DOCKETED

Docket Number:	08-AFC-08A
Project Title:	Hydrogen Energy Center Application for Certification Amendment
TN #:	201026
Document Title:	Letter from Michael Carroll to Robert Oglesby re Senate Bill 1368 Emissions Performance Standard
Description:	N/A
Filer:	Paul Kihm
Organization:	Latham & Watkins LLP
Submitter Role:	Applicant Representative
Submission Date:	10/23/2013 3:31:07 PM
Docketed Date:	10/23/2013

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LATHAM & WATKINS LLP

October 23, 2013

Mr. Robert Oglesby
Executive Director
California Energy Commission
1516 Ninth Street
Sacramento, CA 95814

File No. 050056-0001

Re: Senate Bill 1368 Emissions Performance Standard
Hydrogen Energy California Power Plant (08-AFC-8A)

Dear Mr. Oglesby:

Hydrogen Energy California, LLC ("Applicant" or "HECA") proposed the Hydrogen Energy California integrated gasification combined cycle facility (08-AFC-8) on July 31, 2008 ("Project"). On May 2, 2012, Applicant filed an Amended AFC and a new Docket number, 08-AFC-8A, was assigned.

At the Preliminary Staff Assessment/Draft Environmental Impact Statement Workshop held at the Buttonwillow Recreation and Park District Multi-Purpose Facility in Buttonwillow, California on Tuesday, September 17, 2013, the Applicant indicated that it would submit to California Energy Commission ("CEC") Staff a technical memorandum addressing the Project's compliance with the Senate Bill ("SB") 1368 Emissions Performance Standard ("EPS").

The enclosed white paper and URS technical appendix constitute the discussed technical memorandum. Applicant appreciates the opportunity to comment on CEC Staff's examination of HECA's compliance with the SB 1368 EPS and respectfully requests that CEC Staff give due consideration to the analysis enclosed herein.

Very truly yours,

/s/ Michael Carroll

Michael Carroll
of LATHAM & WATKINS LLP

enclosures

Senate Bill 1368 Emissions Performance Standard Compliance Review – Hydrogen Energy California Power Plant

I. HECA ADVANCES CALIFORNIA'S CLIMATE STRATEGY

Hydrogen Energy California, LLC ("Applicant" or "HECA") fully supports an in-depth and rigorous examination of the Project's overall efficiency and carbon footprint, including an appropriate Senate Bill ("SB") 1368 Emissions Performance Standard ("EPS") compliance review. The Hydrogen Energy California integrated gasification combined cycle facility ("Project") will be a clean and reliable alternative energy solution that will advance California's and the nation's long term climate strategy.

Many scientists, academics, and policy makers acknowledge that carbon capture and sequestration ("CCS") will play a significant role in decarbonizing electricity and that it is critical for California to meet its 2050 greenhouse gas ("GHG") emission reduction goals. HECA will demonstrate that capturing carbon is a safe and viable strategy for mitigating global climate change in the power and manufacturing industries. Through the combination of hydrogen fuel production and CCS, HECA will "raise the bar" for environmental standards for these industries.

The U.S. Environmental Protection Agency ("EPA") recently proposed limits on carbon emissions from future power plants, designating CCS the technology of choice for fossil units.[1] EPA identified CCS as the "best system of emission reduction" ("BSER") for new coal plants. The draft rulemaking states that "efficiency-improvement technologies alone result in only very small reductions in [carbon dioxide] CO_2 emissions, especially in contrast to those achieved by the application of CCS."[2] EPA stated that four large-scale CCS projects are evidence that CCS is being commercially demonstrated: "The existence and apparent ongoing viability of these projects which include CCS justify a separate BSER determination for new fossil fuel-fired utility boilers and IGCC power plants."[3] EPA repeatedly referenced HECA as a one of those projects that is in advanced stages of development.[4]

The U.S. Department of Energy ("DOE") also recognizes HECA's importance in advancing CCS:

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[1] EPA, "Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units" (Sept. 20, 2013) (prepublication version) [EPA-HQ-OAR-2013-0495] (available at http://www2.epa.gov/sites/production/files/2013-09/documents/20130920proposal.pdf) (hereafter "NSPS for GHGs").

[2] *Id.* at 27.

[3] *Id.* at 22.

[4] *See e.g., id.* at 242.

> The project will be among the cleanest of any commercial solid fuel power plant built or under construction and will significantly exceed the emission reduction targets for 2020 established under the Energy Policy Act of 2005. In addition, emissions from the project plant will be well below the California regulation requiring baseload plants to emit less greenhouse gases than comparably-sized natural gas combined cycle power plants [i.e., the SB 1368 EPS]. … Carbon capture and storage (CCS) technologies offer great potential for reducing CO_2 emissions and mitigating global climate change, while minimizing the economic impacts of the solution.[5]

At the State level, California has been a global leader in implementing programs to address climate change. The state's GHG mitigation program has its roots in Executive Order S-3-05, which established GHG emission reduction goals for 2010, 2020, and 2050, and in the Global Warming Solutions Act of 2006 ("AB 32"), which committed the state to reduce 2020 emissions of GHG to 1990 levels, and to adopt maximum feasible and cost-effective GHG emission reductions for specified source categories. These aggressive climate goals make California a unique location in which to examine the implications of early deployment of CCS technology.

The Climate Change Scoping Plan that the California Air Resources Board ("ARB") adopted pursuant to AB 32 recognizes that CCS can play a role in helping the state meet its long-term GHG reduction goals:

> CO_2 can be prevented from entering the atmosphere through carbon capture and storage (CCS). This consists of separating CO_2 from industrial and energy-related sources and transporting the CO_2 to a storage location for long-term isolation from the atmosphere. … Large point sources of CO_2 that may pursue CCS include large power plants, fossil fuel-based hydrogen production plants, and oil refineries. … **<u>California should both support near-term advancement of the technology and ensure that an adequate framework is in place to provide credit for CCS projects when appropriate</u>**.[6]

This month ARB released a discussion draft of the First Update to the Climate Change Scoping Plan that further emphasizes the need for CCS:

> Looking beyond 2020, California will need to continue to transform the energy sector with wholesale changes to its current electricity and natural gas systems. **<u>Developing a near zero</u>**

[5] U.S. Department of Energy, HECA Project Facts (November 2011).

[6] ARB, Climate Change Scoping Plan – A Framework for Change, at 116-117 (December 2008)(internal citations omitted)(emphasis added).

