United States Environmental Protection Agency, Region 6

Public Comment Record Index – December 2013

El Paso Electric Company, Montana Power Station

Permit No.: PSD-TX-1290-GHG

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I.41	~~Email from V. Carbajal: Re: El Paso Electric Co. Montana Power Station Permit No. PSD-TX-1290-GHG~~ Withdrawn	December 4, 2013
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I.42	~~Email from V. Carbajal: Re: El Paso Electric Co. Montana Power Station Permit No. PSD-TX-1290-GHG~~ Withdrawn	December 4, 2013
I.42a	~~Attachment for the email from V. Carbajal: Re: El Paso Electric Co. Montana Power Station Permit No. PSD-TX-1290-GHG: FEEPCU Comments on EPE GHG 12-4-13.pdf~~ Withdrawn	December 4, 2013
I.42b	~~Attachment for the email from V. Carbajal: Re: El Paso Electric Co. Montana Power Station Permit No. PSD-TX-1290-GHG: Exh A~~ Withdrawn	December 4, 2013
I.42c	~~Attachment for the email from V. Carbajal: Re: El Paso Electric Co. Montana Power Station Permit No. PSD-TX-1290-GHG: Exh B~~ Withdrawn	December 4, 2013
I.42d	~~Attachment for the email from V. Carbajal: Re: El Paso Electric Co. Montana Power Station Permit No. PSD-TX-1290-GHG: Exh C~~ Withdrawn	December 4, 2013
I.42e	~~Attachment for the email from V. Carbajal: Re: El Paso Electric Co. Montana Power Station Permit No. PSD-TX-1290-GHG: Exh D~~ Withdrawn	December 4, 2013
I.42f	~~Attachment for the email from V. Carbajal: Re: El Paso Electric~~	December 4, 2013

	~~Co. Montana Power Station Permit No. PSD-TX-1290-GHG: Exh E~~ Withdrawn	

U.S. Environmental Protection Agency, Region 6
1445 Ross Avenue, Suite 1200
Dallas, Texas 75202-2733

Comment Card

Comment:

See attached!

Please note than an email or postal address must be provided with your comment if you wish to receive responses to comments submitted during the public comment period and direct notification of EPA's final decision regarding the permit.

Name: Alberto Delgado

Email: [redacted] **Phone:** [redacted]

Address: [redacted]

To whom it may concern:

With this letter we are looking for your support and protection. The Electric Company is thinking as a business entity with profits in mind. We are asking you as the environment protection agency to protect us when you make decisions. Your decision will affect a lot of people and communities. Not only that but the risk of health problem is there and cannot be ignored. The electric company had the opportunity to move farther away from the communities but decided to be close and save 1 million per mile according to KVIA 7 News.

I was reading an article "EMF Watch" and it says that for years the electric company and public officials have ignored the safety of people with excuses like "It hasn't been proven the risk of health problems". It is clear the electric company is doing the same (KVIA news) thing by not presenting a clear plan with the effects on the environment and health problems. The invasion of the electric company will have a massive impact to our community. Do you want to be part again (The El Paso Asarco refinery proved to be a hazard to the community and contamination to the environment) as the public officials that failed to protect the community on the West side of El Paso? Remember us when you make your decision. Sometimes good deeds last forever. The Electric Company wants to get a short cut by saving money on the routes by being close to the communities but in the long run will affect a lot of lives.

On behalf of my family!

Thank you,

Alberto Delgado

Teacher

P.S. Let's pray nothing happens with the fuel tanks by being close to the Electric Company. I know that those people that approved the construction will not have peace of mind if a tragedy occurs.

U.S. Environmental Protection Agency, Region 6
1445 Ross Avenue, Suite 1200
Dallas, Texas 75202-2733

Comment Card

Comment:

My comment my husband use 24 twenty four hrs. Oxygen. I'm worry for his health. We have a lot of land faraway of the point of Waco Tanks. Please think in this ~~far~~ not so far land. No neighbors there.

Please note than an email or postal address must be provided with your comment if you wish to receive responses to comments submitted during the public comment period and direct notification of EPA's final decision regarding the permit.

Name: Alicia Martinez

Email: [redacted] **Phone:** [redacted]

Address: [redacted]

U.S. Environmental Protection Agency, Region 6
1445 Ross Avenue, Suite 1200
Dallas, Texas 75202-2733

Comment Card

Comment:

We reside approximately 1.5 miles from the proposed site. We have two elderly inlaws living with us whom suffer from asthma + other ailments which will be directly affected by pollution created by this plant. We also have a 5 + 9 year old who will be affected by this.

Please note than an email or postal address must be provided with your comment if you wish to receive responses to comments submitted during the public comment period and direct notification of EPA's final decision regarding the permit.

Name: Andrew + Yvonne Aviles

Email: [redacted] **Phone:**

Address: [redacted]

U.S. Environmental Protection Agency, Region 6
1445 Ross Avenue, Suite 1200
Dallas, Texas 75202-2733

Comment Card

Comment:

Mi Nombre es Florentino Moreno - 4161 SQ Vance
Escribo esto Para agradecer Cuanto Asen
Por las Comunidades que estan en Peligro
en esta ocación la planta Electrica en el nombre
de mis hijos esposa nietos Evitar Peligro Futuro
Gracias

Please note than an email or postal address must be provided with your comment if you wish to receive responses to comments submitted during the public comment period and direct notification of EPA's final decision regarding the permit.

Name:

Email: [redacted]

[redacted]

U.S. Environmental Protection Agency, Region 6
1445 Ross Avenue, Suite 1200
Dallas, Texas 75202-2733

Comment Card

Comment:

Was there any other available sites - less inhabited
what long term impact will this do - any studies
Any cognitive affects?
Blast radius?

Please note than an email or postal address must be provided with your comment if you wish to receive responses to comments submitted during the public comment period and direct notification of EPA's final decision regarding the permit.

Name: Ed Martinez

Email:

Phone: [redacted]

Address: [redacted]

U.S. Environmental Protection Agency, Region 6
1445 Ross Avenue, Suite 1200
Dallas, Texas 75202-2733

Comment Card

Comment:

I've lived in this community since 1984 with my children. Please help me to protect my children + grandchildren who grew up here. One of my boys suffers from severe allergies. Building of power plant will affect his health.

Please note than an email or postal address must be provided with your comment if you wish to receive responses to comments submitted during the public comment period and direct notification of EPA's final decision regarding the permit.

[redacted]

[redacted] **Pho**[redacted]

[redacted]

U.S. Environmental Protection Agency, Region 6
1445 Ross Avenue, Suite 1200
Dallas, Texas 75202-2733

RECEIVED - 6PDL
AIR PLANNING SEC.
13 OCT 23 PM 5:07
30 mm

Comment Card

Comment: Pollution is pollution wether its green house gases sulfuric acid ect. do the right thing and say "no" to enviornmental polluters like EPEC before they contaminate whats left of our enviorment

RECEIVED
13 OCT 30 PM 2:2
DALLAS, TX

Please note than an email or postal address must be provided with your comment if you wish to receive responses to comments submitted during the public comment period and direct notification of EPA's final decision regarding the permit.

Name: Guillermo Rodriguez

Email: (915 [redacted] **Phone:** [redacted]

Address: [redacted]

U.S. Environmental Protection Agency, Region 6
1445 Ross Avenue, Suite 1200
Dallas, Texas 75202-2733

Comment Card

Comment:

Yo no estoy de acuerdo, con el Paso-Electric en hacer la planta en nuestra area por los contaminantes que esto afecta. En El paso, ay mucho campo para acerlo. Por favor Piensen en nuestros "NiÑOS" el futuro del País

Please note than an email or postal address must be provided with your comment if you wish to receive responses to comments submitted during the public comment period and direct notification of EPA's final decision regarding the permit.

Name: Irma Amaya

Email: [redacted]

[redacted]

U.S. Environmental Protection Agency, Region 6
1445 Ross Avenue, Suite 1200
Dallas, Texas 75202-2733

Comment Card

Comment:
My concern, is we moved off Flager a little over a year ago. We did not know about the electric Company's plan. We had plan this for our retirement. I have concerns of my wife's health. This plant is going to be near gas lines and tanks. It would be hard to move now

Please note than an email or postal address must be provided with your comment if you wish to receive responses to comments submitted during the public comment period and direct notification of EPA's final decision regarding the permit.

Name: James M. Harris

Email: [redacted]

U.S. Environmental Protection Agency, Region 6
1445 Ross Avenue, Suite 1200
Dallas, Texas 75202-2733

Comment Card

Comment:

No estoy de acuerdo. Por esta Razon.
Nuestros Niños necesitan aire limpio
porque montana Vista habiendo tanto
terreno fuera de la ciudad.
La Persona que penso en hacerlo aqui. no tiene Niños!

Please note than an email or postal address must be provided with your comment if you wish to receive responses to comments submitted during the public comment period and direct notification of EPA's final decision regarding the permit.

Name: [redacted]

[redacted]

U.S. Environmental Protection Agency, Region 6
1445 Ross Avenue, Suite 1200
Dallas, Texas 75202-2733

Comment Card

Comment:

What Securitys are in place to Protect us from one of the four natural gas turbines exploading and hitting one of The 15 Gas filled Refinery tanks that are only 500 ft away from the plant. *Note* we only have a Volinteer fire Department.

Please note than an email or postal address must be provided with your comment if you wish to receive responses to comments submitted during the public comment period and direct notification of EPA's final decision regarding the permit.

[redacted]

[redacted] **Phone** [redacted]

[redacted]

(El paso fined for polution problems)

Dad

1. how many times has EP Electric been fined for going over their proposed Emissions for a year/ how much polution El Paso already has.

2. What securitys Do we have against a natural gass explosion like the others plants in the US. What will be the enviornmental effect if it hits the gas tanks only 500ft away from the Plant.

3. Open water. What actions do you have in place to Keep the Spread of west nial when you have 2 Large pools of open water.

4. How many "Secure" plants have lead to deaths Due to emition problems.

5. Why is there NO National Ambient air Quality Standards in place if everyone in the united States are warried about the Efects of GHG's.

U.S. Environmental Protection Agency, Region 6
1445 Ross Avenue, Suite 1200
Dallas, Texas 75202-2733

Comment Card

Comment: the building of this power plant will be very harmful to my health. I suffer from chronic asthma and bronchitis among other breathing problems. I'd appreciate your consideration on this matter.

Please note than an email or postal address must be provided with your comment if you wish to receive responses to comments submitted during the public comment period and direct notification of EPA's final decision regarding the permit.

Name: Mary L. Gonzalez

Email: [redacted]

From:	adrian rodriguez
To:	Magee, Melanie
Subject:	Formal comments for the montana vista power plant in El Paso County
Date:	Tuesday, November 05, 2013 11:50:59 AM

Dear Ms. Magee,

Please take the following as a formal comment for the proposed power plant in El Paso, Texas.
El Paso Electric (EPE) did not conduct an environmental justice analysis. Why did the the EPA not require EPE to do this analysis? Are we not supposed to be protected by industries that will impact our health and environment. In 1994, President Clinton signed an executive order in which communities with large number of minorities and large number of economically disadvantaged people could have their health and environment impacted by any industry should have an environmental justice analysis conducted. This is precisely our situation. This executive order was designed with communities like Montana Vista in mind. We are requesting that this executive order be implemented and the EPA needs to ensure that our rights are protected.

