after this period, the District expressed concern that the resulting emissions may have an impact on the District's attainment efforts, when compared to a natural gas power plant. In response to those concerns, Hydrogen Energy California LLC has offered to provide additional mitigation, above that required by the District's rules and regulations.

The quantity of NOx emissions to be mitigated was established using the following methodology (see further details in the attached agreement, specifically in attachments A and B):

- During the initial demonstration period, calculate the difference between the facility's potential emissions, at 4 ppmv NOx, and the potential emissions a hypothetical natural gas fired power plant with the same net power output would have, at 2 ppmv NOx.
- After the initial demonstration period, should the facility not achieve the target level of 2 ppmv NOx, calculate the difference between the facility's demonstrated emissions (as will be set forth in their final Permit to Operate) and the emissions that would have occurred if they had met 2 ppmv NOx.

Based on the above methodology, 115.5 tons per year of NOx emissions are to be mitigated within the Valley during the two year initial demonstration period. The mitigation fee for NOx emissions is $56,175 per ton, which is the 2009 weighted average price of all purchases of permanent NOx emission reduction credits (ERCs) in the San Joaquin Valley, plus 5% for administrative costs associate with the District implementing a grant program to bring about the intended NOx reductions. At these rates, and conservatively assuming a twenty year life of the power plant, a sum of $681,262.31 is required for the two year initial demonstration period. A commensurate sum would be required after the initial demonstration period should the facility be permitted at a NOx level above 2 ppmv.

Similar to the past emission reduction incentive programs sponsored by the District, the funds received under this Air Quality Improvement Agreement will be used to provide contemporaneous emission reductions in the Valley and to the extent possible in or near Kern County, within the District's Southern Region. Emission reduction programs that will be funded will be the most cost-effective projects available and are likely to include replacement or retrofitting of heavy duty diesel internal combustion engines and electrification of agricultural pump engines.

FISCAL IMPACT:

Under the terms of the Air Quality Improvement Agreement, Hydrogen Energy California LLC will pay $681,262.31 to the District within thirty (30) days after physical delivery of the first hydrogen combustion turbine generator to the Project site. In general, this means that the funds will be available approximately nine months in advance of the project completion date. To ensure contemporaneous reduction in emissions, the District intends to award these funds in accordance with a schedule that would allow emission reductions to take place prior to the initial commercial operation of the proposed power plant. Accordingly, it is estimated that necessary budget resolutions authorizing the related appropriations will be presented to the Governing Board sometime in 2014.

Attachment:
Air Quality Improvement Agreement (14 pages)

DW

HYDROGEN ENERGY CALIFORNIA POWER PLANT PROJECT
AIR QUALITY IMPROVEMENT AGREEMENT

This Air Quality Improvement Agreement ("**Agreement**") is entered into this 19th day of August, 2010 by and between Hydrogen Energy California LLC, a Delaware limited liability company ("**HECA**"), and the San Joaquin Valley Air Pollution Control District (the "**District**"). HECA and the District may be referred to individually as a "**Party**" or collectively as the "**Parties.**"

RECITALS

WHEREAS, on May 28, 2009, HECA filed a Revised Application for Certification ("**AFC**") with the California Energy Commission ("**CEC**") for the Hydrogen Energy California Power Plant, for a nominal 390 megawatt facility that will produce baseload, low-carbon electricity by gasifying coal and/or petroleum coke (or, as needed, blends of petroleum coke and other solid fuels) to produce hydrogen for electric generation in an integrated gasification combined cycle plant, and capturing carbon dioxide to be delivered via pipeline for use in enhanced oil recovery and sequestration in the oil fields located in Kern County, California (the "**Project**"). HECA is seekeing approval from the CEC to construct and operate the Project; and

WHEREAS, on June 26, 2009, HECA filed an Application for Authority to Construct (ATC) with the District for the Project. HECA is seeking approval from the District to construct and operate the Project; and

WHEREAS, the Project site will consist of approximately 473 acres, located approximately 7 miles west of the outermost edge of the City of Bakersfield and 1.5 miles northwest of the unincorporated community of Tupman in Western Kern County; and

WHEREAS, the District has determined that the Project, as proposed, complies with all applicable District requirements, including all requirements related to emission offsets and best available control technology (BACT); and

WHEREAS, HECA believes that any and all air quality impacts from the Project will be fully mitigated by the Project's design and incorporated construction and operation mitigation measures, including, but not limited to, diluent injection, the increased capabilities of the Selective Catalytic Reduction ("**SCR**") NOx unit to reduce NOx emissions to or below 4 parts per million (ppm), the implementation of BACT for the type of hydrogen turbines to be used at the HECA Project plant, and HECA's SJVAPCD emission reduction credit ("**ERC**") offset package (which includes NOx ERCs with a ratio of 1.5 for all the physical NOx emissions associated with plant operations at a NOx concentration of 4 ppm); and

WHEREAS, for a period of two (2) years after the Start Date of commercial operations at the HECA Project plant (the "**Initial Demonstration Period**"), HECA proposes to undertake efforts to increase the capabilities of the SCR to further reduce its NOx emissions. As used herein, "**Start Date**" shall mean the date that the plant has completed initial performance testing, completed final plant tuning, and is available for commercial operation. HECA will test and determine the NOx emissions level achieved within two (2) years after the Start Date of commercial operations; and

WHEREAS, notwithstanding that the Project complies with all applicable District requirements, and the District acknowledges that HECA is a first of its kind project and the use of NOx reduction technologies have not been previously demonstrated on hydrogen turbines, the District is concerned about the higher NOx emissions this Project will have during the Initial Demonstration Period versus the 2 ppm NOx emissions level consistent with certain types of natural gas turbines; and

WHEREAS, HECA desires to cooperate with the District to address the District's air quality concerns by entering into this Agreement to provide additional air quality benefits, despite being under no legal obligation to do so; and

WHEREAS, the District and HECA have determined that payment of an air quality improvement fee to be used for air quality benefit programs, to the extent feasible, within Kern County, or within the San Joaquin Valley with quantifiable direct or indirect benefits to the air quality of Kern County, is the appropriate method for HECA to address the District's concerns and to ensure additional localized benefits within the District.

NOW THEREFORE, for good and valuable consideration, including the mutual covenants set forth herein, HECA and the District hereby agree as follows:

1. Recitals. All recitals above are incorporated herein by this reference.

2. Air Quality Improvement Fee. Subject to the conditions precedent set forth in Section 2 below, HECA agrees to contribute to the District the total sum of Six Hundred Eighty One Thousand Two Hundred Sixty Two and 31/100 Dollars ($681,262.31), which includes a five percent (5%) administration fee, to ensure localized benefits within the District, and, in particular, direct or indirect benefits in Kern County (the "**Air Quality Improvement Fee**"). An outline of the methodology used to determine the Air Quality Improvement Fee and the calculation of the Air Quality Improvement Fee are attached hereto as Attachment A, incorporated herein by this reference. HECA agrees to pay the Air Quality Improvement Fee to the District within thirty (30) days after the physical delivery of the first hydrogen combustion turbine to the Project site. If HECA ceases to be the owner of the Project and a new owner of the Project has made the payment contemplated in this Agreement to the District, then HECA shall be relieved of any further obligations under this Agreement.

3. Conditions Precedent. The Parties acknowledge and agree that HECA's obligation to pay the Air Quality Improvement Fee shall be subject to the fulfillment or waiver (such waiver to be in HECA's sole discretion) of both of the following conditions precedent:

   (a) Issuance of the final CEC certification for the Project; and

   (b) Commencement of commercial operations of the Project.

Notwithstanding the above, if the AFC with the CEC has been terminated, withdrawn or denied, or if the Project is certified but not constructed during the term of the CEC's certification, then this Agreement shall automatically terminate, and neither Party shall have any further obligations hereunder.

4. Use of Air Quality Improvement Fee. The District agrees to set up a specific account into which the Air Quality Improvement Fee will be deposited.

The District agrees to use the Air Quality Improvement Fee exclusively to establish specific programs that create real time air quality benefits within the District. HECA will work with SJVAPCD to identify the most effective and appropriate programs, in particular HECA will work with the District to establish that:

- programs selected to receive funding will focus on replacing agricultural equipment, including old tractors and old haul trucks operating, to the extent possible, within the San Joaquin Valley portion of Kern County, or within nearby communities in the San Joaquin Valley with quantifiable direct or indirect benefits to the air quality of Kern County,

- assurance is provided that the equipment replaced through the use of funds is in regular use and not already idled,

- opportunities to participate in programs are provided to smaller users that regularly use high emitting equipment,

- programs selected to receive funding will benefit, to the extent possible, the San Joaquin Valley portion of Kern County to ensure emissions reductions occur locally, and

- programs selected to receive funding will also, in general, reduce other criteria pollutants and green house gases (GHGs) at the same time as reducing NOx emissions.

The District agrees to share with HECA the data regarding the actual NOx (and GHGs and other criteria pollutants) emission reduction volumes achieved through the Air Quality Improvement Fee funded programs. HECA's obligations hereunder shall remain as set forth herein regardless of the level of emission reductions achieved.

Except for the administrative fee portion of the Air Quality Improvement Fee, the District agrees not to place the Air Quality Improvement Fee (excluding administrative fees) into any operating account, or to use the Air Quality Improvement Fee for any purpose other than those designated in this Agreement.

5. Fee Payment; Agreements. The District acknowledges and agrees that payment of the Air Quality Improvement Fee pursuant to this Agreement is the appropriate method for HECA to address the District's desires relating to emissions of pollutants from the Project during the Initial Demonstration Period and to ensure localized benefits within the District, and that, other than necessary compliance with applicable District, state and federal regulations, except as set forth in Section 6, the payment of such Air Quality Improvement Fee is the only action requested by the District in connection with the development, construction, operation and maintenance of the Project. Further, the District acknowledges and agrees that HECA believes that, notwithstanding this Agreement, any and all air quality impacts from the Project have been

fully mitigated by HECA's original ERC offset package and that nothing in this Agreement can or should be interpreted as an admission by HECA to the contrary.

6. HECA's Demonstration Required. The Parties agree that HECA will be required to demonstrate NOx emissions from the hydrogen turbines at the HECA Project plant. The actual NOx emissions level demonstrated shall be referred to herein as, the "**Demonstration Level**". HECA shall submit its proposed Demonstration Level in a report to the District within 90 days of the end of the Initial Demonstration Period. Such report shall also include all relevant information pertaining to HECA's efforts to control and reduce NOx during the Initial Demonstration Period. The Parties further agree that if the Demonstration Level is at or below the target level of 2 ppm (the "**Target Level**"), then HECA will not be required to take any further action in connection with any NOx emissions requirements. However, despite the fact that HECA will remain in compliance with District requirements (and HECA's SJVAPCD ERC offset package covers NOx emissions at the applicable BACT level of 4 ppm), if the Demonstration Level exceeds the Target Level, HECA agrees to an additional voluntary air quality improvement fee payment to address the difference between the Demonstration Level and the Target Level. The one-time payment will be calculated in accordance with the provisions set forth in Attachment B. Such additional voluntary air quality improvement fee payment amount will not exceed the equivalent value of NOx ERCs calculated based on the Equivalent ERC Cost (as defined in Attachment B), and will be due to the District within 60 days of HECA's receipt of District notification of the District's final decision on the Demonstration Level. Such District notification will be made within 120 days of the end of the Initial Demonstration Period.

7. Cooperation. The Parties agree to cooperate with each other with respect to any requests or actions related to this Agreement from the CEC, the Environmental Protection Agency, the California Air Resources Board, and/or any interveners in the Project, and to do or cause all things necessary, proper or advisable to help consummate and make effective the transaction contemplated by this Agreement.

8. U.S. Department of Energy Requirements. The District acknowledges that HECA is subject to oversight by the U.S. Department of Energy ("**DOE**") and is obligated to obtain from contracting parties certain agreements including those set forth on Attachment C hereto. The District hereby agrees to comply with the requirements set forth on Attachment C. Failure to comply with this Section shall be deemed a default by the District under this Agreement. This Section shall survive the expiration or termination of this Agreement. In the event that additional provisions are required by the DOE, the District shall amend this Agreement to add all of the provisions required by the DOE, or if the District refuses to amend this Agreement to add all of the provisions required by the DOE, then either party shall have the right to terminate this Agreement upon five (5) days prior written notice to the other party. This Agreement may be terminated by HECA for District's default as well as for any force majeure events beyond the control of the District.

9. Governing Law. This Agreement shall be governed by, construed under and enforced in accordance with the laws of the State of California.

10. Authority. Each Party acknowledges and agrees that it has the full right, power and authority to execute this Agreement, and to perform its obligations hereunder.

11. Relationship of the Parties. Nothing herein is intended to create or is to be construed as creating a joint venture, partnership, agency or other taxable entity between the Parties. The rights and obligations of the Parties shall be independent of one another and shall be limited to those expressly set forth herein and, except as expressly provided to the contrary, shall not be construed to apply to any affiliate of the Parties.

12. No Third Party Beneficiary. The Parties mutually agree that this Agreement is for their sole benefit and is not intended by them to be, in part or in whole, for the benefit of any third party.

13. Notices. All notices necessary to be given under the terms of this Agreement, except as herein otherwise provided, shall be in writing and shall be communicated by prepaid mail, telegram or facsimile transmission addressed to the respective Parties at the address below or to such other address as respectively designated hereafter in writing from time to time:

To HECA: HYDROGEN ENERGY CALIFORNIA LLC
One World Trade Center, 16th Floor
Long Beach, CA 90831
Attn: Mr. Giorgio Zoia
Phone: (562) 276-1514
Fax: (562) 276-1571

To District: 1990 East Gettysburg Avenue
Fresno, CA 93726-0244
Attn: Mr. David Warner
Phone: (559) 230-5900
Fax: (559) 230-6061

14. Assignment. This Agreement shall be binding upon, and inure to the benefit of, each of the Parties and their respective successors and permitted assigns. No Party shall assign this Agreement or its rights or interests hereunder without the prior written consent of the other Party, such consent not to be unreasonably withheld or delayed. Notwithstanding the above, the Parties agree that HECA may freely assign its rights and duties under this Agreement, without District's prior written consent, to: (a) an affiliate of HECA; (b) a successor-in-interest by merger, consolidation or reorganization; (c) a purchaser or other transferee of the Project; or (d) a lender for purposes of financing the Project.

15. Entire Agreement. This Agreement, together with the Exhibits attached hereto, contains the entire understanding between the Parties with respect to the subject matter herein. This Agreement may not be amended except by an instrument in writing signed by each Party.

16. Joint Effort. The Parties acknowledge and agree that each Party and its counsel have read this Agreement in its entirety, fully understand it, and accept its terms and conditions. Accordingly, the normal rule of construction to the effect that any ambiguities are to be resolved

against the drafting party is not applicable and therefore shall not be employed in the interpretation of this Agreement or any amendment of it.

17. Counterparts. This Agreement may be executed in counterparts (including by facsimile or e-mailed Adobe® portable document format file), all of which shall constitute one document, and that by the signature(s) hereto, the undersigned further agree that facsimile or e-mailed Adobe® portable document format file signatures shall be effective for all purposes.

* * *

IN WITNESS WHEREOF, the Parties hereto have executed this Agreement the day and date first above written.

APPROVED

LEGAL

HYDROGEN ENERGY CALIFORNIA LLC

By:____________________ Dated: 8/5/2010

Jonathan Briggs
President

SAN JOAQUIN VALLEY AIR POLLUTION CONTROL DISTRICT

By:____________________ Dated:____________

Tony Barba,Chair
Governing Board
San Joaquin Valley APCD

Approved:

By:____________________ Dated: 8/10/10

Seyed Sadredin
Executive Officer/Air Pollution Control Officer
San Joaquin Valley Air Pollution Control District

Approved as to Legal Form:

By:____________________ for

Philip M. Jay
District Counsel

Approved as to Accounting Form:

By:____________________

Cindi Hamm,
Director Administrative Services

ATTACHMENT A

Outline of Methodology and Calculation for Determining the Air Quality Improvement Fee (During the Initial Demonstration Period)

1. **Summary.** Despite the fact that HECA will remain in compliance with District requirements (and HECA's SJVAPCD ERC offset package covers NOx emissions at the applicable BACT level of 4 ppm), in order to further offset NOx emissions during the Initial Demonstration Period, HECA proposes to fund certain air quality improvement programs through the payment of a voluntary Air Quality Improvement Fee.

2. **Methodology and Calculations.** The following calculation was used to determine the amount of the Air Quality Improvement Fee:
   a. **Initial Assumptions and Calculations:**
      i. The HECA Project plant will have approximately 168t/y* of NOx emissions, if operating on the following assumptions (collectively, "**Assumption A**"):
         1. Hydrogen turbines operating at the pertinent BACT level of 4ppm NOx emissions; and
         2. An approximate net power output of 250MW (note that although the actual power output is approximately 400MW, a portion of such actual power output will be used to reduce GHG emissions).

         Note: 168t/y reflects HECA's total actual combustion turbine generator ("CTG") and heat recovery steam generator ("HRSG") NOx emissions as per the April 2010 Permit Application revision.
      ii. A hypothetical natural gas plant will have approximately 52.5t/y** of NOx emissions, if operating on the following assumptions (collectively, "**Assumption B**"):
         1. No reduction of GHG emissions from the plant;
         2. Natural gas turbines operating at 2ppm NOx emissions;
         3. An approximate actual power output of 250MW, including negligible internal parasitic load; and
         4. NOx emissions of 52.5t/y**, which is calculated by scaling emissions level based on Assumption A to emissions level based on Assumption B:

            168t/y x (2ppm / 4ppm) x (250MW / 400MW) = **52.5t/y****

Note that:

If 168t/y* results from 4ppm at 400MW,

then 52.5t/y** results from 2ppm at 250MW.

*****Note: This analysis is approximate and greatly simplified for the sole purpose of calculating a basis for the voluntary improvement fee. Furthermore, this analysis should not be construed in any way as a comparison of technologies. Such comparative analysis would involve far greater complexity and is beyond the scope of this example.***

b. **Calculation Used to Determine Difference in NOx Emissions between HECA and a Hypothetical Gas Plant Operated Under the Above Assumptions:**

168t/y - 52.5t/y = <u>115.5t/y</u> of NOx.

3. <u>**Determination of Air Quality Improvement Fee (During the Initial Demonstration Period)**</u>. In order to calculate the Air Quality Improvement Fee to be paid by HECA during the Initial Demonstration Period, the current Equivalent ERC Cost analysis will be used to determine the amount of investment theoretically required to mitigate 115.5t/y of NOx emissions during the Initial Demonstration Period:
    a. **The current Equivalent ERC Cost analysis is based on the following assumptions:**
        i. An effective life of ERCs associated with a power plant life of 20 years;
        ii. Two (2) years of mitigation; and
        iii. Weighted average reported cost, as calculated by the District, of purchasing NOx credits in the District in 2009 of $56,175/(t/y). This is calculated by totaling the individual purchase prices (in dollars) and dividing by the sum of the ERC purchased (in t/y). The report of all ERC transactions in 2009 is available at <u>www.valleyair.org/busind/pto/erc/ERCCost2009.pdf</u>.
    b. **Based on the foregoing assumptions, the Air Quality Improvement Fee (not including any administrative fees) will be:**

        (115.5t/y x $56,175 / (t/y)) x (2 years / 20 years) = **$648,821.25**
    c. **A 5% administration fee of $32,441.06 will be paid to the District:**

        $648,821.25 x .05 = **$32,441.06**
    d. **The total Air Quality Improvement Fee (including the 5% administrative fee) will be:**

        $648,821.25 + $32,441.06 = **$681,262.31**

ATTACHMENT B

Outline of Methodology and Calculation for Determining the Air Quality Improvement Fee (After the Initial Demonstration Period)

1. **Summary.** Despite the fact that HECA will remain in compliance with District requirements (and HECA's SJVAPCD ERC offset package covers NOx emissions at the applicable BACT level of 4 ppm), if the Demonstration Level exceeds the Target Level after the Initial Demonstration Period, then, in order to further offset NOx emissions after the Initial Demonstration Period, HECA proposes to fund certain air quality improvement programs through the one-time payment of an additional voluntary fee based on the difference between the Demonstration Level and the Target Level (which difference shall herein be referred to as "[Y]t/y" ***).

   ******[Y]t/y = t/y at the Demonstration Level – t/y at the Target Level.***

2. **Methodology and Calculations.** In the foregoing circumstance, the additional fee will be determined as follows:
   a. **Initial Assumptions and Calculations:**
      i. The fee will be based on NOx emissions from the hydrogen turbines in excess of the Target Level.
      ii. Assuming HECA's NOx emissions from the hydrogen turbines at the applicable BACT level of 4ppm to be 168t/y as per the April 2010 Permit Application revision, each 1ppm ABOVE the Target Level will be associated with a certain number of NOx t/y which is calculated as follows:

      t/y / ppm = 168 t/y / 4ppm = 41.94 t/y / ppm.

      iii. For illustrative purposes only, if the Demonstrated Level is:
         1. 2ppm, then: [Y] t/y = 41.94t/y/ppm x 0ppm = 0 t/y
         2. 3ppm, then: [Y] t/y = 41.94t/y/ppm x 1ppm = 41.94 t/y

3. **Determination of Air Quality Improvement Fee (After the Initial Demonstration Period).** In order to calculate the Air Quality Improvement Fee after the Initial demonstration Period, a then-current Equivalent ERC Cost analysis will be used to determine the amount of investment theoretically required to mitigate [Y]t/y of NOx:
   a. **The then-current Equivalent ERC Cost analysis is based on the following:**
      i. Weighted average reported cost, as calculated by the District, of purchasing NOx credits in the District in 2009 of $56,175/(t/y), as detailed in Attachment A.

b. **Based on the foregoing, the Air Quality Improvement Fee (not including any administrative fees) will be:**

   $ = [Y] t/y x $56,175/(t/y) where [Y] t/y is the number calculated as per paragraph 1 and 2.a.iii above.

c. **A 5% administration fee will be added to the foregoing amount.**

ATTACHMENT C

DOE Provisions

1. None of the compensation provided by HECA to the District pursuant to this Agreement shall be expended, directly or indirectly, to influence congressional action on any legislation or appropriation matters pending before Congress, other than to communicate to Members of Congress as described in 18 U.S.C. 1913

2. To the extent required under the American Recovery and Reinvestment Act of 2009, Pub. L. 111-5, any representative of an appropriate inspector general appointed under section 3 or 8G of the Inspector General Act of 1988 (5 U.S.C. App.) or of the Comptroller General is authorized –

a) to examine any records of the contractor or grantee, any of its subcontractors or subgrantees, or any State or local agency administering such contract that pertain to, and involve transactions that relate to, the subcontract, grant, or subgrant; and

b) to interview any officer or employee of the contractor, grantee, subgrantee, or agency regarding such transactions.

3. The requirements of Section 1553 of the American Recovery and Reinvestment Act of 2009, Pub. L. 111-5, including, but not limited to:

a) Prohibition on Reprisals: An employee of any non-Federal employer receiving covered funds under the American Recovery and Reinvestment Act of 2009, Pub. L. 111-5, may not be discharged, demoted, or otherwise discriminated against as a reprisal for disclosing, including a disclosure made in the ordinary course of an employee's duties, to the Accountability and Transparency Board, an inspector general, the Comptroller General, a member of Congress, a State or Federal regulatory or law enforcement agency, a person with supervisory authority over the employee (or other person working for the employer who has the authority to investigate, discover or terminate misconduct), a court or grant jury, the head of a Federal agency, or their representatives information that the employee believes is evidence of:

- gross management of an agency contract or grant relating to covered funds;
- a gross waste of covered funds;
- a substantial and specific danger to public health or safety related to the implementation or use of covered funds;
- an abuse of authority related to the implementation or use of covered funds; or
- as violation of law, rule, or regulation related to an agency contract (including the competition for or negotiation of a contract) or grant, awarded or issued relating to covered funds.

b) Agency Action: Not later than 30 days after receiving an inspector general report of an alleged reprisal, the head of the agency shall determine whether there is sufficient basis to conclude that the non-

Federal employer has subjected the employee to a prohibited reprisal. The agency shall either issue an order denying relief in whole or in part or shall take one or more of the following actions:

- Order the employer to take affirmative action to abate the reprisal.
- Order the employer to reinstate the person to the position that the person held before the reprisal, together with compensation including back pay, compensatory damages, employment benefits, and other terms and conditions of employment that would apply to the person in that position if the reprisal had not been taken.
- Order the employer to pay the employee an amount equal to the aggregate amount of all costs and expenses (including attorneys' fees and expert witnesses' fees) that were reasonably incurred by the employee for or in connection with, bringing the complaint regarding the reprisal, as determined by the head of a court of competent jurisdiction.

c) Nonenforceability of Certain Provisions Waiving Rights and remedies or Requiring Arbitration: Except as provided in a collective bargaining agreement, the rights and remedies provided to aggrieved employees by this section may not be waived by any agreement, policy, form, or condition of employment, including any predispute arbitration agreement. No predispute arbitration agreement shall be valid or enforceable if it requires arbitration of a dispute arising out of this section.

d) Requirement to Post Notice of Rights and Remedies: Any employer receiving covered funds under the American Recovery and Reinvestment Act of 2009, Pub. L. 111-5, shall post notice of the rights and remedies as required therein. (Refer to section 1553 of the American Recovery and Reinvestment Act of 2009, Pub. L. 111-5, www.Recovery.gov, for specific requirements of this section and prescribed language for the notices.).

4. The requirements of 10 CFR 600.21, including, but not limited to:

a) In addition to responsibilities relative to access to records specified in §§600.153 and 600.242, for any negotiated contract or subcontract in excess of $10,000 under a grant or cooperative agreement, DOE, the Comptroller General of the United States, HECA, or any of their authorized representatives shall have the right of access to any books, documents, papers, or other records of the District or any subcontractor which are pertinent to this Agreement, in order to make audit, examination, excerpts, and copies.

b) The right of access may be exercised for as long as the applicable records are retained by HECA, District, or any subcontractor.

5. The requirements of 10 CFR 600.331, including, but not limited to::

a) If District violates or breaches the terms of this Agreement, then administrative, contractual, or any other legal remedies as may be deemed appropriate by HECA shall be allowed hereunder.

b) Termination rights of HECA are set forth in Section 6 of the Agreement, including the manner by which termination shall be effected and the basis for settlement. In addition, pursuant to Section B, the Agreement may be terminated by HECA for District's default as well as for any Force Majeure events beyond the control of the District.

c) HECA, DOE, the Comptroller General of the United States, or any of their duly authorized representatives, shall have access to any books, documents, papers and records of the District which are directly pertinent to a specific program for the purpose of making audits, examinations, excerpts and transcriptions.