> **emission strategy for the energy sector will require** efficient next-generation technology; vast new low carbon generation resources; a robust transmission and distribution infrastructure; and **carbon capture, utilization, and sequestration for the remaining fossil generation**.[7]

The deployment of CCS can materially help California to achieve its long-term GHG emissions reduction goals. The International Energy Agency's 2011 World Energy Outlook P4 describes CCS as a "key abatement option" that accounts for 18 percent of emission savings in a key modeled scenario. The International Energy Agency further reports that CCS investment must be made "now" if emission reductions are to be achieved economically. The August 2010 report of the President's Interagency Task Force on CCS describes the technology as one that can "greatly reduce" GHG emissions while playing an "important role in achieving national and global" GHG reduction goals. In its December 2010 report, the California Carbon Capture and Storage Review Panel states that "[t]here is a public benefit from long-term geologic storage of [carbon dioxide] as a strategy for reducing GHG emissions to the atmosphere as required by California laws and policies."[8]

As indicated below, the Project easily would comply with the SB 1368 EPS. Moreover, the Project's SB 1368 CO_2 emission performance validates its ability to facilitate achievement of long-term federal, state, and international GHG emissions reduction goals.

II. THE CALIFORNIA PUBLIC UTILITIES COMMISSION WILL DETERMINE THE PROJECT'S EPS COMPLIANCE

The California Legislature directed the California Energy Commission ("CEC") to implement the SB 1368 EPS for Publicly Owned Utilities ("POUs") and the California Public Utilities Commission ("CPUC") to implement the EPS for Investor Owned Utilities ("IOUs"):

> No load-serving entity or local publicly owned electric utility may enter into a long-term financial commitment unless any baseload generation supplied under the long-term financial commitment complies with the greenhouse gases emission performance standard established by the commission, pursuant to subdivision (d), for a load-serving entity, or by the Energy Commission,

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[7] ARB, Climate Change Scoping Plan First Update – Discussion Draft for Public Review and Comment, at ES-4. (October 1, 2013)(emphasis added); *id.* at 79 ("Carbon capture, utilization, and sequestration can fill the void where low carbon electricity and biofuels are not feasible. The capture and long-term geologic storage of carbon dioxide may represent one way to 'green up' fossil fuels and further mitigate climate change.").

[8] California Carbon Capture and Storage Review Panel, Findings and Recommendations by the California Carbon Capture and Storage Review Panel, at 3 (December 2010)(available at http://www.climatechange.ca.gov/carbon_capture_review_panel/).

> pursuant to subdivision (e), for a local publicly owned electric utility.[9]
>
> …
>
> The [public utilities] commission shall not approve a long-term financial commitment by an electrical corporation unless any baseload generation supplied under the long-term financial commitment complies with the greenhouse gases emission performance standard established by the commission pursuant to subdivision (d).[10]
>
> …
>
> The Energy Commission shall adopt regulations for the enforcement of this chapter with respect to a local publicly owned electric utility.[11]

The electricity off-taker(s) for HECA are expected to be IOU(s). Therefore, it is expected that the CPUC will assess HECA's EPS compliance. Accordingly, the CPUC's decisions on the SB 1368 EPS govern the application of the EPS to HECA, not the CEC's regulations implementing the EPS for Publicly Owned Utilities.

While Public Resource Code Section 25500 grants broad jurisdiction to the CEC to issue a certificate in lieu of any state permit or certificate, this authority does not give the CEC the ability to override the CPUC's SB 1368 EPS compliance decisions. Otherwise, the express provisions of SB 1368 dividing authority over EPS reviews based on the identity of the utility (i.e., POU versus IOU) would be rendered void and of no effect. Such an outcome is strongly disfavored by the courts, particularly where it is possible, as it is here, to give SB 1368 meaning and comply with earlier-adopted statutes.

Moreover, Public Utilities Code Section 8341(b)(4) directs the CPUC when "determining whether a long-term financial commitment is for baseload generation" to consider, among other things, "any certification received from the Energy Commission…." This express direction to the CPUC implies that the Legislature was fully aware of the CEC's power plant siting certification procedures and chose to imbue the CPUC with authority to review the SB 1368 EPS compliance of power plants that deliver electricity to IOUs. If the CEC's certification could override the CPUC's decision on EPS compliance, then Public Utilities Code Section 8341(b)(4) would be rendered void and of no effect. Rather, Public Resource Code Section 25500 and Public Utilities Code Section 8341 should be reconciled to ensure they both have meaning. In sum, the CPUC will perform the SB 1368 compliance review for HECA if, as expected, the electricity off-taker(s) for HECA are IOU(s).

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[9] Public Utilities Code § 8341(a).

[10] *Id.* at § 8341(b)(1).

[11] *Id.* at § 8341(c)(1).

III. PURPOSE AND ROLE OF THE SB 1368 EPS

CEC Staff and select Intervenors in the CEC certification process (e.g., Sierra Club) are advocating for an overly broad analysis of HECA's compliance with the SB 1368 EPS. In doing so, they are not acknowledging the purpose of a SB 1368 EPS compliance review and its role in California's efforts to address climate change.[12] In short and as explained herein, a SB 1368 EPS compliance review should be limited to the electricity generation component of HECA and not expanded beyond that to cover other aspects of the Project. While the carbon efficiency of the entire Project is an important matter worthy of discussion and analysis during the CEC's certification process for purposes of the California Environmental Quality Act, and during DOE's review under the National Environmental Policy Act ("NEPA"), such a broad assessment is improper for a SB 1368 EPS compliance review.

A. Overview of SB 1368

SB 1368 limits long-term financial commitments in baseload generation by the state's utilities to power plants that meet an EPS, jointly established by the CEC and the CPUC.[13] Specifically, the SB 1368 EPS applies to electricity from new power plants, new investments in existing power plants, and new or renewed contracts with terms of five years or more where the power plant is intended and designed to operate as a baseload power plant ("covered procurements"). Accordingly, if a power plant intends to sell electricity to a California utility under a long-term contract (five years or more), then the utility must demonstrate that the power plant complies with the EPS. As correctly indicated in the Preliminary Staff Assessment/Draft Environmental Impact Statement ("PSA/DEIS"), it is expected that the Project will be subject to the EPS.

B. Relationship To The Cap-And-Trade Program

When establishing the proper scope of a SB 1368 EPS compliance review, it is critical to recognize that HECA's GHG emissions would be subject to reporting under California's Mandatory Reporting of Greenhouse Gas Emissions ("MRR")[14] and regulation by its cap-and-trade program.[15] Exclusion of CO_2 emissions not associated with electricity generation (e.g., emissions associated with the fertilizer manufacturing process) from a SB 1368 EPS compliance review does not somehow allow these emissions to escape regulation. Rather, these CO_2 emissions, plus those associated with electricity generation, explicitly are covered by the cap-and-trade program and are expected to trigger compliance obligations (and associated costs) for

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[12] *See e.g.*, Letter from Andrea Issod, Staff Attorney, Sierra Club Environmental Law Program to Mr. John Heiser, CEC, Re: Sierra Club Comments on Carbon Sequestration and Greenhouse Gas Emissions (08-AFC-8A)(September 27, 2013)(Docket TN# 200639), at 5-6 (misidentifying the "intent of SB 1368" as "to reduce greenhouse gas emissions associated with electricity generation contracted by California utilities.").

[13] Public Utilities Code § 8340 et seq.

[14] 17 Cal. Code Regs. §§ 95100-95158.

[15] 17 Cal. Code Regs. §§ 95800 to 96023.