EPE has never justified the need for an additional power plant in El Paso, TX. EPE has not given any scientifically based reasons to why there is a need for an additional power plant in our community. Why 4 generators for this power plant?
Is there a good enough reason that would consider demographic data that would support the need for 4 additional generators?
You the EPA need to explain to us why you gave EPE the permit without a scientifically based justification.

Why are you considering giving EPE the permits for 4 generators all at once?
EPE is required to use BACT for their permit. Who knows which will be the BACT in the time frame in which they will actually use the third and fourth generator?
There are many discrepancies in the application for this power plant in the Montana Vista community in El Paso County. Please consider this when reviewing their application.
We are demanding that the EPA not fail our community!

Thank You for Your Consideration to this Permit.

Adrian Castillo
[redacted]

From:	Andrew Aviles
To:	Magee, Melanie
Subject:	Montana Power Plant
Date:	Sunday, November 03, 2013 9:48:56 AM

To: EPA

We are the Aviles family residents of the Haciendas Del Norte Subdivision (HDNS). We oppose the building of the Montana Power Station (MPS) because our home and the HDNS is less then two miles down wind from the proposed MPS. The HDNS would fall victim to all the pollution and dangerous chemicals that would be emitted from the proposed MPS, we would in fact be victims of the second hand smoke and pollution generated from the giant fossil fuel burning turbines. Initially EP Electric requested permits for two fossil fuel burning turbines, but as the public has recently found out that EP Electric was actually planning to maximize their operations by building an additional two turbines, for a total of four turbines. EP Electric is purposely under reporting all of their environmental impact study information and future plans in an effort to get the MPS project approved. We are asking that the EPA protect us, the citizens of the HDNS, and the citizens of Montana Vista from the MPS health and environmental dangers.

I find it very disturbing and irresponsible that EP Electric has decided two build and develop so much infrastructure such as their operations center, warehouse, and power distribution plant around El Paso's largest and extremely dangerous fuel storage facility. Has EP Electric even evaluated a worst case scenario were the entire fuel tank storage facility is compromised and explodes. Their are other undeveloped area's in far east El Paso that EP Electric can use to build such a facility but the EP Electric executives have put their salaries and million dollar bonuses ahead of the safety of their employee's and citizen's of El Paso. Please protect the employees of El Paso Electric and the citizen's of El Paso from EP Electric corporate greed.

Thank You.

Andrew Aviles
[redacted]

Sent from Yahoo! Mail on Android

From:	Edward Martinez
To:	Magee, Melanie
Subject:	power plant in el paso texas
Date:	Tuesday, November 05, 2013 10:08:19 AM

I am a resident and NOT in favor of the power plant being built less than a mile from my family. Please investigate and stop this criminal act, why not have it built in the open desert and let the company take the loss and they will still profit in the long run and it will be a win-win for everyone. There are many low income families and this will only make us suffer more-socioeconomically and emotionally. Thank you for your time-Eddie Martinez [redacted]

From: Groten, Eric
To: Magee, Melanie
Cc: Chacon, Roger; PGreywall@trinityconsultants.com; Herrera, Nora; Andy Ramirez
Subject: RE: El Paso Electric Montana Power Station
Date: Wednesday, December 04, 2013 11:25:05 PM
Attachments: Modeling Audit - 102294 El Paso Electric Company.pdf

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Melanie,

I notice that the copy of El Paso Electric's comments as transmitted to you did not include the referenced attachment, an oversight corrected with this transmittal.

Regards,
Eric

Eric Groten
Partner

Vinson & Elkins LLP
Attorneys at Law
2801 Via Fortuna, Suite 100
Austin, TX 78746-7568
Tel +1.512.542.8709
E-mail egroten@velaw.com

From: Herrera, Nora [mailto:nora.herrera@epelectric.com]
Sent: Wednesday, December 04, 2013 6:57 PM
To: magee.melanie@epa.gov
Cc: Chacon, Roger; Groten, Eric; PGreywall@trinityconsultants.com
Subject: El Paso Electric Montana Power Station

Ms. Magee:

Attached is a signed letter from Andy Ramirez regarding:

Comments and Supplemental Information on Proposed Greenhouse Gas ("GHG") Prevention of Significant Deterioration ("PSD") Preconstruction Permit El Paso Electric Company, Montana Power Station PSD Permit Number: PSD-TX-1290-GHG

Regards

Nora Herrera
El Paso Electric Company
100 N. Stanton |El Paso, Texas 79901
Phone: 915-543-4004 | Fax: 915-521-4728
Nora.Herrera@epelectric.com | www.epelectric.com

TCEQ Interoffice Memorandum

To: Sean O'Brien
Combustion/Coatings Section

Thru: Daniel Menendez, Team Leader
Air Dispersion Modeling Team (ADMT)

From: Roberto Castro and Justin Cherry, P.E.
ADMT

Date: October 2, 2012

Subject: Air Quality Analysis Audit – El Paso Electric Company (RN106392624)

1. Project Identification Information

Permit Application Number: 102294
NSR Project Number: 176890
ADMT Project Number: 3819
NSRP Document Number: 447695
County: El Paso
ArcReader Published Map: \\Msgiswrk\APD\MODEL PROJECTS\3819\3819.pmf

Air Quality Analysis: Submitted by Trinity Consultants, September 2012, on behalf of El Paso Electric Company.

2. Report Summary

The air quality analysis (AQA) is acceptable for all review types and pollutants. The results are summarized below.

A. De Minimis analysis

A De Minimis analysis was initially conducted to determine if a full impacts analysis would be required. The De Minimis analysis modeling results for 24-hr and annual PM_{10}, annual $PM_{2.5}$, 1-hr and annual NO_2, and 1-hr and 8-hr CO indicated that the project is below the respective de minimis concentrations and no further analysis is required. The De Minimis analysis modeling results for 24-hr $PM_{2.5}$ indicated that the project is below the de minimis concentration for the NAAQS analysis, but exceeds the de miminis concentration for the PSD Increment analysis and requires a full impacts analysis for the 24-hr $PM_{2.5}$ increment.

While the De Minimis levels for both the NAAQS and increment are identical for $PM_{2.5}$ in Table 1 below, the procedures to determine significance (that is, predicted concentrations to compare to the De Minimis levels) are different. This difference occurs because the NAAQS for $PM_{2.5}$ are statistically-based, but the corresponding increments are exceedance-based.

SO_2 did not trigger a PSD review and the modeling results for SO_2 are listed in section F (Minor NSR analysis).

The justification for selecting the EPA's interim 1-hr NO_2 De Minimis level was based on the assumptions underlying EPA's development of the 1-hr NO_2 De Minimis level. As explained in EPA guidance memoranda[1], the EPA believes it is reasonable as an interim approach to use a De Minimis Level that represents 4% of the 1-hr NO_2 NAAQS.

Table 1. Modeling Results for PSD De Minimis Analysis in Micrograms Per Cubic Meter (µg/m³)

Pollutant	Averaging Time	GLCmax (µg/m³)	De Minimis (µg/m³)
PM_{10}	24-hr	1.67	5
PM_{10}	Annual	0.16	1
$PM_{2.5}$ (NAAQS)	24-hr	1.19	1.2
$PM_{2.5}$ (NAAQS)	Annual	0.14	0.3
$PM_{2.5}$ (Increment)	24-hr	1.63	1.2
$PM_{2.5}$ (Increment)	Annual	0.15	0.3
NO_2	1-hr	7.49	7.5
NO_2	Annual	0.15	1
CO	1-hr	56.52	2000
CO	8-hr	20.89	500

The 1-hr NO_2 and the 24-hr and annual $PM_{2.5}$ (NAAQS) GLCmax are based on the highest five-year average of the high, first high (H1H) predicted concentrations determined for each receptor. The GLCmax for all other pollutants and averaging times represent the H1H predicted concentrations over five years of meteorological data.

[1] www.epa.gov/nsr/documents/20100629no2guidance.pdf

B. Air Quality Monitoring

The De Minimis analysis modeling results indicate that 24-hr PM_{10}, 24-hr $PM_{2.5}$, annual NO_2, and 8-hr CO are below their respective monitoring significance level.

Table 2. Modeling Results for PSD Monitoring Significance Levels

Pollutant	Averaging Time	GLCmax (µg/m³)	Significance (µg/m³)
PM_{10}	24-hr	1.67	10
$PM_{2.5}$	24-hr	1.19	4
NO_2	Annual	0.15	14
CO	8-hr	20.89	575

The 24-hr $PM_{2.5}$ GLCmax is based on the highest five-year average of the H1H predicted concentrations determined for each receptor. The GLCmax for all other pollutants and averaging times represent the H1H predicted concentrations over five years of meteorological data.

C. National Ambient Air Quality Standard (NAAQS) Analysis

The De Minimis analysis modeling results for 24-hr and annual PM_{10}, 24-hr and annual $PM_{2.5}$ (NAAQS), 1-hr and annual NO_2, and 1-hr and 8-hr CO indicated that the project is below the respective de minimis concentrations and no further analysis is required.

As stated in 40 CFR 52.21 (i)(5)(i)(f), no de minimis air quality level has been established for ozone. Any net emissions increase of 100 tons per year (tpy) or more of volatile organic compounds or nitrogen oxides subject to PSD would be required to perform an ambient impact analysis for ozone, including the gathering of ambient air quality data. The emission increases for the proposed Montana Power Station of both VOC and NOX are less than 100 tpy and an ozone ambient impact analysis is not required.

D. Increment Analysis

The De Minimis analysis modeling results indicate that 24-hr $PM_{2.5}$ (Increment) exceeds the de minimis concentration and requires a PSD increment analysis.

Table 3. Results for PSD Increment Analysis

Pollutant	Averaging Time	GLCmax (µg/m³)	Increment (µg/m³)

Pollutant	Averaging Time	GLCmax (µg/m³)	Increment (µg/m³)
$PM_{2.5}$	24-hr	1.24	9

The 24-hr $PM_{2.5}$ GLCmax represents the maximum high, second high (H2H) predicted concentration over five years of meteorological data.

E. Additional Impacts Analysis

The applicant performed an Additional Impacts Analysis as part of the PSD AQA. The applicant conducted a growth analysis and determined that population will not significantly increase as a result of the proposed project. The applicant conducted a soils and vegetation analysis and determined that all evaluated criteria pollutant concentrations are below their respective primary and secondary NAAQS. The applicant meets the Class II visibility analysis requirement by complying with 30 TAC 111. The Additional Impacts Analyses are reasonable and possible adverse impacts from this project are not expected.

The ADMT evaluated predicted concentrations from the proposed site to determine if proposed emissions could adversely affect a Class I area. The nearest Class I area, Guadalupe Mountains National Park, is located approximately 113 kilometers (km) from the proposed site.

The predicted concentrations of PM_{10}, $PM_{2.5}$, NO_2, and SO_2 for all averaging times, are all less than de minimis levels at a distance of 1.2 km from the proposed sources in the direction of the Guadalupe Mountains National Park Class I area. Guadalupe Mountains National Park is an additional 111.8 km from the location where the predicted concentrations of PM_{10}, $PM_{2.5}$, NO_2, and SO_2 for all averaging times are less than de minimis. Therefore, emissions from the proposed project are not expected to adversely affect the Guadalupe Mountains National Park Class I area.

