Responses to Sierra Club Data Requests: Nos. 1 through 97 (30-Day Extension)

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

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RESPONSES TO DATA REQUESTS 1 THROUGH 97 FROM SIERRA CLUB

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TABLES

LIST OF ACRONYMS AND ABBREVIATIONS USED IN RESPONSES

ACC	air-cooled condenser
AFC	Application for Certification
BACT	Best Available Control Technology
BGRP	brackish groundwater remediation project
BVWSD	Buena Vista Water Storage District
CARB	California Air Resources Board
CEC	California Energy Commission
°F	degrees Fahrenheit
FWP	fire water pump
gpm	gallons per minute
HAP	hazardous air pollutant
HECA	Hydrogen Energy California
IGCC	Integrated Gasification Combined Cycle
mm	million
MW	megawatt
NO_X	oxides of nitrogen
petcoke	petroleum coke
PM	particulate matter
RH	relative humidity
ROM	rough order of magnitude
SCR	selective catalytic reduction
syngas	synthesis gas
TAC	Toxic Air Contaminant
U.S. EPA	United States Environmental Protection Agency
VOC	volatile organic compound
WCC	water-cooled condenser

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.

RESPONSE

a. The MHI technology is a newer design and has features that work to reduce capital costs, reduce operations and maintenance costs, improve efficiency, and improve product availability. All of these factors work to lower the cost of the finished products that Hydrogen Energy California (HECA) will produce.

The 2009 Revised Application for Certification (AFC) was based on an entrained flow, slurry-fed, refractory-lined, quench design featuring two operating 900-cubic-foot reactors with a common spare to facilitate maintenance on feed nozzles, refractory, and other wear items. For comparison, the MHI gasifier is a two-stage, dry feed, entrained flow, membrane wall gasifier that employs a synthesis gas (syngas) cooler for steam production. The membrane wall and feed nozzle design in the MHI configuration is expected to provide a longer run time between shutdowns. A single MHI gasifier is capable of producing 50 percent more syngas at a level of availability comparable to the original configuration—which required three vessels along with their associated structures, appurtenances, piping, and instrumentation. Although the gasifier is larger and more complex, the Project expects to capture economies of scale, reductions in equipment count, and a reduction in the frequency of shutdowns; this would translate into lower costs, higher efficiencies, and lower emissions.

See the response to Data Request 16 below for additional information on the MHI gasifier.

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.***

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[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

a. As indicated in the Data Request, many key features of this Project have been demonstrated in part by Dakota gasification and in part by the many other facilities where the individual technologies that HECA will use have been demonstrated and proven in a related application. The HECA Project will combine and use these technologies to generate electricity and products with high levels of carbon capture and low criteria emissions. Although the integration of these technologies requires advances in the design and operation of the facility, HECA does not expect any particular technological or other problems that would preclude successful integration. By integrating these technologies, HECA will advance the state of the art in low carbon power generation and manufacturing; this is an example of the kind of creative thinking needed to solve the climate crisis.

b. HECA believes that the aforementioned project (and other plants) provide an important underlying precedent and technical basis for the HECA Project. The Applicant is not familiar enough with the specific technical details of the Weyburn/Midale project to discuss any differences between the projects.

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

a. Please see Applicant's response to Data Request 5a.

b. The MHI gasifier has the *theoretical capability* to achieve feedstock flexibility similar to that of the previously proposed General Electric refractory lined gasifier; however, more operating experience is necessary to determine whether this theoretical capability can be fully realized. During the gasification process, ash from coal and petroleum coke (petcoke) is melted, and then cooled by a membrane wall in the MHI design, where it vitrifies to form a protective layer. This protective function is a critical design element of all entrained flow gasifiers, and the melting point, viscosity, and other important properties are very dependent on the ash properties of the feedstock. Petcoke has a much different quantity and composition of ash; demonstration at scale must be incorporated into the experience base of MHI before the full range of feedstock flexibility can be determined and guarantees can be made. This is part of the normal technology deployment/learning cycle, and is consistent with the step-by-step progression that other technologies have followed.

c. All commercially viable gasifier technologies were reviewed when the MHI technology was selected.

d. The vendor performance guarantees for all of the plant components will be included in the agreements currently under negotiation for engineering, procurement, and construction, and operations and maintenance. The details of these guarantees, once finalized, are very closely held by the equipment manufacturers, because they determine each manufacturer's competitive position in the markets.

e. HECA requested feedstock flexibilities that would maximize its ability to feed various blends of coals and petcoke from multiple refineries.

f. To date, the maximum performance guarantee the manufacturer has been willing to provide HECA is a 25 percent petcoke, 75 percent coal blend.