HECA. Further, as indicated in the PSA/DEIS, OEHI's enhanced oil recovery operations also are expected to be subject to the MRR and the cap-and-trade program. Therefore, a SB 1368 EPS compliance review can and should be limited to the electricity generation component of HECA and need not be expanded beyond that to cover other HECA components in an attempt to capture unrelated CO_2 emissions that will be regulated by other California programs.

C. SB 1368 Focuses On Protection Of Utility Ratepayers

SB 1368 was a companion bill to AB 32, which has a broad reach and an aggressive mandate to reduce statewide GHG emissions to 1990 levels by 2020. Numerous GHG emission reduction measures have been promulgated by ARB under the authority granted to it by AB 32, including but not limited to the economy-wide cap-and-trade program. In stark contrast, SB 1368 is narrowly focused on the protection of electric utility ratepayers and is not designed to reduce greenhouse gas emissions associated with electricity generation, a task explicitly and directly assigned to the aforementioned cap-and-trade program. As explained by the CPUC:

> An EPS is needed to reduce California's financial risk exposure to the compliance costs associated with future GHG emissions (state and federal) and associated future reliability problems in electricity supplies. Put another way, it is needed to ensure that there is no "backsliding" as California transitions to a statewide GHG emissions cap: If LSEs [Load Serving Entities] enter into long-term commitments with high-GHG emitting baseload plants during this transition, **California ratepayers will be exposed to the high cost of retrofits (or potentially the need to purchase expensive offsets) under future emission control regulations**. They will also be exposed to potential supply disruptions when these high-emitting facilities are taken off line for retrofits, or retired early, in order to comply with future regulations. **A facility-based GHG emissions performance standard protects California ratepayers from these backsliding risks and costs** during the transition to a load-based GHG emissions cap.[16]

SB 1368's express (and limited) purpose of protecting California ratepayers is the lens through which HECA's SB 1368 EPS compliance must be viewed and analyzed. A SB 1368 EPS compliance review cannot satisfy its purpose if it includes CO_2 emissions that would not impose costs on California ratepayers.

The CPUC conducted a proceeding on how power plants' GHG emissions will affect California ratepayers.[17] ARB designed the cap-and-trade program so that a generator of electricity includes its cap-and-trade compliance costs in the price it charges an IOU for power delivered. The CPUC then allows the IOU to recover that cap-and-trade compliance cost from its ratepayers. Accordingly, the costs to California ratepayers due to HECA's GHG emissions

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[16] CPUC, Decision 07-01-039 (January 25, 2007), at 3-4 (emphasis added).

[17] *See generally*, CPUC, Decision 12-12-033 (December 20, 2012).

can be pinpointed. Specifically, GHG emissions associated with HECA's generation of electricity sold to an IOU will accrue a compliance obligation under ARB's cap-and-trade regulations that the IOU's ratepayers ultimately will bear. Costs associated with other sources of GHG emissions at HECA will not be passed through to an IOU and, therefore, those costs will not be borne by California ratepayers.

Thus, in order to satisfy the intent of the Legislature in passing SB 1368 and to maintain consistency with the cap-and-trade program, a SB 1368 EPS compliance review must be limited to the electricity generation component of HECA. As summarized by the CPUC in its denial of a request to consider CO_2 emissions associated with industrial processes under SB 1368, "in light of Assembly Bill 32, an industrial source of emissions is already regulated [by the cap-and-trade program] and the EPS is solely measuring the emissions associated with the generation of electricity."[18]

IV. CPUC EPS APPROVAL PROCESS

As indicated above, HECA expects the Project's electricity off-taker to be an IOU. Thus, the CPUC would assess HECA's EPS compliance as set forth below. The CPUC has adopted detailed procedures for reviewing a power plant's EPS compliance, including plants that utilize CCS. CPUC Decision 07-01-039, issued January 29, 2007, not only established an EPS of 1,100 pounds ("lbs") CO_2 per megawatt-hour ("MWh"), but also the CPUC's approach to implementing the EPS.

CPUC Decision 07-01-039 summarizes how the Commission will employ a pre-existing Power Purchase Agreement ("PPA") review procedure as the platform for determining SB 1368 EPS compliance of PPAs executed by IOUs:

> SCE, PG&E and SDG&E currently bring all power purchase contracts with terms of five years or longer before the Commission for review and pre-approval by filing … an application (for non-RPS [non-Renewables Portfolio Standard] contracts). … Under existing procurement rules … PG&E, SCE and SDG&E file applications requesting Commission review and pre-approval of all non-RPS contracts with a term of five years or more. The Commission issues a decision addressing the applications. We will use these existing procedural vehicles for reviewing and preapproving PG&E, SCE and SDG&E's covered procurements with respect to EPS compliance. … For PG&E, SCE and SDG&E, each of the various types of covered procurements subject to the EPS will be reviewed and preapproved through the … application process (for non-RPS resources) ….[19]

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[18] CPUC, Decision 09-06-051 (June 18, 2009), at 7.

[19] CPUC, Decision 07-01-039 (January 25, 2007), at 155.

Accordingly, any IOU that purchases electricity from HECA will be required to demonstrate that HECA complies with the EPS: "For all non-RPS covered procurements, PG&E, SCE and SDG&E shall submit documentation to demonstrate compliance with the EPS through the non-RPS application process established by our procurement rules. This includes any request for a Commission finding of EPS compliance for **covered procurements that employ geological formation injection for CO2 sequestration**."[20]

A. Carbon Capture And Sequestration

In 2010, the CPUC issued a decision granting in part a petition to modify Decision 07-01-039 to clarify the requirements for CCS projects.[21] In that decision, the CPUC modified its Order 3(c) in Decision 07-01-039 to read as follows:

> Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E) shall submit for Commission pre-approval all procurements subject to the Interim EPS Rules ("covered procurements") as follows:
>
> …
>
> (c) For covered procurements that employ geological formation injection for carbon dioxide (CO2) sequestration:
>
> i. PG&E, SCE and SDG&E shall request pre-approval through the non-RPS application process established by the Commission's procurement rules in R.06-02-013, or its successor proceeding, and
>
> ii. As part of this filing, PG&E, SCE and SDG&E shall provide documentation demonstrating that the CO2 capture, transportation and geological formation injection project has a reasonable and economically and technically feasible plan that will result in the permanent sequestration of CO2 once the project is operational, and that the CO2 injection project complies with applicable laws and regulations. The plan must comply with Federal and/or State monitoring, verification and reporting requirements applicable to projects designed to permanently sequester CO2 by preventing its release from the subsurface. If at the time the application is filed Federal and/or State requirements have not been finalized, the plan must include monitoring activities to detect releases of injected CO2 from the subsurface, must provide for verification of any detected releases and must include a schedule for reporting any detected releases to the Commission or

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[20] *Id.* at 156 (emphasis added).

[21] CPUC, Decision 10-07-046 (July 29, 2010).

> other Federal and/or State agencies requesting that information. This showing shall include any emissions-related provisions that may be required through contract and/or permit conditions.[22]

The above quoted language defines an IOU's burden of proof for demonstrating to the CPUC that HECA complies with the EPS, which Applicant fully expects an IOU would be able to meet.