F. Minor Source NSR and Air Toxics analysis

Table 4. Site-wide Modeling Results for State Property Line

Pollutant	Averaging Time	GLCmax (µg/m³)	Standard (µg/m³)
SO_2	1-hr	78.82	1021

The justification for selecting the EPA's interim 1-hr SO_2 De Minimis level was based on the assumptions underlying EPA's development of the 1-hr SO_2 De Minimis level. As explained in EPA guidance memoranda[2], the EPA

[2] www.epa.gov/region07/air/nsr/nsrmemos/appwso2.pdf

believes it is reasonable as an interim approach to use a De Minimis Level that represents 4% of the 1-hr SO_2 NAAQS.

Table 5. Modeling Results for Minor NSR De Minimis

Pollutant	Averaging Time	GLCmax (μg/m3)	De Minimis (μg/m3)
SO_2	1-hr	0.57	7.8
SO_2	3-hr	14.44	25
SO_2	24-hr	0.62	5
SO_2	Annual	0.03	1

The 1-hr, 3-hr, 24-hr, and annual SO_2 GLCmax represent the H1H predicted concentrations over one year of meteorological data.

Table 6. Minor NSR Site-wide Modeling Results for Health Effects

Pollutant & CAS#	Averaging Time	GLCmax (μg/m3)	ESL (μg/m3)
ammonia 7664-41-7	1-hr	6.41	170

The GLCmax for ammonia is located along the property line. The applicant did not provide a GLCni.

3. Model Used and Modeling Techniques

AERMOD (Version 12060) was used in a refined screening mode.

Each source was modeled in a separate source group to determine source culpability.

A. Land Use

Medium roughness and elevated terrain were used in the modeling analysis. These selections are consistent with the AERSURFACE analysis, topographic map, DEMs, and aerial photography. The selection of medium roughness is reasonable.

B. Meteorological Data

Surface Station and ID: El Paso, TX (Station #: 23044)
Upper Air Station and ID: El Paso, TX (Station #: 23044)
Meteorological Dataset: 1987-91 for PSD modeling, 1988 for all other reviews
Profile Base Elevation: 1189 meters

The profile base elevation was input as 1189 meters. The profile base elevation should have been 1198 meters. However, this discrepancy does not significantly affect the modeling results.

C. Receptor Grid

The grid modeled was sufficient in density and spatial coverage to capture representative maximum ground-level concentrations.

D. Building Wake Effects (Downwash)

Input data to Building Profile Input Program Prime (Version 04274) are consistent with the plot plan and modeling report.

4. Modeling Emissions Inventory

The modeled emission point, area, and volume source parameters and rates were consistent with the modeling report. The source characterizations used to represent the sources were appropriate.

Several off-property sources were modeled with hour-of-day scalars to represent operational limitations. These operational limitations were based on representations made in the respective permit.

NO_x to NO_2 conversion factors of 0.8 and 0.75 were applied to the modeled 1-hr and annual NO_x predicted concentrations, respectively, which is consistent with guidance for combustion sources.

No more than one of the four turbines (EPNs GT-1, 2, 3, and 4) will undergo a startup and shutdown in any 30 minute period. Therefore, multiple scenarios were modeled for the 1-hr NO_2 analysis to determine the worst-case scenario regarding the four turbines when operating in normal and planned MSS modes. Four scenarios were based on each turbine undergoing startup and shutdown operations in the same hour while the other three turbines are in normal operation. In addition, twelve scenarios were based on one turbine undergoing startup operations in the first 30 minute period of an hour and a second turbine undergoing startup operations in the second 30 minute period of the same hour while all other turbines are in normal operation. Only the results of the worst-case scenario are reported in Table 1.

For the CO short-term averaging periods, all four turbines (EPNs GT-1, 2, 3, and 4) were simultaneously modeled with the worst-case hourly emission rates (planned MSS operations) as a conservative approach.

Each turbine (EPNs GT-1, 2, 3, and 4) was conservatively modeled with the lowest stack temperature and lowest exit velocity regardless of the operating scenario (i.e. planned MSS, routine, etc.).

The applicant evaluated simultaneous startups of two or more turbines following EPA guidance on intermittent emissions for the 1-hr NO_2 modeling analysis. The applicant calculated annual average emissions rates based on 52 hours per year of simultaneous startups. The annual average emission rates were added to the maximum hourly emission rates corresponding to normal operations, and the resulting total emissions were modeled.

The diesel firewater pump engine (EPN FWP1) was modeled with an exit velocity of 0.001 m/s since this source will exhaust horizontally.

The diesel firewater pump engine (EPN FWP1) was excluded from the 1-hr NO_2 and 1-hr SO_2 modeling analyses, which is consistent with EPA guidance for evaluating intermittent emissions since the diesel firewater pump engine will operate for no more than a total of 52 hours per year.

For the 3-hr SO_2 modeling, the diesel firewater pump engine (EPN FWP1) was modeled using a 3-hr average emission rate. For the 24-hr SO_2, 24-hr and annual PM_{10}, and 24-hr and annual $PM_{2.5}$ modeling, the diesel firewater pump engine was modeled using a 24-hr average emission rate.

For the annual SO_2 modeling, the four turbines (EPNs GT-1, 2, 3, and 4) were modeled using the maximum allowable hourly emission rates.

For the annual NO_2 modeling, the four turbines (EPNs GT-1, 2, 3, and 4) were modeled using the maximum allowable hourly emission rates for normal operations assuming continuous operation for the entire year. This is conservative since it results in an annual modeled NO_x emission rate of 34.43 tpy for each turbine, which is greater than the proposed annual NO_x emission limit of 24.08 tpy for each turbine. The proposed annual NO_x emission limit of 24.08 tpy incorporates all emissions scenarios, restrictions on the number of startups and shutdowns, and limitations on annual hours of operation.

For the annual PM_{10} and $PM_{2.5}$ modeling, the four turbines (EPNs GT-1, 2, 3, and 4) were modeled using the maximum allowable hourly emission rates.

Maximum allowable hourly emission rates were used for the short-term analysis for the ammonia modeling.

For all other sources, maximum allowable hourly emission rates were used for the short-term averaging time analyses, and annual average emission rates were used for the annual averaging time analyses.

From:	Groten, Eric
To:	Magee, Melanie
Cc:	Tomasovic, Brian
Subject:	Extension of Comment Period Established for El Paso Electric Co. Montana Power Station Permit No. PSD-TX-1290-GHG
Date:	Wednesday, November 06, 2013 12:04:18 PM
Importance:	High

Dear Ms. Magee,

On behalf of El Paso Electric, I am requesting a four-week extension in the comment period on the above-referenced draft permit (to close on December 4, 2013). The additional time will be used by El Paso Electric to engage with interested parties, which may lead to the need to supplement the record prior to its close. We thank you in advance for your favorable and (very) prompt consideration of this request. As you know, the comment period presently is scheduled to close at midnight tonight.

Regards,

Eric Groten
Partner
Vinson & Elkins LLP
2801 Via Fortuna
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Tel +1.512.542.8709
Fax +1.512.236.3272
Cell +1.512.669.3283
egroten@velaw.com

From:	Fred and Carmen Johnson
To:	Magee, Melanie
Subject:	El Paso Electric Power Plant - Formal Letter
Date:	Tuesday, December 03, 2013 9:55:59 AM

Dear Melanie and the EPA,

Please take this email as a formal letter of concern about El Paso Electric building another set of power plants to their already supposedly approve plan.

El Paso Electric does not need an additional power plant. Fort Bliss is now going to a Net Zero Generation of electricity where they will be generating their own energy. Why not see if El Paso Electric can follow Fort Bliss in this. Fort Bliss' need for electricity will now **not** depend on El Paso Electric, which will reduce the need for additional power plants. My husband and I are totally **against** El Paso Electric building any power plants close to our neighbor but especially now for additional plants. Please see our point of view and not allow EL Paso Electric to do this.

Thank you,

Fred and Carmen Johnson
[redacted]

From:	Ivette Doblado
To:	Magee, Melanie
Subject:	EPA's proposed PSD permit for the Montana Power Station located in El Paso,
Date:	Wednesday, November 06, 2013 2:59:02 PM

Melanie Magee
Air Permits Section (6PD-R) *Shipped via e-mail*
U.S. EPA, Region 6 magee.melanie@epa.gov
1445 Ross Avenue, Suite 1200
Dallas, TX 75202

Ref: EPA's proposed PSD permit for the Montana Power Station located in El Paso,

Texas

Mrs. Magee,

Please accept this correspondence as my formal comment in reference to the matter indicated above. My family and I have live a few miles away from El Paso Electric's proposed Montana Power Station and we are very concerned that they want to bring this electrical plant to our neighborhood. We've lived in the neighborhood for 5 years and specifically choose to build our home in the area to keep away for city pollution. El Paso Electric failed to conduct an environmental justice analysis for the plant. The public was never asked about our opinions on how the power plant was going to impact our health and our environment. We were never given the opportunity to be involved in the decision making process. They have clearly demonstrated gross business practices and clearly an example of how big business bullies their way into neighborhoods.

In most cases the EPA requires an environmental justice analysis for a power plant of this scope. Why was this plant an exception? I plead to you Mrs. Magee for my family's health to help us stop El Paso Electric. We do NOT want this in our neighborhood.

Respectfully,

Ivette Doblado

[redacted]

From:	Lorne Bay
To:	Magee, Melanie
Subject:	Montana Power Station-Health problems
Date:	Tuesday, October 29, 2013 8:52:51 PM
Attachments:	Midwest Today Do High-Voltage Power Lines Cause Cancer.mht.msg

Please accept this attachment as a formal comment. Thanks, Lornr

Magee, Melanie

From: Saved by Windows Internet Explorer 8
Sent: Wednesday, October 23, 2013 9:57 AM
Subject: Midwest Today: Do High-Voltage Power Lines Cause Cancer?

***Midwest Today*, April/May 1996**

NEWSFRONT

DO HIGH-VOLTAGE POWER LINES CAUSE CANCER

Studies link Electromagnetic Fields (EMFs) To Illness

By NEAL LAWRENCE

It was sort of a funny story when we first heard about it a few years ago: A dairy farmer living in Wisconsin near high voltage utility company transmission lines couldn't turn out the lights in his barn. Even with the switches in the off position, night after night after he had finished his chores, he'd go back out to the barn to find the light bulbs still glowing from the electrical charge hovering in the air. The cows were none too happy about it either, because the constant light prevented them from sleeping, and they gave less milk.

But the story doesn't seem so funny any more -- not after the spate of recent reports of children developing deadly illnesses or adults dying prematurely of rare diseases -- all apparently because they had the misfortune of living near high amounts of electrical current.

A growing body of scientific evidence suggests that invisible electromagnetic fields (EMFs) -- created by everything from high-voltage utility company lines to personal computers, microwave ovens, TVs and even electric blankets -- are linked to a frightening array of cancers and other serious health problems in children and adults.

Though it received scant attention from the mainstream press, a report leaked last October from the U.S. National Council on Radiation Protection said there is a powerful body of impressive evidence showing that even very low exposure to electromagnetic radiation has long-term effects on health.

The report cited studies that show EMFs can disturb the production of the hormone melatonin, which is linked with sleep patterns. It said there was strong evidence that children exposed to EMFs had a higher risk of leukemia.