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 ("NO_X") 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 NO_X, 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 NO_X concentration in vent gas of 15 ppmv "based on Uhde EnviNO$_X$ system" and 50% NO2/NO_X 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

The Applicant requires an additional 30 days to respond to this Data Request.

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

The Applicant expects to enter into a long-term truck transportation supply chain management agreement with a single contractor for fuel, product, and waste byproducts. The agreement will include provisions addressing ongoing compliance with applicable emission standards, including tractor emissions certification requirements, and tractor age and life cycle. The contractor's performance in providing transportation services will be controlled by the Applicant through the terms of this agreement.

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

The Applicant does not intend to purchase trucks for materials delivery. Instead, as stated in the response to Data Request 43, the Applicant expects to enter into a long-term transportation supply chain management agreement with a contractor. At the commencement of operations, the average fleet mix will consist of tractors manufactured in 2010 or later. Furthermore, based on discussions with the long-term transportation contractor, it is expected that the contractor will use an operational model based on a tractor replacement life cycle that will ensure a projected maximum fleet age of 30 months. This model will ensure that the materials are transported in accordance with the most current safety standards, certified emissions performance standards, and original equipment manufacturer engine efficiency standards available throughout the life of the Project.

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

Please see Applicant's response to Data Requests 43 and 44.

BACKGROUND: NO_X EMISSIONS FROM AUXILIARY BOILER

The Project would use a natural gas-fired auxiliary boiler equipped with low-NO_X 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 NO_X BACT emission limit for the auxiliary boiler of 0.006 pounds per million British thermal units ("lb/MMBtu") based on a NO_X concentration of 5 parts per million by volume, dry ("ppmvd") at 3% oxygen. The AFC's emission estimates assume that NO_X 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 NO_X in the exhaust gas, NO_X 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 NO_X 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

Emissions associated with the auxiliary boiler during the commissioning period were addressed in the response to Data Request 51.

The oxides of nitrogen (NO_X) emission factor for the auxiliary boiler during startup, before the selective catalytic reduction (SCR) catalyst has reached its optimal operating temperature, is 0.060 pounds per million British thermal units. This is based on a NO_X concentration of 50 parts per million by volume, dry at 3 percent oxygen.

DATA REQUEST

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

RESPONSE

During startup before the SCR has reached operating temperature, NO_X emissions from the auxiliary boiler will be at a rate of 50 parts per million, for 4 hours per startup, with two startups per year. This results in 20.45 pounds of NO_X per year before the SCR has reached operating temperature during startup.

Please note that the annual emissions in the Amended AFC for the auxiliary boiler are based on the auxiliary boiler operating at full capacity for 25 percent of the year, to provide operational flexibility; however, the facility anticipates significantly less usage of this unit. Therefore, the annual emissions presented in the Amended AFC (1.4 tons per year NO_X) more than account for these emissions during startup.

During shutdown, the SCR will be 100 percent effective, and there will not be higher emissions from the auxiliary boiler.

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

The Applicant requires an additional 30 days to respond to 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

The Applicant requires an additional 30 days to respond to 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.