6. The requirements of Appendix B to 10 CFR 600, Subpart D, including, but not limited to:

a) *Equal Employment Opportunity* —Compliance with E.O. 11246 (3 CFR, 1964–1965 Comp., p. 339), "Equal Employment Opportunity," as amended by E.O. 11375 (3 CFR, 1966–1970 Comp., p. 684), "Amending Executive Order 11246 Relating to Equal Employment Opportunity," and as supplemented by regulations at 41 CFR chapter 60, "Office of Federal Contract Compliance Programs, Equal Employment Opportunity, Department of Labor."

b) *Copeland "Anti-Kickback" Act (18 U.S.C. 874 and 40 U.S.C. 276c)* —District is required to be in compliance with the Copeland "Anti-Kickback" Act (18 U.S.C. 874), as supplemented by Department of Labor regulations (29 CFR part 3, "Contractors and Subcontractors on Public Building or Public Work Financed in Whole or in Part by Loans or Grants from the United States"). The Act provides that District must be prohibited from inducing, by any means, any person employed in the construction, completion, or repair of public work, to give up any part of the compensation to which he is otherwise entitled. HECA shall report all suspected or reported violations to the responsible DOE contracting officer.

7. The requirements of Clean Air Act (42 U.S.C. 7401 et seq.) and the Federal Water Pollution Control Act (33 U.S.C. 1251 et seq.), as amended, including, but not limited to:

a) Compliance with all applicable standards, orders or regulations issued pursuant to the Clean Air Act (41 U.S.C. 7401 et seq.) and the Federal Water Pollution control act as amended (33 U.S.C. 1251 et seq.). Violations must be reported to the responsible DOE contracting officer and the Regional Office of the Environmental Protection Agency (EPA).

8. The requirements regarding debarment and suspension in Subpart C of 2 CFR parts 180 and 901.

20. Please indicate whether HECA believes that the Agreement remains binding for the revised HECA project. If no, please explain why not. If yes,

a) Please explain under which conditions the Agreement could be waived.

b) Please provide an inventory of older high-emitting agricultural equipment in the SJVAPCD and in Kern County (including age, expected remaining useful life, horsepower, location) that could be addressed by the Agreement and estimate their annual emissions.

c) Please identify and discuss any other rules, regulations, and agreements that are expected to reduce emissions from such older high-emitting agricultural equipment. Please specify the time frame in which these rules, regulations, and agreements would take effect and discuss their impact.

d) Please explain how the fees were calculated and how they relate to HECA's emissions.

RESPONSE

a. The Voluntary Air Quality Improvement Agreement was based on emissions from the former HECA Project configuration; nonetheless, HECA is committed to working with San Joaquin Valley Air Pollution Control District (SJVAPCD) and mitigating Project emissions.

b. As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1,* docketed on August 22, 2012, the Applicant objects to this Data Request.

c. As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1,* docketed on August 22, 2012, the Applicant objects to this Data Request.

d. The fees were calculated based on the former project configuration, and are no longer applicable to the current Project. However, please refer to Attachments A and B of the Agreement, provided in response to Data Request 19, for an explanation of the fee calculation.

DATA REQUEST

21. The Project has been designed for an operating life of 25 years. (AFC, p. 3-1.) Experience with other power plants has shown that their lifetime is frequently extended far beyond their initial life expectancy with some coal-fired power plants now operating in their 60th or even 70th decade. Would the Applicant be willing to commit to funding additional air quality improvement agreements if the Project would operate longer than its expected lifetime?

RESPONSE

Although we cannot speculate on the Project operating life beyond the 25-year design life, HECA is committed to working with San Joaquin Valley Air Pollution Control District (SJVAPCD) and mitigating Project emissions.

BACKGROUND: BACT ANALYSIS

The AFC in Appendix E provides a best available control technology ("BACT") analysis for the Project, dated April 2012. In May 2012, the Applicant submitted a revised BACT analysis as part of the Application for Authority to Construct to the San Joaquin Valley Air Pollution Control District ("SJVAPCD") and the U.S. Environmental Protection Agency ("EPA"). This revised May 2012 BACT analysis appears to provide additional discussion.[12] The Applicant did not provide a discussion of why the BACT analysis was revised and which revisions were made.

12 See, e.g., May 2012 BACT Analysis, p. 1: "SJVAPCD defines BACT to be…"

DATA REQUEST

22. Please provide a redline strikeout version comparing the two versions of the BACT analysis submitted to the California Energy Commission ("CEC") (April 2012) and to SJVAPCD and EPA (May 2012).

RESPONSE

Changes to content in the best available control technology (BACT) Analysis (non-technical changes) are limited to Section 5.0, Other Permitted IGCC Projects; and Section 6.1, Combustion Turbine Generator/Heat Recovery Steam Generator (CTG/HRSG) BACT Analysis. These changes primarily add detail to the discussion. Some changes were made to other IGCC projects in Tables 6-1 through 6-6. No information regarding the HECA Project was changed in these comparison tables.

A redline strikeout version of the document showing these changes is provided as Attachment 22-1, Criteria Pollutant BACT Analysis Comparison.

ATTACHMENT 22-1
BACT ANALYSIS COMPARISON

Note: Tracked changes indicate differences between draft version dated April 2012 submitted to CEC as Appendix E-11 of the Amended AFC and the version dated May 2012 submitted to SJVAPCD and USEPA.

BEST AVAILABLE CONTROL TECHNOLOGY (BACT) ANALYSIS
HYDROGEN ENERGY CALIFORNIA PROJECT
KERN COUNTY, CALIFORNIA

Prepared For:

San Joaquin Valley Air Pollution Control District
California Energy Commission
U.S. Environmental Protection Agency Region IX

Prepared on behalf of

Hydrogen Energy California LLC

~~April~~ May 2012

URS

Second, the Project intends to generate hydrogen for the production of electricity and nitrogen-based products. Hydrogen is one of the cleanest, purest fuels that can be combusted to generate electricity, especially in regards to GHG emissions. However, hydrogen use for this purpose has not yet been demonstrated in a large-scale application. This Project is revolutionary in the advancement of clean fuel production and electricity generation, as well as reduction of GHGs through low-carbon fuels. The Project will take the revolutionary step of producing clean gaseous hydrogen-rich fuel from some of the most abundant solid fuel resources in the U.S.: petcoke and coal. This hydrogen-rich fuel will be used for both the generation of electricity and production of nitrogen-based products. The production of hydrogen is a key element of the Project.

Third, the Project will demonstrate the capture of over 90 percent of the carbon from the fuel, prior to combustion in the turbines or use in the Manufacturing Complex. The simple combustion of natural gas for electricity generation would not achieve this goal. Likewise, the "gasification" of natural gas would be superfluous. The power generation portion of the Project, which uses syngas with the majority of the carbon removed prior to combustion, results in CO_2 emissions of approximately 400 pounds per megawatt hour (lb/MWh). This is less than half of the CO_2 emissions from a typical natural gas-fired simple cycle combustion turbine of 1,100 lb/MWh and easily complies with U.S. and California's stringent GHG emissions performance standard (EPS) for electricity generation of 1,000 and 1,100 lb/MWh, respectively. The CO_2 that is captured from the syngas will be used for sequestration and EOR in the Elk Hills Oil Field in San Joaquin Valley, California. This sequestration step is significant as a demonstration for the DOE funding, as well as integral to the financial objectives of the Project. The use of EOR to recover local petroleum reserves increases the United States' energy independence.

For all the above reasons, it is clear that the use of natural gas as the primary fuel to the combustion turbine, as the feedstock to the gasification process or raw material for production of nitrogen-based products would not achieve the inherent business purposes of the Project. Hydrogen generated from solid fuels with advanced pollution controls has great promise as a clean source of electricity and nitrogen based products. However, it has not yet been used or demonstrated in large scale application. The Project is an important first step in the advancement of clean fuel production and electricity generation, as well as reduction of GHGs through the use of low-carbon fuels. It is vital to the Project's goals, and to the DOE Clean Coal Project demonstration, that solid petcoke/coal feeds be used to demonstrate that these abundant resources can be used in an environmentally-sensitive manner to generate low-carbon electricity and capture and sequester carbon dioxide to reduce impacts of GHGs, along with the production of nitrogen-based products from a low carbon fuel. The use of natural gas would simply not fulfill these business, project and national energy program purposes and would constitute a substantial redesign of the source.

5.0 OTHER PERMITTED IGCC PROJECTS

The available control options were identified by querying the RBLC database and by consulting available literature on control options for IGCC. Applications and/or permits from a number of other IGCC facilities that have completed the New Source Review process were also reviewed to provide additional reference material for this BACT analysis.

There are currently two existing operational, commercial-sized IGCC facilities in the United States. These were examined for this BACT determination.

- Duke Energy, Wabash River Generating Station, West Terre Haute, Indiana.
- Tampa Electric Company, Polk Power Station, Mulberry, Florida.

Wabash River Generating Station: The Wabash River Coal Gasification Repowering Project includes a gasification island with a General Electric (GE) E-Gas two-stage, oxygen blown gasifier and GE MS 7001FA turbine with HRSG generating 262 MW (net). This facility has been operating since 1995. NO_X emissions are permitted at 25 parts per million by volume, dry basis (ppmvd) at 15 percent oxygen (0.15 pound per million British thermal units [lb/MMBtu]). Steam injection is used to control NO_X. CO emissions are permitted at 15 ppmvd.

Tampa Electric Company – Polk Power Station: The facility includes a GE oxygen-blown gasifier with full heat recovery using both radiant and convective syngas coolers. The GE STAG-107FA power block integrates process syngas, steam, and nitrogen. This IGCC facility has been operating since 1996. NO_X emissions are permitted at 15 ppmvd at 15 percent oxygen (0.055 lb/MMBtu). Nitrogen injection is used to control NO_X. CO emissions are permitted at 14 ppmvd.

The proposed NO_X and CO emissions from the CTG/HRSG at HECA will be significantly lower than currently operating IGCC turbines.

A brief summary of the other recently permitted IGCC plants in the United States and their emissions limits is presented below:

Deleted: in this section. Recently permitted IGCC facilities that will be used for comparison in this BACT analysis are

- Duke Energy, Edwardsport Generating Station
- Christian County Generation (formerly ERORA Group), Taylorville Energy Center
- ERORA Group, Cash Creek Generation Station (CCGS)
- Hyperion Energy Center
- Mississippi Power Company, Kemper IGCC Facility
- Summit Power TCEP, IGCC Power Plant

The air permits, BACT analyses, and additional literature were reviewed for each of these recently permitted IGCC facilities. Each facility is discussed briefly below. The emissions associated with the CTG/HRSG at each facility are listed in Table 6-1 in ppmvd and/or lb/MMBtu, depending upon available data.

Deleted: The facilities that were subject to BACT determinations are listed as such

Duke Energy, Edwardsport Generating Station: Duke Energy Indiana, owner of Edwardsport Generating Station, obtained approval, via Indiana Department of Environmental Management Significant Modification Title V Permit, to install an IGCC facility in Knox County, Indiana. The Title V Significant Modification Permit was issued in January 2008 and is expected to start commercial operation in 2012. The 630 MW (net) IGCC plant will replace four older, less efficient

Deleted: . The Edwardsport Generating Station generating units capable of generating approximately 160 MW at the Edwardsport site. The Edwardsport Generating Station is expected to use coal as feedstock, and SCR as add-on control to minimize NO_X emissions from the plant. The SCR system is being installed on a trial basis to investigate technical feasibility for effective operation in recognition of technical uncertainties posed by SO_2 residuals, ammonia slip, and potential inorganic precipitants. The SCR system is not required to demonstrate compliance with federal or state statutes.

The Edwardsport NO_X, CO and PM_{10} emission rates for both syngas and natural gas are higher than HECA; SO_2 and VOC emissions for syngas are higher and for natural gas are lower.

Christian County Generation* – *Taylorville Energy Center: Christian County Generation LLC is developing the Taylorville Energy Center, a 716 MW (gross) IGCC facility to be located in Christian County, southern Illinois. Taylorville Energy Center obtained a draft Illinois Environmental Protection Agency air permit in October 2011. Final public comments were due December 31, 2011; a final permit has not yet been issued. Commercial operation is expected to start in 2014. Taylorville Energy Center proposed to use Siemens gasification technology and local coals (Illinois coal) as the feedstock. The Taylorville Energy Center will use a Rectisol® acid gas removal (AGR) system, for syngas cleanup followed by a Methanation Unit in the gasification process to produce Substitute Natural Gas (SNG), which has virtually the same composition as natural gas. Because the SNG is essentially the same as natural gas, the combustion turbine is designed to operate on natural gas. BACT for NO_X will be dry low-NO_X (DLN) burners and SCR.

The technology chosen for the Taylorville Energy Center is significantly different from that proposed for HECA. HECA will burn primarily hydrogen-rich fuel with diffusion burners in the CTG. Taylorville Energy Center has chosen DLN burners to combust natural gas and synthetic natural gas (which has the same composition as natural gas). These are not comparable technologies.

ERORA Group – Cash Creek Generation Station: The ERORA Group is developing the CCGS IGCC facility, to be located near Owensboro, Henderson County, Kentucky. CCGS obtained a final Kentucky DAQ air permit in January 2008 and is expected to start commercial operation in 2012. The 770 MW (gross) IGCC proposes to use GE Energy gasification technology and local coals (Kentucky coal) as the feedstock. The CCGS will use a Selexol® AGR system to clean up the syngas. CCGS will use SCR to minimize NO_X emissions from the plant; this will allow them to minimize the cost to acquire NO_X allowances from the market, although SCR is not required for BACT purposes. ERORA notes that in order to increase the chance that the SCR system will work in this unproven application on coal-derived syngas, higher sulfur removal will be required, and can be achieved by using Selexol® instead of methyldiethanol-amine (MDEA).

The CCGS emission rates for all pollutants for both syngas and natural gas are higher than HECA.

Deleted: 630

Deleted: .

Deleted: Since

Deleted: Cash Creek Generation Station

Deleted: Cash Creek Generation Station

Deleted: 630

Deleted: Cash Creek Generation Station

Deleted: systems, as well as SCR. Because

Deleted: proposed facility site is in an ozone attainment area, SCR is not required for BACT purposes. ERORA is using

Deleted: , but not as BACT. This

Deleted: .

Deleted: ,

Deleted:), will be required.

Hyperion Energy Center: The South Dakota Department of Environmental and Natural Resources issued a PSD permit for the Hyperion Energy Center on August 20, 2009, and a revised PSD permit in September 2011. The facility will consist of a greenfield petroleum refinery and an IGCC plant, to be located in Union County, South Dakota. The IGCC plant will use petroleum coke as primary feedstock, and is designed to provide the refinery with up to 450 million cubic feet per day of hydrogen, 200 MW (net) of electricity, and 2.4 million pounds of steam per hour. The application did not specify the type of combustion turbine to be used. The project can generate up to 532 MW gross from combustion of syngas.

The co-located refinery will not be able to make enough petroleum coke to supply the IGCC, so additional fuel will be imported to make up the energy shortfall. Hyperion was permitted for two mutually exclusive configurations for the power plant. The first configuration, Option 1, is termed the "maximum coke design case," and will use imported solid fuels (coke and/or coal) to meet the energy needs. In this configuration, the combustion turbines will be fired with hydrogen-rich syngas in the diffusion burners, and the HRSGs will be fired with both syngas and tailgas from the plant's pressure swing absorption (PSA) process (which is part of its process for generating hydrogen for use by the refinery processes) and ultra-low sulfur distillate as a backup fuel. For NO_X control, the use of low-NO_X duct burners, diluent injection, and SCR was determined to be BACT for Option 1 when combusting syngas.

The second configuration, Option 2, is termed the "natural gas design case." In this configuration, the turbines will be fired with natural gas as the primary fuel, and ultra-low sulfur distillate as a backup fuel. The HRSGs will be fired with natural gas and PSA tailgas. For NO_X control, the use of low-NO_X duct burners, DLN combustion burners, and SCR was determined to be BACT for Option 2 combusting natural gas. This configuration (using no syngas fuel in the turbine) is fundamentally different from HECA's proposed turbine operation, because Hyperion will use DLN burners in the turbine. Therefore, we have not used this configuration in our comparison, but instead focused our comparison on the Hyperion "maximum coke design case," which is more similar to the HECA Project.

These two options are mutually exclusive turbine configurations: one or the other will be selected, not a combination of the two. Thus, only Option 1 will be compared to the technologies chosen for the HECA Project.

For Option 1, the use of low-NO_X duct burners, diluent injection, and SCR was determined to be BACT with NO_X emissions of 3 ppmvd when firing syngas and PSA tailgas, and 6 ppmvd for backup on distillate oil. The Hyperion NO_X emission rate for syngas combustion is higher than HECA.

For SO_2 and particulate, the permitted Hyperion IGCC BACT control technology is syngas sulfur cleanup by physical absorption (Rectisol®). For CO and VOCs, the use of oxidation catalyst and good combustion practice was selected as BACT. These are the same control technologies proposed as BACT by HECA with similar emission rates. It should be noted that some of the pollutant limits for this facility are based on long-term (24-hour and 365-day) rolling averages.

Deleted: Facility

Deleted: heat recovery steam generators

Deleted: tail gas

Deleted: absorber

Deleted: heat recovery steam generators

Deleted: tail gas.

Deleted: than

Deleted: HECA's

Deleted: For NO_X the use of low-NO_X duct burners, diluent injection, and SCR was determined to be BACT for the maximum coke design case.

Deleted: .

Mississippi Power Company, Kemper IGCC Facility: The Mississippi Department of Environmental Quality issued a final PSD permit for the Kemper IGCC Facility on March 9, 2010. Commercial operation is expected to start in 2014. The facility will be located in Kemper County, Mississippi. The primary fuel for the proposed facility will be syngas derived from lignite coal. Natural gas will be used as a secondary fuel. The facility will use Siemens 5000F turbines, and generate a 582 MW of electric power.

Deleted: nominal

Deleted: net

For NO_X, BACT was determined to be the use of good combustion and operating practices for a diffusion flame combustion turbine when using syngas. BACT when using natural gas was determined to be the use of steam or water injection in conjunction with the use of SCR. (Note: SCR was not required when firing syngas because of the project's use of lignite coal and an oxygen-blown gasifier. When using syngas fuel, the permit does not require ammonia to be added to the SCR, allowing the exhaust gas to pass through the system without forming ammonium sulfates.) The Kemper NO_X emission rate for syngas combustion is higher than HECA; and for natural gas, combustion is the same as HECA.

Deleted: allows

Deleted: not

For CO and VOC, the use of good combustion practice was selected as BACT. (Note: oxidation catalyst was not required.) For SO_2, use of the Selexol® AGR system was determined to be BACT. For particulate, BACT was determined to be the use of clean fuels and good combustion practices. The Kemper permit does not require as stringent emissions controls as those proposed by HECA.

Summit Texas Clean Energy, LLC (Summit) TCEP, IGCC Power Plant: The Texas Commission on Environmental Quality issued a final PSD permit for Summit's Texas Clean Energy Project (TCEP) IGCC Facility on December 28, 2010. Commercial operation is expected to start in 2015. The facility will be located in Odessa, Ector County, Texas. The primary fuel for the proposed facility will be syngas derived from coal. Natural gas will be used as a secondary fuel. The facility will use Siemens gasifiers fueling a single Siemens 5000F turbine and one steam turbine, and will generate 400 MW (gross) of electric power.

Deleted: a nominal

Deleted: net

For NO_X, combustion control diluent injection and SCR was determined to be BACT. When firing on syngas, diluent injection will provide combustion control; when firing on natural gas, steam injection will provide combustion control. The TCEP NO_X emission limit was set to 15 ppmvd, based on a 1-hour averaging time for both syngas and natural gas. There is also a long-term NO_X limit of 3.5 ppmvd for syngas combustion, and 2.5 ppmvd for natural gas combustion, which is based on a 30-day rolling average. The short-term TCEP NO_X limits for both syngas and natural gas are significantly higher than HECA. The long-term TCEP NO_X limit on syngas is higher than HECA. Although the long-term TCEP limit for natural gas is lower than HECA, HECA will not operate the turbine on natural gas for more than 2 weeks in a given year, so this long-term rate is not comparable.

For CO and VOC, the use of good combustion practice was selected as BACT. For SO_2, use of the clean, low sulfur fuel was determined to be BACT. For particulate, BACT was determined to be the use of clean fuels and good combustion practices. It should be noted that some of the emission limits for this facility (for both syngas and natural gas) are based on 30-day rolling averages. The TCEP emission rates for all other pollutants for both syngas and natural gas are higher than HECA, except that VOC is lower than HECA for natural gas.

Deleted: NO_X

6.0 SOURCE-SPECIFIC BACT ANALYSIS

The following BACT analysis evaluates control technologies applicable to each of the criteria pollutants that would be emitted from the HECA Project to determine appropriate BACT emission limits. This BACT analysis is based on the current state of IGCC and nitrogen-based product production technology, energy and environmental factors, current expected economics, energy, and technical feasibility.

6.1 CTG/HRSG BACT Analysis

The following is the BACT analysis for the proposed combustion turbine. The proposed combustion turbine will be a Mitsubishi Heavy Industries (MHI) 501 GAC® model turbine with a gross capacity of approximately 405 MW. The MHI 501 GAC® is a new turbine model designed to optimally use hydrogen-rich fuel and natural gas as a backup fuel, and includes changes to the fuel system, combustion system, and hot gas path. The use of hydrogen-rich fuel requires the use of a diffusion-type combustor, because the high concentration of hydrogen precludes the use of DLN combustor technology. HECA selected Rectisol® as the syngas cleanup control technology to remove sulfur dioxide and other impurities from the hydrogen-rich fuel stream before entering the CTG/HRSG.

The air permits, BACT analyses, and additional literature for each of the recently permitted IGCC facilities discussed in the last section were reviewed. Table 6-1 summarizes the criteria pollutant emission levels permitted for the combustion turbine units at each facility. This table also shows the proposed BACT limits for the HECA Project as a comparison.

6.1.1 Nitrogen Oxides BACT Analysis for the CTG/HRSG

The criteria pollutant NO_X is primarily formed in combustion processes via the reaction of elemental nitrogen and oxygen in the combustion air (thermal NO_X), and the oxidation of nitrogen contained in the fuel (fuel NO_X). The hydrogen-rich fuel produced in the Project contains negligible amounts of fuel-bound nitrogen; therefore, it is expected that essentially all NO_X emissions from the CTG/HRSG will originate as thermal NO_X.

The rate of formation of thermal NO_X in a combustion turbine is a function of residence time, oxygen radicals, and peak flame temperature. Front-end NO_X control techniques are aimed at controlling one or more of these variables during combustion. Examples include dry low-NO_X combustors, flue gas recirculation, and diluent injection (steam, water, or nitrogen). Higher peak flame temperature during combustion may increase thermodynamic efficiency, but it also increases the formation of thermal NO_X. The injection of an inert diluent such as atomized water, steam, or nitrogen into the fuel gas line or the high-temperature region of a combustor flame serves to inhibit thermal NO_X formation by reducing the peak flame temperature.

For the Project's turbine, nitrogen is used as a diluent that reduces thermal NO_X produced when hydrogen-rich fuel is combusted. Water is used as a diluent when natural gas is combusted. This method effectively lowers the fuel heat content, and consequently the combustion temperature, thereby reducing NO_X emissions.

SCR is a technology that achieves post-combustion reduction of NO_X from flue gas within a catalytic reactor. The SCR process involves the injection of ammonia into the exhaust gas stream upstream of a specialized catalyst module to promote the conversion of nitrogen oxides and ammonia to nitrogen and water. SCR will be used when firing hydrogen-rich fuel or natural gas.

The Project selected SCR and diluent injection technology to control NO_X emissions from the CTG/HRSG. This combination of control processes will achieve an NO_X emission rate of 2.5 ppmvd at 15 percent oxygen, based on a 3-hour rolling average, when firing hydrogen-rich fuel; or 4 ppmvd at 15 percent oxygen, based on a 3-hour rolling average, when firing natural gas.

It is necessary to recognize the fundamental differences between natural-gas-fired and hydrogen-rich fuel-fired combustion turbines in evaluating these techniques. Compared to natural gas and substitute natural gas (SNG), hydrogen-rich fuel has a much higher hydrogen content (natural gas is often over 90 percent methane), and a much lower heating value (about 250 Btu/scf for hydrogen-rich fuel versus 1,000 Btu/scf for natural gas). HECA will be fired primarily on hydrogen-rich fuel. The other power plants used for comparison in this analysis are fired on syngas. Plants firing SNG will be discussed, but are not comparable to HECA, because SNG is essentially the same as natural gas.

Deleted: These technologies are considered to be commercially available pollution prevention techniques.

Deleted: vs.

The HECA combined-cycle power-generation unit will primarily combust hydrogen-rich syngas in the combustion turbine, and PSA off-gas plus additional syngas in the duct burners. Certain combustion characteristics of hydrogen-rich syngas, such as flame speed and flame temperature, are substantially different from the more familiar natural gas fuel. Modern combined-cycle units using natural gas typically are equipped with DLN combustors in the combustion turbine. These low-emission burners will typically produce emission levels in the range of 9 to 15 ppmvd NO_X (depending on duct-firing rates) downstream of the duct burners. Thus, a BACT emission limit of 2 ppmvd can be easily achieved with SCR efficiencies of 85 percent or less. The proposed HECA SCR reduction efficiencies significantly exceed the corresponding reduction efficiencies currently needed for a natural-gas–fueled combined-cycle plant to meet the proposed BACT levels.

In the case of hydrogen-rich fuel, natural gas DLN combustors cannot be used, due to the difference in combustion characteristics. Similar-type burners for hydrogen-rich fuel have not been developed. Only diffusion-type combustors are available for this fuel.

HECA requests operation of the combined-cycle unit on natural gas fuel for a limited period of up to 2 weeks per year when the gasifier is unavailable, and during start-up and shut-down. The higher emission rate from combustion of natural gas is caused by the difference in combustion characteristics of natural gas compared to the hydrogen-rich fuel in the diffusion burners.