This follows on the heels of three epidemiological reports released in 1994. One indicated a tie between occupational exposure to EMFs and Alzheimer' s disease. Another suggested a link with Sudden Infant Death Syndrome (SIDS). The third study indicated a tie with Amyotrophic lateralsclerosis.

Now a surprising new report released in February by physicists at Britain's University of Bristol shows that power lines attract particles of radon -- a colorless, odorless gas irrefutably linked with cancer.

What's this all about? And why have the media failed to report with the appropriate emphasis the implications of these significant health risks?

Shortly after her son Kevin was diagnosed with leukemia, Julie Larm of Omaha, NE. began to notice other children at the local pool who had lost their hair or had surgical scars. As her suspicion rose, she began talking to other parents. One person she contacted was Dee Hendricks, whose son was also undergoing cancer treatment. Together they collected the names of eleven children in the area who had cancer.

When they plotted them on a map they were surprised to see that all lived within one mile of each other and an electric power substation.

"If there was nothing to worry about, why does our utility have an EMF committee...which was in effect long before we came and started making noise ?" asks Larm, a member of the Omaha Parents for the Prevention of Cancer. "Why do they need such things if theres nothing to it?"

The group's efforts have been buttressed by Paul Brodeur, a campaigning environmental journalist who had in his day taken on asbestos and chlorofluorocarbons and is the author of two books on the subject of EMFs. Brodeur is convinced that EMFs are one of the greatest environmental threats facing the nation.

"Never before has there been this much epidemiological evidence of the carcinogenicity of any agent," says Brodeur, "and that agent declared to be benign."

Robert Becker, M.D., author of *Cross Currents* (Tarcher, 1990), who has studied this subject since the 1960s warns, "EMFs could turn out to be a far worse environmental disaster, affecting far more people, than toxic waste, radiation or asbestos."

To some, especially the families of people with unexplained cancers, the sheer volume of research that has been carried out on this issue suggests there must be a cancer connection and perhaps a cover-up. Their suspicion is heightened by the fact that many of the studies are funded by the utility industry, which would be directly affected by the studies' outcomes.

At the heart of the matter is a relatively simple and well-understood physical phenomenon: When an electric current passes through a wire, it generates an electromagnetic field that exerts forces on surrounding objects. Electric fields arise from the strength of an electric charge; magnetic fields, from the charge's motion.

Unlike ionizing radiations such as x-rays -- which pack sufficient wallop to knock electrons out of the molecules that make up the human body -- EMFs do not produce charged particles, so experts always believed they posed no danger. Therefore, the Federal government has never regulated EMFs, and the electric industry was allowed to set its own standards.

But other recent experimental studies have shown that even weak magnetic fields can change the chemistry of the brain, impair the immune system, and inhibit the synthesis of melatonin, a hormone known to suppress several types of tumors and to be present in reduced amounts in men as well as women who develop breast cancer.

Some lab tests have confirmed that EMFs affect living cells in a variety of ways, most of them harmful. (Scientists are intrigued, however, by their ability to speed slow-healing fractures, enhancing bone formation).

What's confusing is that the studies have produced widely divergent and often contradictory results. On the one hand, many scientists are convinced the study of electromagnetic fields is a massive waste of time and money -- costing an estimated one billion dollars a year. After years of extensive study, Dr. Garry Boorman says, "We're not sure what part of the field, if any, is toxic or important, or could be hazardous to your health."

As a PBS "Frontline" documentary reported, scientists have been unable to locate a mechanism by which electromagnetic fields would trigger a biological reaction. The energy in the fields to which most of us are exposed is tiny tens of millions of times too small to break the molecules in cells. All living organisms evolved in the presence of the earths magnetic field, which is two hundred times larger.

Dozens of animal experiments have been carried out in which rats and mice are exposed to very large magnetic fields for long periods -- some for their entire lives -- but no animal has ever been proven to contract cancer due to this exposure. Generations of rodents raised in the presence of high magnetic fields do not show any increased evidence of birth defects or depressed immune systems.

With no animal data to support the claim and no physical mechanism to explain how it might affect the body, the main support for a connection has come from epidemiology.

As for clusters like the ones which motivated Julie Larm and her group in Omaha, many scientists are skeptical about their significance, if any, to the debate about EMFs. Because conditions like cancer are surprisingly common about one-third of the population gets cancer in their lifetimes random clusters of the disease are not unusual and are found close to and far from power lines.

Still, because of our reliance on electricity and the potential financial consequences for utilities and other companies, the regulation of EMFs is a politically sensitive issue. There is evidence to establish that the Bush administration tried to suppress findings of a study by the Environmental Protection Agency linking electromagnetic fields to certain health problems. The Clinton White House, meanwhile, has been largely silent on the issue.

Cover-Up?

Lending credence to claims that there is, indeed, a public health risk from EMFs and that the government knows about it is that an EPA report a few years ago raised suspicions of a causal link between electromagnetic fields and leukemia, brain tumors, breast and prostrate cancer, even birth defects.

Less-publicized but still significant are some of the foreign studies. Last July, Canadian researchers told the Lancet medical journal they had found a high rate of leukemia among children whose mothers had worked at sewing machines while pregnant.

Checks showed the operators were exposed to more electromagnetic radiation than people who work on power lines or in power stations.
In another study, Swedish researchers assessed the long-term exposure of people living near high-voltage transmission lines by taking spot measurements of the field strength in each home, and using them to confirm the accuracy of a computer model that calculated the strength of the fields emitted by each of the lines, according to distance from the lines, the wiring configurations, and the current level the lines were known to be carrying.

Then they programmed a computer with records of past current loads that had been maintained over the previous 20 years for each of the transmission lines. They were thus able to pinpoint with great accuracy EMF exposure for each cancer victim. What they found was a clear dose-response relationship between exposure to even weak power-frequency electromagnetic fields and the development of cancer, especially acute and chronic myeloid leukemia.

A second Swedish study, which also employed cases and controls, was conducted by epidemiologists. It confirmed that average magnetic field exposure over time was the critical factor in the development of disease. Interestingly, these studies were funded in part by the Swedish utility industry.

Maria Feychting of Swedens Karolinska Institute looked at 127,000 children who lived near big power lines for over 25 years and found twice the risk of leukemia.

"In our study we found about a two-fold increase in the risk if the children were living close, within 50 meters (yards) of a big power line," she told Britain's Channel Four television.

The new study by the University of Bristol showing that power lines can attract cancer-causing gases like radon has heightened concerns.

Even scientists who have failed to find a reason for the apparent link refuse to say it is safe to live near a high-voltage power line.

Warning to Parents

Of critical importance to all parents is that some studies have suggested that children exposed to magnetic fields of between two and three milligauss or above experienced a significantly increased risk of developing cancer. Since ambient levels of two to three milligauss can routinely be measured in buildings within 50 to 150 feet of wires carrying strong electric current, these findings are especially troublesome.

The report leaked last October by the mellitus National Council on Radiation Protection recommended a safety limit of 0.2 microteslas, a very weak field compared to those generated by household appliances. A person standing one foot away from a vacuum cleaner or electric drill can be exposed to anywhere between two and 20 microteslas.

There is no way to block EMFs (they even penetrate lead shielding), and the only protection is distance from the source.

In our electronic age, its almost impossible to eliminate exposure to the myriad of electrical sources with which we come in contact on a daily basis.

Thousands of electric company substations are scattered throughout our cities large and small and they abut homes, apartments and office buildings -- even schools. Since few of the high-voltage lines that lead into and out of these substations have been buried to prevent harmful emissions, magnetic fields of potent strength can be found virtually everywhere.

Concerns have also been raised about magnetic fields given off by faulty household wiring, by high-current conductors concealed in the walls, ceilings and floors of commercial office buildings and other large structures; and by high-voltage transformers that can be found in almost any large building.

The EPA Raises Questions

Concerns about so-called non-ionizing radiation began to mount in 1979, when a study of cancer rates among Colorado school children determined that those who lived near power lines had two or three times as much chance to develop cancer. The link seemed so improbable that power companies eagerly paid to have the study replicated. To their surprise, the subsequent scientific inquiry supported the original findings, which have since been buttressed by a variety of additional studies and reports of increased cancer rates among workers employed in the electric industry.

One such study, conducted by the Fred Hutchinson Cancer Research Center in Seattle, WA. confirmed that telephone linemen, electricians and electric-power workmen are developing breast cancer at six times the expected rate.

But it was the Environmental Protection Agency's scientific review that has had an explosive impact, lending the most credence to those who have been warning of EMF health hazards.

The report -- a 367-page document entitled "Evaluation of the Potential Carcinogenicity of Electromagnetic Fields" -- came to light in 1990, when someone in the agency leaked a draft version of it to Louis Slesin, editor of an influential newsletter called *Microwave News*.

Chief among the conclusions was one specifying that power line electromagnetic fields should be classified as a "probable human carcinogen." William Farland, then-director of the EPA's Office of Health and Environmental Assessment ordered this conclusion deleted from the report.

Then the Associated Press reported that the Bush administration tried to delay release of the EPA's findings. Robert E. McGaughy, the project manager and chief author of the report, was quoted as saying that the White House "was concerned not about the accuracy of the report...[but] about how people would react to the news and how it would affect the electric power industry."

Ultimately, after two major TV networks and newspapers throughout the country exposed the Bush administration's efforts at censorship, the report was released. It contained a disclaimer that asserted "the controversial and uncertain nature of the scientific findings of this report" and declared that it should not be construed as "representing Agency policy or position."

The Medical Connection

Just how EMFs affect humans is still not entirely known.

In the case of cancer, most specialists theorize that a malignant tumor forms in at least two stages. In the first, referred to as "initiation," an outside agent damages the cell's genetic material. Because EMFs are not strong enough to break molecular and chemical bonds, scientists are concentrating on the second stage of cancer, a series of steps called "promotion." Researchers are tying to pinpoint ways in which EMFs might cause cells to grow and multiply abnormally.

Some studies suggest that EMFs may promote cancer by interfering with the transmission of calcium across the cell membrane, a flow that governs such processes as muscle contraction, egg fertilization, cell division, and growth. EMFs may also disturb a cell's ability to process hormone, enzyme, and other biological signals that regulate normal growth.

EMFs are known to affect nerve impulses. Melatonin, a regulatory hormone secreted by the pineal gland near the brain, ordinarily stimulates immune responses and may suppress tumor growth. Reduced melatonin production has been linked to breast and prostate cancer. Melatonin secretion in turn is controlled by norepinephrine, a neurotransmitter in the brain. Receptors for its relative, the hormone epinephrine, are disturbed by EMFs.

Some doctors stated that their observations led them to believe that it was possible that magnetic fields stimulate the rate of cancer cell growth, or act as a cancer promoter.

A San Antonio researcher discovered human cancer cells exposed to 60 Hz fields (the frequency of a high-voltage line) grew as much as 24 times as fast as unexposed cells and showed greatly increased resistance to destruction by the cells of the body's defense system.

Female breast cancer has reached epidemic proportions, with one in ten American women developing it and one in four dying. Alarmingly, of women who develop the disease, 55% have no known risk factors. Breast cancer mortality rates are five times lower in Asia and Africa than in industrialized North America and northern Europe regions where EMFs are omnipresent.

Electric Companies On the Spot

A contention of the electric utility industry in the United States had been that the pathologies referred to in most of the studies might actually have been induced by exposure to pesticides, chemicals or other toxic agents in the environment.