As indicated above, the CPUC has an established process for evaluating SB 1368 EPS compliance. Moreover, the CPUC has adopted specific requirements for projects, like HECA, that employ geological formation injection for permanent CO_2 sequestration. Accordingly, the CEC need not formulate its own procedures to assess HECA's SB 1368 EPS compliance as part of the certification process.

B. CPUC Review Is A One-Time Determination

The PSA/DEIS contemplates the need for HECA to submit "a detailed list of the monitoring and recordkeeping methods and procedures that are proposed to be used to **<u>demonstrate ongoing compliance</u>** with the SB 1368 emission performance standard (EPS) during facility operations."[23] However, the CPUC has indicated that determination of EPS compliance is a one-time event and not subject to ongoing monitoring: "Once the financial commitment [i.e., power purchase agreement] successfully passes through the gateway screen, the LSE has demonstrated EPS compliance for that particular commitment. **<u>Ongoing Commission review or monitoring</u>** of the facilities underlying that commitment is **<u>not</u>** required."[24] The CEC Staff should acknowledge and respect the fact that the CPUC makes a one-time EPS decision "based on reasonably projected net emissions over the life of the facility."[25] Accordingly, all requirements and language in the PSA/DEIS suggesting that EPS compliance must be re-evaluated or maintained in any way are inconsistent with the CPUC's SB 1368 EPS procedures and should be removed.

V. TECHNICAL CONSIDERATIONS

At the recent PSA/DEIS Workshop, there was discussion between CEC Staff and HECA regarding the proper scope of the EPS analysis and other technical issues. The CPUC has addressed scoping issues, as indicated above. HECA expects the CPUC's guidance will be particularly helpful in resolving some of these issues, including those variously raised by Intervenors.

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[22] *Id.* at 14.

[23] CEC, PSA at page 4.3-100 (Information Request GHG-7.M) (emphasis added).

[24] CPUC, Decision 07-01-039 (January 25, 2007), at 153 (emphasis added).

[25] CPUC, Decision 07-01-039 (January 25, 2007), at 94.

A. On-Site Load Should Not Be Subtracted From Power Generation

The CPUC has clarified that electricity generated by HECA but not sold to an IOU under a PPA due to utilization on-site (e.g., for the production of syngas and fertilizer products) should not be excluded from the EPS calculation:

- "The annual average [capacity factor] must be calculated in a manner that is consistent with today's decision, that is, it must be based on the annual production of the underlying facility, and not just what might be delivered under a specific contract with an LSE."[26]

- "A related issue is how to treat LSE contracts with powerplants that also generate power for on-site load (referred to interchangeably … as 'customer generators,' 'self-generators' or 'self-generation facilities') … [T]he EPS should be applied consistently to the characteristics of the underlying facility or facilities supplying power under contract to the LSE, irrespective of whether those facilities are operated by a customer generator or by a merchant generator (i.e., that does not use any of the power produced on site)."[27]

It is the carbon efficiency of the underlying electricity generation unit that is being measured by the SB 1368 EPS. If an electricity generation unit were not credited for each MWh produced because, for example, some of the electricity was used for an on-site industrial process, then that electricity generation unit's CO_2 emissions performance would be artificially inflated. Accordingly, very carbon efficient electricity generation units could flunk the SB 1368 EPS while less carbon efficient units would pass.

Put another way, the CPUC has explained that power plants should not be penalized under the SB 1368 EPS for having on-site load. Therefore, the electricity consumed by the Project to service other components not associated with electricity generation should be credited to HECA when calculating its total MWh produced. Accordingly, the enclosed technical appendix prepared by URS does not subtract from HECA's power generation the electricity consumed for syngas production, fertilizer production, or enhanced oil recovery.

B. Carbon Dioxide Emissions From Other Industrial Processes Should Not Be Included in EPS Calculation

In a related CPUC decision regarding the proper treatment of so-called "bottom-cycling" cogeneration facilities under the SB 1368 EPS, the CPUC addressed how CO_2 emissions associated with non-electricity generation components of a facility should be treated under the EPS. The CPUC explained: "NRDC [Natural Resources Defense Council] argues that the emissions from the industrial process should be included in the calculation of the EPS."[28] The CPUC rejected this argument because: "NRDC's comments do not recognize that in light of

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[26] *Id.* at 186.

[27] *Id.* at 76-77.

[28] CPUC, Decision 09-06-051 (June 18, 2009), at 7.

Assembly Bill 32, an industrial source of emissions is already regulated [by the cap-and-trade program] and the **EPS is solely measuring the emissions associated with the generation of electricity**."[29] Therefore, CO_2 emissions not associated with HECA's power block would be excluded from the CPUC's EPS calculations and review. Accordingly, the enclosed technical appendix prepared by URS does not include CO_2 emissions associated with syngas production, fertilizer product production, or enhanced oil recovery.

C. Lifecycle Analysis of Fuel Not Required

The CPUC has clarified that SB 1368 does not require, and the CPUC will not conduct during its EPS review, a lifecycle analysis of GHG emissions associated with fossil fuels. For example, the CPUC rejected a request to conduct a lifecycle analysis of net emissions for natural gas plants that may use natural gas sourced from liquefied natural gas ("LNG"). The requested lifecycle analysis would have included "the upstream carbon emissions associated with the extracting and shipping of LNG in addition to those resulting from the production of electricity at the natural gas plant."[30] The CPUC declined to conduct a lifecycle analysis, explaining that SB 1368 pointedly omits such a requirement for fossil fuels:

> SB 1368 specifically directs us to consider lifecycle net emissions in one context only, and not in others, and we have followed that specific direction (e.g., for biomass, biogas or landfill gas-fueled plants where CO2 is removed from the atmosphere at one lifecycle stage and put into the atmosphere at another). If we were to go beyond that specific direction and take a lifecycle approach to other net emission calculations, we would have to do so for all other resources to treat them consistently--and not just for LNG …. For these reasons, we do not adopt … [the] recommendation [to conduct a lifecycle analysis].[31]

The CPUC explicitly has rejected conducting lifecycle analyses of fossil fuels for power plants. The fuel for HECA's power block primarily is hydrogen-rich syngas, which is produced in the gasifier from solid feedstock (i.e., coal and petcoke) and oxygen provided by the Air Separation Unit ("ASU"). Therefore, CO_2 emissions, whether direct or indirect (e.g., electricity usage), associated with producing the fuel for HECA's power block should not be included in the SB 1368 EPS calculation. For example, the electricity consumed by the gasification block and the ASU are irrelevant to an EPS determination, which is narrowly focused on the power block. While a full lifecycle analysis may be informative of the Project's overall carbon efficiency and mitigation of climate change impacts, it is not required by SB 1368 and is not proper for consideration under the CPUC's pertinent EPS decisions.

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[29] *Id.* (emphasis added).

[30] *Id.* at 192.