Table 6-1
Permitted Criteria Pollutant BACT Limits for Combined-Cycle Combustion Turbines at IGCC Facilities

Facility	HECA	Cash Creek Generation Station	Edwardsport Generating Station	Taylorville Energy Center	Hyperion Energy Center	Kemper County IGCC Project	Summit TCEP
Location	Kern County, CA	Henderson County, KY	Knox County, IN	Christian County, IL	Union County, SD	Kemper County, MS	Ector County, TX
Permit Date	Not Yet Permitted	January 2008	June 2007	Public Comment Period on Draft PSD Permit Ended December 31, 2011	September 2011	March 2010	December 2010
Fuel	Hydrogen-based syngas ----- Natural Gas backup	Coal-derived Syngas ----- Natural Gas backup	Coal-derived Syngas ----- Natural Gas backup	Substitute Natural Gas (SNG) and Natural Gas	Petroleum coke-derived Syngas with PSA Tail gas *or* Natural Gas with PSA Tail gas[a] ----- Ultra Low Sulfur Distillate (ULSD) backup	Lignite coal-derived Syngas ----- Natural Gas backup	Coal-derived Syngas ----- Natural Gas backup
MW (gross)	405	770	630 (net)	716	532	582	400
Turbine	MHI 501 GAC®	GE 7FB	GE 7FB	Siemens MHI 501GAC® CT	Not Specified	Siemens 5000F	Siemens 5000F
NO_X	2.5 ppmvd (0.011 lb/MMBtu) hydrogen-rich fuel, 3-hr rolling average; 4.0 ppmvd (0.015 lb/MMBtu) Natural Gas, 3-hr rolling average	5 ppmvd (0.0331 lb/MMBtu) Syngas; 5 ppmvd (0.0246 lb/MMBtu) Natural Gas	5 ppmvd (0.027 lb/MMBtu) Syngas; 0.018 lb/MMBtu Natural Gas	2.0 ppmvd SNG[b] or Natural Gas	3.0 ppmvd (0.018 lb/MMBtu)[c] Syngas/PSA Tailgas; 2.0 ppmvd (0.012 lb/MMBtu)[d] Natural Gas/PSA Tailgas; 6.0 ppmvd ULSD	0.061 lb/MMBtu Syngas (LHV); 0.015 lb/MMBtu Natural Gas (LHV)	15 ppmvd Syngas or Natural Gas, 1-hr average; 3.5 ppmvd (0.014 lb/MMBtu) Syngas, 30-day rolling average; 2.5 ppmvd (0.009 lb/MMBtu) Natural Gas, 30-day rolling average
SO_2	≤ 2 ppmv in undiluted hydrogen-rich fuel; and ≤ 10 ppmv in PSA off-gas (0.0002 lb/MMBtu); 0.75 grains/100 scf of total sulfur Natural Gas (0.002 lb/MMBtu)	3.8 ppmvd (0.0158 lb/MMBtu) Syngas; 0.0006 lb/MMBtu Natural Gas	0.0138 lb/MMBtu Syngas; 0.0006 lb/MMBtu Natural Gas	0.25 grains/100 scf sulfur in SNG or Natural Gas	1.0 ppmv sulfur in Syngas, 0.5 ppmv in PSA Tail gas (0.0005 lb/MMBtu Syngas/PSA Tail gas); 9 ppmv sulfur in Natural Gas; 15.0 ppmw sulfur in ULSD (0.0015 lb/MMBtu)	0.004 lb/MMBtu Syngas; 1.9 lb/hr Natural Gas	10 ppmv sulfur in Syngas (0.006 lb/MMBtu); 2 grains/100 dscf in Natural Gas (0.006 lb/MMBtu)
CO	3 ppmvd (0.008 lb/MMBtu) hydrogen-rich fuel; 5 ppmvd (0.011 lb/MMBtu) Natural Gas	0.0485 lb/MMBtu Syngas; 0.0449 lb/MMBtu Natural Gas	0.0441 lb/MMBtu Syngas; 0.0421 lb/MMBtu Natural Gas	4.3 ppmvd SNG or Natural Gas	3.0 ppmv Syngas/PSA Tailgas/ ULSD; 3.0 ppmv Natural Gas/PSA Tailgas/ULSD	0.031 lb/MMBtu Syngas (LHV); 0.063 lb/MMBtu Natural Gas (LHV)	10 ppmvd (0.02 lb/MMBtu) Syngas; 10 ppmvd (0.02 lb/MMBtu) on Natural Gas
PM_{10}	15 lb/hr (0.008 lb/MMBtu)	76 lb/hr[e] Syngas;	63 lb/hr[e] Syngas;	0.0065 lb/MMBtu SNG or	36.9 lb/hr (0.022 lb/MMBtu)	36 lb/hr[c] Syngas;	0.008 lb/MMBtu Syngas or

Moved down [1]: *1. Identify Control Technologies¶*
The following NO_X control technologies were evaluated for the proposed CTG/HRSG:¶
Combustion Process Controls¶ ... [1]
Deleted: Section Break (Next Page) ... [2]
Deleted: net
Deleted: 630
Deleted: 630 (net)
Deleted: 280[b]
Deleted: ppmc on
Deleted: ppmc…(0.011 lb/MMBtu) on ... [3]
Deleted: ppmc…(0.018 lb/MMBtu)[c] on ... [7]
Deleted: ppmc…(0.014 lb/MMBtu) on ... [10]
Deleted: ppmc…(0.0331 lb/MMBtu) on ... [5]
Deleted: on…Syngas; ... [6]
Deleted: ppmc…(0.012 lb/MMBtu)[d] on ... [8]
Deleted: on …yngas (LHV); ... [9]
Deleted: ppmc…(0.015 lb/MMBtu) on ... [4]
Deleted: on
Deleted: ppmc on SNG
Deleted: ppmc on
Deleted: on
Deleted: ppmc…(0.0158 lb/MMBtu) on ... [11]
Deleted: on
Deleted: on …yngas; ... [12]
Deleted: on
Deleted: on
Deleted: on
Deleted: ppmc…(0.008 lb/MMBtu) on ... [13]
Deleted: on…Syngas; ... [15]
Deleted: on…Syngas; ... [16]
Deleted: on
Deleted: ppmc…(0.02 lb/MMBtu) on ... [18]
Deleted: on …yngas (LHV); ... [17]
Deleted: ppmc…(0.011 lb/MMBtu) on ... [14]
Deleted: on
Deleted: ppmc on
Deleted: hr[e] on
Deleted: hr[e] on
Deleted: on
Deleted: on
Deleted: on

Facility	HECA	Cash Creek Generation Station	Edwardsport Generating Station	Taylorville Energy Center	Hyperion Energy Center	Kemper County IGCC Project	Summit TCEP
	hydrogen-rich fuel or Natural Gas	57 lb/hr[e] Natural Gas	29 lb/hr[e] Natural Gas	Natural Gas	Syngas/PSA Tailgas; 18.4 lb/hr (0.011 lb/MMBtu) Natural Gas/PSA Tailgas; 36.9 lb/hr (0.022 lb/MMBtu) ULSD	0.01 lb/MMBtu Natural Gas (LHV)	Natural Gas
VOC	1 ppmvd (0.0015 lb/MMBtu) hydrogen-rich fuel; 2 ppmvd (0.003 lb/MMBtu) Natural Gas	NA	0.0016 lb/MMBtu Syngas; 0.0016 lb/MMBtu Natural Gas	0.0013 lb/MMBtu SNG or Natural Gas	0.0017 lb/MMBtu Syngas or Natural Gas	0.005 lb/MMBtu Syngas (LHV); 0.008 lb/MMBtu Natural Gas (LHV)	1 ppmvd (0.0012 lb/MMBtu) Syngas; 1 ppmvd (0.0012 lb/MMBtu) Natural Gas

Notes:

[a] Hyperion turbines are designed to operate in one of two configurations. Option 1 is a turbine designed to burn petcoke-derived syngas with PSA tail gas fired only in the duct burner; diluent injection and SCR are proposed. Option 2 is a natural gas-fired turbine with PSA tail gas fired only in the duct burner; DLN control will be included. These two options are mutually exclusive turbine configuration, one or the other will be selected, not a combination of the two.

[b] DLN technology is feasible for substitute natural gas (SNG) – fired turbines. Emission limits are for SNG firing.

[c] The DLN technology is not applied for this limit, because the technology is not feasible for a hydrogen-rich syngas-fired turbine.

[d] Emission limit for separate natural gas turbine option using DLN and SCR (see footnote a).

[e] PM_{10} lb/hr limits have been prorated to HECA-sized turbine in MW for comparison purposes. This is only done in cases where no other limits (such as lb/MMBtu) are provided.

dscf = dry standard cubic foot
HHV = higher heating value
lb/hr = pounds per hour
lb/MMBtu = pounds per million British thermal units
LHV = lower heating value
MW = megawatt
ppmvd = parts per million by volume, dry basis, corrected to 15 percent O_2
ppmv = parts per million by volume
ppmw = parts per million by weight
scf = standard cubic foot

Deleted: on
Deleted: hr[c] on
Deleted: hr[c] on
Deleted: on
Deleted: on
Deleted: on
Deleted: on
Deleted: ppmc
Deleted: ppmc
Deleted: on
Deleted: on
Deleted: on
Deleted: on
Deleted: ppmc
Deleted: on
Deleted: on
Deleted: on
Deleted: ppmc
Deleted: on
Deleted: on
Deleted: on
Deleted: 2
Deleted: .
Deleted: Hyperion
Deleted: defined in permit, except
Deleted: fuel input rate of 1,677 MMBtu/hr (each
Deleted:). The MW size for each of these is prorated from the HECA
Deleted: (405 MW
Deleted: approximately 2,400 MMBtu/hr (HHV)), for an individual turbine size of 280 MW.
Deleted: [c]
Deleted: ppmc

1. Identify Control Technologies

Moved (insertion) [1]

The following NO_X control technologies were evaluated for the proposed CTG/HRSG:

Combustion Process Controls

- Dry Low-NO_X Burner
- Diluent Injection

Post-Combustion Controls

- $SCONO_X$™
- Selective Non-Catalytic Reduction (SNCR)
- Selective Catalytic Reduction (SCR)

2. Evaluate Technical Feasibilities

- Dry Low-NO_X Combustor

DLN combustor technology has been successfully demonstrated to reduce thermal NO_X formation from natural-gas combustion turbines. This is done by designing the combustors to control both the stoichiometry and temperature of combustion by tuning the fuel and air locally within each individual combustor's flame envelope. Combustor design includes features that regulate the aerodynamic distribution and mixing of the fuel and air. A lean, pre-mixed combustor design mixes the fuel and air prior to combustion. This results in a homogeneous air/fuel mixture, which minimizes localized fuel-rich pockets that produce elevated combustion temperatures and higher NO_X emissions. A lean fuel-to-air ratio approaching the lean flammability limit is maintained, and the excess air serves as a heat sink to lower the combustion temperature, which in turn lowers thermal NO_X formation. A pilot flame is used to maintain combustion stability in this fuel-lean environment.

Hydrogen-rich fuel differs from natural gas in heating value, gas composition, and flammability characteristics. Available DLN combustor technologies are designed for natural gas (methane-based) fuels and will not operate on the hydrogen-rich fuel (CO-based) used by an IGCC combustion turbine. DLN combustors are not technically feasible for this application due to the potential for explosion hazard in the combustion section due primarily to the high hydrogen content of the fuel. No manufacturer currently makes DLN combustors that can be used for a combustion turbine fueled by fuels containing significant hydrogen. Thus, DLN combustor is not a technically feasible control option for this unit. [Note that the Hyperion Energy Center has DLN for NO_X BACT for their natural gas design case only. This technology is not combined with the diffusion burner technology (and diluent injection) for the Syngas design case. Therefore, the use of DLN at Hyperion is not comparable to the HECA facility.]

Deleted: syngas or other

Deleted: The more recently constructed natural gas combustion turbines use the latest technology dry low nitrogen oxide (DLN) combustors, which are typically guaranteed to achieve 9 to 15 ppm NO_X in the turbine exhaust gas when operating with natural gas.

The MHI combustion turbine proposed for the HECA Project must use a diffusion combustor, because a DLN or other low-NO_X combustor has not yet been developed for hydrogen-rich fuel, due to its high flame front speed and broad range of combustibility. When hydrogen-rich fuel is unavailable and during start -up/shut -downs, the HECA Project will fire natural gas for very limited periods as a backup fuel. The natural gas must be fired through the same diffusion burner because the MHI turbine does not have the option of a separate natural gas DLN combustor. Thus, the use of DLN combustor is not a technically feasible control option for this unit.

Deleted: During periods when

- Diluent Injection

Higher peak flame temperature during combustion may increase thermodynamic efficiency, but it also increases the formation of thermal NO_X. The injection of an inert diluent such as atomized water, steam, or nitrogen into the high-temperature region of a combustor flame serves to inhibit thermal NO_X formation by reducing the peak flame temperature.

For the Project's CTG/HRSG, nitrogen is used as a diluent that reduces thermal NO_X produced when hydrogen-rich gas is combusted. Steam is used as a diluent when natural gas is combusted. This method effectively lowers the fuel heat content, and consequently, the combustion temperature, thereby reducing NO_X emissions.

A secondary benefit of diluent injection is that it will increase the mass flow of the exhaust. Therefore, the power output per unit of fuel input also increases.

Deleted: *<object><object>*MHI guarantees that diluent injection can achieve turbine exhaust emission levels of 35 ppmvd NO_X (at 15 percent oxygen) over a 3-hour average (excluding start up, shutdown, and upset periods) when firing 100 percent hydrogen-rich fuel. For natural gas combustion and co-firing, MHI guarantees emission levels of 70 ppmvd NO_X (at 15 percent oxygen) from the turbine exhaust. The higher emission rate from combustion of natural gas is caused by the difference in combustion characteristics of natural gas compared to the hydrogen-rich fuel.¶

Diluent injection represents an inherently lower-emitting process for IGCC units, and is a technically feasible control technology. Diluent injection (steam for natural gas and nitrogen for hydrogen-rich fuel) is proposed as the baseline case for the CGT/HRSG combustion turbine NO_X BACT analysis. This NO_X control technology and emission level has also been determined as BACT for all other recent IGCC permits. This NO_X diluent injection control technology has been commercially demonstrated on syngas turbines.

- $SCONO_X$™

The $SCONO_X$™ system is an add-on control device that reduces emissions of multiple pollutants. $SCONO_X$™ uses a single catalyst for the reduction of CO, VOC, and NO_X, which are converted to CO_2, water (H_2O), and nitrogen (N_2).

All installations of the technology have been on small natural gas facilities, and have experienced performance issues. The fact that $SCONO_X$™ has not been applied to large-scale natural gas combustion turbines creates concerns regarding the timing, feasibility, and cost-effectiveness of necessary design improvements. $SCONO_X$™ has also not been applied to syngas (or hydrogen-rich fuel).

In evaluating technical feasibility for large IGCC projects, the additional concerns are:

– $SCONO_X$™ uses a series of dampers to re-route air streams to regenerate the catalyst. The HECA Project is significantly larger than the facilities where $SCONO_X$™ has been used. This would require a significant redesign of the damper system, which raises feasibility concerns regarding reliable mechanical operation of the larger and more numerous dampers that would be required for application to the HECA CTG/HRSG.

– SCONO$_X$™ would not be expected to achieve lower guaranteed NO$_X$ levels than SCR, and, for reasons described above, it has even greater feasibility concerns with respect to application on IGCC turbines than those for SCR.

For the above reasons, SCONO$_X$™ is considered technically infeasible for this unit.

- Selective Non-Catalytic Reduction

Selective non-catalytic reduction is a post-combustion NO$_X$ control technology in which a reagent (ammonia or urea) is injected into the exhaust gases to react chemically with NO$_X$ to form elemental nitrogen and water without the use of a catalyst. The success of this process in reducing NO$_X$ emissions is highly dependent on the ability to achieve uniform mixing of the reagent into the flue gas, which must occur within a narrow flue gas temperature zone (typically from 1,700 to 2,000 degrees Fahrenheit [°F]).

The consequences of operating outside the optimum temperature range are severe. Above the upper end of the temperature range, the reagent will be converted to NO$_X$. Below the lower end of the temperature range, the reagent will not react with the NO$_X$ resulting in very high ammonia slip concentrations (ammonia discharge from the stack).

This technology is occasionally used in conventional fired heaters or boilers upstream of any HRSG or heat recovery unit. SNCR has never been applied in IGCC service, primarily because there are no flue gas locations within the combustion turbine or upstream of the HRSG with the optimal requisite temperature and residence time characteristics to facilitate the SNCR flue gas reactions. Therefore, SNCR is not technically feasible for this unit.

- Selective Catalytic Reduction

Selective Catalytic Reduction (SCR) is a technology that achieves post-combustion reduction of NO$_X$ from flue gas within a catalytic reactor. The SCR process involves the injection of ammonia into the exhaust gas stream upstream of a specialized catalyst module to promote the conversion of NO$_X$ to molecular nitrogen. SCR is a common control technology for use on natural gas–fired combustion turbines.

In the SCR process, ammonia, usually diluted with air or steam, is injected through a grid system into the exhaust gas upstream of the catalyst bed. On the catalyst surface, the ammonia reacts with NO$_X$ to form molecular nitrogen and water. The basic reactions are:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$$

$$8NH_3 + 6NO_2 \rightarrow 7N_2 + 12H_2O$$

The Project selected SCR and diluent injection technology to control NO$_X$ emissions from the CTG/HRSG unit. Anhydrous ammonia is injected into the stack gases upstream of a

Deleted: NH_3

Deleted: NH_3

Deleted: NH_3

Deleted: NH_3

Deleted: NH_3

Deleted: NH_3

Deleted: The SCR system reduces nitrogen oxide emissions from the HRSG stack gases by up to about 92 percent when firing hydrogen-rich fuel.

catalytic system that converts nitrogen oxide and ammonia to nitrogen and water. The SCR system reduces nitrogen oxide emissions from the HRSG stack gases by up to 92 percent when firing hydrogen-rich fuel, and up to 94 percent when firing natural gas. The maximum NO_X reductions that SCRs can typically achieve are 90 to 95 percent. HECA will optimize the SCR system to achieve NO_X reductions of this magnitude.

It is anticipated that this combination of control processes will achieve a NO_X emission limit of 2.5 ppmvd at 15 percent oxygen, based on a 3-hour rolling average, when firing hydrogen-rich fuel, or 4 ppmvd at 15 percent oxygen, based on a 3-hour rolling average, when firing natural gas.

The HECA Project has been designed to use steam injection and SCR for NO_X control when in natural gas service. A comparison with other recent IGCCs using SCR indicate that 4 ppm is an appropriate emission stack concentration for natural gas operation using a diffusion burner. (Note that the Hyperion Project's BACT limit for NO_X on natural gas is slightly lower than this, but uses DLN technology that is not available with syngas-fired turbines. Also, the Summit Project, when combusting natural gas, has a significantly higher short-term NO_X limit of 15 ppm, but a slightly lower long-term [30-day] rolling average limit; this is not comparable to the short-term limit proposed for HECA.) To provide the high level of confidence necessary to meet a 4 ppm permit limit, the HECA Project will plan to achieve very high conversion efficiency in the SCR. Therefore, the HECA LLC believes that the proposed 4 ppm NO_X level is an appropriate BACT level for the HECA Project when burning natural gas and is consistent with other recently permitted IGCCs.

These emission limitations for both hydrogen-rich fuel and natural gas represent a removal efficiency that is better than the approved emissions for recently permitted IGCC units. HRSG vendors confirm the feasibility of achieving these NO_X levels.

3. Rank Control Technologies

Among the control technologies considered in the previous subsection, only one was determined to be both technically feasible and commercially demonstrated at a cost level acceptable as a BACT option. Specifically, the feasible option is diluent injection upstream of the combustion zone.

Although there is no commercial demonstration of SCR performance for an IGCC plant using coal or petcoke feedstock, SCR technology has been proposed as emission limits for many recently permitted IGCC projects; therefore, SCR is determined to be technically feasible. The HECA HRSG vendor confirm that the SCR catalyst will be able to achieve combined NO_X reduction to 2.5 ppmvd at 15 percent oxygen, based on a 3-hour rolling average, when firing hydrogen-rich fuel, and 4 ppmvd at 15 percent oxygen, based on a 3-hour rolling average, when firing natural gas.

4. Evaluate Control Options

The next step in a BACT analysis is to evaluate the feasible control technology. Based on the evaluation in the previous step, the only feasible technologies suitable for establishment of BACT limits are diluent injection and SCR. The principal environmental consideration with respect to implementation of SCR is that, while it will reduce NO_X emissions, it will add ammonia emissions associated with use of ammonia as the reagent chemical. A portion of the unreacted ammonia passes through the catalyst and is emitted from the stack. This is called ammonia slip, and the magnitude of these emissions depends on the catalyst activity and the degree of NO_X control desired. For the Project, the concentration of ammonia slip is limited to 5 ppmvd at 15 percent oxygen.

Deleted: NH_3

Deleted: NH_3

Deleted: NH_3

Table 6-2 shows the typical NO_X BACT determination (when firing hydrogen-rich fuel and natural gas, respectively) and control technology for other recently permitted IGCC projects, in comparison with HECA's proposed NO_X BACT for the CTG/HRSG.

As shown in Table 6-2, the BACT limitation for NO_X emissions from HECA CTG/HRSG is more stringent than the historic BACT determination for other recently permitted IGCC projects.

NSPS 40 CFR 60 Subpart Da is considered as the BACT "floor" for this source category. As shown above, the BACT emission limit proposed for HECA is significantly lower than the applicable NSPS Subpart Da limit of 0.5 lb/MMBtu heat input for gaseous fuel. The proposed NO_X reduction technology is also more stringent than the NSPS Subparts Da recommended minimum reduction efficiency of 25 percent.

5. Select Control Technology

The final step in the top-down BACT analysis process is to select BACT based on the results of the previous steps. As has been explained, for this application of hydrogen-rich fuel-fired combustion turbine within an IGCC facility, diluent injection in the combustion turbine and SCR installation as post-combustion NO_X control are the appropriate control techniques for setting BACT-based emission limits. The BACT selection described above is strongly supported by recent precedents for similar IGCC projects.

The proposed BACT limits based on this technology are 2.5 ppmvd NO_X at 15 percent oxygen for hydrogen-rich–fuel firing, and 4 ppmvd NO_X at 15 percent oxygen for natural-gas firing.

Deleted: O_2

Deleted: O_2

6.1.2 Carbon Monoxide BACT Analysis for the CTG/HRSG

CO is a product of incomplete combustion. Control of CO is typically accomplished by providing adequate fuel residence time and high temperature in the combustion zone to ensure complete combustion. However, these same control factors can increase NO_X emissions. Conversely, lower NO_X emission rates achieved through flame temperature control (by diluent injection) can increase CO emissions for natural gas and un-shifted syngas. Thus, a compromise must be established whereby the flame temperature reduction is set to achieve the lowest NO_X emission rate possible while keeping CO emissions to an acceptable level. However, CO emissions are inherently low for hydrogen-rich fuels that contain very little reduced carbon and are less affected by the conventional trade-off between CO and NO_X.

Table 6-2
NO_X BACT Emission Limit Comparison

Facility	State	MW[a]	Turbine	NO_X BACT Technology	Emission Limit on Syngas		Emission Limit on Natural Gas	
					ppmvd[b]	lb/ MMBtu	ppmvd[b]	lb/ MMBtu
HECA	CA	405	MHI 501 GAC®	SCR	2.5	0.011	4	0.015
Cash Creek Generation Station	KY	770	GE 7FB	SCR	5	0.0331	–	0.0246
Edwardsport Generating Station	IN	630 (net)	GE 7FB	SCR operated in trial mode	5	0.027[c]	–	0.018[c]
Taylorville Energy Center	IL	716	Siemens F Class; SNG fuel	DLN[d] SCR (SNG and natural gas)	2[d]	–	2	–
Hyperion Energy Center	SD	532	Not specified	Diluent Injection and SCR (syngas option) DLN and SCR (natural gas option)[e]	3[f]	0.018	2[g]	0.012
Kemper County IGCC Project	MS	582	Siemens 5000F	GCP and diffusion flame combustion (syngas); Steam/Water Inject and SCR (natural gas)	–	0.061	–	0.015
Summit TCEP	TX	400	Siemens 5000F	Combustion control and SCR	15[h] 3.5[i]	0.014[i]	15[h] 2.5[i]	0.009[i]

Notes:

[a] MW represents gross power unless otherwise noted.

[b] ppmvd = parts per million by volume, dry basis, corrected to 15 percent O_2.

[c] Calculated from mass emissions rate of 57 lb/hr on hydrogen-rich fuel and 38 lb/hr on natural gas.

[d] DLN technology is feasible for substitute natural gas (SNG) – fired turbine. Emission limits are for SNG firing.

[e] For the syngas Option 1, diluent injection and SCR are proposed. DLN control will only be included if Option 2 is chosen, which is a natural gas-fired turbine with PSA tail gas fired only in the duct burner. These two options are mutually exclusive turbine configuration, one or the other will be selected, not a combination of the two.

Deleted: MW
Deleted: ppmc
Deleted: ppmc
Deleted: 630
Deleted: --
Deleted: --
Deleted: 027[a]
Deleted: --
Deleted: 018[a]
Deleted: DLN[b]
Deleted: MHI 501GAC® CT
Deleted: 630 (net)
Deleted: 2[b]
Deleted: --
Deleted: --
Deleted: 280
Deleted: 3[d]
Deleted: 2[e]
Deleted: [c]
Deleted: --
Deleted: --
Deleted: 15[f]
Deleted: 15[f]
Deleted: Diluent Injection
Deleted: 014[g]
Deleted: 009[g]
Deleted: 5[g]
Deleted: 5[g]
Deleted: [b]
Deleted: only
Deleted: [c]

Table 6-2
NO_X BACT Emission Limit Comparison

Facility	State	MW[a]	Turbine	NO_X BACT Technology	Emission Limit on Syngas ppmvd[b]	Emission Limit on Syngas lb/ MMBtu	Emission Limit on Natural Gas ppmvd[b]	Emission Limit on Natural Gas lb/ MMBtu

[f] The DLN technology is not applied for this limit, as the technology is not feasible for a hydrogen-rich syngas-fired turbine.
[g] Emission limit for separate natural gas turbine option using DLN and SCR (see footnote e).
[h] Emission limit based on 1-hour averaging time.
[i] Emission limit based on 30-day averaging time.

DLN = dry low-NO_X burners
GCP = good combustion practice
MMBtu = million British thermal units
MW = megawatt
ppmvd = parts per million by volume, dry basis, corrected to 15 percent O_2
SCR = selective catalytic reduction

1. *Identify Control Technologies*

The following CO control technologies were evaluated for the proposed CTG/HRSG:

Combustion Process Controls

- Good Combustion Practices (GCPs)

Post-Combustion Controls

- $SCONO_X$™
- Oxidation Catalyst

2. *Evaluate Technical Feasibilities*

Good Combustion Practices

Good combustion practices include the use of operational and design elements that optimize the amount and distribution of excess air in the combustion zone to ensure optimum complete combustion. This technology has been determined to be BACT for CO emissions in other operational or recently permitted IGCC projects.

- $SCONO_X$™

  The $SCONO_X$ system was evaluated in the NO_X BACT analysis, and determined to be not technically feasible for this unit.