For a time they contended that if power-line magnetic fields really did cause cancer, the fivefold increase in electrical usage during the past 30 years would have been expected to have produced an epidemic of childhood leukemia. The utility industry stopped making this statement in June of 1991, after the National Cancer Institute disclosed that a study it had made showed that in recent years there had been unexplained increases of nearly 11% in childhood leukemia, and of more than 30% in childhood brain cancer.

A study in the *American Journal of Industrial Medicine* reported a steep increase in brain-cancer rates over the past dozen years among the general population.

People working with computer monitors are developing primary brain tumors at nearly five times the expected rate.

Still, as Dr. Becker observes, "Companies wont admit that EMFs are risky, because they will become liable. And the government wont, because it is the largest user of the electromagnetic spectrum, especially for military communications. Our whole economy depends on them now."

Not surprisingly, as people begin to focus on the problem of EMFs, property values near power lines and electric substations have been plummeting, and numerous lawsuits have been filed.

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MIDWEST TODAY
P.O. BOX 6[illegible], PANORA, IA. 50216

From:	Mario Solano
To:	Magee, Melanie
Subject:	Comments for the Proposed Electric Plant in east El Paso Texas
Date:	Tuesday, November 05, 2013 10:11:19 AM

Good morning,

Just a few words of concerns over the proposed Electric Power Plant in East El Paso Texas. First and foremost My family lives within 500 feet of the proposed plant. The site location has to be the most unsafe location in the world! ho in there right mind would put a huge powerplant in a fuel farm that has over MILLION GALLONS OF FUEL! he plant would be within 250 feet of the storage tanks. REMEMBER, just a fews months ago a fertilizer plant in West Texas, Texas blew up with small quantities of of ferlizer fuel tanks. WE ask ourselves after a devastating event WHY?, simply because we are reactive instead proactive.

EPA, you all have the authority to prevent, protect our families and communities from this type of potential.

Besides the safety factors involved, we look at the health effects of our children and all of those elderly folks living within this "Colonia". T health effects of Air contaminates that will be emitted, the skewed data used byThe El Paso Electric company, just look at the historical data from New Mexicos Environmental Division (equal to TCEQ) who has over the last 12 years cited El Paso Electric for air contaminates violations at the Rio Grande and Newman Plants.

SO MUCH FOR THE DATA SUBMITTED WITH THE APPLICATION!

The health effects, the creation of the stench of the ponding areas(leach fields) the, higher possibility of the West Nile Virus affecting the community with 75 acres of open waterponds the obsortion of millions of gallons of water in a drought restricted area.

The EPA's no compliance with the ACT of 1994:

In 1994 President Clinton signed an executive order **“that was intended to provide minority communities and low income communities access to public information on, and an opportunity for public participation in, matters relating to human health or the environment”.**

We wihere never asked about our opinions on how this power plant was going to impact our health and our environment. The public did not participate on the decision making process. We were only told that they were coming! The EPA did not require El Paso Electric to conduct this analysis. This is not appropriate because in most cases the EPA must require this.
Is our health and our community not worthy of the same considerations that other communities in this country receive?

Please consider the impact of the above statements which are factual and not skewed data as used by the Electric Company. The greed that is upon El Paso Electric of not moving this

plant to another location th does not impact our community was not aoption, when we learned of this we ask them what other sites were considered, said no other site or plan "B" was an option or "they did not have one"
When the EP Electric Company reported a $83 Million dollar profit for the last quarter,you can't qualify this other than a total disregard for the communities safety and health over greed.

These comments are going into an official file that the State of Texas, The TCEQ, and the Federal EPA were appraised of for future use when an incident occurs due to this power plant. History has showed that it will occur.

My family of Four and our neighbors ask for your intervention in stopping this power plant, we are not against new technology which this plant is not the newest available, we are asking why this location when their is other sites away from the community that does not affect the safety and health of our families.

The proposed transmission lines can also be installed from other safe sites.
Thank You for the opportunity to comment

Mario Solano Jr. //S//	Mario A Solano IV //S//
Mario Solano, Jr.	Son: Mario A. Solano IV age 12
Arlennee R. Solano //S//	Miguel Angel Solano //S//
wife: Arlennee R. Solano	Son: Miguel Angel Solano, age 4

--
Mario Solano

Mario Solano, Vice President
TRIPLE "S" ENTERPRISES, INC.
4196 Flager Street
El Paso, Texas 79938
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triples.solano@gmail.com

From:	Mario Solano
To:	Magee, Melanie
Subject:	Comments re-sent from Mario Solano and family, regarding EP Electric Power Plant
Date:	Tuesday, November 05, 2013 10:22:56 AM
Attachments:	power plant epa comments Good morning 1.docx

Hi Melanie, I am re-sending this comment I forgot to Spell check
Thank You

--
Mario Solano

Mario Solano, Vice President
TRIPLE "S" ENTERPRISES, INC.
4196 Flager Street
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Good morning,

Just a few words of concerns over the proposed Electric Power Plant in East El Paso Texas. First and foremost my family lives within 500 feet of the proposed plant. The site location has to be the most unsafe location in the world! Who in their right mind would put a huge power plant in a fuel farm that has over 4 MILLION GALLONS OF FUEL! The plant would be within 250 feet of the storage tanks. REMEMBER, just a few months ago a fertilizer plant in West Texas, Texas blew up with small quantities of fertilizer fuel tanks. WE ask ourselves after a devastating event WHY? simply because we are reactive instead proactive.

EPA, you all have the authority to prevent, protect our families and communities from this type of potential.

Besides the safety factors involved, we look at the health effects of our children and all of those elderly folks living within this "Colonia". T health effects of Air contaminates that will be emitted, the skewed data used by The El Paso Electric company, just look at the historical data from New Mexico's Environmental Division (equal to TCEQ) who has over the last 12 years cited El Paso Electric for air contaminates violations at the Rio Grande and Newman Plants.

SO MUCH FOR THE DATA SUBMITTED WITH THE APPLICATION!

The health effects, the creation of the stench of the ponding areas(leach fields) the, higher possibility of the West Nile Virus affecting the community with 75 acres of open water ponds the absorption of millions of gallons of water in a drought restricted area.

The EPA's no compliance with the ACT of 1994:

In 1994 President Clinton signed an executive order **"that was intended to provide minority communities and low income communities access to public information on and an opportunity for public participation in, matters relating to human health or the environment".**

We were never asked about our opinions on how this power plant was going to impact our health and our environment. The public did not participate on the decision making process. We were only told that they were coming! The EPA did not require El Paso Electric to conduct this analysis. This is not appropriate because in most cases the EPA must require this.
Is our health and our community not worthy of the same considerations that other communities in this country receive?

Please consider the impact of the above statements which are factual and not skewed data as used by the Electric Company. The greed that is upon El Paso Electric of not moving this plant to another location the does not impact our community was not an option, when we learned of this we ask them what other sites were considered, said no other site or plan "B" was an option or "they did not have one"

When the EP Electric Company reported an $83 Million dollar profit for the last quarter, you can't qualify this other than a total disregard for the community's safety and health over greed.

These comments are going into an official file that the State of Texas, The TCEQ, and the Federal EPA were appraised of for future use when an incident occurs due to this power plant. History has showed that it will occur.

My family of Four and our neighbors ask for your intervention in stopping this power plant, we are not against new technology which this plant is not the newest available, we are asking why this location when there is other sites away from the community that does not affect the safety and health of our families.

The proposed transmission lines can also be installed from other safe sites.
Thank You for the opportunity to comment

Mario Solano Jr. //S//	Mario A Solano lV //S//
Mario Solano, Jr.	Son: Mario A. Solano lV age 12
Arlennee R. Solano //S//	Miguel Angel Solano //S//
Wife: Arlennee R. Solano	Son: Miguel Angel Solano, age 4

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Mario Solano

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From: Mario Solano
To: Magee, Melanie
Date: Tuesday, December 03, 2013 9:38:27 AM

We are residents and business owner(s) within 500 feet of the power plant proposed site. We have grave concerns for the safety of our families and employees. The El Paso Electric Plant has submitted an air application with skewed data. The data used is from 12 years back and not representative of the current contaminants they wil be releasing.
The El Paso Electrics plants in the Rio Grande Plan as well as the Newman Plant also submitted skewed data and for years the NM Enviornmental Division has repeatedly cited El Paso Electric on violations of the Air Quality Standards. So itdoes matter what they sya on the application. El Paso Electric is content in being cited and pay daily fines afterwards for the lack of safety and health considerations of the public.

On another note these safety and health issues have not been addressed:

El Paso Electric has not justified the need for an additional power plant. Fort Bliss is going to Net Zero generation of electricity. Fort Bliss will generate it's own energy. This means that their need for electricity for El Paso Electric will be reduced. Population growth will not justify the need for an additional power plant.

--
Mario Solano

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From:	Mario Solano
To:	Magee, Melanie
Subject:	Comments for the El Paso Electric Power Plant
Date:	Tuesday, December 03, 2013 9:48:27 AM

Sorry, I sent an incomplete comment a few minutes ago.

Please let me try again and accept these as formal complaint comments for the record.

We are residents and business owner(s) within 500 feet of the power plant proposed site. We have grave concerns for the safety of our families and employees. The El Paso Electric Plant has submitted an air application with skewed data. The data used is from 12 years back and not representative of the current contaminants they wil be releasing.
The El Paso Electrics plants in the Rio Grande Plan as well as the Newman Plant also submitted skewed data and for years the NM Enviornmental Division has repeatedly cited El Paso Electric on violations of the Air Quality Standards. So it does matter what they say on the application. El Paso Electric is content in being cited and pay daily fines afterwards for the lack of safety and health considerations of the public.

On another note these safety and health issues have not been addressed:

1)El Paso Electric has not justified the need for an additional power plant. Fort Bliss is going to Net Zero generation of electricity. Fort Bliss will generate it's own energy. This means that their need for electricity for El Paso Electric will be reduced. Population growth will not justify the need for an additional power plant.

2) Increase Risk for "Bird Strikes" as the ponding areas will be in the approach route for all aviation flights into El Paso International Airport.

3) Increase health risk for mosquitoes from the ponding areas (75 acres)

4) Fire and Explosion Hazards by allowing them to built the Electric Plant inside of a Fuel Tank Farm with over Four(4) Million Gallons of Gasoline stored. This would make the West Texas Fertilizer Plant explosion a minor disaster.
5) El Paso Electric has targeted a "Colonia" and low income neighborhoods to achieve its greed for the plant not conducting an environmental impact study or did not have a plan "B" location. This in effect will cause grave health and safety consequences for the community.

The Amount of air contaminants that will be released is a grave health risk.

Please accept our responses as real and the risk involved is immenent to our families and the entire community.

Thank You
Mario Solano
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Mario Solano

Mario Solano, Vice President
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From:	Michael Gossett
To:	Magee, Melanie
Subject:	El Paso Electric Power Station
Date:	Saturday, October 26, 2013 2:51:28 PM

Dear Ms. Magee,

I am a resident of Homestead Meadows North, a community that will be directly effected by the Electric Company's proposed Power Station and Facility Complex to be located near Montana Avenue in El Paso, Texas.

This letter is to voice my opinion of the addition of four combustion turbines - NO! This is a bad idea! They will sit right next to 25 huge fuel tanks!