[31] *Id.*

1. EPA New Source Performance Standard Proposal Considers ASU Not Part of Affected Facility

In its proposed NSPS for GHGs that would establish a performance standard of 1,100 lbs CO_2 per MWh, EPA recognizes that subtracting the parasitic load from an ASU when determining the emissions performance of an Integrated Gasification Combined Cycle ("IGCC") facility is not appropriate.[32] EPA explains that the energy output of an IGCC facility under criteria pollutant NSPS regulations is calculated by subtracting "any electricity used to power the feedwater pumps and any associated gas compressors (air separation unit main compressor, oxygen compressor, and nitrogen compressor)…."[33] Upon "further consideration and because many of the proposed IGCC facilities are actually co-production facilities (i.e., they produce useful byproducts and chemicals along with electricity), we have concluded that measuring the electricity used by the primary gas compressors [e.g., those of air separation units] associated with electricity production at IGCC facilities could be more challenging to implement."[34]

Accordingly, EPA is "proposing to define the … electric output for IGCC … affected facilities to include the electricity measured at the generator terminals."[35] In other words, EPA would not subtract the load consumed by the ASU when determining HECA's power generation for purposes of the NSPS for GHGs. EPA has considered this issue at length, including review of more than 2.5 million comments it received on the April 2012 NSPS for GHGs proposal. CEC Staff should respect EPA's work on defining the electric output for IGCC co-production facilities like HECA and acknowledge that the electricity consumed by ASU should not be subtracted when determining HECA's emissions performance for purposes of the SB 1368 EPS.

VI. HECA SB 1368 EMISSIONS PERFORMANCE

The enclosed technical appendix prepared by URS contains HECA's calculation of the Project's emissions performance, following the CPUC's and EPA's procedures and guidance. There are two relevant operating scenarios for the Project, as summarized below:

- **Early Operations –** expected during the first two years of commercial operation. During this period, all sources are expected to be operated at maximum operating conditions, including two plant startups and shutdowns. Power output includes 8,000 hours/year of hydrogen-rich fuel operation and 336 hours/year of natural gas operation. This scenario represents the maximum permitted emission profile.

- **Steady-State Operations –** expected to occur after the first two years of commercial operation. In this scenario, emissions are estimated based on maximum operating conditions, excluding startups, shutdowns, and natural gas usage. Power output includes 8,000 hours/year of hydrogen-rich fuel operation.

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[32] EPA, NSPS for GHGs, at 89-96.

[33] *Id.* at 90.

[34] *Id.* at 92.

[35] *Id.*

The table below presents the Project's annual CO_2 emissions, net power generation, and SB 1368 emissions performance for the two operating scenarios. HECA's SB 1368 emissions would be 197 lbs CO_2/MWh during Steady-State Operations and 224 lbs CO_2/MWh during Early Operations. Both operating scenarios are well below the EPS of 1,100 lbs CO_2 per MWh. Therefore, HECA would comply with the SB 1368 EPS.

SB 1368 Emissions Performance		
Operating Parameter	**Early Operations**	**Steady-State Operations**
Total CO_2 Annual Emissions (tonnes/yr)	301,628	256,655
Annual Net Power Output (MWh)	2,966,904	2,866,104
CO_2 Emissions Performance (lbs/MWh)	224	197
CO_2 Emissions Performance (tonnes/MWh)	0.102	0.090

URS TECHNICAL APPENDIX TO SENATE BILL 1368 EMISSIONS PERFORMANCE STANDARD COMPLIANCE REVIEW – HYDROGEN ENERGY CALIFORNIA POWER PLANT: BASIS FOR SB 1368 EMISSION PERFORMANCE STANDARD CALCULATIONS

The following appendix provides the technical basis for the carbon dioxide (CO_2) emissions and power generation megawatt-hours (MWh) included in the Senate Bill (SB) 1368 emission performance standard (EPS) calculations. This standard is a one-time compliance determination for the duration of the power purchase contract; thus annual average emissions and power generation are examined.

1.0 CO_2 EMISSIONS

For demonstration of the SB 1368 EPS only CO_2 emissions resulting from the production of electricity at HECA are included in the CO_2 emissions inventory. Carbon dioxide emissions from other industrial processes are not subject to SB 1368. Therefore, emissions associated with fertilizer production, syngas (hydrogen) production, the supplying of CO_2, and enhanced oil recovery (EOR) at Elk Hills Oil Field (EHOF) by Occidental Elk Hills, Inc. (OEHI) are not included in the calculation. Emissions from these industrial processes will be regulated under the Mandatory Reporting Rule (MRR) and the Cap-And-Trade program.

All CO_2 emissions associated with the CT/HRSG are included in the inventory, including emissions from burning syngas, PSA off-gas and natural gas. Emissions associated with startup and shutdown have been included and conservatively estimated at full firing rate for each event. Since approximately 15% of the exhaust from the CT/HRSG is directed to the feedstock dryer, and these CO_2 emission originated in power generation, all feedstock dryer emissions are included in the inventory. Emission estimates are based on the on-peak power production at the annual average ambient temperature of 65F. The fuel for the CT/HRSG is syngas, PSA off-gas and natural gas, thus only emissions associated with burning these fuels is included in the inventory. Emissions associated with processing these fuels is not included in the inventory.

The remainder of the emission sources at HECA are not included in the CO_2 inventory since their operation does not support power production.

Annual CO_2 emissions were estimated for two operating scenarios, as described below:

- **Early Operations –** expected to last the first two years of commercial operation. During this period, all sources are expected to be operated at maximum operating conditions, including two plant startups and shutdowns. Power output includes 8,000 hours/year of hydrogen-rich fuel operation and 336 hours/year of natural gas operation. This scenario describes the maximum permitted emission profile.

- **Steady-State Operations –** expected to occur after the first two years of commercial operation. In this scenario, emissions are estimated based on maximum operating conditions, excluding startups, shutdowns, and natural gas usage. Power output includes 8,000 hours/year of hydrogen-rich fuel operation.

Table 1 presents the annual CO_2 emissions (in metric tons) that are included in the SB 1368 inventory for the two scenarios. These emissions are the same as those presented in the Updated Emission and Modeling Report, May 2013, and the responses to CEC Informational Requests Set 1, August 2013.

Table 1
HECA Annual CO_2 Emissions for SB1368 Emission Performance Standard

Sources of CO2	Early Operations (Maximum Permitted)	Steady-State Syngas Operations
	CO_2 Emissions (tonnes/yr)	
CTG/HRSG burning syngas/PSA off-gas	256,900	256,655
CTG/HRSG burning natural gas	44,729	0
Total Power Generation Emissions	**301,628**	**256,655**

2.0 POWER GENERATION

The annual electricity production, or net power generation, is based on the total power produced by the CT/HRSG (gross MW) minus the auxiliary loads needed for power generation. Power consumption for the fertilizer production, hydrogen production, CO_2 compression and EOR are not subtracted from the gross MW to determine net power generation, since these activities are not related to power production. In addition, the power usage for the ASU is not subtracted from the gross power generation, as the ASU is not directly involved with power generation.