- Oxidation Catalysts

Deleted: MW
Deleted: ppmc
Deleted: ppmc
Deleted: d
Deleted: e
Deleted: c
Deleted: f
Deleted: g
Deleted: ppmc
Deleted: <object><object>
Deleted: MHI guarantees the turbine exhaust can achieve CO emission levels of 50 ppmvd CO when firing hydrogen-rich fuel, and 40 ppmvd CO when operating on natural gas.¶

Catalytic oxidation is a post-combustion control technology that uses a catalyst to oxidize CO into CO_2. Other operational or recently permitted IGCC projects determined GCPs as the only feasible BACT for CO emissions, with the exception of the Hyperion Energy that is proposing use of an oxidation catalyst to reduce CO emissions to 3 ppm. HECA anticipates CO conversions greater than 90 percent are attainable across the CO catalyst, thus HECA proposed CO emission limits of 3 ppmvd at 15 percent oxygen while firing hydrogen-rich fuel, and 5 ppmvd CO at 15 percent oxygen while firing natural gas.

3. Rank Control Technologies

Oxidation catalyst is the only technically feasible CO control technology identified in addition to Good Combustion Practices.

4. Evaluate Control Options

GCP is considered the baseline and only feasible and commercially demonstrated CO control technology for IGCC combustion turbines. GCP has been selected as BACT for other recent IGCC permits. The Hyperion Energy Center is the only IGCC project to propose use of oxidation catalysts to control CO. In comparison to other operational or recently permitted IGCC projects, this emission limitation represents a removal efficiency that is lower than the emission achieved in practice at currently operating IGCC turbines, and the lowest proposed emission limits for proposed syngas-fired units, including other proposed IGCC turbines.

Table 6-3 shows the typical CO BACT determination (when firing hydrogen-rich fuel and natural gas) and control technology for other recently permitted IGCC projects, in comparison with HECA's proposed CO BACT for the CTG/HRSG.

Table 6-3
CO BACT Emission Limit Comparison

Facility	State	MW[a]	Turbine	CO BACT Technology	Emission Limit on Syngas		Emission Limit on Natural Gas	
					ppmvd	lb/MMBtu	ppmvd	lb/MMBtu
HECA	CA	405	MHI 501 GAC®	Oxidation catalyst and GCP	3	0.008	5	0.011
Cash Creek Generation Station	KY	770	GE 7FB	GCP	–	0.0485	–	0.0449
Edwardsport Generating Station	IN	630 (net)	GE 7FB	GCP	–	0.0441[b]	–	0.0421[b]
Taylorville Energy Center	IL	716	Siemens MHI 501GAC® CT; SNG fuel	GCP	4.3[c]	–	4.3	–
Hyperion	SD	532	Not specified	Oxidation	3	–	3[d]	–

Deleted: .0
Deleted: O_2
Deleted: .0
Deleted: O_2
Deleted: MW
Deleted: ppmc
Deleted: ppmc
Deleted: 630
Deleted: --
Deleted: --
Deleted: --
Deleted: 0441[a]
Deleted: --
Deleted: 0421[a]
Deleted: 630 (net)
Deleted: 3[b]
Deleted: --
Deleted: --
Deleted: 280
Deleted: --
Deleted: 3[c]
Deleted: --

Energy Center				catalyst and GCP				
Kemper County IGCC Project	MS	582	Siemens 5000F	GCP		0.031		0.063
Summit TCEP	TX	400	Siemens 5000F	GCP	10	0.02	10	0.02

Deleted: --

Deleted: --

Notes:

[a] MW represents gross power unless otherwise noted.

[b] Calculated from mass emissions rate of 93 lb/hr on hydrogen-rich fuel and 88.7 lb/hr on natural gas.

[c] Emission limit for substitute natural gas (SNG) – fired turbine; turbines are set up for natural-gas type of firing only.

[d] Emission limit for separate natural gas turbine option set up with CO catalyst and GCP specifically for natural gas use. The natural gas turbine option is a mutually exclusive turbine configuration from the syngas Option 1, only one turbine configuration will be selected, not a combination of the two.

Deleted: [a]

Deleted: [b]

Deleted: [c]

GCP = good combustion practice
lb/MMBtu = pound per million British thermal units
MW = megawatt
ppmvd = parts per million by volume, dry basis, corrected to 15 percent O_2.

Deleted: ppmc

As shown in Table 6-3, the BACT limitation for CO emissions from HECA CTG/HRSG is more stringent than most of the historic BACT determination for other recently permitted IGCC units. This emission limitation represents a removal efficiency that is better than the emission achieved in practice at currently operating IGCC turbines, and equals the lowest proposed emission limits for recently permitted IGCC turbines. The proposed CO emission limit for backup natural gas firing is lower than other similarly operated units. It is slightly higher than the limits proposed for Taylorville and Hyperion; turbines at both of these facilities are designed specifically for natural gas firing as the primary fuel, not as a backup, as is the case for HECA.

5. Select Control Technology

The final step in the top-down BACT analysis process is to select BACT based on the results of the previous steps. As explained, GCPs and oxidation catalyst are the appropriate control technique for setting BACT-based emission limits.

HECA proposed the CO BACT-based limit of 3 ppmvd at 15 percent oxygen while firing hydrogen-rich fuel, and 5 ppmvd CO at 15 percent oxygen while firing natural gas during non-start-up operation, using GCPs and an oxidation catalyst.

Deleted: .0

Deleted: O_2

Deleted: .0

Deleted: O_2

6.1.3 Particulate Matter Emissions BACT Analysis for the CTG/HRSG

Particulate matter emissions from gas-fired combustion sources consist of inert contaminants in gaseous fuel, sulfates from fuel sulfur, ammonia compounds for the SCR reagent, dust drawn in from the ambient air that passes through the combustion turbine inlet air filters, and particles of carbon and hydrocarbons resulting from incomplete combustion. Low ash content and high combustion efficiency exhibit correspondingly low particulate matter emissions for hydrogen-rich fuel.

BEST AVAILABLE CONTROL TECHNOLOGY

1. Identify Control Technologies

The following particulate matter control technologies were evaluated for the proposed CTG/HRSG:

Pre-Combustion Controls

- Gas Cleanup (for hydrogen-rich fuel)

Combustion Process Controls

- Good Combustion Practices

Post-Combustion Controls

- Baghouse
- Electrostatic Precipitation

2. Evaluate Technical Feasibilities

In a typical solid fuel combustion process, fuel particulate matter is removed by post-combustion processes such as fabric filters or electrostatic precipitators. However, in an IGCC plant, particulate matter could damage the turbine, so particulate matter is removed prior to combustion. Post-combustion controls, such as electrostatic precipitators (ESPs) or baghouses, have never been applied to commercial combustion turbines burning gaseous fuels. Therefore, the use of ESPs and baghouses are considered technically infeasible control technology.

In the absence of add-on controls, the most effective control method demonstrated for gas-fired combustion turbines is the use of low-ash fuel, such as natural gas or hydrogen-rich fuel and GCPs. Therefore, it is necessary to use pre-combustion controls such as particulate removal as an integral part of the gasification process, in addition to GCPs.

The use of clean hydrogen-rich fuel and good combustion control is proposed as BACT for PM/PM_{10} control in the proposed HECA CTG/HRSG. These operational controls will limit filterable plus condensable PM/PM_{10} emissions to 15 lb/hr when operating on hydrogen-rich fuel or natural gas.

3. Rank Control Technologies

The use of clean fuels with low potential particulate emissions from optimum gas cleanup processes and GCPs were identified as the only technically feasible particulate emissions control technologies applicable to the proposed combustion turbines.

4. Evaluate Control Options

The USEPA has indicated that particulate matter control devices are not typically installed on combustion turbines and that the cost of installing a particulate matter control device is prohibitive. When the NSPS for Stationary Gas Turbines (40 CFR 60 Subpart GG) was promulgated in 1979, the USEPA acknowledged, "Particulate emissions from stationary gas turbines are minimal." Similarly, the recently revised Subpart GG NSPS (2004) did not impose a particulate emission standard. Therefore, performance standards for particulate matter control of stationary gas turbines have not been proposed or promulgated at a federal level.

Table 6-4 shows the typical PM BACT determination (when firing hydrogen-rich fuel and natural gas) and control technology for other recently permitted IGCC projects, in comparison with HECA's proposed PM BACT for the CTG/HRSG.

Based on the evaluation in the previous step, GCPs and optimum gas cleanup are considered as technically feasible PM/PM_{10} control technologies that are suitable for establishment of BACT limits. As shown in Table 6-4, HECA emission limitation represents a removal efficiency that is cleaner in comparison to other operational or recently permitted IGCC units. Therefore, the BACT limitation for PM emissions from HECA CTG/HRSG is more stringent than the historic BACT determination for other recently permitted IGCC units.

Table 6-4
PM BACT Emission Limit Comparison

Facility	State	MW[a]	Turbine	PM_{10} BACT Technology	Emission Limit on Syngas (lb/hr)	Emission Limit on Natural Gas (lb/hr)
HECA	CA	405	MHI 501 GAC®	Gas Cleanup and GCP	15 (0.008 lb/ MMBtu)	15 (0.008 lb/ MMBtu)
Cash Creek Generation Station	KY	770	GE 7FB	Gas Cleanup and GCP	76[b]	57[b]
Edwardsport Generating Station	IN	630 (net)	GE 7FB	Gas Cleanup and GCP	63[b]	29 [b]
Taylorville Energy Center	IL	716	Siemens MHI 501GAC® CT; SNG fuel	GCP	0.0065 lb/ MMBtu[c]	0.0065 lb/ MMBtu
Hyperion Energy Center	SD	532	Not specified	AGR, Rectisol®	36.9 (0.022 lb/ MMBtu)	18.4 (0.011 lb/ MMBtu)[d]
Kemper County IGCC Project	MS	582	Siemens 5000F	Clean fuels and GCP	36[b]	0.01 lb/MMBtu

Split Cells
Split Cells
Split Cells
Split Cells
Deleted: MW
Split Cells
Deleted: ¶ ... [19]
Deleted: 630
Deleted: 76[a]
Deleted: 57[a]
Deleted: 63[a]
Deleted: [a]
Deleted: 630 (net)
Deleted: MMBtu[b]
Deleted: 280
Deleted: [c]
Deleted: 36[a]

Summit TCEP	TX	400	Siemens 5000F	Clean fuels and GCP	0.008 lb/MMBtu	0.008 lb/ MMBtu

Notes:

[a] MW represents gross power unless otherwise noted.
[b] Emission limits have been prorated to HECA-sized turbine in MW for comparison purposes. This is only done in cases where no other limits (such as lb/MMBtu) are provided.
[c] Emission limit using substitute natural gas (SNG); turbines are set up for natural-gas type firing only.
[d] Emission limit for separate natural gas turbine option specifically for natural gas use.

Deleted: [a]
Deleted: [b]
Deleted: [c]

AGR = acid gas removal
lb/MMBtu = pound per million British thermal unit
MW = megawatt
PM_{10} = particulate matter 10 microns in diameter or less

NSPS 40 CFR 60 Subpart Da is considered as the BACT "floor" for this source category. The BACT emission limits proposed in Table 6-4 are equivalent to 0.006 lb/MMBtu on hydrogen-rich fuel, and 0.006 lb/MMBtu on natural gas. These emission limits are significantly lower than the applicable NSPS Subpart Da limit of 0.03 lb/MMBtu heat input derived from the combustion of solid, liquid, or gaseous fuel.

5. Select Control Technology

The final step in the top-down BACT analysis process is to select BACT based on the results of the previous steps. As explained, GCPs and optimum gas cleanup are the appropriate control technique for setting BACT-based emission limits. The use of optimum gas cleanup to produce clean fuels with low potential particulate emissions and GCPs were selected as LAER for particulate emissions from the proposed combustion turbines. The following emission limit resulting from the implementation of these technologies is proposed for each combustion turbine.

HECA proposed the PM BACT-based limit of 15 lb/hr while firing hydrogen-rich fuel or natural gas, during non-start-up operation, using GCPs and optimum gas cleanup.

6.1.4 Sulfur Dioxide and Sulfuric Acid Mist BACT Analysis for the CTG/HRSG

Sulfur dioxide emissions from any combustion process are largely defined by the sulfur content of the fuel being combusted and the rate of the fuel usage. The combustion of hydrogen-rich fuel in the combustion turbines creates primarily SO_2 and small amounts of sulfite (SO_3) by the oxidation of the fuel sulfur. The SO_3 can react with the moisture in the exhaust to form sulfuric acid mist, or H_2SO_4. Emissions of these sulfur species can be controlled, either by limiting the sulfur content of the fuel (pre-combustion control), or by scrubbing the SO_2 from the exhaust gas (post-combustion control).

1. *Identify Control Technologies*

The following sulfur dioxide and sulfuric acid mist control technologies were evaluated for the proposed CTG/HRSG when operating on hydrogen-rich fuel:

Pre-Combustion Controls

- Chemical Absorption Acid Gas Removal (AGR), e.g., methyldiethanol-amine (MDEA)
- Physical Absorption Acid Gas Removal, e.g., Selexol®, Rectisol®

Post-Combustion Controls

- Flue Gas Desulfurization

The sulfur dioxide BACT for the proposed CTG/HRSG when operating on natural gas is PUC-grade natural gas fuel with less than 0.75 grain/100 scf sulfur content.

2. *Evaluate Technical Feasibilities*

- Acid Gas Removal

  In the gasification process, sulfur in the petcoke or coal feedstock converts primarily to hydrogen sulfide (H_2S). Solvent-based acid gas cleanup is commonly used for "gas sweetening" processes in petroleum refinery fuel gas or tail gas treating units, where H_2S in the process gas is removed before use as a fuel. The removed H_2S is recovered either as elemental sulfur in a Sulfur Recovery Unit (e.g., using a Claus process).

  In a chemical absorption process, acid gases in the sour syngas are removed by chemical reactions with a solvent that is subsequently separated from the gas and regenerated. The chemical absorption occurs in amine-based systems that use solvents such as MDEA. Amine solvents chemically bond with the H_2S. The H_2S can be easily liberated with low-level heat in a stripper to regenerate the solvent. However, amine-based systems such as MDEA are not effective at removing COS and have not demonstrated the deep total sulfur removal levels required by the Project.

  Lower levels of sulfur removal are possible using physical absorption AGR systems. Physical absorption methods, including Selexol® and Rectisol®, use solvents that dissolve acid gases under pressure. Selexol® or Rectisol® are normally applied when low syngas sulfur levels are required for SCR. Solubility of an acid gas is proportional to its partial pressure and is independent of the concentrations of other dissolved gases in the solvent. Consequently, increased operating pressure in an absorption column facilitates separation and removal of an acid gas like H_2S. The dissolved acid gas can then be removed from the solvent, which is regenerated by depressurization in a stripper.

  To selectively remove H_2S and CO_2, two absorption and regeneration columns or two-stage process are required. In general, H_2S is selectively removed in the first column by a lean solvent that has been deeply stripped with steam, while CO_2 is removed from the now H_2S-free gas in the second absorber. The second-stage solvent can be regenerated if very deep CO_2 removal is required. If only bulk CO_2 removal is required, then the flashed gas containing the bulk of the CO, can be vented, and the second regenerator duty can be substantially lowered or totally eliminated.

- Flue Gas Desulfurization

  Flue gas desulfurization (FGD) is a post-combustion SO_2 control technology that reacts an alkaline with SO_2 in the exhaust gas. Typical FGD processes operate by contacting the exhaust gas downstream of the combustion zone with an alkaline slurry or solution that absorbs and subsequently reacts with the acidic SO_2. FGD technologies may be wet, semi-dry, or dry, based on the state of the reagent as it is injected or pumped into the absorber vessel. Also, the reagent may be regenerable (where it is treated and reused) or non-regenerable (all waste streams are de-watered and either discarded or sold). Wet, calcium-based processes that use lime (CaO) or limestone ($CaCO_3$) as the alkaline reagent are the most common FGD systems in PC unit applications. After the exhaust gas has been scrubbed, it is passed through a mist eliminator and discharged through a stack.

  Flue gas desulfurization systems are commonly employed in conventional PC plants, where the concentration of oxidized sulfur species in the exhaust is relatively high. If properly designed and operated, FGD technology can reliably achieve more than 95 percent sulfur removal. However, FGD cannot provide as high a level of control as the pre-combustion AGR systems. In addition, FGD has the environmental drawbacks of substantial water usage and the need to dispose of a solid byproduct (the scrubber sludge). The solid by-product requires the installation of a significant number of ancillary support systems to accommodate treatment, handling, and disposal. Given these disadvantages and the fact that FGD could not achieve the high removal efficiencies associated with AGR, even though FGD is not technically infeasible, it is not considered to be a reasonable technical option for IGCC. Therefore FGD will not be considered further in this BACT analysis

3. Rank Control Technologies

Both chemical and physical absorption methods for AGR are considered feasible for an IGCC, and can achieve control of the sulfur in syngas up to 99 percent or better. Both of these systems are further considered in the BACT analysis.

4. Evaluate Control Options

Physical absorption AGR systems (including Selexol® and Rectisol®) are considered as feasible sulfur dioxide and sulfuric acid mist control technology for the proposed CTG/HRSG turbine. Selexol® has been selected as BACT for several of the recent IGCC permits. Rectisol® was selected for Taylorville Energy Center and the Hyperion Energy Project and has also been widely used in gasification projects in the chemical industry where both deep sulfur removal and CO_2 removal are required. Both Rectisol® and Selexol® are considered viable alternatives to MDEA. However, the Project selected Rectisol® because there are more units operating at similar capacities and similar conditions to those required for the Project, making Rectisol® the more proven alternative.

Table 6-5 shows the typical SO_2 BACT determination (when firing hydrogen-rich fuel and natural gas, respectively) and control technology for other recently permitted IGCC projects, in comparison with HECA's proposed SO_2 BACT for the CTG/HRSG.

As shown in Table 6-5, the BACT limitation for SO_2 emissions from HECA CTG/HRSG when firing hydrogen-rich fuel is similar to the historic BACT determination for other recently permitted IGCC units. This emission limitation represents a removal efficiency that is better than the emission achieved in practice at currently operating IGCC units, and similar to the proposed emission limits compared to recently permitted IGCC units.

NSPS 40 CFR 60 Subpart Da is considered as the BACT "floor" for this source category. The proposed SO_2 emission limits are significantly lower than the applicable NSPS Subpart Da limit of 180 nanograms per joule (1.4 lb/MWh) or 95 percent reduction on a 30-day rolling average.

When firing natural gas, SO_2 emission from CTG/HRSG is slightly higher than other recently permitted IGCC units. The SO_2 BACT for the proposed CTG/HRSG when operating on natural gas is PUC-grade natural gas fuel with less than 0.75 grain/100 scf sulfur content.

Table 6-5
SO_2 BACT Emission Limit Comparison

Facility	State	MW[a]	Turbine	SO_2 BACT Technology	Emission Limit on Syngas		Emission Limit on Natural Gas	
					ppm	lb/MMBtu	ppm	lb/MMBtu
HECA	CA	405	MHI 501 GAC®	AGR, Rectisol®	≤ 2 ppm Sulfur in undiluted Hydrogen-rich fuel ≤ 10 ppm Sulfur in PSA off-gas	0.0002	0.75 grains/ 100 scf	0.002
Cash Creek Generation Station	KY	770	GE 7FB	AGR, Selexol®	3.8[b]	0.0158		0.0006
Edwardsport Generating Station	IN	630 (net)	GE 7FB	AGR, Selexol®		0.0138[c]		0.0006[c]
Taylorville Energy Center	IL	716	Siemens MHI 501GAC® CT; SNG fuel	AGR, Rectisol®	0.25 grains/ 100 scf in SNG		0.25 grains/ 100 scf	

Deleted: MW
Deleted: 630
Deleted: 8[a]
Deleted: 0138[b]
Deleted: 0006[b]
Deleted: 630 (net)
Deleted: --
Deleted: --

Table 6-5
SO_2 BACT Emission Limit Comparison

Facility	State	MW[a]	Turbine	SO_2 BACT Technology	Emission Limit on Syngas		Emission Limit on Natural Gas	
					ppm	lb/MMBtu	ppm	lb/MMBtu
Hyperion Energy Center	SD	532	Not specified	AGR, Rectisol®	1 ppmv Sulfur in syngas[d]; 0.5 ppmv in PSA off-gas	0.0005[d]	9 ppmv	
Kemper County IGCC Project	MS	582	Siemens 5000F	AGR, Selexol®		0.004		1.9 lb/hr
Summit TCEP	TX	400	Siemens 5000F	Low Sulfur fuel	10 ppmv Sulfur in Syngas	0.006	2 grains/ 100 dscf	0.006

Notes:
[a] MW represents gross power unless otherwise noted.
[b] Parts per million by volume, dry basis, corrected to 15 percent O_2.
[c] Calculated from mass emissions rate of 2.9 lb/hr on hydrogen-rich fuel and 1.30 lb/hr on natural gas.
[d] Emission limit based on 24-hr rolling average.

AGR = acid gas removal
dscf = dry standard cubic foot
lb/MMBtu = pounds per million British thermal units
MW = megawatt
ppm = parts per million
ppmv = parts per million by volume
scf = standard cubic foot
SNG = substitute natural gas

Deleted: MW
Deleted: syngas[c];¶
Deleted: 280
Deleted: 0005[c]
Deleted: --
Deleted: --
Deleted: [b]
Deleted: [c]

5. Select Control Technology

The final step in the top-down BACT analysis process is to select BACT based on the results of the previous steps. HECA selected Rectisol® as the syngas cleanup control technology to remove sulfur dioxide from the hydrogen-rich fuel stream entering the CTG/HRSG. The reduction efficiency of Rectisol® is above the NSPS floor requirement, and the overall performance of this technology is more stringent than the historic BACT determination for other recently permitted IGCC units. The following emission limit resulting from the implementation of these technologies is proposed for each combustion turbine.

HECA proposed the SO_2 BACT-based limit of ≤ 2 ppmv sulfur in undiluted hydrogen-rich syngas, ≤ 10 ppmv sulfur in PSA off-gas using an AGR system (Rectisol®) and ≤0.75 grains/ 100 scf of natural gas sulfur content using PUC-grade natural gas. These levels will meet the SJVAPCD BACT guideline 7.2.6 for sulfur recovery plants.

6.1.5 Volatile Organic Compounds BACT Analysis for the CTG/HRSG

VOCs are a product of incomplete combustion of the organic components in the hydrogen-rich fuel. Hydrogen-rich fuel contains very low concentrations of VOC; therefore, emissions of VOC are inherently very low. Reduction of VOC emissions is accomplished by providing adequate fuel residence time and a high temperature in the combustion zone to ensure complete combustion. A survey of the RBLC database indicated that good combustion control and burning clean gas fuel are the VOC control technologies primarily determined to be BACT. The advantage of IGCC technology is the fact that the combustion turbine operates on hydrogen-rich fuel, which contains a very low organic content, and yields very low levels of uncombusted VOC emissions.

1. Identify Control Technologies

The following VOC control technologies were evaluated for the proposed CTG/HRSG:

Combustion Process Controls

- Good Combustion Practices

Post-Combustion Controls

- $SCONO_X$™
- Oxidation Catalyst

2. Evaluate Technical Feasibilities

- Good Combustion Practices

  GCPs include the use of operational and design elements that optimize the amount and distribution of excess air in the combustion zone to ensure optimum complete combustion.

  This technology has been determined to be BACT for VOC emissions in other operational or recently permitted IGCC projects.

- $SCONO_X$™

  The $SCONO_X$ system was evaluated in the NO_X BACT analysis, and determined to be not technically feasible for this unit.

- Oxidation Catalysts

  Catalytic oxidation is a post-combustion control technology that uses a catalyst to oxidize VOC. The catalyst beds that functions to reduce CO emissions can also be effective in reducing VOC emissions. Such systems typically achieve a maximum VOC removal efficiency of up to 50 percent, while providing control for CO.

Other operational or recently permitted IGCC projects determined GCPs as the only feasible BACT for VOC emissions, with the exception of the Hyperion Energy that is proposing use of an oxidation catalyst to reduce VOC emissions. The turbine exhaust will achieve VOC emission levels of 1.0 ppmvd VOC (at 15 percent oxygen) when firing hydrogen-rich fuel, and 2.0 ppmvd VOC (at 15 percent oxygen) when operating on natural gas.

3. Rank Control Technologies

Oxidation catalyst is the only technically feasible VOC control technology identified in addition to GCPs.

4. Evaluate Control Options

GCPs are considered the baseline and the only commercially demonstrated VOC control technology for IGCC combustion turbines. GCP has been selected as BACT for all other recent IGCC permits, with the exception of the Hyperion Energy, that is proposing use of an oxidation catalyst. In comparison to other operational or recently permitted IGCC projects, this emission limitation represents a removal efficiency that is lower than the emissions achieved in practice at currently operating IGCC units, and the lowest proposed emission limits for proposed turbines combusting syngas.

Table 6-6 shows the typical VOC BACT determination (when firing hydrogen-rich fuel and natural gas, respectively) and control technology for other recently permitted IGCC projects, in comparison with HECA's proposed VOC BACT for the CTG/HRSG.

As shown in Table 6-6, the BACT limitation for VOC emissions from HECA CTG/HRSG is comparable to the historic BACT determination for other recently permitted IGCC turbines when firing syngas. This emission limitation represents a removal efficiency that is as good as the emissions proposed in recently permitted syngas turbines.

Table 6-6
VOC BACT Emission Limit Comparison

Facility	State	MW[a]	Turbine	VOC BACT Technology	Emission Limit on Syngas		Emission Limit on Natural Gas	
					ppmvd	lb/MMBtu	ppmvd	lb/MMBtu
HECA	CA	405	MHI 501 GAC®	Oxidation catalyst and GCP	1	0.0015	2	0.003
Cash Creek Generation Station	KY	770	GE 7FB	GCP		N/A		N/A
Edwardsport Generating Station	IN	630 (net)	GE 7FB	GCP		0.0016[b]		0.0016[b]

Deleted: MW
Deleted: ppmc
Deleted: ppmc
Deleted: 630
Deleted: --
Deleted: --
Deleted: --
Deleted: 0016[a]
Deleted: --
Deleted: 0016[a]

Taylorville Energy Center	IL	716	Siemens MHI 501GAC® CT; SNG fuel	GCP		0.0013[c]		0.0013
Hyperion Energy Center	SD	532	Not specified	Oxidation catalyst and GCP		0.0017		0.0017[d]
Kemper County IGCC Project	MS	582	Siemens 5000F	GCP		0.005		0.008
Summit TCEP	TX	400	Siemens 5000F	GCP	1	0.0012	1	0.0012

Notes:
[a] MW represents gross power unless otherwise noted.
[b] Calculated from mass emissions rate of 3.3 lb/hr on hydrogen-rich fuel and natural gas.
[c] Emission limit using substitute natural gas (SNG); turbines are set up for natural-gas type of firing only.
[d] Emission limit for separate natural gas turbine option set up with CO catalyst and GCP specifically for natural gas use. The natural gas turbine option is a mutually exclusive turbine configuration from the syngas Option 1, only one turbine configuration will be selected, not a combination of the two.