Sincerely,
Michael Gossett

From:	Herrera, Nora
To:	Magee, Melanie
Cc:	Chacon, Roger; egroten@velaw.com; PGreywall@trinityconsultants.com
Subject:	El Paso Electric Montana Power Station
Date:	Wednesday, December 04, 2013 6:57:47 PM
Attachments:	Letter Magee - US Enviironmental Protection Agency.pdf

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Ms. Magee:

Attached is a signed letter from Andy Ramirez regarding:

Comments and Supplemental Information on Proposed Greenhouse Gas ("GHG") Prevention of Significant Deterioration ("PSD") Preconstruction Permit El Paso Electric Company, Montana Power Station PSD Permit Number: PSD-TX-1290-GHG

Regards

Nora Herrera
El Paso Electric Company
100 N. Stanton |El Paso, Texas 79901
Phone: 915-543-4004 | Fax: 915-521-4728
Nora.Herrera@epelectric.com | www.epelectric.com

Go Green! Print this email only when necessary. Thank you for helping to be environmentally responsible.

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*********************** ATTACHMENT NOT DELIVERED  *******************

This Email message contained an attachment named
  image001.jpg
which may be a computer program. This attached computer program could
contain a computer virus which could cause harm to EPA's computers,
network, and data.  The attachment has been deleted.

This was done to limit the distribution of computer viruses introduced
into the EPA network.  EPA is deleting all computer program attachments
sent from the Internet into the agency via Email.

If the message sender is known and the attachment was legitimate, you
should contact the sender and request that they rename the file name
extension and resend the Email with the renamed attachment.  After
receiving the revised Email, containing the renamed attachment, you can
rename the file extension to its correct name.

For further information, please contact the EPA Call Center at
(866) 411-4EPA (4372). The TDD number is (866) 489-4900.

***********************  ATTACHMENT NOT DELIVERED ***********************
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El Paso Electric

P.O. Box 982
El Paso, Texas
79960-0982
(915) 543-5711

December 4, 2013

Ms. Melanie Magee
Air Permits Section (6PD-R)
U.S. Environmental Protection Agency-Region 6
1445 Ross Avenue, Suite 1200
Dallas, TX 75202

Re: Comments and Supplemental Information on Proposed Greenhouse Gas ("GHG") Prevention of Significant Deterioration ("PSD") Preconstruction Permit
El Paso Electric Company, Montana Power Station
PSD Permit Number: PSD-TX-1290-GHG

Dear Ms. Magee:

El Paso Electric Company (EPE) is writing in support of the issuance of the above-referenced Draft GHG PSD Permit (dated September 22, 2013). Our purposes here are two-fold. First, EPE asks EPA to consider two changes to the permit, one to eliminate duplicative terms related to performance testing, and the other to further tighten the GHG limits. Second, EPE provides additional information in support of permit issuance.

1. **REQUESTED CHANGES TO TERMS OF DRAFT PERMIT**

a. **Duplicative Performance Testing Requirements**

In the Draft GHG PSD Permit, on Pages 11 and 12, Conditions V.A through V.G. (captioned "Initial Performance Testing and 5-year Emissions Testing Requirements"), EPE has identified redundant conditions related to initial and 5-year stack testing. Consistent with EPE's proposal, EPA has included in the draft permit a condition compelling installation of a Continuous Emissions Monitoring System (CEMS) for carbon dioxide (CO_2) emissions in order to demonstrate compliance with the applicable Best Available Control Technology (BACT) and annual emission limits for CO_2. The CEMS will be subject to relative accuracy test audits (RATA) at initial commissioning and annually thereafter. Those RATAs require performance tests equivalent to those that would also be compelled by Conditions V.A. - V.G., and the CEMS, of course, will be generating emissions data on a continuous basis, as well. Therefore, the traditional three-run performance test (i.e., stack test) requirements in conditions V.A. through V.G. are redundant. To eliminate duplication and confusion, EPE asks that Conditions V.A. through V.G. be removed from the draft permit. Condition III.A already includes the requirements and procedures to compel periodic performance tests at a frequency greater than that established by Conditions V.A. - V.G.

b. **Tightening of Emission Limit Identified as BACT**

EPE's permit application includes a BACT analysis which establishes that a CO_2 emission limit of 1194 lb/MWh represents BACT for this project. EPE supports EPA Region 6's conclusion in its Statement of Basis that this value represents BACT. EPE also maintains that EPA's recently signed proposed rule establishing new source performance standards for electric generating units does not affect the BACT analysis for the Montana Power Station. First, EPA has not yet published any proposed standard, much less finalized one, and it solicits comments on levels up to 1200 lb/MWh. Second, the NSPS does not and will not apply to the Montana Power Station because EPE has taken actual delivery of or contractually committed to the fabrication of the MPS turbines prior to the publication of the proposed NSPS in the *Federal Register*. Finally, even if the NSPS were to apply to the MPS, it would do so by its own terms and supersede any inconsistent provisions in the permit, both by its terms and by operation of law; accordingly, there is no need to pre-judge in this action whether or how the NSPS might change the draft permit.

Although EPE does not concede that 1100 lb/MWh reflects BACT at the Montana Power Station, EPE has a business interest in avoiding undue permitting delays associated with this project. Furthermore, EPE believes that MPS will be able to meet a limit of 1100 lb/MWh (albeit with reduced margins of compliance) because EPE selected the most efficient of all aeroderivative turbines on the market (LMS100 with evaporative cooling). In order to avoid any delays that could result from potential legal challenges alleging that the proposed NSPS represents a BACT ceiling that should apply at MPS—an argument that EPE believes lacks merit—EPE requests that EPA Region 6 reduce the 1194 lb/MWh limit to 1100 lb/MWh.

2. **ADDITIONAL INFORMATION IN SUPPORT OF ISSUANCE OF DRAFT PERMIT**

EPE believes that its permit application and the Region 6 statement of basis provide ample support for a decision to issue the draft permit (subject to the two above changes). Although the record already suffices, EPE offers the following information in the event it may prove helpful in addressing issues that may arise during the comment process.

a. **EPE Already is Among the Least "Carbon-Intensive" Utilities in the Nation.**

EPE's generation portfolio already exhibits dramatically lower carbon intensity than any other utility in the southwestern U.S. The following table compiles from public sources the reported lb CO_{2e}/MWh for each listed utility for the most recent years available:

Table 1: Ranking of Carbon Intensity of Generation Fleet

Utility	lb CO_{2e}/MWh
El Paso Electric	668
Austin Energy	1030
City Public Service (San Antonio)	1120
Arizona Public Service	1166
Public Service of New Mexico	1353
Salt River Project (Arizona)	1472
Tucson Electric Power Co.	2074

And EPE's system performance will improve even further in 2014 and beyond with the addition to EPE's portfolio of the MPS and 50 MW of solar photovoltaic (PV) generation via power purchase agreement for the output of the Macho Springs project because operating these resources will displace generation at higher-emitting, older gas- and coal-fired power plants that drive up EPE's already low average. In other words, the portion of EPE's portfolio that generates power from coal is decreasing, while the amount of solar generation in EPE's portfolio is increasing. By next year, EPE expects to use as much solar generation as it does coal.

EPE also has been supporting development of solar technology, in ways large and small. EPE actively encouraged net metering in Texas; as a result, distributed solar generation is taking off in EPE's service area. It helped the Fort Bliss Army Base understand how it could develop its own significant solar capabilities, which is now underway as Fort Bliss pursues a "net zero" goal for 2020 (i.e. no net power purchases). Additionally, EPE donated $200,000 to support UT-El Paso's participation in the U.S. Department of Energy's Solar Decathlon, a solar home design competition.

EPA has recognized EPE's contributions to reducing greenhouse gas emissions through the delivery of energy efficiency information and services to its customers, presenting the Company with an ENERGY STAR Partner of the Year Award for two years in a row. In announcing the award, Assistant Administrator Bob Perciasepe commented that "El Paso Electric sets the bar for promoting energy-efficient products and services that help Americans learn how to save money and energy while protecting the environment. . . . El Paso Electric's program delivery methods demonstrate how communities across the nation can protect the climate through greater energy efficiency and provide a road map for future program implementers."

b. **EPE Selected the MPS Project After Much Analysis and for Many Reasons, Including Support for Renewables.**

El Paso Electric serves roughly 391,000 customers over about 10,000 square miles of western Texas and southeastern New Mexico. It is regulated by public utility commissions in both of those states, which impose very specific obligations to maintain the highest possible reliability (as also directed by the Western Electricity Coordinating Council (WECC)), at the lowest possible cost. Both states also establish renewable portfolio standards or goals, which seek to maximize renewables while not exceeding a "reasonable cost threshold." All three of these expectations—reliability, cost, and support of renewables—played a major role in leading EPE to propose the Montana Power Station.

EPE is designing a generation system, not just picking the technology for a single power plant. These decisions are not based solely on ranking of carbon intensity at steady-state load for a theoretical megawatt. The (small) size and relative age and mix of the EPE system also strongly influences its range of choices.

i. ***EPE is a Relatively Small and Isolated Utility, but with Growing Demand.***

Although El Paso Electric operates within the WECC, it is largely a self-contained system within its service territory. For this coming year, EPE's native system peak load is expected to be about 1800 MW (excluding necessary reserves), to be met with the following resources:

Table 2: Type and Capacity of Current EPE Generation Resources (Expected 2014)

EPE Generation Resources	Fuel	Net Capacity (MW)
Rio Grande Units 6-8 (gas-fired boilers) and 9 (LMS100)	NG	316 (87 from Unit 9)
Newman Units 1-3 (gas-fired boilers) and 4 and 5 (2x1 combined cycle)	NG	752 (278 from Unit 5)
Copper Station (1980 Westinghouse 501B turbine)	NG	62
Four Corners PC (7% ownership)	Coal	108
Palo Verde (15.8% ownership)	Uranium	633
Power Purchase Agreements (PPAs) for Renewables		
Hueco Mountain Wind Ranch	Wind	<1
Hatch	Solar	5
NRG	Solar	20
SunEdison	Solar	22
Macho Springs	Solar	50
Newman Project	Solar	10
TOTAL RENEWABLES		107
Total		**1978**

Based on El Paso Electric's current 10-year Load and Resource forecast, that load (excluding reserve margin) is forecast to increase from ~1800 to ~ 2225 MW by 2023. By 2023, EPE projects that it will need to have installed or available net resources of over 2400 MW.

ii. ***EPE's Generation Fleet is Expected to Experience Significant Retirements During a Period of Forecast Growth.***

EPE's fleet also is somewhat aged: Except for Rio Grande Unit 9 and Newman Unit 5, all of EPE's fossil fuel-based generation first saw service before 1976. And so EPE also must plan to compensate for significant retirements over the next decade even as its load grows. The following table presents the current retirement schedule implicating units most likely to come off line during this 10-year planning horizon (subject to change):

Table 3: EPE's Currently Planned Ten-Year Retirement Schedule

Unit	Technology	Capacity	Currently Scheduled Retirement Year
Rio Grande 6	Gas-fired boiler (built in 1957)	45	2014
Rio Grande 7	Gas-fired boiler (built in 1958)	46	2020
Newman 1	Gas-fired boiler (built in 1960)	74	2022
Newman 2	Gas-fired boiler (built in 1963)	76	2023
Newman 3	Gas-fired boiler (built in 1965)	97	2024
Newman 4	Combined cycle (built in 1975)	227	2021-2023*
Four Corners Units 4 & 5	Pulverized coal (1969-70)	108 (7% interest)	2016
Total		**604**	

*To be retired in phases.