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[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

Elevated flares have a simpler design, and therefore are more reliable than ground flares. Elevated flares burn the flared gasses at the flare tip, which is mounted on the open end of the flare header. There are no potential obstructions in the flare header between the outlet of the various pressure safety valves and the flare tip. Ground flares typically have staged burners, which require a control valve to regulate the flow to individual burners as the total flow to the flare increases. The individual burners have individual pilots and controls. The increased number of active components increases the probability of malfunctions, which in turn increases concerns regarding reliability. Elevated flares are inherently safer than ground flares because elevated flares are physically removed from personnel on the ground; ground flares rely on the refractory shell to separate personnel on the ground from the heat released by the combustion of the flared gasses. Moreover, elevation of flares provides better dispersion of the flared gasses, protecting people on the ground—both operating personnel within the plant, and the public beyond the limits of the Project Site. This comparison applies to all three of the Project's flares.

DATA REQUEST

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

RESPONSE

The Sierra Club's background statement for this Data Request suggests that the considered use of ground flares for the proposed PurGen One facility in Linden, New Jersey, and the proposed Integrated Gasification Combined Cycle (IGCC) Unit B at the Curtis H. Stanton Energy Center near Orlando, Florida, lead to the conclusion that ground flares rather than elevated flares are best available control technology (BACT). BACT is a case-by-case determination, and technology deployed at one facility, even if it was determined to be the BACT for that facility (as asserted in the background discussion above), would not necessarily be the BACT for another facility. Furthermore, to the best of the Applicant's knowledge, neither of these two projects has progressed into detailed design or construction. The Applicant also understands that the PurGen One facility was conceived for a tightly constrained site, which did not afford the space necessary to use an elevated flare. The inherently safer design addressed in the Applicant's response to Data Request 55 is the basis for selecting elevated flares.

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.

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[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

The Applicant switched to an elevated flare due to the inherently safer design (see the response to Data Request 55).

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

Although it is feasible to use a ground flare for routine periodic flaring, there is no routine periodic flaring planned for the Applicant's current plant configuration. With the previous plant configuration, there was a need for routine flaring during regularly scheduled gasification maintenance activities. The current gasification process only requires flaring during start-up or unplanned events. The inherently safer design addressed in the Applicant's response to Data Request 55 is the basis for selecting an elevated flare.

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

Because the United States Environmental Protection Agency (U.S. EPA) has not published emissions factors for hazardous air pollutants (HAPs) from flares, the emission factors for HAPs from natural gas combustion in boilers have been used. During normal operation of the pilot, natural gas is being combusted—the same fuel represented in the emission factors. During start up and shut down of the gasifier and Rectisol flares, syngas is being burned, which is composed primarily of hydrogen. In this case, the applied emission factors are an overestimate of HAPs from flare combustion. Therefore, the emission factors used are appropriate and conservative.

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 noted in the Applicant's response to Data Request 59, the emission estimates for HAPs from the flares are appropriate. Emissions estimates of HAPs from flaring at an existing IGCC plant could not be identified.

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

The Applicant inquired with MHI, and was advised that MHI had only limited access to flare emissions data at the Nakoso facility in Japan. MHI is unable to share these data because of an existing confidentiality agreement with the Nakoso facility owner. Furthermore, the applicability of such data to the HECA Project would be limited in that the Nakoso plant feedstock and plant configuration are different from that of the HECA Project (100 percent Chinese coal, very little gas clean-up, no carbon dioxide capture, etc.).

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 requested, the cost effectiveness analysis in Tables 1 through 3 of the Water Minimization Study (included in 2008 Revised AFC, Appendix X) has been revised to account for the use of brackish water at three cycles of concentration. The revised tables are provided below, and include effects of brackish water being used in the Power Block Cooling Tower, the Process Cooling Tower, and the Air Separation Unit Cooling Tower (see Tables 71-1 through 71-3).