GCP = good combustion practice
lb/MMBtu = pound per million British thermal units
MW = megawatt
ppmvd = parts per million by volume, dry basis, corrected to 15 percent O_2.
VOC = volatile organic compound

The proposed VOC emission limit for backup natural gas firing is comparable to other similarly operated units, although it is slightly higher than the limits proposed for Taylorville and Hyperion; turbines at both of these facilities are designed specifically for natural gas firing as the primary fuel, not as a backup, as is the case for HECA. The Summit Project, when combusting natural gas, has a slightly lower long-term average limit than HECA is proposing, although this is not comparable to the short-term limit proposed for HECA.

5. Select Control Technology

The final step in the top-down BACT analysis process is to select BACT based on the results of the previous steps. As explained, GCPs and oxidation catalyst are the appropriate control technique for setting BACT-based emission limits.

HECA proposes the VOC BACT-based limit of 1.0 ppmvd at 15 percent oxygen while firing hydrogen-rich fuel, and 2.0 ppmvd VOC at 15 percent oxygen while firing natural gas during non-start-up operation, using GCPs and oxidation catalyst.

6.1.6 Startup and Shutdown BACT Analysis for the CTG/HRSG

The proposed turbine is a MHI 501 GAC® model turbine with a gross capacity of approximately 405 MW, operating in a combined cycle mode and discharging its exhaust gases through a HRSG. The MHI 501 GAC® turbine is a new turbine model designed for optimum performance on both hydrogen-rich fuel and natural gas and includes changes to the fuel system, combustion system and hot gas path to accommodate this combination of fuels.

Deleted: 630 (net)
Deleted: --
Deleted: 0013[b]
Deleted: --
Deleted: 280
Deleted: --
Deleted: --
Deleted: 0017[c]
Deleted: --
Deleted: --
Deleted: [b]
Deleted: [c]
Deleted: ppmc
Deleted: O_2
Deleted: O_2

DATA REQUEST

23. Please provide any correspondence with the SJVAPCD relating to the Applicant's Authority to Construct for the Project on an ongoing basis.

RESPONSE

Per the Applicant's response to CEC Data Request A22, docketed in August 22, 2012, all correspondence with the SJVAPCD will be docketed with the CEC.

BACKGROUND: EMISSION CALCULATION SPREADSHEETS

The AFC, Appendix E, provides emission estimates for construction and operation of the Project; Appendix M provides emission estimates of TACs and HAPs. These estimates, which do not include any confidential information, are contained in a large number of Excel spreadsheets. The estimates were provided in PDF format which are often nearly illegible when printed due to their small font size. Because calculations often extend over several linked spreadsheets, they are difficult to follow in print as opposed to in electronic format. While most spreadsheets can be re-engineered in electronic format, presuming all assumptions are documented, it is very time-consuming to do so. Further, some calculations cannot be verified because not all information is shown in the printouts.

DATA REQUEST

24. Please provide all Excel spreadsheets used to support the emission estimates in the AFC, Appendices E and M, in their native electronic format and unprotected (i.e., showing formulas), if necessary under confidential cover and/or pass-word protected.[13]

---

13 It is neither unusual nor unreasonable for CEC staff or intervenors to request and for the Applicant to make available Excel spreadsheets containing emission estimates and calculations for health risk assessments. See, for example, the following CEC proceedings:

Victorville 2 Solar Gas-Hybrid Power Project: Construction and operational criteria pollutant and TAC emission estimates were provided on CD as password-protected Excel spreadsheets in response to California Unions for Reliable Energy ("CURE") data requests. See http://www.energy.ca.gov/sitingcases/victorville2/documents/applicant/2007-07-02_APPLICANTS_OBJECTIONS_TO_CURE_DATA_REQUEST_SET_01.PDF and http://www.energy.ca.gov/sitingcases/victorville2/documents/applicant/2007-07-12_RESPONSES_TO_CURE_DATA_REQUEST_SET_01.PDF;

Blythe Solar Power Project: Operational emissions were provided as unprotected Excel spreadsheets in response to CEC staff data requests. See http://www.energy.ca.gov/sitingcases/solar_millennium_blythe/documents/applicant/data_responses_ set_1/Air%20Quality/Air%20Quality%20Supporting%20Documentation/Blythe%20DR%20Operating%20Emissions.xlsx and http:// www.energy.ca.gov/sitingcases/solar_millennium_blythe/documents/applicant/data_responses_set_1/Air%20Quality/Air%20Quality%20Supporting%20Documentation/Blythe%20Data%20Rrespons e%20Emissions.xlsx;

Palen Solar Power Project: Construction and operational emission estimates were provided as unprotected Excel spreadsheets in response to CEC staff data requests. See http://www.energy.ca.gov/sitingcases/solar_millennium_palen/documents/applicant/data_responses_s et_1/Air%20Quality/Air%20Quality%20Supporting%20Documentation/Palen%20DR%20Constructio n%20Emissions.xlsx and http://www.energy.ca.gov/sitingcases/solar_millennium_palen/documents/applicant/data_responses_s et_1/Air%20Quality/Air%20Quality%20Supporting%20Documentation/Palen%20DR%20Operating%20Emissions.xlsx;

Bullard Energy Center: Operational emission estimates were provided as unprotected Excel spreadsheets in response to CEC staff data requests. See http://www.energy.ca.gov/sitingcases/bullard/documents/applicant/DA-response-1/appendix-A/Attachment-7-1.xls and http://www.energy.ca.gov/sitingcases/bullard/documents/applicant/DA-response-1/appendix-A/Attachment-19-1.xls; and

Riverside Energy Resource Center: Estimates for startup, shutdown, maintenance emissions from turbines and emissions estimates for on-road vehicle travel were provide as unprotected Excel spreadsheets in response to CURE data requests. See http://www.energy.ca.gov/sitingcases/riverside/documents/applicants_files/2004-08-10_CURE_DATA_REQ4.PDF and http://www.energy.ca.gov/sitingcases/riverside/documents/applicants_files/cure_set4.

RESPONSE

As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1,* docketed on August 22, 2012, the Applicant objects to this Data Request.

BACKGROUND: CONSTRUCTION TRAFFIC TRAVEL DISTANCES

The AFC, p. 5.1-9, states that trip distances for estimating off-site construction emissions were based on the assumption that workers and delivery trucks are traveling within Kern County. Appendix E-2, p. 35, shows that the AFC assumes off-site roundtrip distances worker commuting vehicles, delivery trucks, and import fill trucks of between 38.0 to 39.8 miles, i.e., it assumes that all vehicles operate only within a radius of less than 20 miles around the Project site. The AFC does not provide any support for these assumptions. A 20-mile roundtrip distance appears unrealistically short for both the construction workforce and the delivery/fill import vehicles and may therefore underestimate emissions associated with vehicle travel.

DATA REQUEST

25. According to the AFC, p. 5.8-15, the average size of the workforce over the approximately 49-month construction and commissioning period would be 1,159 workers (including construction workers and contractor staff); the peak month of construction would require 2,090 craft workers (on site) and 371 contractor staff. It appears unlikely that a sufficiently skilled construction labor force would be available in Kern County within a 20 mile radius of the Project site. Further, based on the 1982 report Socioeconomic Impacts of Power Plants by the Electric Power Research Institute, construction workers will commute as much as 60 miles daily to construction sites from their homes rather than relocate, and considerably further on a weekly basis. This indicates that the construction workforce would likely come from farther than 20 miles from the Project site. Elsewhere, the AFC states that approximately 60 percent of the workforce is expected to be hired from within Kern County but that it is possible that some portion of the labor force will be drawn from Los Angeles County. (AFC, pp. 5.8-3, -16 and -18.) In addition, HECA has recently signed a project labor agreement ("PLA")[14] with the National Building and Construction Trades Department, the State Building and Construction Trades Council of California, and the Kern, Inyo, and Mono Counties Building and Construction Trades Council. Thus, some of the construction workforce may come from Inyo and Mono Counties. The southern border of Mono County is more than 150 miles from the Project site.

- ***a) Please provide a copy of the PLA and/or indicate whether the PLA contains a breakdown for the origin of the construction workforce by county.***
- ***b) Please provide a breakdown of the available construction labor workforce by county.***
- ***c) Please identify typical travel distances for the construction workforce by county.***
- ***d) Please discuss whether you anticipate that construction workers would commute from their residence on a daily or weekly basis or seek lodging closer to the Project site.***
- ***e) Please revise emission estimates for worker vehicle travel during Project construction according to your responses above.***

---

14 Hydrogen Energy California, Announcing Project Labor Agreement for HECA Project, May 31, 2012; http://hydrogenenergycalifornia.com/uncategorized/announcing-project-labor-agreement-for-heca-project.

RESPONSE

a. The Project Labor Agreement (PLA) does not contain a breakdown for the origin of the construction workforce by county.

b. Information about the construction labor-force (for 2010) for Kern and Los Angeles counties is included in Section 5.8, Socioeconomics/Environmental Justice, of the 2012 Amended AFC. No workers were anticipated to be drawn from Inyo or Mono counties. As stated in Section 5.8, Socioeconomics/Environmental Justice, of the 2012 Amended AFC, the Applicant estimated that approximately 60 percent of the construction workforce would be from the Kern County labor force.

c. Table 5.10-6 in the 2012 Amended AFC summarizes the expected origins of construction vehicle travel to the project site.

d. For the purposes of the analysis, as a worst-case scenario, one-quarter of the non-local workers (116 workers, on average) were assumed to relocate to Kern County. The remaining 75 percent (348 workers, on average) of non-local workers would commute on a daily or weekly basis. Section 5.8, Socioeconomics/Environmental Justice, of the 2012 Amended AFC, also included calculation of a “worst-case scenario,” in which an average of 388 workers would stay in local hotels for the construction and commissioning period.

e. No changes to the assumptions regarding worker vehicle travel have been made; therefore, no revisions to emissions estimates are necessary.

DATA REQUEST

26. The AFC, p. 5.8-16, states that an estimated 60 percent of non-labor construction cost is anticipated to be spent within Kern County on materials and supplies. The remaining materials (comprising approximately 40 percent of non-labor cost), including the turbines, would be purchased outside Kern County.

a) Please specify whether the "remaining materials" (comprising approximately 40 percent of non-labor cost) would be transported to Bakersfield via rail and then reloaded onto trucks or whether these materials would be transported to the site via truck from their point of origin.

b) Please identify the quantities and source(s) of fill materials including their distance to the Project site.

c) Please quantify the number of truck trips required to transport materials and fill that would originate outside of Kern County.

d) Please revise emission estimates for off-site delivery/import fill truck travel during Project construction according to your responses above.

RESPONSE

a. The method of material deliveries will depend on where the material are sourced. Items sourced from the eastern USA or Europe will likely come in by rail if they meet rail sizing criteria. As noted in Section 2.7.1.6 of the 2012 Amended AFC, heavy haul items will come in through the Port of Stockton and then be transported to the site via specialty trucks. Shipments from Asia will likely be transported by truck from their ports of entry.

b. As stated on page 5.9-11 of the 2012 Amended AFC, preliminary grading plans indicate that approximately 500,000 cubic yards of soil will be required from off-site sources. It is expected that this fill material would come from Syndex Ready Mix, which is located within a 5-mile radius of the Project Site.

c. It was estimated that during construction, there will be a total of 60 light- and heavy-duty delivery trucks at the site per day transporting materials. Assuming 40 percent of materials and associated truck trips originate outside Kern County, a total of 24 trucks per day would be required from outside Kern County.

d. Revised emission estimates for off-site delivery and import fill truck travel are not necessary, because the Applicant believes the assumptions used are appropriate.

BACKGROUND: EMISSION ESTIMATES FOR FUGITIVE DUST DURING CONSTRUCTION

The estimates for fugitive dust emission from Project construction are based on a number of assumptions that appear to be not representative for the Project site.

DATA REQUEST

27. The AFC, Appendix E-2, p. 40, estimates emissions of fugitive dust particulate matter from paved roads during Project construction based on an equation from U.S. EPA's Compilation of Air Pollutant Emission Factors ("AP-42"), Section 13.2.1, Paved Roads. Fugitive dust emissions from paved roads have been found to vary with the "silt loading" present on the road surface as well as the average weight and speed of vehicles traveling the road. (The higher these values, the higher the estimated emissions.) The AFC uses the default silt loading value for Kern County from URBEMIS 9.2 (urban emissions model) of 0.031 grams per square meter ("g/m2") Use of this default silt loading value underestimates fugitive dust emissions from paved roads. The silt loading default value used in URBEMIS 9.2 applies only to operational traffic associated with a project (contained in module Operational Data), not the construction phase of a project. Re-entrained road dust emissions estimated with URBEMIS 9.2 assume traffic on a variety of public roads and freeways throughout the county and an average vehicle weight representing passenger cars as well as heavier vehicles. Here, during construction, traffic will mostly consist of heavy-duty equipment and trucks and use local roads which experience deposition of soils from agricultural activities and mud/dirt carryout from the construction site and are less frequently traveled. Thus, emissions of fugitive dust are likely substantially underestimated.

a) Would the Applicant be willing to conduct a silt loading study for the roads leading to the Project construction site?

b) Please revise your estimates for fugitive dust emissions from public paved roads based on an appropriate silt loading factor (recommended site-specific value or ubiquitous baseline value of 0.2 g/m2 recommended by EPA for roads with 500-5,000 average daily trips) and appropriate average vehicle weight on the roads accessing the site.

RESPONSE

a. As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1,* docketed on August 22, 2012, the Applicant objects to this Data Request.

b. Over the course of the 49-month construction period, there will be on average approximately 14.7 times more worker vehicles than trucks (light- and heavy-duty delivery trucks plus soil import trucks); therefore, it is appropriate to use parameters based on an average vehicle weight representing passenger cars, as well as heavier vehicles. Heavy-duty construction equipment will remain onsite during the construction period, and does not travel on area paved roads, and thus does not need to be accounted for in paved-road calculations.

In order to control track-out from the delivery trucks on site, a number of measures will be implemented, such as cleaning and inspection of truck tires before leaving the site; unpaved exits from the site will be graveled or stabilized; and sweeping of paved roads onsite. These measures were proposed by the CEC as Conditions of Certification in the August 2010 Preliminary Staff Assessment for the HECA Project, and can be expected to be required again.

Given the anticipated vehicle types and numbers accessing the site, and on-site mitigation measures to reduce track-out, the Applicant believes the silt loading and average vehicle weight factors used to estimate fugitive dust from paved roads are appropriate.

DATA REQUEST

28. The AFC estimates emissions from material handling and bulldozing/earthclearing activities based on 500,000 cubic yards of fill material. Elsewhere, the AFC states that preliminary grading plans indicate that approximately 1.1 million cubic yards of soil would be derived from off-site sources. (AFC, p. 5.9-14.)

a) Please provide the preliminary grading plan for the Project.

b) Please discuss this discrepancy between the amount of fill assumed to estimate fugitive dust emissions from dirt piling and material handling of 500,000 cubic yards and the amount of fill derived from off-site sources of 1.1 million cubic yards indicated by the preliminary grading plan.

c) Please revise your estimates of fugitive dust emissions from material handling and bulldozing/earthclearing activities if indicated.

RESPONSE

a. The preliminary grading plan for the Project is Figure 2-50, Preliminary Grading Plan, in the 2012 Amended AFC.

b. As shown on Figure 2-50, Preliminary Grading Plan, the estimated amount of fill to be imported is approximately 500,000 cubic yards, not 1.1 million cubic yards. Also, on page 5.9-12 of the 2012 Amended AFC, it states "[P]reliminary grading plans indicate that approximately 500,000 cubic yards of soil required for construction will be derived from off-site sources."

It appears that this comment is referring to the 2009 Revised AFC, and not the current 2012 Amended AFC. The 1.1 million cubic yards of fill was from the 2009 Revised AFC.

c. There are no changes related to material handling and bulldozing/earthclearing activities that require revising the estimates of fugitive dust emissions.

DATA REQUEST

29. For estimating fugitive dust emissions from dirt piling or material handling for both the excavated soil (850,000 cubic yards) and imported fill (500,000 cubic yards), the AFC assumes a moisture content of 19% based on the average of soil borings taken at five feet depth. The AFC uses the same moisture content to estimate fugitive dust emissions from bulldozing/earth clearing activities. (AFC, Appx. E-2, p. 36.) The higher the assumed moisture content, the lower the estimated emissions. A moisture content of 19% based on the average of soil borings at five feet does not appear to be a reasonably conservative assumption for the soil handled during these activities for a number of reasons.

RESPONSE

Comment noted. No response provided, since no question was posed.

DATA REQUEST

30. Import fill material, depending on its origin, may have considerably lower moisture content than on-site soils. Please identify the likely origin of the fill material and provide an appropriate moisture content for the 500,000 cubic yards of fill material that would be required. Please document your assumptions.

RESPONSE

Regarding the likely origin of the fill material, see Applicant's response to Data Request 26b.

With respect to the expected moisture content of the fill, the Applicant objected to this Data Request because it is speculative to know what the moisture content might be for a future supply of material.

DATA REQUEST

31. The average soil moisture content at five feet depth is not representative for most soils that will be moved during bulldozing/earth clearing activities on site. Unless these activities occur after sustained rainfalls or the area is wetted first, the moisture content in the surficial soil layers is considerably lower than at five feet and will therefore result in more dust emissions. For example, of the five soil borings that were taken at the Project site, the soil moisture content of the upper two to five feet were indicated once as "dry to slightly moist," twice as dry to moist," and twice as "moist." Further, the soil moisture content is affected by precipitation and irrigation. Review of the soil boring logs indicates that samples were taken in January of 2009 and the use at the time was indicated as agricultural. Thus, due to the time of year and use of the land, these samples may not be representative of the fallow land that would be graded. Please identify an appropriate soil moisture content for the soils at the site.

RESPONSE

As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1,* docketed on August 22, 2012, the Applicant objects to this Data Request.

DATA REQUEST

32. Please revise your estimates of fugitive dust emissions from dirt piling or material handling for both the excavated soil and imported fill based on your responses above.

RESPONSE

Based on Applicant's responses to Data Requests 27 through 31, no revisions to the estimates for fugitive dust emissions from dirt piling or material handling for both excavated soil and imported fills are required.

DATA REQUEST

33. The AFC assumes a control efficiency of 67% for fugitive dust emissions from dirt piling/material handling, grading, bulldozing/earthclearing, storage piles, and truck travel on unpaved roads and 98% for truck travel in soil import areas. (AFC, Appx. E-2, pp. 37-38.)These control efficiencies were derived by combining control efficiencies of two measures, watering and reducing traffic speed to 15 miles per hour ("mph"), for unpaved roads (45% and 40%, respectively) and soil import areas (85% and 70%, respectively) based on control efficiencies established by the South Coast Air Quality Management ("SCAQMD") in their 1993 California Environmental Quality Act ("CEQA") Air Quality Handbook. (AFC, Appx. E-2, p. 37, Footnote 1.) There are a number of problems with the AFC's approach.

First, the information in the SCAQMD's 1993 CEQA Air Quality Handbook relied upon by the AFC has been superseded. The agency is in the process of updating its CEQA guidelines and has published updated fugitive dust emission factors specific for each construction activity and mitigation measure in April of 2007.[15]

Second, the use of a combined control efficiency for dirt piling/material handling and storage piles that accounts for the effects of limiting traffic speed on site is nonsensical.

Third, the equation for grading emissions incorporates the speed of the grader. Here, the AFC assumes a travel speed of 4 mph. Assuming additional control from reducing traffic speed to 15 mph double-counts this measure and, thus, underestimates emissions.

Fourth, the assumption of a 19% soil moisture content inherently assumes control and additional watering would likely turn the site into a mud bath. Assuming additional control through watering double-counts this measure and, thus, underestimates emissions.

Fifth, the AC's assumption of the upper range of the recommended control efficiencies for the areas where soil will be imported because "extra care will be taken to keep the area watered and speeds extremely low" is not reflected in the proposed construction mitigation measures and is therefore unsupported.

---

15 http://www.aqmd.gov/CEQA/handbook/mitigation/fugitive/MM_fugitive.html.

RESPONSE

Comment noted. No response provided, since no question was posed.

DATA REQUEST

34. Please provide a list of control efficiencies for each category of activities taking into account the above discussion. Please justify and document your assumptions.

a) Please revise the proposed mitigation measures for fugitive dust control during construction to account for any assumptions inherent in the assumed control efficiencies.

b) Please revise control efficiencies for fugitive dust emissions from dirt piling/material handling, grading, bulldozing/earthclearing, storage piles, and truck travel on unpaved roads and in soil import areas taking care to avoid double-counting and applying control efficiencies to the applicable source of fugitive dust.

RESPONSE

a. The mitigation measures in the 2012 Amended AFC are those that have been proposed by the Applicant. Ultimately, the required mitigation measures to be implemented and enforced during construction will be determined by the CEC, and included as Conditions of Certification in the Final Staff Assessment.

b. The proposed mitigation measures are believed to be appropriate; as mentioned above, final mitigation measures will be determined by the CEC, and complied with by the Applicant.

DATA REQUEST

35. Please revise your estimates for fugitive dust from dirt piling/material handling, grading, bulldozing/earthclearing, storage piles, and truck travel on unpaved roads and in soil import areas based on revised assumptions and control efficiencies.

RESPONSE

There are no changes to the proposed mitigation measures and control efficiencies that require revised fugitive dust emissions estimates.

BACKGROUND: CONSTRUCTION MITIGATION MEASURES

The AFC, Table 5.1-25, p. 5.1-100, shows that Project construction would contribute substantially to existing exceedances of short-term and annual ambient air quality standards for particulate matter equal to or smaller than 10 micrometers (“PM10”) and 2.5 micrometers (“PM2.5”). To provide mitigation for these impacts, the AFC states that the Project will implement a rigorous mitigation program to minimize fugitive dust and construction equipment exhaust and “will implement all of the SJVAPCD and CEC recommended mitigation measures … to control emissions during the construction phase of the Project from both fugitive dust and equipment combustion exhaust when feasible.” The AFC lists eight mitigation measures for fugitive dust control (AIR-1) and four mitigation measures to control exhaust emissions from the diesel heavy equipment used during construction (AIR-2). (AFC, p. 5.1-57.) These mitigation measures are not sufficient to reduce the Project’s impacts on air quality during construction to the extent feasible, as required by CEQA. Additional mitigation is feasible and should be required.

DATA REQUEST

36. The qualifier “when feasible” in the AFC’s proposed mitigation measures makes them not enforceable. Please indicate whether the Applicant is willing to accept compliance with the proposed mitigation measures without this qualifier.

RESPONSE

As acknowledged in the background discussion above, subject to applicable constitutional limits, the California Environmental Quality Act (CEQA) grants authority to lead agencies to impose *feasible* mitigation measures to lessen or avoid the significant environmental effects of a project. As stated in CEQA Section 21002.1, “[e]ach public agency shall mitigate or avoid the significant effects on the environment of projects that it carries out or approves *whenever it is feasible to do so*” (emphasis added). The authority of agencies to impose mitigation is further addressed in CEQA Guidelines Section 15041(a), which provides that “[a] lead agency for a project has authority to require *feasible* changes in any or all activities involved in the project in order to substantially lessen or avoid significant effects on the environment...” (emphasis added). CEQA defines “feasible” as “capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, social, and technological factors” (CEQA Section 21061.1). Thus, the qualification that certain mitigation measures will be implemented “when feasible” is wholly appropriate and consistent with the requirements of CEQA.

DATA REQUEST

37. Additional mitigation measures are feasible. Please indicate whether the Applicant would be willing to accept the following mitigation measures as conditions of certification.

a) Require a construction mitigation manager.

b) EPA in its scoping comments for the Project recommended a number of mitigation measures that were not incorporated and/or are more stringent than those proposed by the AFC:[16]

i. To reduce emissions of diesel particulate matter, hydrocarbons, and NOx associated with construction activities, EPA recommended the following with regard to all construction-related engines:

- ***Minimize use, trips, and unnecessary idling of heavy equipment.***
- ***Maintain and tune engines per manufacturer's specifications to perform at EPA certification levels, where applicable, and to perform at verified standards applicable to retrofit technologies. Employ periodic, unscheduled inspections to limit unnecessary idling and to ensure that construction equipment is properly maintained, tuned, and modified consistent with established specifications. The California Air Resources Board has a number of mobile source anti-idling requirements which could be employed. See their website at: http://www.arb.ca.gov/msprog/truck-idling/truck-idling.htm.***
- ***Prohibit any tampering with engines and require continuing adherence to manufacturer's recommendations.***
- ***If practicable, lease new, clean equipment meeting the most stringent of applicable Federal or State Standards.***
- ***In general, commit to the best available emissions control technology. Tier 4 engines should be used for project construction equipment to the maximum extent feasible. Lacking availability of non-road construction equipment that meets Tier 4 engine standards, DOE should commit to using the best available emissions control technologies on all equipment.***
- ***Include all available mitigation measures to reduce greenhouse gas emissions.***

---

16 See Kathleen M. Goforth, U.S. Environmental Protection Agency, Region IX, Letter to R. Paul Detwiler, U.S. Department of Energy, National Energy Technology Laboratory, Re: Scoping Comments for the Hydrogen Energy California's Integrated Gasification Combined Cycle Project, Kern County, May 28, 2010; http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/08-AFC-8/others/2010-05-28_US_EPA_Comments_on_SA-DEIS_TN-57034.PDF.

- ***Utilize EPA-registered particulate traps and other appropriate controls where suitable to reduce emissions of diesel particulate matter and other pollutants at the construction site.***

- ***Include control devices to reduce air emissions. The determination of which equipment is suitable for control devices should be made by an independent Licensed Mechanical Engineer. Equipment suitable for control devices may include drilling equipment, generators, compressors, graders, bulldozers, and dump trucks.***

ii. To reduce fugitive dust emissions during construction, the EPA recommended the following measures in addition to the SJVAPCD-recommended mitigation measures:

- ***Stabilize open storage piles and disturbed areas by covering and/or applying water or a non-toxic soil stabilizer or dust palliative where appropriate, to both inactive and active sites, during workdays, weekends, holidays, and windy conditions.***

- ***Install wind fencing and phase grading operations where appropriate, and operate water trucks for surface stabilization under windy conditions.***

- ***When hauling material and operating non-earthmoving equipment, prevent spillage and limit speeds to 15 miles per hour (mph). Limit speed of earth-moving equipment to 10 mph.***

- ***Cover vehicles hauling soil or other loose materials with tarp or other means.***

- ***Sweep adjacent paved streets with water sweepers in the event soil materials are carried onto them.***

- ***Reclaim and revegetate disturbed areas as soon as practicable after completion of activity at each site.***

RESPONSE

a. Yes, an Air Quality Construction Mitigation Manager will likely be required as a Condition of Certification (COC) by the CEC, similar to COC AQ-SC1 in the 2010 CEC Preliminary Staff Assessment (PSA).

b. (i) (1) Yes, this will likely be required, because it was required by COC AQ-SC5(e) in the 2010 CEC PSA.