And so, to maintain system reliability in light of expected load growth and retirements, EPE will need to build or purchase over 1000 MW of new capacity over the next 10 years (400+ MW in load growth plus 600+ MW in retirements). MPS will provide 352 MW of that total (measured at summer peak temperatures). At least one new combined cycle plant also is likely to be included, to match in rough time frame the retirement of another, 40-year-old combined cycle plant (Newman 4).

iii. ***EPE Undertook a Comprehensive Analysis of Options for Meeting System Requirements for the Next Five Years.***

Recognizing the need to install new capacity in increments designed to match load growth and retirements, EPE's Resource Planning Department issued in 2011 an RFP seeking bids to install 80-100 MW of new capacity by 2014, 80-100 MW in 2015, and 160-200 MW in 2016. EPE spent many months soliciting bids from both inside and outside offerors, receiving a broad array of proposals from 23 different companies, which proffered multiple design options (5 solar, 19 natural gas, 4 wind, and 10 demand management/storage). EPE ran econometric and process models, consulted with engineers, winnowed proposals, sought additional information from candidate projects, and ultimately performed very detailed cost and feasibility analyses on the highest-scoring options. EPE's Resource Planning Department even engaged an outside evaluator to ensure the independence and rigor of the selection process. The end result, considering all of the myriad factors that influence the selection of capital additions to a utility's generation portfolio, was a combination of the MPS and the 50 MW Macho Springs PV solar projects.

The MPS project is as described in the permit applications filed with EPA and Texas Commission on Environmental Quality (TCEQ), and in certificate of convenience and necessity (CCN) applications filed with the Texas and New Mexico utility commissions. These applications call for four LMS100 turbines to be installed in stages between 2015 and 2017. The CCNs already have been approved for Units 1 and 2, and are well underway for Units 3 and 4. New Mexico approved the PPA for Macho Springs in May 2013.

c. Any Delay in the Issuance of the Authorization to Construct MPS Will Have Serious Adverse Consequences for EPE's Customers and for CO_2 Emissions.

EPE and its customers do not have the luxury of starting the selection process over again to consider selecting some other technology to meet demand: Without MPS, the system would start experiencing shortfalls in its planning reserves by 2015, growing worse over time:

Table 4A: Planning Capacity Shortfalls without MPS or Extensions of Retirements

	2015	2016	2017	2018
Shortfall (deficiency) MW	155	195	342	384

Even if EPE were to delay scheduled retirements (which would raise the carbon intensity of its generation), its system still will experience shortfalls in planning reserves over the next five years:

Table 4B: Planning Capacity Shortfalls Retaining Four Corners & Rio Grande Unit 6

	2015	2016	2017	2018
Shortfall (deficiency) MW	110	150	189	231

Transmission bottlenecks render the EPE system incapable of importing that much firm power even if it were available for purchase. This threat to EPE's ability to discharge its obligations to its customers weighs heavily in favor of concluding that the draft permit should issue as soon as possible, and that its terms represent use of BACT, "taking into account energy, environmental and economic impacts and other costs," as required by Section 169(3) of the Clean Air Act.

i. ***Building MPS and Purchasing All of Macho Springs' Output Significantly Reduces EPE's Carbon Footprint in the Short Term.***

The addition of MPS will displace capacity that emits GHGs at a higher rate. The present EPE system average heat rate for all other gas-fired generation is 10,457 Btu/kWh, whereas the LMS100 achieves a heat rate of 9,074 Btu/kWh at peak and 9,700 Btu/kWh at 40% load. Each day of delay in the MPS means another day that the EPE system must operate at a higher heat rate and higher GHG emissions (and higher fuel costs). The following table shows the consequences of delaying operation of the MPS, in terms of additional GHG emissions that would result from perpetuating the operation of the existing fleet instead of allowing the MPS to commence construction as planned:

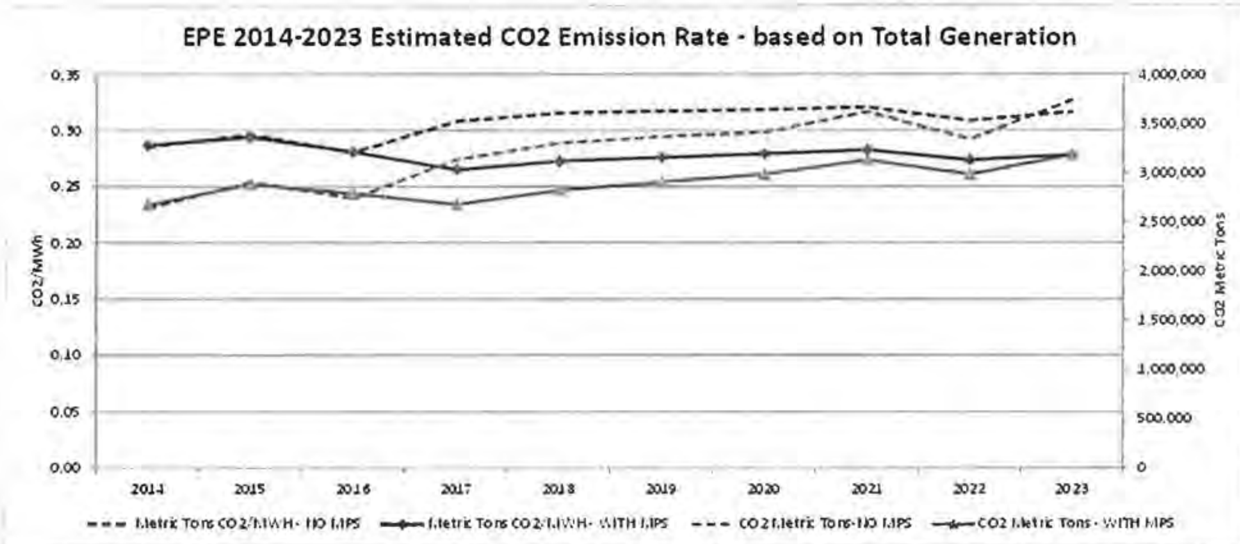
Table 5: GHG Emission Increases resulting from Delays in MPS

Year	Additional CO_2e Metric Tons Without MPS	CO_2e lb/MWH % Increase Without MPS
2014	578.9	0.02
2015	39,604.6	1.37
2016	215,121.8	7.72
2017	422,057.0	15.75
2018	407,451.7	14.44
2019	410,069.3	14.11
2020	418,198.2	14.01
2021	400,367.1	12.79
2022	404,921.4	13.57
2023	392,961.0	12.36
TOTAL	**3,111,331.2**	**10.62 (AVG)**

As you can see, operating MPS will yield a 10.62% decrease in system-wide GHG emissions on average over the next ten years relative to emissions that would occur from generating the same amount of electricity from the existing portfolio. This translates to an excess of over 3 million tons of GHG reduction. Although EPE has not undertaken any calculations to quantify the effect, it is necessarily true that delaying the operation of MPS will have equivalent adverse consequences for emissions of other air pollutants, as well.

Here is the same information presented graphically. As Figure 1 shows, the adverse effect on carbon intensity carries through until 2023, when EPE has completed its 10-year plan.

Fig. 1: Effect of No-Build Scenario on GHG Emissions



EPE is using this transition in its fleet as an opportunity to add renewables to its portfolio. By next year, roughly 6 percent of EPE's peak system demand will be met by solar resources, either by self-generation or PPA: Out of roughly 1800 MW, 107 MW will come from solar resources (see Table 2, above).

By 2014, EPE estimates (using 2012 peak generation data and 2014 projected solar capacity) that it will rank 5th among all utilities nationwide for total solar capacity, behind only the following:

Table 6: Approximate 2014 Rankings of Top Solar-Reliant Utilities

Utility (in order of committed capacity)	**Solar Capacity (2014 MW)**	**Estimated Peak Generation (2012 MW)**	**Solar Fraction (%)**
1. Pacific Gas & Electric Co. (CA)	806	20,153	4.0
2. Southern California Edison (CA)	195	22,088	0.9
3. Public Service Electric & Gas Co. (NJ)	145	10,521	1.4
4. Arizona Public Service (AZ)	124	9,137	1.4
5. EPE	107	1,683	6.4

Table 6 also shows that EPE would be ranked a clear first, based on solar fraction of total generation (using the most recently available year).

In addition, EPE strongly supports the development of distributed generation by residential-scale PV solar. Starting with less than 1 MW on the system 4 years ago, EPE's customers have installed 3 MW in each of the past two years, and an additional 5 MW is expected in each of the next two years. One of EPE's most significant customers, Fort Bliss, has announced plans to achieve "net zero" by 2020 for all 70 MW of its current peak demand, to be accomplished largely by rooftop and utility-scale solar. All of these distributed energy projects create system instability and the need to make small and fast adjustments in power to the grid, one of the great strengths of the LMS100. El Paso Electric must have quick-start power available to meet the demands of all of these customers at any time when their own generation ebbs or fails.

ii. ***The Addition of MPS Allows EPE to Consider Substantial Addition of Renewables in the Next Five-year Plan (2018-2023).***

Although it meets or exceeds present renewable portfolio standard (RPS) requirements or goals, El Paso Electric hopes to do more. To that end, EPE commissioned from GE Energy Consulting a study to assess EPE's capacity to integrate increases in amounts of wind and solar into its generation and transmission system. This evaluation is being used to support decision-making for soliciting the next five-year plan (from 2018-2023), during which EPE will need to know how much more renewables can be supported on its system. According to the study, which used advanced systems models, "the new flexible LMS100 gas generation slated for addition by EPE is a valuable contributor to the ability of the system to stay in balance with wind and solar variability and uncertainty." With MPS in its portfolio, EPE is equipped to give serious consideration to up to several hundred MW of renewables in its future operations, assuming they are otherwise financially responsible choices for EPE customers. Based on the successful performance of the Macho Springs PPA in the latest RFP process, EPE expects that solar resources will revive prominence in the next round.)

d. **Combined-Cycle Units Cannot Meet the Start Times Required by the System to Satisfy Spinning Reserve Requirements.**

As noted elsewhere in the record, EPE has investigated the possibility of using either aeroderivative- or frame-based combined cycle units. Its efforts confirmed that a combined cycle design would not work at this stage in the evolution of EPE's system. .

An aeroderivative-based combined cycle plant would not achieve the heat load needed to generate steam with any meaningful efficiency, and so add-on HRSGs would be uneconomic: Vendor data indicates that EPE would gain only about 9 MW with a HRSG and the efficiency does not improve significantly even at full load (improving the heat rate from 8700 Btu/kWh in simple cycle to 7900 Btu/kWh in combined cycle configuration). And so the costs associated with recasting the Montana Power Station to combined cycle configuration are not warranted by the small increase in efficiency.

As for the classic frame-based combined cycle plant, while it is true that the thermal penalty associated with repeated fast ramp-ups is decreasing as technologies improve, there is still a thermal penalty. The LMS100 still gets up to load faster, and without any thermal penalty. And the higher efficiencies associated with combined cycle are achieved only at full load, which would not be the profile for much of its time in service.