This cost effectiveness analysis update continues to demonstrate that the water-cooled condenser (WCC) system is the appropriate system for the HECA Project. The WCC system will have the lowest starting capital investment, the highest plant output, and the smallest plot space requirement. This conclusion is consistent with similar analyses performed for other projects, and specifically with the technical report sponsored by EPRI and the California Energy Commission (CEC), titled "*Comparison of Alternate Cooling Technologies for California Power Plants: Economic, Environmental, and Other Tradeoffs.*"

In addition to the economic and efficiency benefits of using WCCs, there are beneficial groundwater impacts, as outlined in Amended AFC Section 5.14.3, which states:

> *"Withdrawal of impaired quality groundwater to alleviate impacts on agriculture is consistent with the Drainage Control and Irrigation Conservation Programs described in the Buena Vista Water Storage District (BVWSD) Groundwater Management Plan and is part of BVWSD's brackish groundwater remediation project (BGRP), which provides benefits for BVWSD's Buttonwillow Service Area. BVWSD's BGRP was analyzed in the Final Environmental Impact Report for the Buena Vista Water Storage District Buena Vista Water Management Program, dated December 2009.*
>
> *The process water supply for the Project will consist of groundwater of impaired quality. Drawdown (lowered water levels) in response to pumping at the proposed water supply well field area will be localized around the well field itself and normal BVWSD recharge activities would offset Project-specific pumping.*
>
> *Overall Project-specific pumping is seen as a benefit to BVWSD in that it impedes eastward flow of poor quality groundwater, enhances westward flow of good quality groundwater, and removes a significant volume of total dissolved solids/salts from the local aquifer system. The Project also would use groundwater that other users do not want and find objectionable for their needs. As such there is no cumulative impact expected, but rather a regional benefit."*

Table 71-1
Brackish Water Usage Summary at Summer Design Conditions
(102 °F/16 Percent RH)

Design	WCC	ACC
Output Effect	Base	(27.4 MW)
Cycles of Concentration	3	3
Total Plant Makeup Water	5,980 gpm	2,510 gpm
Makeup Water Savings	Base	3,470 gpm

Notes:

ACC = air cooled condenser
°F = degrees Fahrenheit
gpm = gallons per minute
MW = megawatt
RH = relative humidity
WCC = water-cooled condenser

Table 71-2
Brackish Water Usage Summary at Average Ambient Conditions
(65 °F/60 Percent RH)

Design	WCC	ACC
Output Effect	Base	(8.4 MW)
Cycles of Concentration	3	3
Total Plant Makeup Water	3,720 gpm	1,570 gpm
Makeup Water Savings	Base	2,150 gpm

Notes:

ACC = air cooled condenser
°F = degrees Fahrenheit
gpm = gallons per minute
MW = megawatt
RH = relative humidity
WCC = water-cooled condenser

Table 71-3
ROM Cost and Plot Space Impact using Brackish Water

Design	WCC	ACC
Cost Delta	Base	~+32 mm
Total Required Plot Space	1.5 acre	2.4 acre

Notes:

ACC = air cooled condenser
mm = million
ROM = rough order of magnitude
WCC = water-cooled condenser

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.

RESPONSE

a. A 7 percent interest level was assumed, based on economic conditions at the time of the analysis. Even assuming the lowest possible interest rate presented in the U.S. EPA Guidance (U.S. EPA, 2002) of 5.5 percent, and accounting for the 25-year Project life, the air cooled condenser (ACC) would still exceed cost effectiveness thresholds. At 5.5 percent interest and 25-year project life, the capital recovery factor would be 0.07455. As presented in the response to Data Request 71, the capital cost estimate of replacing the cooling towers with ACC is $32 million. This would control all cooling tower emissions of 25.5 tons of particulate matter (PM) per year; the cost would be approximately $94,000 per ton of PM controlled. Even if the cost of emission reduction credits were excluded from this very conservative cost estimate, the cost to control one ton of PM would be approximately $92,000. Even this very conservative estimate far exceeds the most recent cost effectiveness threshold from the San Joaquin Valley Air Pollution Control District for PM 10 microns in diameter or less, which is $11,400 per ton.

b. The design life of the previous Project presented in the 2009 Revised AFC, upon which the 2008 Water Usage Minimization Study was based, was 20 years.

c. The design operating life of an ACC can be specified to align with the design life requirements for most projects. Twenty-five years is a typical design life. The operational life of some of the components of the ACC may be shorter than 25 years, and would require maintenance to retain the design performance. For example, the tubes on an ACC are exposed to the elements and could be damaged by wind-blown debris in a storm; such damage would have to be repaired.