(2) Yes, this will likely be required, because it was required by COC AQ-SC5(d) in the 2010 CEC PSA.

(3) Yes, the Applicant would be willing to accept this mitigation measure.

(4) Yes, this will likely be required, similar to COC AQ-SC5(b), which requires the use of Tier 3 or higher engines when available.

(5) For most construction equipment, Tier 4 engines are not available. As prescribed by COC AQ-SC5(b), Tier 3 or higher engines will be used when available.

(6) Applicant would agree to the following: Include all practical ~~available~~ mitigation measures to reduce greenhouse gas emissions.

(7) The Applicant would be willing to accept this mitigation measure, although final decisions regarding necessary mitigation measures will be made by the CEC.

(8) The Applicant would be willing to accept this mitigation measure, although final decisions regarding necessary mitigation measures will be made by the CEC.

b. (ii) (1) This mitigation measure is required by SJVAPCD Rule 8031, Bulk Materials, and COC AQ-SC3(l), and the Applicant will comply with all SJVAPCD Rules.

(2) Phased grading operations are required by Regulation 8021, Table 8021-1, A2. Wind barriers are required by Regulation 8021, Table 8021-1, B2, and additional wind erosion control measures related to bulk storage are required in Rule 8031. The Applicant will comply with all SJVAPCD Rules.

(3) Yes, this measure will likely be required, similar to COC AQ-SC3(c) in the 2010 PSA, which limits all vehicles to 10 miles per hour on unpaved surfaces.

(4) Yes, this measure will likely be included, similar to COC AQ-SC3(m) in the 2010 PSA.

(5) Yes, this measure will likely be included, similar to COC AQ-SC3(k) in the 2010 PSA, which requires the Applicant to sweep 500 feet of public paved roads exiting the site.

(6) Yes, Applicant would be willing to accept this mitigation measure.

BACKGROUND: SUPPORT FOR OPERATIONAL EMISSION ESTIMATES

The AFC relies on a number of unsupported assumptions and emission factors for its estimates of Project operational emissions of criteria pollutants and TACs/HAPs. Without adequate documentation, e.g., the underlying vendor guarantees or other information such as stack tests, studies, etc., these assumptions and emission factors are unsupported and the public cannot meaningfully comment on their appropriateness.

DATA REQUEST

38. Please provide support for all assumptions for estimating Project operational emissions, including, but not limited to:

a) Support for molar flow rates for exhaust gases from the heat recovery steam generator ("HRSG"), coal dryer stack, CO_2 vent, and Rectisol flare. (AFC, Appx. E-3, pp. 3-4, 6, and 12-13.)

b) Support for emission factors, pollutant concentrations in exhaust gas, duration of various startup/shutdown phases, and other information "provided by MHI" used to estimate criteria pollutant emissions from the HRSG and coal dryer during normal operations and startup and shutdown. (AFC, Appx. E-3, pp. 3-6.)

c) Support for emission factors for "similar equipment from previous project" used to estimate PM10/PM2.5 and VOC emissions from the auxiliary boiler. (AFC, Appx. E-3, p. 7.)

d) Support for maximum short-term total sulfur content of 12.65 ppmv in pipeline natural gas used for estimating sulfur dioxide ("SO2") emissions from the auxiliary boiler. (AFC, Appx. E-3, p. 7.)

e) Support for emission factors used for estimating nitrogen oxides ("NOx") and carbon monoxide ("CO") emissions from the tail gas thermal oxidizer "based on previous project." (AFC, Appx. E-3, p. 8.)

f) Support for emission factor used for estimating SO2 emissions from the tail gas thermal oxidizer "assuming an allowance of 2 lb/hr SO2 emission to account for sulfur in the various vent streams plus fuel." (AFC, Appx. E-3, p. 8.)

g) The "plant performance study" used to support short term emission rates of from CO_2 vent and support for hydrogen sulfide ("H2S"), carbonyl sulfide ("COS"), CO, and VOC concentrations in vent gas. (AFC, Appx. E-3, p. 10.)

h) Support for emission factors based on "supplier data" used to estimate NOx, CO, and PM10/PM2.5 for flares. (AFC, Appx. E-3, p. 11.)

i) Support for 99% VOC destruction assumed for combustion of typical natural gas in flare. (AFC, Appx. E-3, p. 11.)

j) ***Support for emission factors for flares "Based on Startup/Shutdown Procedures provided by MHI for the PurGen One Project." (AFC, Appx. E-3, p. 12.)***

k) ***Support for 99.6% sulfur removal efficiency for caustic scrubber. (AFC, Appx. E-3, p. 12.)***

l) ***Support for SO2 concentration in vent gas of 50 ppmv used to determine SO2 emissions from the Rectisol flare. (AFC, Appx. E-3, p. 13.)***

m) ***Support for sulfur concentration in pipeline natural gas used to estimate SO2 emissions from the ammonia synthesis plant startup heater. (AFC, p. 20.)***

n) ***Support for emission factors for "similar equipment from previous project" used to estimate PM10/PM2.5 and VOC emissions from the ammonia synthesis plant startup heater. (AFC, p. 20.)***

o) ***The "[t]echnical proposal provided by Urea Casale for the SCS PurGen One project" used to derive NH3 emission factors for the urea HP and LP absorber. (AFC, Appx. E-3, p. 20.)***

p) ***Support for the "[r]eference plant information provided by Sandvik Fellbach for the SCS PurGen One project" used to derive ammonia ("NH3") and urea dust particulate matter emission factors from urea pastillation. (AFC, Appx. E-3, p. 20.)***

q) ***Support for NOx concentration in vent gas of 15 ppmv "based on Uhde EnviNOx system" and 50% NO2/NOx in stack-ratio used for modeling. (AFC, Appx. E-3, p. 20.)***

r) ***Vendor guarantee for PM emission rate used to calculate PM emissions from ammonium nitrate plant. (AFC, Appx. E-3, p. 20.)***

s) ***Support for emission factors and control efficiency for leak detection and repair ("LDAR") program used to estimate fugitive emissions of CO_2, methane ("CH4"), CO, H2S, NH3, COS, methanol ("CH3OH"), propene ("C3H6"), and hydrogen cyanide ("HCN") from various process areas. (AFC, Appx. E-3, p. 23.)***

t) ***Support for emission factors used to estimate TAC/HAP emissions from the combustion turbine generator ("CTG")/HRSG and coal dryer stacks "taken from Wabash River test data and the National Energy Technology Laboratory, U.S. Dept of Energy, Major Environmental Aspects of Gasification-based Power Generation Technologies, Final Report, December 2002. (AFC, Appx. M, p. 2.) Please provide Wabash River test data and identify the source for each emission factor used to calculate TAC/HAP emissions for the Project. Please discuss why Wabash River test data are deemed representative for the Project's CTG/HRSG and coal dryer stack.***

u) ***Support for the assumption that 85% of the HRSG exhaust gas would be exhausted through the HRSG exhaust and 15% through the coal dryer exhaust under normal operations. (AFC, Appx. M, p. 2.)***

v) ***Support for the assumption of 0.09 parts per million by weight ("ppmw") mercury in coal. (AFC, Appx. M, p. 2.)***

w) ***Support for the assumption that 5.5% of the mercury concentration in coal is volatilized. (AFC, Appx. M, p. 2.)***

x) ***Support for the coal dryer mercury control efficiency of 80% and the control efficiency of the mercury cleanup in syngas of 96%. (AFC, Appx. M, p. 2.)***

y) ***Support for emission factors used to estimate arsenic, fluoride, manganese, and selenium emissions from cooling towers based on "average of analytical test results" from "Fruit Growers Laboratory" and "DWR". (AFC, Appx. M, p. 3.) Please provide these analytical test results and discuss why these emissions are deemed representative for the Project.***

z) ***Support for the assumption that copper emissions from the cooling towers would be "one-half of stated detection limit." (AFC, Appx. M, p. 3.)***

aa) ***Support for emission factors used to estimate emissions of ammonia from manufacturing complex based on "reference plant information." (AFC, Appx. M, p. 13.)***

RESPONSE

As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1*, docketed on August 22, 2012, the Applicant is requesting additional time to address this Data Request.

BACKGROUND: EMISSIONS ASSOCIATED WITH RAIL TRANSPORTATION

The diesel-powered rail locomotives that would be used for transporting coal from New Mexico to California and other materials to and from the Project site can have substantial emissions. In addition, the transportation of coal results in losses of coal dust during transportation in uncovered rail cars and fugitive dust emissions from trucks and during loading/unloading activities. The AFC fails to provide adequate information for rail transport and appears to substantially underestimate both sources of emissions, combustion and fugitive dust, associated with coal transportation.

DATA REQUEST

39. The AFC assumes that the Project would use line-haul and switching engines that meet EPA Tier 3 emission standards for new engines to estimate on-site and off-site combustion emissions from locomotives delivering feedstock and products to and from the site or the Wasco transloading facility. (AFC, Appx. E-3, p. 33, and Appx. E-5, p. 4.). Since these locomotives would not be owned or operated by HECA but rather by commercial rail freight carriers, the assumption that all engines would comply with EPA Tier 3 emission standards is unrealistic. Further, the AFC's assumption for the engine size of the on-site switcher locomotive of 260 horsepower appears to be too small.

a) Please identify the rail carrier(s) for each material transported by rail and provide their respective locomotive fleet composition and respective emission factors. Please provide adequate support.

b) Please provide emission estimates based on either the engine fleet(s) operated by the respective rail carrier(s) or based on average fleet average emission factors for locomotives established by EPA in its April 2009 document Emission Factors for Locomotives (EPA-42-F-025).

c) Please provide manufacturer data for the on-site switcher locomotive and confirm the horsepower rating or provide updated emission estimates for

RESPONSE

a. Please refer to the Applicant's response to CEC Data Request A18. The fleet mix of line-haul engines that will be used to move feedstock and products for HECA will meet or exceed U.S. Environmental Protection Agency (USEPA) Tier 2+ or 3. Tier 2+ engines are remanufactured engines that meet the revised 2008 standards, and have the same emission limits as new Tier 3 engines. Currently, the fleet mix of line-haul engines in South Coast Air Quality Management District (SCAQMD) meets these standards; and by 2017, when commercial operation will start, the state mix is expected to meet these standards. HECA will also specify that the rail contractor use engines for the Project that meet these standards.

b. Please see the Applicant's response to CEC Data Request A18 and Attachment A18-1, Revised Appendix E5 Offsite Operational Transportation Emissions, docketed August 22, 2012.

c. Please see the Applicant's response to CEC Data Request A17 and Attachment A17-1, Switching Engine Specifications, docketed August 22, 2012.

DATA REQUEST

40. The AFC, p. 2-22, states that under Alternative 1 (train transportation), the Project site would be equipped with a rail unloading and transfer system and indicates that the transfer conveyor would be fully enclosed. However, it is unclear whether unloading of coal from railcars onto the transfer conveyor would also be fully enclosed.

a) Please discuss railcar unloading at the Project site under Alternative 1 and clarify whether railcar unloading would be fully enclosed. If not, please indicate whether the Applicant would be willing to fully enclose railcar unloading.

b) If railcar unloading would not be fully enclosed, please provide an estimate of fugitive dust emissions from railcar unloading onto the enclosed transfer conveyor.

RESPONSE

a. Rail car unloading will occur within the fully enclosed unloading building, with a negative pressurize dust collection and removal system.

b. Not applicable.

DATA REQUEST

41. The AFC presents onsite and offsite transportation emissions associated with Alternative 1 (train transportation) and Alternative 2 (truck transportation) in Tables 5.1-20 and 5.1-37, and Appendix E-5 and E-12, respectively. These emission estimates do not include offsite material handling emissions, e.g., from transfer of coal from railcars onto trucks at the Wasco transloading facility under Alternative 2. Please estimate these emissions.

RESPONSE

As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1,* docketed on August 22, 2012, the Applicant objects to this Data Request.

DATA REQUEST

42. Coal dust can become airborne in particle sizes smaller than 500 microns and is notoriously hard to control. A thick layer of black coal dust can often be observed along the railroad right-of-way and in between the tracks and frequently dust plumes are seen rising from rail cars. Studies conducted by the Burlington Northern Santa Fe ("BNSF") Railway indicate that each uncovered loaded rail car loses between 500 pounds and a ton of coal dust in transit.[17] Another study on a West Virginia rail line showed loss of coal dust of up to a pound of coal per rail car per mile.[18] This loss occurs throughout the entire transport, as the mechanical fracturing of the coal continuously produces fugitive dust as the coal settles. There are even substantial coal dust emissions on the return trip, as the "empty" cars actually contain a significant quantity of fine particles known as "carry back."[19] Based on this information, coal dust losses for the Project can be estimated at about 4,500 tons/year, a fraction of which is PM10 and PM2.5.[20] The AFC does not estimate PM10 and PM2.5 emissions from fugitive coal dust associated with rail transport.

a) Please provide estimates for PM10/PM2.5 emissions associated with fugitive coal dust losses from rail car transport.

b) Coal dust suppression measures for rail cars exist have been used successfully. Effective measures include covering the rail cars with tarp and application of a surfactant, e.g., latex coating. Would the Applicant be willing to require the coal supplier to cover rail cars or apply dust suppressants?

---

17 BNSF, Coal Dust Frequently Asked Questions, http://www.coaltrainfacts.org/bnsf-coal-dust-frequently-asked-questions.

18 E.M. Calvin, G.D. Emmett, J.E. Williams, A Rail Emission Study: Fugitive Coal Dust Assessment and Mitigation, 1996; http://www.powerpastcoal.org/wp-content/uploads/2011/08/A-RAIL-EMISSION-STUDY-FUGITIVE-COAL-DUST-ASSESSMENT-AND-MITIGATION.pdf.

19 Connell Hatch, Coal Loss Literature Review, Coal Loss Management Project, Queensland Rail, January 11, 2008; http://www.qrnational.com.au/InfrastructureProjects/Rail%20Network/Coal_Loss_Management_Project -_Interim_Report_-_Part_2.pdf.

20 (1 lb coal dust loss/rail car/mile) × (13,034 rail cars/year) × (700 miles from Grants, NM, to Bakersfield, CA) / (2000 lb/ton) = 4,561.9 ton coal dust loss/year)

RESPONSE

The rail cars will be covered; therefore, there will be no coal dust.

BACKGROUND: OFFSITE EMISSIONS FROM MATERIALS TRANSPORTATION VIA TRUCK

The offsite emissions from fuel, product, and waste hauling for the Project are substantial. In response to a data request by CEC staff for the prior configuration of the Project—inquiring whether the Applicant would be willing to stipulate to contracting for only new trucks for fuel delivery at the time of starting operations and maintaining a maximum average fleet age, or some other measures to mitigate this large emissions source—the Applicant indicated that they are "willing to commit to only employing trucks that meet or exceed the 2010 heavy diesel emission standards."[21] This response is ambiguous and the current AFC is silent on such a condition as potential mitigation.

21 08-AFC-08, November 11, 2009 Responses to CEC Data Requests Set One – Nos. 1 through 132, #27.

DATA REQUEST

43. Please identify the percentage of trucks that would be owned by or under control of the Applicant for each fuel, product, waste, and other material delivery and the percentage of truck trips that would be contracted out where the Applicant would have no control over the emission standards of the respective truck fleet.

RESPONSE

As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1*, docketed on August 22, 2012, the Applicant is requesting additional time to address this Data Request.

DATA REQUEST

44. Please indicate whether the Applicant would be willing to accept a condition of certification stipulating that it purchase only new trucks for materials delivery (at the time of starting operations) and maintain a maximum average fleet age (please identify).

RESPONSE

As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1*, docketed on August 22, 2012, the Applicant is requesting additional time to address this Data Request.

DATA REQUEST

45. Please indicate whether the Applicant would be willing to explore additional potential mitigation for emissions from haul contractor trucks over whose fleet the Applicant would have no control.

RESPONSE

As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1*, docketed on August 22, 2012, the Applicant is requesting additional time to address this Data Request.

BACKGROUND: EMISSIONS FROM COMBUSTION TURBINE GENERATOR/HEAT RECOVERY GENERATOR

Based on a top-down analysis, the AFC determines Best Available Control Technology ("BACT") for NOx emissions from the Project's combustion turbine generator/heat recovery steam generator ("CTG/HRSG") as diluent injection in the combustion turbine and installation of a selective catalytic reduction ("SCR") system for post-combustion control with BACT emission limits of 2.5 ppm NOx at 15% oxygen ("O2") when firing hydrogen-rich syngas and 4 ppm at 15% O2 when firing natural gas, both on a 3-hour rolling average. For carbon monoxide ("CO") emissions, the AFC proposes good combustion practice and a CO catalyst as BACT with emission limits of 3 ppm CO at 15% O2 on hydrogen-rich syngas and 5 ppm CO at 15% O2 on natural gas, both on a rolling 3-hour average. (AFC, Appx. E-11, pp. 4, 23-24, and 26-28.)

The AFC "anticipates" that this combination of control technologies would achieve the proposed BACT emission limits. (Ibid.) However, it is unclear whether the Project would indeed be able to comply with the proposed emission limits as information on emissions associated with the proposed technology is scarce to non-existent. The proposed technology has not been installed in the United States and the Applicant did not supply any data or information based on experienced gathered at MHI's 250-MW Nakoso, Japan, facility. The AFC's BACT analysis identifies neither the SCR and CO catalyst control efficiency nor the uncontrolled CO and NOx emission rates from the CTG/HRSG. (Portions of the BACT analysis that contain information regarding the uncontrolled emission rates are blacked out; see AFC, Appx. E-11, pp. 21 and 26.). The Applicant's legal counsel indicated that this information is considered confidential business information and cannot be released.[22] Instead, the CEC and the public are expected to accept the proposed emission limits at face value.

---

22 Phone conversation with Michael Carroll, Latham & Watkins, July 20, 2012.

DATA REQUEST

46. Please provide either a) information on uncontrolled CO and NOx emissions rates from the CTG/HRSG or b) manufacturer guarantees indicating that the proposed BACT emission limits can be achieved with the proposed combination of control technologies.

RESPONSE

This response addresses the second option (option b) of the two alternates requested. The oxides of nitrogen (NO_x) control will use diffusion burners with diluent addition for the gas turbine, best combustion practice for the duct burners, and selective catalytic reduction (SCR) for post-combustion NO_x control. Dry low-NO_x burners are not available for gas turbines, which burn hydrogen fuel. The HRSG has not been purchased; therefore, no guarantees for the performance of the carbon monoxide (CO) and NO_x catalysts are available at this time. The performance of the NO_x catalyst and SCR system is expected to achieve the outlet NO_x concentrations described in the Project permit application, based on performance quotations from manufacturers.

BACKGROUND: ALTERNATIVE FUELS/FEEDSTOCKS OR FEEDSTOCK BLENDS AS BACT FOR TURBINES

The Project would result in substantial emissions of criteria pollutants, TACs/HAPs, and greenhouse gases and contribute to the region's already severely impaired air quality and global climate change. These emissions could be reduced by using alternative fuels/feedstocks such as natural gas or biomass[23] instead of the proposed solid carbon feedstocks (coal and petcoke) or by reducing or eliminating the amount of coal as feedstock. The AFC's BACT analysis for the Project does not adequately discuss the use of alternative fuels/feedstocks.

---

23 See, for example, Henry A. Long, III and Ting Wang, Case Studies for Biomass/Coal Co-Gasification in IGCC Applications, Proceedings of ASME Turbo Expo 2011, Vancouver, Canada, June 6-10, 2011; http://eccc.uno.edu/pdf/Long-Wang-GT2011-45512.pdf.

DATA REQUEST

47. The AFC concludes that the use of natural gas would not meet the Project's design and purpose which it narrowly defines as a) the use of solid carbon feedstocks (coal and petcoke) to produce low-emission electricity; b) the generation of hydrogen for low-carbon electricity and nitrogen-based products; and c) the capture of CO_2 and transporting CO_2 for use in enhanced oil recovery. (AFC, Appx. E-11, p. 11).

a) The first stated objective for the Project, to use solid-carbon feedstocks relies on the invalid circular argument that the objective of the Project is to use coal and petcoke. The AFC supports the choice of these solid fuel feedstocks because a) they are historically cheaper (per British thermal unit) than natural gas; b) they are more widely available in the United States than natural gas; and c) the use of natural gas would not qualify for funding or meet the objectives of DOE's Clean Coal Power Initiative. (AFC, Appx. E-11, p. 13.)

i. In recent years and particularly the last year, prices for natural gas have decreased dramatically with prices at the Henry Hub falling from between \$4 to \$8 per million Btu ("MMBtu") with spikes up to \$15 before 2010 to consistently between \$2 to 3 per million 2012.[24] Please provide a discussion of natural gas vs. coal/petcoke prices (as delivered) and their impact on operating costs.

ii. Please discuss why the qualification for funding or meeting the objectives of DOE's Clean Power Initiative qualifies as a project objective that precludes the use of cleaner feedstocks and/or technologies.

---

24 Natural Gas Spot Prices at the Henry Hub 2012; http://www.neo.ne.gov/statshtml/124.htm.

b) The latter two stated objectives (b and c) for the Project could also be achieved by the combustion of natural gas or the combustion or gasification of biomass or biomass blends with solid fossil feedstocks.

i. Please indicate whether you acknowledge that b) the generation of low-carbon electricity and nitrogen-based products and c) the capture of CO_2 and transporting CO_2 for use in enhanced oil recovery products could also be achieved by a natural gas-fired combined-cycle plant.

ii. Please indicate whether you acknowledge that b) the generation of low-carbon electricity and nitrogen-based products and c) the capture of CO_2 and transporting CO_2 for use in enhanced oil recovery products could also be achieved by combustion or gasification of biomass or biomass blends with solid fossil feedstocks.

RESPONSE

a.

i) The HECA Project is an Integrated Gasification Combined Cycle (IGCC) facility that generates electricity and fertilizers, while capturing and sequestering more than 90 percent of carbon dioxide (CO_2) emissions by converting a blend of coal and petcoke into clean-burning hydrogen gas. Since inception, HECA has contemplated the use of solid feedstocks for the production of hydrogen gas and capture of CO_2. As evidenced by receipt of the DOE Clean Coal Power Initiative (CCPI-3) award, HECA is recognized as an advanced coal-based project capable of demonstrating next-generation technologies to produce electricity, while capturing and sequestering a significant portion of CO_2 emissions. In fact, it is specifically through its use of coal that HECA is able to offer California, the nation, and the world progress toward controlling global climate change, while demonstrating the commercial viability of an advanced coal-based power facility.

Although natural gas prices have decreased recently, coal is priced lower than natural gas in California. Based on current U.S. Energy Information Administration data and project discussions with coal transporters, delivered western sub-bituminous coal will cost the Project approximately $2.77/million British thermal units (MMBTU)[1], while California natural gas prices for electrical power facilities are approximately $4.85 MMBTU[2], or over 1.5 times more expensive than coal. Coal prices are also more stable historically than natural gas prices; and are therefore more predictable for investors and lenders. Regarding availability, both coal and natural gas are domestically plentiful fossil fuels, but rare in California, and would therefore need to be imported. California currently imports approximately 90 percent of its natural gas needs each year.

---

[1] USEIA. Average sale price of New Mexico sub-bituminous coal for 2010 (most recent available) is $30.67/short ton. Release date November, 2011. http://www.eia.gov/coal/data.cfm#prices

[2] USEIA. California industrial natural gas price. May 2012 (most recent available). http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_SCA_m.htm

ii) As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1,* docketed on August 22, 2012, the Applicant objects to this Data Request.

b. As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1,* docketed on August 22, 2012, the Applicant objects to this Data Request.

DATA REQUEST

48. The AFC concludes that use of natural gas would require substantial re-design of the facility and lists a number of Project units that would be affected. Please discuss how each of these units would be affected if using natural gas.

RESPONSE

As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1,* docketed on August 22, 2012, the Applicant objects to this Data Request.

DATA REQUEST

49. The AFC does not discuss the use of biomass as an alternative feedstock or the use of feedstock blends with different percentages than proposed, for example by reducing or eliminating the amount of fuel in the feedstock blend (e.g., 50% coal/ 50% petcoke, 25% coal/75% petcoke, or 100% petcoke) or substituting biomass for a portion of the feedstock blend. Please discuss whether these alternative fuels or fuel blends would require substantial re-design of the facility and indicate which process units would be affected and how the design would have to be changed.

RESPONSE

As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1,* docketed on August 22, 2012, the Applicant objects to this Data Request.

BACKGROUND: NOX EMISSIONS FROM AUXILIARY BOILER

The Project would use a natural gas-fired auxiliary boiler equipped with low-NOx burners and a selective catalytic reduction ("SCR") system to provide steam for pre-start equipment warm-up and other miscellaneous purposes when steam from the gasification block or HRSG is not available. The AFC determined a NOx BACT emission limit for the auxiliary boiler of 0.006 pounds per million British thermal units ("lb/MMBtu") based on a NOx concentration of 5 parts per million by volume, dry ("ppmvd") at 3% oxygen. The AFC's emission estimates assume that NOx concentrations in the boiler exhaust would not exceed this limit regardless of operating conditions. (AFC, Appx. E-3, p. 7.)

Because the SCR catalyst must reach a certain temperature to effectively reduce NOx in the exhaust gas, NOx emissions from the auxiliary boiler may be underestimated during periods when the exhaust gas temperature is below the minimum needed for effective SCR, such as during the commissioning period and part of the startup period of the auxiliary boiler. The majority of boiler operations are expected to be at low load, likely below the minimum needed for effective SCR control.

DATA REQUEST

50. Please provide emission factors for NOx emissions from the auxiliary boiler during initial auxiliary boiler commissioning and during startup while the SCR catalyst has not reached its optimal operating temperature.

RESPONSE

As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1*, docketed on August 22, 2012, the Applicant is requesting additional time to address this Data Request.

DATA REQUEST

51. Please provide estimates for short-term NOx emissions during the initial auxiliary boiler commissioning period.

RESPONSE

Emissions during the commissioning period for the auxiliary boiler may be found in the 2012 Amended AFC (May 2012), Section 5.1.2.3, Gasification Block and Balance of Plant Commissioning; and in corresponding Table 5.1-16.

DATA REQUEST

52. Please provide updated emission estimates for NOx emissions from the auxiliary boiler accounting for higher NOx emissions while the SCR catalyst has not reached operating temperature and during shutdown.

RESPONSE

As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1*, docketed on August 22, 2012, the Applicant is requesting additional time to address this Data Request.

BACKGROUND: VOC AND PM10/PM2.5 EMISSIONS FROM TAIL GAS THERMAL OXIDIZER

The Project would operate a tail gas thermal oxidizer to safely dispose of a) tail gas from the sulfur recovery unit ("SRU") in the event of an emergency or upset, b) waste gas during SRU startups, and c) miscellaneous vent streams from the gasification area. The AFC estimates VOC and PM10/PM2.5 emissions from the tail gas thermal oxidizer while combusting these gas streams based on emission factors from EPA's AP-42, Chapter 1.4 for natural gas combustion. These calculations may underestimate VOC and PM10/PM2.5 emissions from the tail gas thermal oxidizer. The AFC provides no support for this assumption.