HECA is designed to run in two modes of operation. On-peak, or maximum power production mode, lasts for 16 hours per day. Off-peak, or maximum fertilizer production mode, lasts for 8 hours per day. The gross power output, auxiliary loads and syngas allocation vary between the two modes of operation; thus, two operating mode allocations were made, along with the daily average. In addition, like other combustion turbine-based power plants, the gross power output will vary with ambient temperature. To account for this, the annual average ambient temperature (65F) was used for the two operating mode allocations.

Table 2 presents the gross power output, the net power generation from syngas, and the auxiliary loads of the entire HECA facility during on-peak and off-peak modes. All facility auxiliary loads are shown for completeness, and these match the loads presented in the Updated Emission and Modeling Report, May 2013, and the responses to CEC Informational Requests Set 1 and 2, August 2013. Only the loads associated with the power generation will be used in the EPS calculation.

The auxiliary load from the common facility supporting systems, such as plant lighting, building HVAC, etc., is split between power production and fertilizer production, based on syngas usage in these areas. The split is on a lower heating value basis, calculated for the on-peak and off-peak modes.

Net power generation is calculated based on the gross output allocated to the power block, less the auxiliary loads attributable to the power block and the power portion of the common supporting systems.

The daily average net power generation from syngas firing was multiplied by 8,000 hours of operation per year to obtain the MWh of net power generation per year. Natural gas fired net power generation was determined by multiplying 336 hours per year (2 weeks) by the net power generation from natural gas of 300 MW. As described in the Amended AFC, natural gas firing produces 320 gross MW, and 20 MW of auxiliary load are subtracted to obtain the net power generation. The total net power generation is the sum of power generated from operation on syngas, plus power generated from operation on natural gas, as shown in Table 3. Conservatively the net power generation does not include the power output during start-up or shut-down operations.

Table 2
HECA Power Generation and Auxiliary Loads for SB1368 Emission Performance Standard

Power Balance	**Unit**	**On-Peak**	**Off-Peak**	**Daily Average**
Power Generation				
Gross Output	MW	416.0	315.2	382.4
Allocation to Fertilizer	MW	3.5	11.3	6.1
Allocation to Power	**MW**	**412.5**	**303.9**	**376.3**
Auxiliary Power				
Power Block	**MW**	**12.7**	**12.4**	**12.6**
Common - supporting systems - power	**MW**	**5.9**	**4.5**	**5.5**
Gasification block	MW	41.3	41.3	41.3
CO2 Compression for transfer to OEHI	MW	36.1	36.1	36.1
Fertilizer	MW	52.1	65.6	56.6
Common - supporting systems - balance of plant	MW	2.4	4.2	3.0
Power Allocation				
Net Power Generation - Syngas	**MW**	**393.9**	**286.9**	**358.3**
Syngas Allocation				
To Power Block	%	71.3%	52.1%	64.9%
To Fertilizer	%	28.7%	47.9%	35.1%

Notes:
The auxiliary power needed for the common supporting systems is divided between power production and the balance of the plant based on the syngas usage between power and fertilizer production.

Table 3
Annual Net Power Generation

Annual Syngas Power Operations	hr/yr	8000
Annual Natural Gas Power Operations	hr/yr	336
Net Power Generation - Syngas	MW	358.3
Net Power Generation - Natural Gas	MW	300
Annual Net Power Generation - Syngas	MW-hr/year	2,866,104
Annual Net Power Generation - Natural Gas	MW-hr/year	100,800

3.0 EMISSION PERFORMANCE STANDARD

HECA achieves low GHG emissions by using only hydrogen-rich fuel, or CPUC-regulated natural gas as backup fuel, to produce electricity. Both of these fuels are recognized as low in carbon content.

Table 4 presents the annual CO_2 emissions, net power generation of the Project and the CO_2 emissions performance calculated for the two operating scenarios. CO_2 emissions from the electricity production at HECA are less than 200 lb CO_2/MWh during steady-state operations on hydrogen-rich fuel. The maximum CO_2 emissions during early operations, including emissions from natural-gas operation, startup, and shutdown would be slightly higher than 200 lb CO_2/MWh. The HECA facility CO_2 emissions performance will be well below the SB 1368 EPS of 1,100 lb CO_2/MWh. Detailed calculations are provided in the accompanying spreadsheet file.

Table 4
SB1368 Emission Performance Standard

Operating Parameter	Early Operations (Maximum Permitted)	Steady-State Syngas Operations
Total CO_2 Annual Emissions Attributable to Power Production (tonne/yr)	301,628	256,655
Annual Net Power Output (MWh)	2,966,904	2,866,104
CO_2 Emissions Performance (lb/MWh)	224	197
CO_2 Emissions Performance (tonne/MWh)	0.102	0.090

Notes:
Early Operations emissions presented include CO_2 from the turbine during startups and shutdowns.
The annual power output conservatively does not include the megawatts generated during startup and shutdown, thus the Emissions Performance actually would be lower than presented.

HECA Annual CO2 Emissions for SB1368 Emission Performance Standard

Sources of CO2	Early Operations (Maximum Permitted)	Steady-State Syngas Operations
	CO_2 Emissions (tonnes/yr)	
CTG/HRSG burning syngas/PSA off-gas	256,900	256,655
CTG/HRSG burning natural gas	44,729	0
Total Power Generation Emissions	**301,628**	**256,655**

Notes:
Only emissions associated with power production are included in the inventory.

HECA Power Generation and Auxiliary Loads for SB1368 Emission Performance Standard

Power Balance	Unit	On-Peak	Off-Peak	Daily Average
Power Generation				
Gross Output	MW	416.0	315.2	382.4
Allocation to Fertilizer	MW	3.5	11.3	6.1
Allocation to Power	**MW**	**412.5**	**303.9**	**376.3**
Auxiliary Power				
Power Block	**MW**	**12.7**	**12.4**	**12.6**
Common - supporting systems - power	**MW**	**5.9**	**4.5**	**5.5**
Gasification block	MW	41.3	41.3	41.3
CO2 Compression for transfer to OEHI	MW	36.1	36.1	36.1
Fertilizer	MW	52.1	65.6	56.6
Common - supporting systems - balance of plant	MW	2.4	4.2	3.0
Power Allocation				
Net Power Generation - Syngas	**MW**	**393.9**	**286.9**	**358.3**
Syngas Allocation				
To Power Block	%	71.3%	52.1%	64.9%
To Fertilizer	%	28.7%	47.9%	35.1%

Notes:
The auxiliary power needed for the common supporting systems is divided between power production and the balance of the plant based on the syngas usage between power and fertilizer production

Annual Net Power Generation

Annual Syngas Power Operations	hr/yr	8000
Annual Natural Gas Power Operations	hr/yr	336
Net Power Generation - Syngas	MW	358.3
Net Power Generation - Natural Gas	MW	300
Annual Net Power Generation - Syngas	MW-hr/year	2,866,104
Annual Net Power Generation - Natural Gas	MW-hr/year	100,800

SB1368 Emission Performance Standard

Operating Parameter	Early Operations (Maximum Permitted)	Steady-State Syngas Operations
Total CO_2 Annual Emissions Attributable to Power Production (tonne/yr)	301,628	256,655
Annual Net Power Generation (MWh)	2,966,904	2,866,104
CO_2 Emissions Performance (lb/MWh)	224	197
CO_2 Emissions Performance (tonne/MWh)	0.102	0.090

Notes:

Early operations emissions presented include CO_2 from the turbine during startups and shutdowns.