Reference:

U.S. EPA (U.S. Environmental Protection Agency), 2002. Air Pollution Control Cost Manual. Sixth Edition. EPA/452/B-02-001. January 2002.

BACKGROUND: EMISSIONS FROM THE COOLING TOWERS

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.

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

b. The estimated toxic air contaminant (TAC)/HAP emissions associated with the use of sulfuric acid in the cooling tower are zero. There are no sulfuric acid emissions, because the sulfuric acid immediately reacts to form sulfate salts when added to the cooling water. The sulfate salts are not TACs/HAPs.

In a California study of chloroform emissions and exposure (CARB, 1990), a cooling tower emission factor of 0.0034 pounds of chloroform per pound of chlorine was devised. Using this emission factor and an estimated annual use of sodium hypochlorite, 88.5 pounds per year of chloroform would be emitted between all cooling towers. The calculation assumes that all chlorine in the sodium hypochlorite solution is available for the chloroform reaction, and also assumes that sufficient biological loading is present for full conversion of chlorine to chloroform. However, biological loading is expected to be very low. Both of these assumptions are conservative, and the calculated emissions are an overestimate.

Reference

CARB (California Air Resources Board), 1990. "Proposed Identification of Chloroform as a Toxic Air Contaminant. Part A Exposure Assessment." September 1990.

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

Tank parameters and estimates of fugitive volatile organic compounds (VOCs) from the methanol tank and diesel storage tanks are provided in Table 76-1. Fugitive emissions were calculated using the U.S. EPA TANKS model (U.S. EPA, 2005). It should be noted that the diesel tanks are not individual tanks, but an integral part of the base of the diesel generator skid. There are no other organic liquid storage tanks at the site. Roof landing losses apply only to floating roof tanks, whereas all tanks at the site have fixed roofs, so this does not apply. The methanol tank is equipped with a vent scrubber that has a control efficiency of 99.977 percent, but no tanks are equipped with a tank vent oxidizer.

Table 76-1
Organic Liquid Storage Tanks, Parameters and Fugitive Emissions

Tank ID	Description	Capacity (gallon)	Turnovers per year (#)	Annual VOC emissions (lb/year)
Diesel 1	800-gallon diesel generator #1	800	0.75	0.56
Diesel 2	800-gallon diesel generator #2	800	0.75	0.56
Diesel FWP	400-gallon diesel fire pump	400	0.30	0.34
Methanol	300,000-gallon storage tank	300,000	1.32	3.72
Total				**5.18**

Notes:

FWP = fire water pump
lb/year = pounds per year
VOC = volatile organic compound

Reference

U.S. EPA (U.S. Environmental Protection Agency), 2005. TANKS, Storage Tank Emission Calculation Software. Version 4.0.9d. Available at http://www.epa.gov/ttnchie1/software/tanks/index.html.

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

Fugitive VOC emissions were updated and provided in the response to CEC Data Request A16. The material balances in the waste water treatment area were examined, and it was determined that there are no VOCs of significant concentration that would warrant inclusion in the updated estimates.

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.

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

The Applicant requires an additional 30 days to respond to this Data Request.

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

The Applicant requires an additional 30 days to respond to 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

The Applicant requires an additional 30 days to respond to this Data Request.

DATA REQUEST

97. Please indicate whether the rail system would require improvements to the existing rail corridors.

RESPONSE

The Applicant requires an additional 30 days to respond to this Data Request.

BEFORE THE ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION OF THE STATE OF CALIFORNIA
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AMENDED APPLICATION FOR CERTIFICATION FOR THE HYDROGEN ENERGY CALIFORNIA PROJECT

Docket No. 08-AFC-08A
(Revised 8/28/12)

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DECLARATION OF SERVICE

I, Dale Shileikis, declare that on October 3, 2012, I served and filed a copy of the attached Responses to Sierra Club Data Requests: Nos. 1 through 97 (30-Day Extension), dated October, 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;

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AND

For filing with the Docket Unit at the Energy Commission:

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___ 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
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1516 Ninth Street, MS-4
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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
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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