DATA REQUEST

53. Please discuss why the emission factors for VOC and PM10/PM2.5 provided in AP-42, Chapter 1.4, for natural gas combustion are deemed representative for combustion in the tail gas thermal oxidizer of a) SRU tail gas in the of an emergency or upset, b) waste gas during SRU startups, and c) miscellaneous vent streams from the gasification area.

RESPONSE

As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1*, docketed on August 22, 2012, the Applicant is requesting additional time to address this Data Request.

DATA REQUEST

54. If necessary, please provide revised emission factors and emission estimates for VOC and PM10/PM2.5 emissions from the tail gas thermal oxidizer.

RESPONSE

As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1*, docketed on August 22, 2012, the Applicant is requesting additional time to address this Data Request.

BACKGROUND: BACT FOR FLARES

The Project would operate three flares: a gasifier flare to dispose of gases during gasifier startup and unplanned power plant upsets or equipment failures; a flare in the sulfur recovery unit ("SRU") to dispose of gas emissions from the acid gas removal ("AGR") process during startup (after passing via a scrubber) or to oxidize releases during emergency or upset events; and a flare in the Rectisol area to dispose of low-temperature gas streams during startup, shutdown and unplanned upset and emergency events. (AFC, p. 5.1-20.) All three flares are proposed as conventional elevated flares with natural gas assist. (AFC, p. 2-38.) The AFC eliminates the use of enclosed ground flares due to not further specified concerns with reliability claiming that enclosed ground flares have never been installed on any IGCC plants and are considered unproven technology with an associated risk. (AFC, Appx. E-11, pp. 54 and 57.)

Enclosed ground-level flares are commonly specified as BACT to reduce emergency flaring emissions.[25] In a ground flare, the flare tip and combustion zone are enclosed within a refractory shell that is internally insulated and located at ground level. The gases are vented through an elevated stack. The shell reduces noise, luminosity and heat radiation, and perhaps most importantly, it protects the combustion zone from wind. (The Project is located in an area with high wind events.) Such shells also result in more stable combustion conditions for gases with lower heat content (such as the syngas produced at the Project) and therefore more effective flaring. Thus, ground level flares would reduce emissions compared to elevated flares proposed here.

Several recent IGCC facilities were designed with enclosed ground flares including the PureGen One facility in Linden, NJ[26] and the IGCC Unit B at the Curtis H. Stanton Energy Center near Orlando, FL[27]. Thus, it would appear that the use of ground flares rather than elevated flares is BACT.

---

25 Bay Area Air Quality Management District, Best Available Control Technology (BACT) Guideline, Refinery Flares, June 30, 1995: "Ground level flare, enclosed, steam- or air-assisted, w/ staged combustion; POC destruction efficiency >98.5%;" http://hank.baaqmd.gov/pmt/bactworkbook/default.htm.

26 SCS Energy, PurGen One IGCC Facility, Linden, New Jersey, Preconstruction Permit & Operating Certificate Application, December 30, 2009; http://www.precaution.org/lib/purgen_air_permit_fnl.100127.pdf.

27 Florida Department of Environmental Protection, OUC/Southern Power Company – Orlando Gasification, Curtis H. Stanton Energy Center, IGCC Unit B, PSD Permit No. PSD-FL-373 December 22, 2006; http://www.dep.state.fl.us/air/emission/construction/ouc_southern/373FPERMIT.pdf.

DATA REQUEST

55. Please discuss in detail the reliability concerns and risks associated with using ground as opposed to elevated flares separately for each of the Project's three flares.

RESPONSE

As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1*, docketed on August 22, 2012, the Applicant is requesting additional time to address this Data Request.

DATA REQUEST

56. Please discuss why the use of enclosed ground flares is considered feasible for other IGCC facilities but not for HECA.

RESPONSE

As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1*, docketed on August 22, 2012, the Applicant is requesting additional time to address this Data Request.

DATA REQUEST

57. The Applicant initially considered the use of an enclosed ground flare for gasification block for the Project.[28] Please discuss the reasons for changing the design from a proposed ground flare for the gasifier block to an elevated flare.

28 Southern California Edison, Testimony in Support of Application for Authorization to Recover Costs Necessary to Co-Fund a Feasibility Study of a California IGCC with Carbon Capture and Storage, Before the Public Utilities Commission of the State of California, April 3, 2009, pp. 2-39 –24-40; http://www3.sce.com/sscc/law/dis/dbattach7.nsf/0/2A85B596280D04328825758D0078A926/$FILE/A0 904XXX+HECA+-+SCE+Testimony+in+Support+of+Application.pdf.

RESPONSE

As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1*, docketed on August 22, 2012, the Applicant is requesting additional time to address this Data Request.

DATA REQUEST

58. Please discuss the feasibility of using an enclosed ground flare for routine periodic flaring and an elevated flare as an emergency backup.

RESPONSE

As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1*, docketed on August 22, 2012, the Applicant is requesting additional time to address this Data Request.

BACKGROUND: HAZARDOUS AIR POLLUTANT EMISSIONS FROM FLARES

Flares emit hazardous air pollutants ("HAPs") during both routine and non-routine operations from three sources: (1) pilot; (2) supplementary natural gas fuel; and (3) syngas and waste gases. The AFC estimates emissions of HAPs from flares during pilot operation and gasifier startup/shutdown based on emission factors from EPA's Compilation of Air Pollutant Emission Factors ("AP-42"), Chapter 1.4, for natural gas-fired boilers. (AFC, Appx. M, pp. 6-8.) This assumes the behavior of a flare from a combustion standpoint is similar to a natural gas fired boiler, which is not the case. A natural gas-fired boiler combustion chamber is a highly controlled, contained environment. In contrast, a flare has no combustion chamber and highly variable gas flow and composition, and is exposed to conditions, such as crosswinds, that are not present in a natural gas-fired boiler. Further, the flares would combust syngas and waste gases have a different composition than natural gas.

DATA REQUEST

59. Please explain why HAP emission factors determined for natural gas combustion in boilers are deemed representative for combustion of natural gas, syngas and waste gases in the Project's flares for both normal operating emissions from the pilot and during gasifier and Rectisol startup and shutdown.

RESPONSE

As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1*, docketed on August 22, 2012, the Applicant is requesting additional time to address this Data Request.

DATA REQUEST

60. Please provide conservative estimates for the concentration of HAPs in flared gases based on material balances for the Project's individual process units and experience at existing IGCC plants (e.g., Puertollano, Spain, or Wabash River Generating Station, IN).

RESPONSE

As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1*, docketed on August 22, 2012, the Applicant is requesting additional time to address this Data Request.

DATA REQUEST

61. Did the Applicant inquire with MHI whether they have any experience with HAP emissions from flares at the Nakoso facility in Japan? If yes, please provide the response. If not, please inquire with Mitsubishi whether they have any data or other information available.

RESPONSE

As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1*, docketed on August 22, 2012, the Applicant is requesting additional time to address this Data Request.

BACKGROUND: FLARE MALFUNCTION EMISSIONS

The AFC's emission estimates accounts for flare emissions from normal operations and for two planned startup/shutdown events per year. (AFC, Appx. E-3, p. 12.) These estimates do not include emissions that occur during malfunctions which can be substantially higher than during planned events. (Consequently, the AFC's air quality modeling also did not include malfunction events and, thus, did not model maximum 1-hour impacts.) A malfunction is any unplanned emergency relief in which the plant operators would have to vent emissions to the flares due to non-routine operating conditions, including the failure or probable failure of equipment that needs to be repaired or exchanged, loss of electrical power, loss of water, pressure surges, etc.

The EPA has taken the position that startup, shutdown and malfunction emissions must be strictly prohibited or included in the potential to emit.[29] Most recently, the EPA objected to the proposed Title V and prevention of significant deterioration ("PSD") permit for the Cash Creek coal-to-synthetic natural gas facility in Kentucky because, amongst other issues, the permitting agency's determination of potential to emit ("PTE") for the facility did not account for shutdown and malfunction emissions from the flare.[30] The EPA also recently objected to the proposed Title V permit for the Kentucky Syngas facility for failing to account for shutdown and malfunction emissions from the flare.[31] Similar to the Cash Creek decision, the EPA again emphasized the need to account for all actual emissions including those from all flaring events to ensure compliance with source-wide limits.

---

29 See U.S. Environmental Protection Agency, Order Responding to Petitioners Request that the Administrator Object to Issuance of State Operating Permit from the EPA Administrator regarding BP Products North America, Inc., Whiting Business Unit, Permit No. 089-25488-00453, October 16, 2009. See also Steven C. Riva, U.S. Environmental Protection Agency, Region 2, Letter to William O'Sullivan, New Jersey Department of Environmental Protection, February 14, 2006.

30 U.S. Environmental Protection Agency, In the Matter of Cash Creek Generation, LLC, Henderson County, Kentucky, Title V/PSD Air Quality Permit No. V-09-006, Issued by the Kentucky Division for Air Quality, Order Granting in Part and Denying in Part Petition for Objection to Permit, Petition No. IV-2010-4, June 22, 2012.

31 U.S. Environmental Protection Agency, In the Matter of Kentucky Syngas, LLC, Muhlenberg County, Kentucky, Title V/PSD Air Quality Permit No. V-09-001, Issued by the Kentucky Division for Air Quality, Order Granting in Part and Denying in Part Petition for Objection to Permit, Petition No. IV-2010-9, June 22, 2012.

DATA REQUEST

62. Please estimate criteria pollutant and TAC/HAP emissions from the gasifier, SRU and Rectisol flares during malfunction events and update the facility's potential to emit ("PTE") those pollutants.

RESPONSE

As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1,* docketed on August 22, 2012, the Applicant objects to this Data Request.

DATA REQUEST

63. Please review the PSD requirements for the facility based on a revised PTE that includes malfunction emissions from the flares.

RESPONSE

As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1,* docketed on August 22, 2012, the Applicant objects to this Data Request.

DATA REQUEST

64. Please review the facility's minor source status for HAPs based on a revised PTE that includes malfunction emissions from the flares.

RESPONSE

As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1,* docketed on August 22, 2012, the Applicant objects to this Data Request.

DATA REQUEST

65. Please provide updated air quality modeling for maximum 1-hour impact based on maximum hourly emissions from the flares during malfunction events.

RESPONSE

As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1,* docketed on August 22, 2012, the Applicant objects to this Data Request.

DATA REQUEST

66. Please provide an updated health risk assessment based on a revised PTE that includes malfunction emissions from the flares.

RESPONSE

As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1,* docketed on August 22, 2012, the Applicant objects to this Data Request.

BACKGROUND: COOLING TOWER BACT ANALYSIS

The AFC concludes that BACT for the Project's cooling needs is the use of wet cooling towers over the use of air-cooled condensers mainly based on capital cost differential. This cost differential was determined in a cost-effectiveness analysis contained in a 2008 Water Usage Minimization Study for the Project's previously proposed configuration. (08-AFC-08, Appx. X, and AFC, Appx. E-11, p. 46.) The AFC's analysis is not adequately documented, outdated and flawed.

DATA REQUEST

67. The Water Usage Minimization Study highlights that Kern County is a very dusty area due the vast desert/farm lands and high winds, which will present problems with the wet cooling tower fill material due to fouling and result in mud buildup in the basin. Therefore, the study recommends installation of a less efficient film fill with larger openings in the wet cooling tower better suited to this environment. In addition, the use of brackish water in the cooling tower requires a decrease in the cycles of concentrations to prevent the solids in the circulating water from precipitating out. Further, the use of brackish water requires upgrading of the cooling tower materials to counter the effects of the corrosive brackish water.

a) Please discuss whether the proposed design of the cooling towers (circulation rate, makeup water, etc.) takes into account the above recommendations.

b) Please discuss how the dusty ambient air would affect the performance of an air-cooled condenser.

c) The AFC, Appx. E-11, p. 46, indicates that the Project would use high-efficiency drift eliminators with a drift rate of 0.0005%.

i. Please discuss how the above discussed problems with the dusty and windy environment (see 08 AFC-08, Appx. X) and using brackish water with high total dissolved solids ("TDS") content would affect the performance of the drift eliminators.

ii. Please provide a vendor guarantee for the Project's cooling towers guaranteeing a 0.0005% drift rate under the above discussed conditions.

RESPONSE

a. The vendor would incorporate these recommendations into the Cooling Tower design.

b. Dusty ambient conditions impair the performance of air-cooled condensers. Normal design practice for air-cooled condensers is to use finned tubes for the heat transfer surface to increase the heat transfer area. Air that removes the heat from the steam flows over the outside of the finned tubes, and some of the dust in the air is deposited on the fins. The dust reduces the flow of air, thereby reducing the amount of heat removed from the steam. The result is that the steam turbine generator (STG) exhaust pressure increases slowly as the dust deposits on the fins and the STG output is reduced; which in turn lowers power production for a given fuel consumption. The dust must be removed from the fins periodically to restore performance to acceptable levels.

c. Because the high-efficiency drift eliminators with a drift rate of 0.0005 percent are the best available control technology, the vendor will be required to meet these specifications.

DATA REQUEST

68. The Water Usage Minimization Study, which is now 4 ½ years old (dated January 2008), was conducted for the prior Project proposal which was based on different equipment, did not include a manufacturing complex, and had only one cooling tower for the power block. (See 08-AFC-08, Appx. X.) The 2008 Water Minimization Study is not adequately documented.

a) Please provide all spreadsheets supporting the tables and conclusions in this study.

b) The study indicates that "[h]eat and material balances "from the Phase 3-Prefeed Package" was used as a basis. This information is not provided. Please provide the Phase 3-Prefeed Package including the material balances used for this study.

c) The study indicates that much of the information in this report is "derived from Thermoflex, a power cycle simulator developed by Thermoflow" "which solves the heat and material balance, calculates performance and estimates equipment pricing." This information was used to develop the cost differences for 100% water-cooled condenser, a 100% air-cooled condenser, and a parallel cooling system. The AFC provides no discussion of the adequacy of this study for the Project's three cooling towers other than stating that "the relative cost of controlled PM is expected to remain similar." (AFC, Appx. E 11, p. 46.) This statement does not provide adequate proof to support the AFC's conclusion that BACT for the cooling tower is a wet-cooled condenser; e.g., many of the operating parameters and heat and material balances used to determine costs in Thermoflex have changed.

i. Please provide the study' input values for the Thermoflex modeling and provide a quantitative discussion how the Project's redesign would change these values.

ii. Please discuss why the relative cost of controlled PM is expected to remain similar even though heat and material balances are different for the Project's current configuration.

RESPONSE

As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1,* docketed on August 22, 2012, the Applicant objects to this Data Request.

DATA REQUEST

69. Because of the non-attainment status of the San Joaquin Valley with state and federal national ambient air quality standards for PM10, the Project would require offsets. The Applicant proposes to use SO2 interpollutant emission reduction credits ("ERCs") to offset PM10 emissions. (AFC, Appx. E-10-1). The cost of these ERCs was not factored into the AFC's cost-effectiveness analysis for air-cooled vs. water-cooled condensers.

a) Please identify the purchase price of the SO2 ERCs for PM10 interpollutant offsets that have been or would be acquired for the Project (ERC C-1058-5: $98,000 stpd; ERC C-3275-5: 168,000 stpd).

b) Please include the costs for these ERCs in your revised cost-effectiveness analysis.

RESPONSE

a. The sulfur dioxide (SO_2) Emission Reduction Credits (ERCs) for particulate matter 10 microns in diameter or less (PM_{10}) interpollutant offsets (ERC C-1058-5: 98,000 stpd; ERC C-3275-5: 168,000 stpd) were transferred to HECA LLC as part of the purchase and sale agreement with British Petroleum (BP) and Rio Tinto in September 2011. The details of this agreement are confidential. However, San Joaquin Valley oxides of sulfur (SO_x) ERC transaction prices have remained fairly stable over the last 5 years (2007–2011), and are detailed in the below table.

Year	San Joaquin Valley SO_x ERC Transaction Price
2007	$21,995
2008	$25,856
2009	$29,242
2010	$21,179
2011	$15,267
July 31, 2012*	$25,000
Source: Provided by Evolution Markets. Personal communication August 23, 2012. * = most recent data available.	

b. As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1,* docketed on August 22, 2012, the Applicant objects to this Data Request.

DATA REQUEST

70. The AFC, Appx. E-11, p. 47, provides an estimate of total annualized costs for an air-cooled condenser of $213,900 per ton of particulate matter ("PM") controlled. HECA "believes that this high cost per ton of PM for using an ACC is cost prohibitive for the Project." Please identify the costs in US$ per ton of PM removed that would qualify as cost-effective to HECA.

RESPONSE

Based on the Revised BACT Cost Effectiveness Thresholds (SJVAPCD, 2008), the recommended cost threshold for PM_{10} is $11,400 per ton of reduction. Therefore, using an air-cooled condenser (ACC) at approximately $213,900 per ton of reduction is far above the SJVAPCD threshold, and is cost prohibitive for the Project.

Reference:

SJVAPCD. 2008. Final Staff Report. Update to Rule 2201 Best Available Control Technology (BACT) Cost Effectiveness Thresholds. May 14, 2008.

DATA REQUEST

71. The AFC's calculation assumes a cost differential for the air-cooled vs. the water-cooled condenser of $37 million. This cost differential is based on the assumption that fresh water with five cycles of concentration is used in the wet-cooled condenser. Here, the Project would use brackish water with only three cycles of concentration, which would reduce the cost-differential between the by $5 million. (08-AFC-08, Appx. X, Table 9, p. 12.) Please revise the cost-effectiveness analysis accounting for the use of brackish water (three cycles of concentration) instead of fresh water (five cycles of concentration).

RESPONSE

As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1*, docketed on August 22, 2012, the Applicant is requesting additional time to address this Data Request.

DATA REQUEST

72. The AFC's calculation of the capital recovery factor ("CRF") assumes 7 percent interest and a 20-year life.

a) Please document the basis for the assumed 7 percent interest.

b) Please discuss why the assumed life is only 20 years instead of the Project's design operating life of 25 years (AFC, p. 3-1).

c) Please discuss the design operating life of an air-cooled condenser and its potential life expectancy.

d) Please provide a discussion and estimate of CRF and cost-effectiveness of an air-cooled condenser based on the maximum operating life of the ACC assuming the Project would be operating beyond its 25-year design operating life.

RESPONSE

a. As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1*, docketed on August 22, 2012, the Applicant is requesting additional time to address this Data Request.

b. As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1*, docketed on August 22, 2012, the Applicant is requesting additional time to address this Data Request.

c. As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1*, docketed on August 22, 2012, the Applicant is requesting additional time to address this Data Request.

d. As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1,* docketed on August 22, 2012, the Applicant objects to this Data Request.

DATA REQUEST

73. Please provide a complete revised cost-effectiveness analysis based on the EPA's 2002 Cost Control Manual that analyzes wet cooling towers, air-cooled condensers and combinations thereof to satisfy the Project's cooling needs in the various process areas. Please document all assumptions and calculations taking into account your responses to the above data requests.

RESPONSE

As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1,* docketed on August 22, 2012, the Applicant objects to this Data Request.

BACKGROUND: EMISSIONS FROM THE COOLING TOWERS TEXT.

DATA REQUEST

74. The AFC, p. 2-37, states that the power block cooling tower would use a chemical feed system which will supply water conditioning chemicals to the circulating water to minimize corrosion and control the formation of mineral scale and biofouling. Chemicals would include sulfuric acid, polyacrylate solution, and sodium hypochlorite.

a) Please discuss whether the Project's process and air separation unit cooling towers would use the same supply water conditioning chemicals.

b) Please estimate criteria pollutant and TAC/HAP emissions associated with the use of these chemicals, including emissions of sulfuric acid and chloroform, from the Project's cooling towers.

RESPONSE

a. The Project's cooling towers for the Process Unit, Power Block Unit, and Ammonia Synthesis Unit will use the same conditioning chemicals.

b. As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1*, docketed on August 22, 2012, the Applicant is requesting additional time to address this Data Request.

DATA REQUEST

75. The AFC's estimate of TAC/HAP emissions from the Project's three cooling towers does not include zinc. Please provide an estimate of zinc emissions from the cooling towers.

RESPONSE

Zinc is no longer on the California Office of Environmental Health Hazard Assessment (OEHHA) toxic air contaminant (TAC) list. Zinc is also not a federally listed hazardous air pollutant (HAP), thus emissions estimates are not provided.

BACKGROUND: FUGITIVE EMISSIONS FROM ORGANIC LIQUID STORAGE TANKS, PIPING AND COMPONENTS

Fugitive emissions from the Project would include standing and working losses from organic liquid storage tanks and due to leaks in piping and components, such as valves, pump seals, compressor seals, flanges, pressure relief valves, connectors, open-ended lines, sampling connections, etc. These emissions include both VOCs and TACs/HAPs. The AFC presents a summary of fugitive VOC emissions in Appendix E-3, p. 23, and estimates for TAC/HAP emissions from piping and components in Appendix M, pp. 17-25. These emission estimates are inadequately documented and appear to be substantially underestimated.

DATA REQUEST

76. The AFC's estimates do not include fugitive VOC or TAC/HAP emissions from organic liquid storage tanks. Please identify and provide the capacity and turnover rate for all of the Project's organic liquid storage tanks, such as the 300,000-gallon methanol storage tank, diesel storage tanks, and solvent storage tanks, and provide estimates for fugitive emissions from these sources. Please include roof landing losses. Please indicate if tanks would be equipped with a tank vent oxidizer.

RESPONSE

As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1*, docketed on August 22, 2012, the Applicant is requesting additional time to address this Data Request.

DATA REQUEST

77. Additional information is required to assess the adequacy of the AFC's component count, provided in Appendix M, p. 19, and its estimates of fugitive emission from Project equipment.

a) Please identify all Project equipment from which fugitive emissions could occur including traditional components such as valves, connectors, pumps, compressor seals, relief valves, sampling connections, process drains, and open-ended lines as well as nontraditional component types such as screwed fittings, liquid relief valves, agitators, heat exchanger heads, site glasses, bolted manways/hatches, blind flanges, caps/plugs, connectors, compression, fittings, and metal-to-metal seals. The latter have not traditionally been treated as sources of equipment leaks but recent scientific studies have identified them as such.[32] Please break out the count by process area and component types.

b) The AFC, Appx. M, p. 19, identifies the following components for fugitive equipment leaks for process areas 11 (sulfur) and process unit 12 (tail gas treating unit process gas): 37 heavy-liquid valves and 2 heavy-liquid pumps (process area 11) and 53 gas valves and 203 connectors (process area 12). Previously, the Applicant provided the following component count for fugitive equipment leaks for these process areas: 72 heavy-liquid valves and 4 heavy-liquid pumps (process area 11) and 72 gas valves and 290 connectors (process area 12). Please discuss why the component counts of process areas 11 and 12 are considerably lower than previously assumed.

c) Please revise the emission estimates for VOC and TACs/HAPs if any additional components are identified.

32 Texas Commission on Environmental Quality, Emissions Inventory Guidelines, Technical Supplement 3: Equipment Leak Fugitives, TCEQ Publication RG-360, January 2006; http://www.tceq.state.tx.us/assets/public/comm_exec/pubs/rg/rg360/rg-360-05/techsupp_3.pdf.

RESPONSE

The component counts have been updated due to project design refinements. Nontraditional component types were not included in the revised component count, because the majority of the fugitive emissions are expected from the traditional components. Additionally, SJVAPCD requires that fugitive emissions be estimated using the USEPA Protocol for Equipment Leak Emission Estimates (USEPA, 1995) for compliance with Rule 2020; thus, the USEPA emission factors were used to estimate fugitive emissions.

Please refer to the Applicant's response to CEC Data Request A16, docketed on August 22, 2012, for updated component counts and revised fugitive emissions calculations.

DATA REQUEST

78. The AFC's estimates for fugitive VOC emissions from piping and components appear not to include the wastewater treatment area. Please provide estimates for fugitive emissions from these sources.

RESPONSE

As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1*, docketed on August 22, 2012, the Applicant is requesting additional time to address this Data Request.

DATA REQUEST

79. The AFC, p. 5.6-11, estimates emissions of VOCs and TACs/HAPs based on guidance by the SJVAPCD in its memo Procedures for Quantifying VOC Emissions at Petroleum and Synthetic Organic Chemicals manufacturing Industry (SOCMI), dated 2005, and using emission factors from the EPA document Protocol for Equipment Leak Emission Estimates, dated 1995. This document provides emission factors for four industry types: a) oil and gas production operations, b) refineries, c) marketing terminals and d) synthetic organic chemical manufacturing ("SOCMI"). The AFC finds, based on EPA's criteria for determining the appropriateness of emission factors, that the Project's processes are most similar to a SOCMI plant and therefore used SOCMI emission factors. (AFC, p. 5.6-11.) The AFC provides no justification for or discussion of this finding. Additionally, the emission factors provided in the EPA document are considerably lower for SOCMI facilities than for refineries.

a) Please provide a step-by-step discussion of the EPA's criteria for determining the appropriateness of emission factors for the Project's processes based on 1) process design, 2) process operation parameters, 3) types of equipment used, and 4) types of material handled.

b) Please discuss why the same industry type should be applicable for equipment in the gasification block and the manufacturing complex.

RESPONSE

USEPA's Protocol for Equipment Leak Emission Estimates (USEPA, 1995) shows that the criteria for determining the appropriateness of applying existing emission factors and correlations to another source category may include one or more of the following: (1) process design; (2) process operation parameters (i.e., pressure and temperature); (3) types of equipment used; and (4) types of material handled.

HECA is an IGCC project that produces synthesis gas (syngas) from coal and petroleum coke. Syngas produced via gasification will be purified to produce hydrogen-rich fuel used to generate electricity in the Combined Cycle Power Block, or to produce nitrogen-based fertilizer in an integrated Manufacturing Complex. The process streams from the gasification process and the Manufacturing Complex contain very low volatile organic compounds (VOCs) and hazardous air pollutants (HAPs). The Project will produce syngas and subsequent process streams that are very different from the high-VOC-content streams found in oil and gas production operations, refineries, or marketing terminals.

In the Gasification Block, the feedstock will be gasified to produce syngas (a mixture comprised mainly of carbon monoxide, hydrogen, carbon dioxide, nitrogen, and water), which is then processed to produce hydrogen-rich fuel or nitrogen-based fertilizer. The main process streams in the gasification block contain low VOCs and HAPs, which are more comparable to chemical plants. The Applicant determined the Synthetic Organic Chemical Manufacturing Industry (SOCMI) emission factors were appropriate for the Gasification Block, due to the similarity in materials handled.