The annual power output conservatively does not include the megawatts generated during startup and shutdown, thus the Emissions Performance would be lower than presented.

Scenario definitions:

Early Operations - expected to last approximately 2 years, during which time hydrogen-rich fuel availability will be approximately 65 to 75 percent. During this period, all sources are expected to be operated at maximum operating conditions, including two plant start-ups and shut-downs. Power output includes 8,000 hours/year of hydrogen-rich fuel operation and 336 hours/year of natural gas operation.

Steady State Operations - which occur in the same time frame as mature operations; that is, after the 2 years of early operation. In this scenario, emissions are estimated based on maximum operating conditions, excluding start-ups, shut-downs and natural gas usage. Power output includes 8,000 hours/year of hydrogen-rich fuel operation.

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GHG emissions are numerically depicted as metric tons (tonne) of carbon dioxide equivalents (CO_2e). CO_2e represents CO_2 plus the additional warming potential from CH_4 and N_2O. CH_4 and N_2O have 21 and 310 times the warming potential of CO_2, respectively.

Natural Gas GHG Emission Factors

CO_2 =	53.06	kg/MMBtu =	116.98	lb/MMBtu
CH_4 =	0.001	kg/MMBtu =	0.002	lb/MMBtu
N_2O =	0.0001	kg/MMBtu =	0.00022	lb/MMBtu

Diesel GHG Emission Factors

CO_2 =	10.15	kg/gal =	22.38	lb/gal
CH_4 =	0.0004	kg/gal =	0.001	lb/gal
N_2O =	0.0001	kg/gal =	0.0002	lb/gal

CO_2, CH_4, and N_2O emission factors are taken from Appendix C of the California Climate Action Registry (CCAR) General Reporting Protocol Version 3.1 (Jan 2009)

Turbine - Burning Hydrogen-Rich Fuel - released to HRSG and Feedstock Dryer Stacks

Operating Hours		8012	hr/yr	
Heat Input (HHV)		2,537	MMBtu/hr	
CO_2 =	163,244	tonne/yr		
CH_4 =	288	tonne/yr =	6,043	tonne CO_2e/yr
N_2O =	2.03	tonne/yr =	630	tonne CO_2e/yr

Syngas GHG Emission Factors		
CO_2 =	17.7	lb/MMBtu
CH_4 =	0.03	lb/MMBtu

Total tonne CO_2e/yr = 169,917

HRSG heat input rate is based Case 5, average ambient temperature and peak load.

Operating hours include startup and shutdown operations

Although N2O emissions are expected to be lower than from the combustion of natural gas, N2O emissions were conservatively estimated using the natural gas emission factor.

Duct burner - Burning Hydrogen-Rich Fuel - released to HRSG and Feedstock Dryer Stacks

Operating Hours		8000	hr/yr	
Heat Input (HHV)		165	MMBtu/hr	
CO_2 =	10,603	tonne/yr		
CH_4 =	19	tonne/yr =	393	tonne CO_2e/yr
N_2O =	0.13	tonne/yr =	41	tonne CO_2e/yr

Syngas GHG Emission Factors		
CO_2 =	17.7	lb/MMBtu
CH_4 =	0.03	lb/MMBtu

Total tonne CO_2e/yr = 11,036

Duct burner heat input rate is based Case 5, average ambient temperature and peak load.

Duct burner not operated during turbine startup and shutdown

Although N2O emissions are expected to be lower than from the combustion of natural gas, N2O emissions were conservatively estimated using the natural gas emission factor.

Duct burner - Burning PSA Offgas - released to HRSG and Feedstock Dryer Stacks

Operating Hours		8,000	hr/yr	
Heat Input (HHV)		149	MMBtu/hr	
CO_2 =	83,053	tonne/yr		
CH_4 =	146	tonne/yr =	3,073	tonne CO_2e/yr
N_2O =	0.12	tonne/yr =	37	tonne CO_2e/yr

Syngas GHG Emission Factors		
CO_2 =	153.6	lb/MMBtu
CH_4 =	0.3	lb/MMBtu

Total tonne CO_2e/yr = 86,163

Duct burner heat input rate is based Case 5, average ambient temperature and peak load.

Duct burner not operated during turbine startup and shutdown

Although N2O emissions are expected to be lower than from the combustion of natural gas, N2O emissions were conservatively estimated using the natural gas emission factor.

Turbine - Burning Natural Gas - released to HRSG Stack

Operating Hours		351	hr/yr	
Heat Input (HHV)		2,401	MMBtu/hr	
CO_2 =	44,729	tonne/yr		
CH_4 =	0.84	tonne/yr =	18	tonne CO_2e/yr
N_2O =	0.08	tonne/yr =	26	tonne CO_2e/yr

Total tonne CO_2e/yr = 44,772

HRSG heat input rate is assumed to be the maximum heat input rate firing natural gas. Hours of operation include startup and shutdown.

GHG Emissions Summary of Stationary Sources — Emissions Summary

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Auxiliary Boiler

Operating Hours		2,190	hr/yr			
Heat Input		213	MMBtu/hr			
CO_2 =	24,758	tonne/yr				
CH_4 =	0.47	tonne/yr =	10	tonne CO_2e/yr		
N_2O =	0.05	tonne/yr =	14	tonne CO_2e/yr	Total tonne CO_2e/yr =	24,782

Emergency Generators (2)

Operating Hours		50	hr/yr			
Heat Input		2,922	Bhp			
CO_2 =	3,341	lb/hr =	76	tonne CO_2/yr		
CH_4 =	0.13	lb/hr =	0.063	tonne CO_2e/yr		
N_2O =	0.03	lb/hr =	0.2315	tonne CO_2e/yr	Total tonne CO_2e/yr* =	152

The following conversions were used to convert from lb/gallon to lb/hp-hour; and then multiplying by the rated horsepower rating: 1 gallon/137,000 Btu; and 7,000 Btu/hp-hour.

* Total tonnes CO_2e per year represent the contributions from both generators.

Fire Water Pump

Operating Hours		100	hr/yr			
Heat Input		556	Bhp			
CO_2 =	636	lb/hr =	29	tonne CO_2/yr		
CH_4 =	0.03	lb/hr =	0.024	tonne CO_2e/yr		
N_2O =	0.01	lb/hr =	0.0881	tonne CO_2e/yr	Total tonne CO_2e/yr =	29

The following conversions were used to convert from lb/gallon to lb/hp-hour; and then multiplying by the rated horsepower rating: 1 gallon/137,000 Btu; and 7,000 Btu/hp-hour.