In the Manufacturing Complex, essentially no VOCs and HAPs (very low) are contained in the process streams. In the 1980s, urea production was included as a SOCMI, but later removed due to the fact that it does not contain VOCs or HAPs. The Applicant determined the SOCMI emission factors were appropriate for the Manufacturing Complex, due to the similarity in materials handled.

It should be noted that although fugitive emissions were estimated for the facility using SOCMI emission factors, emissions are expected to be over-estimated due to the limited VOC and HAP content of the process streams, and due to the non-volatile nature of the majority of the process streams.

References:

USEPA. 1995 Protocol for Equipment Leak Emission Estimates. EPA-453/R-95-017. Emission Standards Division. November 1995.

DATA REQUEST

80. Please revise the operational health risk assessment for the Project reflecting any revisions to emission factors for TAC/HAP and emissions from additional sources (piping and components in wastewater treatment area and other process areas, organic liquid storage tanks).

RESPONSE

Please refer to the Applicant's response to CEC Data Request A16, docketed on August 22, 2012, for updated fugitive and TAC emissions. These relatively small increases in emissions are not expected to substantively change the results of the modeling for CO or TACs. The health risk assessment modeling of the TAC emissions was driven primarily by diesel particulate matter, which did not increase; thus, this small increase in fugitive TACs is not expected to significantly change the risks predicted by the model.

DATA REQUEST

81. The AFC, Appx. E-6, p. 65, provides a one-paragraph discussion as a BACT analysis for fugitive emissions from equipment leaks. The AFC, p. 5.1-24, proposes as BACT to apply an LDAR program in select process areas including the gasification block, Area #1 (methanol), Area #5 (propylene), Area #7 (hydrogen sulfide-laden methanol), Area #9 (acid gas), and Area #10 (ammonia-laden gas) and all portions of the manufacturing complex. The AFC's one-paragraph discussion is not acceptable as a BACT analysis for the Project's fugitive equipment leaks because it fails to follow the five-step top-down methodology recommended by the EPA in its New Source Review Manual. Please provide such an analysis. This analysis should identify and analyze the use of leakless components (e.g., welded connectors, bellows valves, double mechanical seals with high pressure fluids on pumps, enclosed distance pieces on compressors with venting to a control device, etc.) as well as routing any fugitive emissions from pressure releases from pressure relief valves to a control device.

RESPONSE

As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1,* docketed on August 22, 2012, the Applicant objects to this Data Request.

BACKGROUND: MERCURY AND AIR TOXICS STANDARDS

The U.S. EPA recently promulgated the so-called mercury and air toxics standards ("MATS") to limit emissions of mercury, acid gases and other toxic pollution from power plants. (FR Vol. 77, No. 32, February 16, 2012.) Effective April 16, 2012, MATS establishes emission limits for new IGCC electric generating units (such as the HECA project) for filterable particulate matter ("PM") of 7.0E–2 pounds per Megawatt-hour ("lb/MWh") (beyond-the-floor limit) or 9.0E–2 lb/MWh (for units with duct burners on syngas); hydrogen chloride ("HCl") of 2.0E–3 lb/MWh; and mercury ("Hg") of 3.0E-3 pounds per Gigawatt-hour ("lb/GWh"). MATS also provides alternate equivalent emission standards: SO2 as a surrogate for HCl of 4.0E-1 lb/MWh and individual non-mercury metals and total non-mercury metals as a surrogate for filterable PM. (FR Vol. 77, No. 32: 9367-9368, February 16, 2012.) The AFC does not address the Project's compliance with MATS requirements.

The AFC estimates emissions of 7.63E-3 tons/year of Hg from the turbine/heat generator and coal dryer stacks. (AFC, Appx. M, p. 1.) Based on an annual electricity generation of 2,699,860 MWh/year for mature operations (AFC, Appx. E-6, p. 3), Project emissions rates can be estimated at 5.7 E-3 lb/GWh of Hg[33], indicating that the Project may not be able to demonstrate compliance with the mercury emission standard of 3.03E-3 lb/GWh of Hg under MATS.

---

33 Mercury: (7.63E-3 tons/year of Hg) / (2,699,860 MWh/year) × (2,000 lb/ton) × (1,000 MWh/GWh) = 5.7E-3 lb/GWh of Hg; MATS standard = 3.03E-3 lb/GWh of Hg.

DATA REQUEST

82. Please provide a quantitative analysis of the Project's emission rates of PM or surrogate, Hg, and HCl or surrogate. Please document all your assumptions.

RESPONSE

As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1,* docketed on August 22, 2012, the Applicant objects to this Data Request.

DATA REQUEST

83. Please discuss how the Project would demonstrate compliance with the emission limits established under MATS.

RESPONSE

As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1,* docketed on August 22, 2012, the Applicant objects to this Data Request.

BACKGROUND: OFFSITE CONSEQUENCE ANALYSIS FOR ANHYDROUS AMMONIA

The Project would produce up to 2,000 stpd anhydrous ammonia and store approximately 3.8 million gallons on site in two double-walled cylindrical steel tanks. In addition to on-site use for selective catalytic reduction, anhydrous ammonia is the basis for the Project's fertilizer production of urea and ammonium nitrate. Anhydrous ammonia would also be sold wholesale to commercial users. (AFC, p. 2-20 and Appx. K, pp. K-5/K-6.) Ammonia is a hazardous material and has a specified toxic endpoint value of 0.14 mg/L, which is approximately equal to 200 parts per million ("ppm"). In its anhydrous form, ammonia is a gas which is maintained in a liquid state through pressurization of the handling and storage systems. When spilled, anhydrous ammonia will vaporize, releasing ammonia vapors to the surrounding atmosphere and potentially resulting in hazardous ambient concentrations in the vicinity of the release. The impact of an accidental release of anhydrous ammonia generated and used by the Project would depend upon the location of the release relative to the public. The AFC's discussion is accidental ammonia releases is inadequate and not adequately supported.

DATA REQUEST

84. The AFC provides an off-site consequence analysis for the potential catastrophic failure of the entire 3.8 million gallons of aqueous ammonia in the storage tanks.

a) Please provide the input/output files for the ALOHA 5.4 air dispersion modeling.

b) The AFC refers to "model results in Figure L-1, Aqueous Ammonia Area of Potential Impact from Worst-Case Scenario" but fails to provide this figure. (AFC, Appx. K, p. K-19.)

c) Please provide a copy of Figure L-1. Please discuss why the dispersion analysis does not account for prevailing wind direction. (See AFC, Appx. K, p. K-19.)

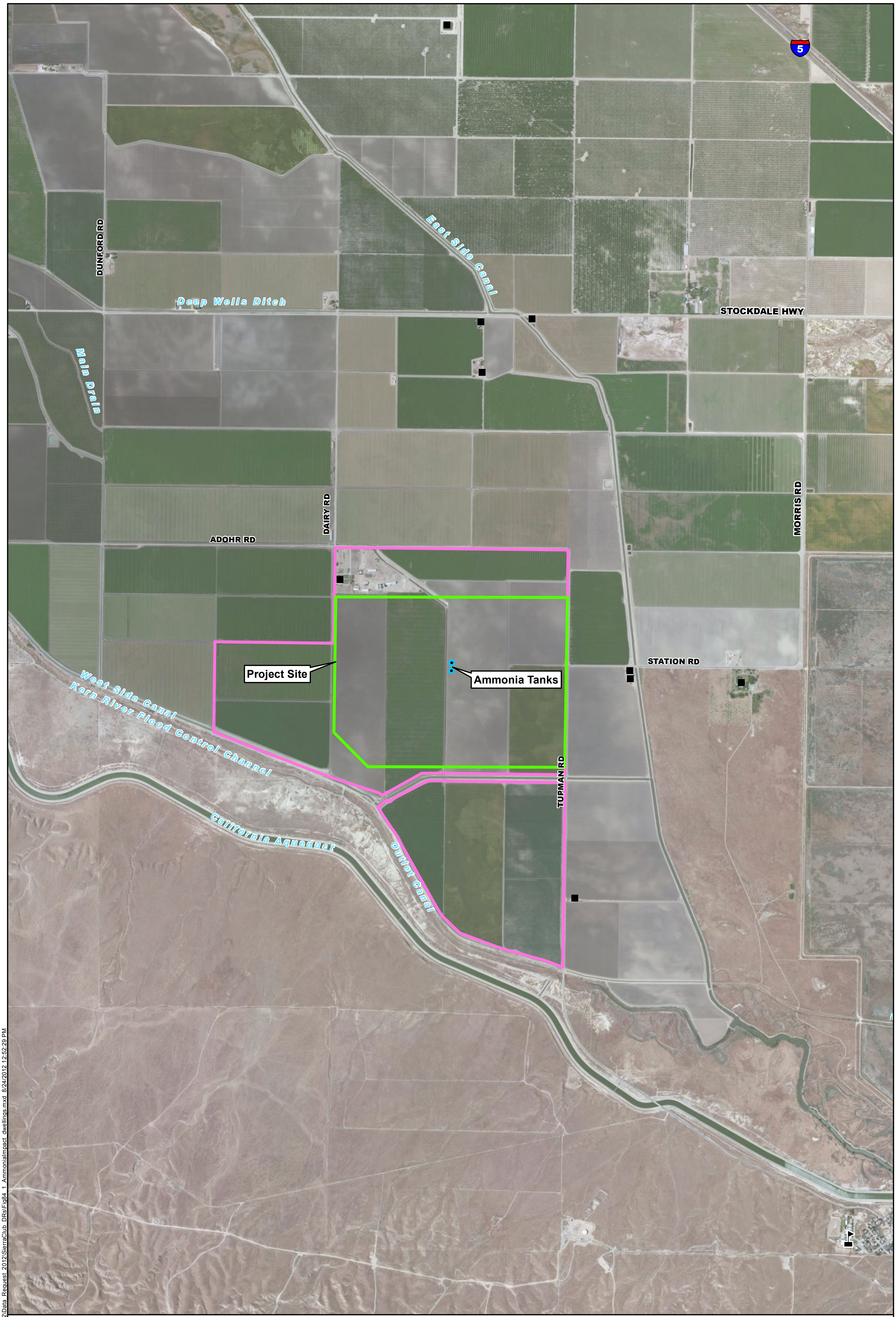
RESPONSE

a. The input and output information for the ALOHA 5.4.1 dispersion model was included in the 2012 Amended AFC, Appendix K, Section 3.3.1.

b. The 2012 Amended AFC, Appendix K, erroneously referred to Figure K-1 and Figure L-1, "Aqueous Ammonia Area of Potential Impact From a Worst-Case Scenario." The current project as described in the 2012 Amended AFC will store anhydrous ammonia, and will not store aqueous ammonia, as did the project described in the 2009 Revised AFC.

c. Figure 84-1, Anhydrous Ammonia Area of Potential Impact From a Worst-Case Scenario, is provided with this response.

The analysis considers the worst-case meteorological scenario for dispersion (e.g., low wind speeds, highly stable atmosphere, and high ambient temperature; see the 2012 Amended AFC, Appendix K, page K-13). This worst-case scenario for dispersion determines the worst case, regardless of wind direction.



Project Site
Controlled Area
School
Dwelling

Note:
No anhydrous ammonia impact areas are shown because a worst-case release of ammonia will be contained in the secondary housing of the storage system.

N
0 1,000 2,000 FEET

ANHYDROUS AMMONIA AREA OF POTENTIAL IMPACT FROM A WORST-CASE SCENARIO

August 2012
28068052

Hydrogen Energy California (HECA)
Kern County, California

URS

FIGURE 84-1

Source: Aerial Photo, Bing Maps, 2009; Schools, USGS GNIS, 2012.

lcd U:\GIS\HECA\Projects\HECA_2012\Data_Request_2012\SierraClub_DRs\Fig84_1_AmmoniaImpact_dwellings.mxd 8/24/2012 12:52:29 PM

DATA REQUEST

85. The transportation of ammonia, and any other hazardous material, poses a risk of exposure to the surrounding population due to an accidental release caused by a traffic accident involving the delivery vehicle. The possibility of accidental release during delivery depends upon the skill of the drivers, the type of vehicle used for transport, and the traffic conditions or road type. Because of the potential impact on the public, there are extensive regulatory programs in place in the United States and California to ensure safety during the transportation of hazardous materials, including the Federal Hazardous Materials Transportation Law (49 U.S.C. §5101 et seq.), the U.S. Department of Transportation Regulations (49 CFR Subpart H, §172-700), and California DMV Regulations on Hazardous Cargo (CCR, Vehicle Code, §34000). These regulations also address the driver's abilities and experience. Because of these regulations, CEC staff typically focuses on the potential for an incidence after the delivery vehicle has left the main highway due to the greater potential for accidents to occur on non-highway roads. The AFC does not provide a risk analysis for transportation of anhydrous ammonia resulting from a tanker accident on non-highway delivery routes.

- ***a) Please identify the non-highway delivery routes for transportation of anhydrous ammonia to customers and identify all sensitive receptors (e.g., residences, schools, places of worship, etc.) along these routes.***
- ***b) Please identify the maximum amount of anhydrous ammonia that could be sold directly to customers.***
- ***c) Please provide a risk analysis for transportation of anhydrous ammonia resulting from a delivery vehicle accident. Please consider the agricultural nature of the surrounding area and the likely presence of slow-moving and oversized agricultural vehicles.***

RESPONSE

a. As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1*, docketed on August 22, 2012, the Applicant is requesting additional time to address this Data Request.

b. The project will sell up to 500 tons per day of production on average as ammonia. Daily delivery volumes may vary, depending upon customer specifications and logistic requirements.

c. As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1*, docketed on August 22, 2012, the Applicant is requesting additional time to address this Data Request.

BACKGROUND: RELIABILITY AND AVAILABILITY

The AFC states that the Mitsubishi Heavy Industries ("MHI") gasification technology for solid fuels has been demonstrated at commercial scale at the

250-MW integrated gasification combined cycle ("IGCC") Facility in Nakoso, Japan, which has been in operation since 2008. The AFC further states that the

MHI gasification technology has been demonstrated on a variety of coal and other feedstocks in pilot facilities, demonstration plants and the commercial facility at Nakoso, Japan. (AFC, p. 2-74.) The AFC does not provide any information demonstrating MHI's experience with this technology or details about the 250-MW Nakoso facility and how they relate to the Project.

DATA REQUEST

86. Does the Nakoso IGCC facility employ a single- or double-walled gasifier?

RESPONSE

The Nakoso IGCC facility has a gasifier with an inner-membrane waterwall surrounded by a pressure vessel on the outside. It is not normally referred to as double-walled, but it can be interpreted to have an inner-membrane waterwall and an outer pressure vessel.

DATA REQUEST

87. Does the Nakoso IGCC facility have a backup gasifier?

RESPONSE

No, the Nakoso IGCC facility has only one gasifier installed, with no spare or backup gasifier.

DATA REQUEST

88. The Nakoso IGCC facility is using an air-blown gasifier; in contrast, the Project would use oxygen-blown gasifier. Please discuss the net plant efficiency and reliability for the Nakoso IGCC facility. Please discuss how the different type of gasifier proposed for the Project would influence plant efficiency and reliability.

RESPONSE

The different type of gasifier is not expected to have any effect on the reliability of the plant. The configuration—as well as the size of the gasifier for the Project—is very similar to the Nakoso IGCC facility. The Nakoso IGCC facility has been optimized to achieve high-efficiency electric power generation using the air-blown gasifier. The Project will use the oxygen-blown gasifier to achieve high efficiency for both chemical production and electric power generation.

DATA REQUEST

89. The Nakoso IGCC facility uses a modified MHI M7010DA gas turbine.[34] The Project would use an MHI 501 GAC combustion turbine. (AFC, p. 6-22.) Please discuss how these turbine designs affect performance.

---

34 http://www.netl.doe.gov/technologies/coalpower/gasification/gasifipedia/4-gasifiers/4-1-2-5_mhi.html.

RESPONSE

The MHI 501 Granular-Activated Carbon (GAC) combustion turbine has a larger gross power output and higher efficiency, which will result in a larger net plant output, and higher efficiency of the overall plant.

DATA REQUEST

90. MHI literature indicates that the Nakoso IGCC facility has experience gasifying a number of different coals but does not appear to have experience gasifying petcoke.[35] Please discuss any challenges associated with gasifying petcoke in the proposed gasifier.

---

35 Koichi Sakamoto, Mitsubishi Heavy Industries, Ltd., Commercialization of Mitsubishi IGCC/Gasification Technology, 2011 Gasification Technologies Conference, October 10, 2011; http://www.netl.doe.gov/technologies/coalpower/gasification/gasifipedia/pdfs/17SAKAMOTO.pdf.

RESPONSE

Gasification of petcoke has been performed at the pilot test plant at MHI.

DATA REQUEST

91. Please demonstrate reliability for running the Project's gasification/power block 100% of the time with only two shutdowns per year, as proposed.

RESPONSE

The Nakoso IGCC facility has demonstrated its high reliability through its long-term continuous operation and durability tests that were completed during its demonstration operation period. Experience obtained from these operations will be used to maximize the Project's Gasification/ Power Block reliability. Based on the Nakoso experience, one planned maintenance shutdown per year is expected, but two per year are proposed in the permit.

DATA REQUEST

92. Please provide any operational data, source tests, or other experience for the Nakoso IGCC facility, if necessary under confidential cover.

RESPONSE

As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1,* docketed on August 22, 2012, the Applicant objects to this Data Request.

BACKGROUND: POTENTIAL IMPACTS ON ENVIRONMENTAL JUSTICE COMMUNITIES ALONG RAW MATERIAL AND PRODUCT TRANSPORTATION ROUTES

The AFC identifies several environmental justice communities within a 6-mile radius of the Project site as well as in Tupman, Buttonwillow and Wasco, where the coal storage/transfer facility is located. The AFC determines whether or not these communities might experience disproportionately high and adverse effects as a result of the Project. (AFC, p. 5.8-24.) The AFC does not identify and evaluate potential impacts associated with fuel and product transportation on environmental justice communities along the transport routes for both raw materials and products. These include increased exposure to diesel particulate matter emissions and respirable particulate matter from coal dust losses from uncovered rail cars and the associated incremental cancer risk and other health impacts such as asthma, chronic obstructive pulmonary disease, and chronic bronchitis. In addition, the potential accidental release of hazardous substances along transportation routes may disproportionately affect environmental justice communities.

DATA REQUEST

93. Please identify environmental justice communities along the rail and truck transport routes for raw materials and products.

RESPONSE

Section 5.8, Socioeconomics/Environmental Justice, identified environmental justice communities within a 6-mile radius of the Project Site; and in addition, identified potential Environmental Justice communities and effects to three communities in Wasco. Thus, the 2012 Amended AFC identifies the Environmental Justice communities for the rail spur and truck transport feedstock routes.

Please refer to CEC Data Request (August 2012) Responses A105 to A107 for information involving diesel particulate matter health risk assessments performed for receptors along the train and truck delivery routes. These analyses identified that all sensitive receptors would fall below the cancer risk significance threshold of 10 in 1 million; therefore, environmental justice areas will also fall below the risk threshold, and not be adversely impacted by transportation diesel particulate matter (DPM) emissions.

As indicated in Applicant's responses to Data Requests 85a and 85c, the Applicant has requested additional time to address questions related to the potential accidental release of hazardous substances along transportation routes. Therefore, the Applicant will address this portion of the question at that time.

DATA REQUEST

94. Please evaluate whether there would be disproportionately high and adverse effects on environmental justice communities along the tracks. Please provide an adequate discussion of potential impacts related to air quality and public health (including emissions of combustion exhaust diesel particulate matter and respirable coal dust losses from transportation) and risks associated with transport of hazardous substances (e.g., anhydrous ammonia).

RESPONSE

Please refer to response to Data Request 93. Coal dust losses during transportation will not occur, because all rail cars and truck beds—for either alternative—will be covered. A risk assessment for the transport of anhydrous ammonia will be submitted in response to Data Request 85, for which a 30-day extension has been requested, as described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1*, docketed on August 22, 2012.

BACKGROUND: IMPACTS ON EXISTING RAIL TRAFFIC ASSOCIATED WITH RAIL TRANSPORT OF RAW MATERIALS AND PRODUCTS

The Project would require up to 20,051 train cars annually for transportation of coal and products (liquid sulfur, gasification solids, ammonia, urea, and urea ammonia nitrate. (AFC, Appx. E-5, p. 3.) The AFC does not discuss the potential impacts on the existing use of rail corridors.

DATA REQUEST

95. Please discuss the practical and theoretical capacity of the existing rail corridors that would be used for transportation of the Project's raw materials and products.

RESPONSE

As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1*, docketed on August 22, 2012, the Applicant is requesting additional time to address this Data Request.

DATA REQUEST

96. Please discuss whether the additional train cars would result in constraints to the passenger rail system or adversely affect the transport of freight in California and/or New Mexico.

RESPONSE

As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1*, docketed on August 22, 2012, the Applicant is requesting additional time to address this Data Request.

DATA REQUEST

97. Please indicate whether the rail system would require improvements to the existing rail corridors.

RESPONSE

As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 1*, docketed on August 22, 2012, the Applicant is requesting additional time to address this Data Request.

BEFORE THE ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION OF THE STATE OF CALIFORNIA
1516 NINTH STREET, SACRAMENTO, CA 95814
1-800-822-6228 – WWW.ENERGY.CA.GOV

AMENDED APPLICATION FOR CERTIFICATION FOR THE HYDROGEN ENERGY CALIFORNIA PROJECT

Docket No. 08-AFC-08A
(Revised 8/28/12)

APPLICANT
SCS Energy LLC
Marisa Mascaro
30 Monument Square, Suite 235
Concord, MA 01742
mmascaro@scsenergyllc.com

Tiffany Rau
2629 Manhattan Avenue, PMB# 187
Hermosa Beach, CA 90254
trau@heca.com

George Landman
Director of Finance and
Regulatory Affairs
Hydrogen Energy California, LLC
500 Sansome Street, Suite 750
San Francisco, CA 94111
glandman@heca.com

APPLICANT'S CONSULTANT
Dale Shileikis, Vice President
Energy Services Manager
Major Environmental Programs
URS Corporation
One Montgomery Street, Suite 900
San Francisco, CA 94104-4538
dale_shileikis@urscorp.com

COUNSEL FOR APPLICANT
Michael J. Carroll
Latham & Watkins, LLP
650 Town Center Drive, 20th Fl.
Costa Mesa, CA 92626-1925
michael.carroll@lw.com

INTERESTED AGENCIES
California ISO
e-recipient@caiso.com

Marni Weber
Department of Conservation
Office of Governmental and
Environmental Relations
(Department of Oil, Gas &
Geothermal Resources)
801 K Street MS 2402
Sacramento, CA 95814-3530
marni.weber@conservation.ca.gov

INTERVENORS
California Unions for Reliable Energy
Thomas A. Enslow
Marc D. Joseph
Adams Broadwell Joseph & Cardozo
520 Capitol Mall, Suite 350
Sacramento, CA 95814
tenslow@adamsbroadwell.com

Tom Frantz
Association of Irritated Residents
30100 Orange Street
Shafter, CA 93263
tfrantz@bak.rr.com

Kern-Kaweah Chapter
Of the Sierra Club
Andrea Issod
Matthew Vespa
85 Second St, Second Floor
San Francisco, CA 94105
andrea.issod@sierraclub.org
matt.vespa@sierraclub.org

INTERVENORS (con't.)
Environmental Defense Fund (EDF)
Timothy O'Connor, Esq.
123 Mission Street, 28th Floor
San Francisco, CA 94105
toconnor@edf.org

Natural Resources Defense Council
George Peridas
111 Sutter Street, 20th Fl.
San Francisco, CA 94104
gperidas@nrdc.org

*Kern County Farm Bureau, Inc.
Benjamin McFarland
801 South Mt. Vernon Avenue
Bakersfield, CA 93307
bmcfarland@kerncfb.com

*indicates change

ENERGY COMMISSION – DECISIONMAKERS

KAREN DOUGLAS
Commissioner and Presiding Member
karen.douglas@energy.ca.gov

ANDREW McALLISTER
Commissioner and Associate Member
andrew.mcallister@energy.ca.gov

Raoul Renaud
Hearing Adviser
raoul.renaud@energy.ca.gov

Eileen Allen
Commissioners' Technical Advisor for Facility Siting
eileen.allen@energy.ca.gov

Galen Lemei
Advisor to Presiding Member
galen.lemei@energy.ca.gov

Jennifer Nelson
Advisor to Presiding Member
jennifer.nelson@energy.ca.gov

David Hungerford
Advisor to Associate Member
david.hungerford@energy.ca.gov

ENERGY COMMISSION – STAFF

Robert Worl
Project Manager
robert.worl@energy.ca.gov

John Heiser
Associate Project Manager
john.heiser@energy.ca.gov

Lisa DeCarlo
Staff Counsel
lisa.decarlo@energy.ca.gov

ENERGY COMMISSION – PUBLIC ADVISER

Jennifer Jennings
Public Adviser's Office
publicadviser@energy.ca.gov

DECLARATION OF SERVICE

I, Dale Shileikis, declare that on September 4, 2012, I served and filed a copy of the attached Responses to Sierra Club Data Requests Nos. 1 through 97, dated August, 2012. This document is accompanied by the most recent Proof of Service list, located on the web page for this project at:
http://www.energy.ca.gov/sitingcases/hydrogen_energy/index.html

The document has been sent to the other parties in this proceeding (as shown on the Proof of Service list) and to the Commission's Docket Unit or Chief Counsel, as appropriate, in the following manner:
(*Check all that Apply*)

For service to all other parties:

_X_ Served electronically to all e-mail addresses on the Proof of Service list;

___ Served by delivering on this date, either personally, or for mailing with the U.S. Postal Service with first-class postage thereon fully prepaid, to the name and address of the person served, for mailing that same day in the ordinary course of business; that the envelope was sealed and placed for collection and mailing on that date to those addresses marked *"hard copy required" or where no e-mail address is provided.

AND

For filing with the Docket Unit at the Energy Commission:

_X_ by sending one electronic copy to the e-mail address below (preferred method); OR

___ by depositing an original and 12 paper copies in the mail with the U.S. Postal Service with first class postage thereon fully prepaid, as follows:

CALIFORNIA ENERGY COMMISSION – DOCKET UNIT
Attn: Docket No. 08-AFC-08A
1516 Ninth Street, MS-4
Sacramento, CA 95814-5512
docket@energy.ca.gov

OR, if filing a Petition for Reconsideration of Decision or Order pursuant to Title 20, § 1720:

___ Served by delivering on this date one electronic copy by e-mail, and an original paper copy to the Chief Counsel at the following address, either personally, or for mailing with the U.S. Postal Service with first class postage thereon fully prepaid:

California Energy Commission
Michael J. Levy, Chief Counsel
1516 Ninth Street MS-14
Sacramento, CA 95814
michael.levy@energy.ca.gov

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct, that I am employed in the county where this mailing occurred, and that I am over the age of 18 years and not a party to the proceeding.

Dale Shileikis