Gasification Flare

Pilot Operation						
Operating Hours		8,760	hr/yr			
Heat Input		0.5	MMBtu/hr			
CO_2 =	232	tonne/yr				
CH_4 =	0.00	tonne/yr =	0.1	tonne CO_2e/yr		
N_2O =	0.0004	tonne/yr =	0.1	tonne CO_2e/yr	Total tonne CO_2e/yr =	233
Flaring Events						
Total Operation		70,536	MMBtu/yr			
CO_2 =	3,744	tonne/yr				
CH_4 =	0.1	tonne/yr =	1	tonne CO_2e/yr		
N_2O =	0.01	tonne/yr =	2	tonne CO_2e/yr	Total tonne CO_2e/yr =	3,747

GHG emissions from flaring events are conservatively estimated using GHG emission factors for natural gas combustion.

Rectisol Flare

Pilot Operation						
Operating Hours		8,760	hr/yr			
Heat Input		0.3	MMBtu/hr			
CO_2 =	139	tonne/yr				
CH_4 =	0.00	tonne/yr =	0.1	tonne CO_2e/yr		
N_2O =	0.0003	tonne/yr =	0.08	tonne CO_2e/yr	Total tonne CO_2e/yr =	140
Flaring Events						
Operating Hours		40	hr/yr			
Vent gas flow		4542	lb-mole/hr			
CO_2 =	3,627	tonne/yr				
CH_4 =	0	tonne/yr =	0	tonne CO_2e/yr		
N_2O =	0	tonne/yr =	0	tonne CO_2e/yr	Total tonne CO_2e/yr =	3,627

GHG emissions from flaring event based on 100% carbon content of the gas during startup.

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SRU Flare

Pilot Operation						
Operating Hours		8,760	hr/yr			
Heat Input		0.3	MMBtu/hr			
CO_2 =	139	tonne/yr				
CH_4 =	0.00	tonne/yr =	0.1	tonne CO_2e/yr		
N_2O =	0.0003	tonne/yr =	0.08	tonne CO_2e/yr	Total tonne CO_2e/yr =	140
Flaring Events - natural gas assist for acid gas venting during startup						
Operating Hours		40	hr/yr			
Heat Input		36	MMBtu/hr			
Throughput (inerts) - acid gas venting during startup						
CO_2 =		140000	scf/hr			
CO_2 =		16,240	lb/hr			
CO_2 =	371	tonne/yr				
CH_4 =	0.001	tonne/yr =	0.03	tonne CO_2e/yr		
N_2O =	0.00014	tonne/yr =	0.045	tonne CO_2e/yr	Total tonne CO_2e/yr =	371

Throughtput (inerts) provided from design engineers.

Tail Gas Thermal Oxidizer

Process Vent Disposal Emissions						
Operating Hours		8,314	hr/yr			
Heat Input		13	MMBtu/hr			
CO_2 =	5,736	tonne/yr				
CH_4 =	0.11	tonne/yr =	2.3	tonne CO_2e/yr		
N_2O =	0.0108	tonne/yr =	3.4	tonne CO_2e/yr	Total tonne CO_2e/yr =	5,742
SRU Startup & Shutdown						
Operating Hours		72	hr/yr			
Heat Input		80	MMBtu/hr			
CO_2 =	306	tonne/yr				
CH_4 =	0.006	tonne/yr =	0.12	tonne CO_2e/yr		
N_2O =	0.00058	tonne/yr =	0.179	tonne CO_2e/yr	Total tonne CO_2e/yr =	306

GHG emissions from thermal oxidizer are estimated using GHG emission factors for natural gas combustion for the assist gas.

Intermittent CO_2 Vent

Operating Hours	504	hr/yr		
CO_2 Emission Rate	767,435	lb/hr		
			Total tonne CO_2e/yr =	175,493

Assumes 504 hours per year venting at full rate.

Fugitives - Gasification Block

Operating Hours		8,760	hr/yr			
CO_2 =	32.0	tpy	31.12	tonne CO_2e/yr		
CH_4 =	0.27	tpy	5.55	tonne CO_2e/yr		
					Total tonne CO_2e/yr =	37

Detailed emission calculations are provided in Appendix M, Public Health.

Fugitives - Manufacturing Complex

Operating Hours		8,760	hr/yr			
CO_2 =	4.7	tpy	4.53	tonne CO_2e/yr		
CH_4 =	0.04	tpy	0.91	tonne CO_2e/yr		
					Total tonne CO_2e/yr =	5

Detailed emission calculations are provided in Appendix M, Public Health.

Ammonia Synthesis Plant Startup Heater

Operating Hours		140	hr/yr			
Heat Input		56	MMBtu/hr			
CO_2 =	416	tonne/yr				
CH_4 =	0	tonne/yr =	0	tonne CO_2e/yr		
N_2O =	0.00	tonne/yr =	0	tonne CO_2e/yr	Total tonne CO_2e/yr =	417

Urea Absorber Vents

Operating Hours		8,000	hr/yr			
CO_2		32	lb/hour			
CO_2 =	116	tonne/yr				
CH_4 =	0	tonne/yr =	0	tonne CO_2e/yr		
N_2O =	0	tonne/yr =	0	tonne CO_2e/yr	Total tonne CO_2e/yr =	116

Emission rate provided by project engineers.

Nitric Acid Unit

Operating Hours		8,052	hr/yr			
N_2O uncontrolled		10.78	lb/ton NHO3			
Production rate		501	ton/day			
N_2O uncontrolled		225	lb/hour			
destruction efficiency		95	%			
N_2O controlled		11.25	lb/hour			
N_2O controlled		0.54	lb/ton NHO3			
CO_2 =	0	tonne/yr				
CH_4 =	0	tonne/yr =	0	tonne CO_2e/yr		
N_2O =	41	tonne/yr =	12,741	tonne CO_2e/yr	Total tonne CO_2e/yr =	12,741

Emission factor and destruction efficiency provided by design engineer.

230 kV Circuit Breakers

Number of Circuit Breakers		6				
SF_6 capacity		240	lb/breaker			
Annual Leakage rate		0.5%				
SF_6 =	0.003	tonne/yr =	78	tonne CO_2e/yr	Total tonne CO_2e/yr =	78

SF6 GWP = 23,900 http://www.epa.gov/electricpower-sf6/faq.html)
Sources: SF6 inventory and maximum leakage rates from electrical equipment suppliers

18 kV Circuit Breakers

Number of Circuit Breakers		2				
SF_6 capacity		73	lb/breaker			
Annual Leakage rate		0.5%				
SF_6 =	0.000	tonne/yr =	8	tonne CO_2e/yr	Total tonne CO_2e/yr =	8

SF6 GWP = 23,900 http://www.epa.gov/electricpower-sf6/faq.html)
Sources: SF6 inventory and maximum leakage rates from electrical equipment suppliers

Total tonne CO_2e/yr for Stationary Sources=	**540,053**