EPE's PROMOD analysis determined that, because of the above factors, a combined cycle plant, run to meet the same needs as the MPS, would have had much higher costs (and GHG emissions) than the 4x100 MW simple cycle plant that EPE selected. The side-by-side comparison of total production cost (meaning fuel use, meaning emissions) calculated a net present value savings over the studied period (2014-2016) of $116,757,640 in favor of the LMS100 plan. The combined cycle alternative, in short, would not and should not have survived CCN review; that choice would have favored neither EPE's customers nor its environment.

In light of the cost and emissions penalties associated with selecting combined cycle for the service for which the capacity is needed, the relatively improving ramping ability of the combined cycle plant is largely immaterial. But that, too, disqualified it from consideration for the intended service, which includes satisfaction of EPE's reserve requirements. The agreements that apply to EPE as a participant in the Southwest Reserve Sharing Group (SRSG) allow a "quick start" unit to remain off-line but still have its generation capacity counted towards meeting reserve requirements without spinning. Even assuming that newer generation combined cycle plants could achieve full turbine load in, say, 12 minutes, those still would fail to be counted as "quick start" (full load in 10 minutes or less). For at least the next five years or more, that would mean maintaining spinning reserves on one or more of EPE's less efficient gas-fired plants, meaning greater emissions. Conversely, the ability of the LMS100 to be started in 3 minutes and ramp to full load in 10 means that it can be used instead of spinning reserve.

Finally, as noted above, EPE is designing a generation system, not a single power plant. EPE already struggles to shed generation from its older boiler-based units during night-time low loads. Adding more combined cycle units, which cannot be cycled off completely without thermal penalty, would exacerbate the problem, at least until EPE's generation portfolio becomes more balanced in the planning horizon that begins after the MPS is built out.

The four LMS100 turbines to be installed at MPS will be but one part of EPE's generation fleet in a decade (along with new combined cycle capacity, substantial renewables, and ongoing zero-emissions nuclear). Also, the nature of the MPS development (a 100 MW turbine each year over the next several years) suits load growth, retirements, capital availability, and the limited ability of a system as relatively small as EPE's to absorb major growth in large increments. It also is important to EPE that the system not have all its eggs only in large baskets (e.g., larger-scale combined cycle plants), because EPE's relatively small scale makes it less able to handle large-scale sudden outages. The larger the worst-case outage, the greater the need for excess reserve capacity (and associated emissions). Of these factors, the most important may be the need to match additions to retirements, which accounts to EPE's plans to await the retirement of Newman 4 (at 273 MW) in ~2021-2023 before bringing on line a replacement plant of that magnitude. At that time, EPE will be able to take advantage of the further improvements that no doubt will occur in the interim relative to the combined cycle plant's ramping ability.

Looking at EPE's portfolio over time, the LMS100 turbines are just a part, needed to support the whole. EPE has every reason to believe that when it becomes a 2400 MW system in 2014, it will need 400+ MW of efficient combustion turbine power (MPS plus Rio Grande Unit 9). If by 2020 or beyond, the LMS100 turbines are not as efficiently dispatched as the combined cycle plants that also will be a part of the system, then the combined cycle plants will receive priority in dispatch.

e. **EPE's Current Use of Intermediate Load Resources to Meet Peak Requirements Should not be Perpetuated by Delay or Denial of Authorization for the MPS.**

EPE manages fluctuations in daily load by using steam-based generation assets because that is what it now has, but that is not ideal: As noted above, EPE already has a surplus of relatively larger units that do not cycle very efficiently (which it will be able to phase out when MPS is built). Using them in this way also increases thermal stresses and associated maintenance costs. EPE's load profile requires that local gas-fired units be shut down or ramped down to minimum levels. Otherwise, EPE has more generation capacity on-line than required to meet off-peak loads. EPE can try to sell the surplus capacity in off-peak hours but it may be at a loss, or even, as EPE as experienced, have to pay someone to take the power. Again, additional combined cycle units at this juncture would make this situation worse. The LMS100 units, in contrast, will allow EPE to manage the fluctuations in a more economic and efficient manner benefitting its customers.

At least until Rio Grande Unit 9 came on line earlier this year, the Copper Station provided the only turbine-based peaking capacity in the EPE system. But, tellingly, its heat rate is the worst of any gas-fired unit in the EPE system (worse even than Rio 6-8 and 80% higher than an LMS100), and so EPE does not often dispatch it. The addition of the MPS will allow Copper to be dispatched only in the event of system emergency (such as loss of imported power).

f. **The BACT Requirement Provides no Basis to Diminish the Operating Hours of the MPS.**

In the TCEQ permit proceedings and elsewhere, it has been argued that the permitting of the MPS for up to 5,000 hours per year of operation of each turbine requires treating the simple cycle turbines like combined cycle turbines for purposes of establishing emission limitations. Even if correct as a matter of law or policy or good sense (it is none of those), this argument would do nothing to change the terms of the draft permit: The emission limit that EPE proposes to meet (1100 lb/MWh) IS the limit proposed by EPA to represent the performance of a combined cycle power plant as best demonstrated control technology. In short, EPE proposes to meet the limits achieved by a combined cycle plant, and so it should be allowed to operate as one.

If EPE does not need to operate MPS for 5,000 hours or under the worst-case heat rates, then its emissions will certainly be lower than the permit allows. It makes sense and is universal air permitting practice, however, to issue a permit for the maximum amount of operating authority that the permittee forecasts.

g. **EPE Provided An Adequate Cost Analysis for Carbon Capture and Sequestration (CCS)**

As EPE explained in its permit application, CCS is not commercially available as BACT. EPA has confirmed this conclusion in its pending proposal of GHG limits for EGU's where it stated as follows:

> NGCC with CCS is not a configuration that is being built today. The EPA considered whether NGCC with CCS could be identified as the BSER adequately demonstrated for new stationary combustion turbines, and we decided that it could not. At this time, CCS has not been implemented for NGCC units, and we believe there is insufficient information to make a determination regarding the technical feasibility of implementing CCS at these types of units. The EPA is aware of only one NGCC unit that has implemented CCS on a portion of its exhaust stream. This contrasts with coal units where, in addition to demonstration projects, there are several full-scale projects under construction and a coal gasification plant which has been demonstrating much of the technology needed for an IGCC to capture CO2 for more than ten years. The EPA is not aware of any demonstrations of NGCC units implementing CCS technology that would justify setting a national standard. Further, the EPA does not have sufficient information on the prospects of transferring the coal-based experience with CCS to NGCC units. In fact, CCS technology has primarily been applied to gas streams that have a relatively high to very high concentration of CO2 (such as that from a coal combustion or coal gasification unit). The concentration of CO2 in the flue gas stream of a coal combustion unit is normally about four times higher than the concentration of CO2 in a natural gas-fired unit. Natural gas-fired stationary combustion turbines also operate differently from coal-fired boilers and IGCC units of similar size. The NGCC units are more easily cycled (i.e., ramped up and down as power demands increase and decrease). Adding CCS to a NGCC may limit the operating flexibility in particular during the frequent start-ups/shut-downs and the rapid load change requirements. This cyclical operation, combined with the already low concentration of CO2 in the flue gas stream, means that we cannot assume that the technology can be easily transferred to NGCC without larger scale demonstration projects on units operating more like a typical NGCC. This would be true for both partial and full capture.

Proposed NSPS for Electric Generating Units, at 35-36 (pre-publication copy as signed by EPA Administrator Gina McCarthy, Sept. 20, 2013).

Even though CCS has not been demonstrated in practice for full-scale natural gas powerplants, EPE still evaluated CCS in its BACT analysis. EPE notes that there are adverse environmental and energy impacts associated with CCS. As the New Source Review Workshop Manual states, such impacts are valid factors to consider when determining BACT. *See* EPA Draft New Source Review Workshop Manual – Prevention of Significant Deterioration and Nonattainment

Area Permitting (Oct. 1990) ("NSR Manual") at B.29, B.46 (step 4 of the BACT analysis includes consideration of energy impacts and environmental impacts).

As explained in the permit application documents, operating CCS at MPS would consume an additional 30% of full load operation. In order to offset the amount of power used to support CCS equipment, EPE would need to use additional fuel to achieve the same level of useful output. The permit record also shows the increase in primary air pollutants associated with CCS. However, these adverse energy and environmental impacts do not alone justify EPA Region 6 eliminating CCS from consideration in step 4 of the BACT analysis. Rather, the adverse energy and environmental impacts are one of many factors that support Region 6's conclusion that CCS should not be considered BACT for this project.

It is appropriate for CCS to be rejected as BACT also based on its cost relative to the overall project cost. EPE acknowledges that EPA typically uses a dollar per ton ($/ton) basis when evaluating the cost of pollution control devices; however, the EPA Environmental Appeals Board (EAB) has upheld using this basis when analyzing the cost of installing CCS at a 570 megawatt baseload hybrid natural gas-solar plant. *See In re: City of Palmdale (Palmdale Hybrid Power Project)*, PSD Appeal No. 11-07 (E.A.B. Sept. 17, 2012).

In the *Palmdale* decision, EAB noted that cost effectiveness "is typically calculated as the dollars per ton of pollutant emissions reduced." *Id.* at 54 (citing the EPA Draft New Source Review Workshop Manual – Prevention of Significant Deterioration and Nonattainment Area Permitting (Oct. 1990)). But EAB noted that when evaluating the economic impacts of GHG control strategies in particular, "it may be appropriate in some cases to assess the cost effectiveness of a control option in a less detailed quantitative (or even qualitative) manner," particularly in the context of CCS. *Id.* (citing EPA, EPA-457/B-11-001, *PSD and Title V Permitting Guidance for Greenhouse Gases* at 42 (Mar. 2011) (the "GHG Permitting Guidance")). The Region argued that evaluating CCS using a "price comparison approach was consistent with" the GHG Permitting Guidance. *Id.* EAB upheld the Region's determination that CCS was cost prohibitive because the "cost of CCS would be so high - twice the annual cost of the entire project." *Id.* at 55.

Here, the same qualitative approach is appropriate as EAB accepted in *Palmdale*. As EPE explained in a follow-up letter to EPA, installing CCS at the MPS would conservatively add an additional $95 million per year to the project cost, which equates to an increase of 30% above the initial total capital cost of the Montana Power Station ($311 million). Therefore, using the rationale articulated in *Palmdale*, EPE believes CCS can be rejected as BACT for the MPS.

h. **Evidence Developed in Support of the PSD Permit for Criteria Pollutants Establishes that the MPS Permitting Actions will Not Result in Disproportionate Effects on Low-Income or Minority Populations.**

EPE also is taking this opportunity to submit for your consideration the TCEQ Air Quality Analysis (AQA) Audit Report, which establishes that emissions of pollutants other than GHGs are expected to be well within applicable national ambient air quality standards and other measures established for the protection of public health and welfare. Although

EPA does not require this information as part of a GHG permit application or to fulfill its obligations under Executive Order 12898 (related to environmental justice), this information reinforces the conclusion that EPA's action in granting the permit would not adversely affect any person, regardless of race or socio-economic condition. *See In re: Shell Gulf of Mexico, Inc. and Shell Offshore, Inc.*, OCS Appeal Nos. 10-1 to 10-4, Slip Op. at 74 (EAB Dec. 30, 2010) ("In the context of an environmental justice analysis, compliance with the NAAQS is emblematic of achieving a level of public health protection that, based on the level of protection afforded by a primary NAAQS, demonstrates that minority or low-income populations will not experience disproportionately high and adverse human health or environmental effects due to exposure to relevant criteria pollutants.").

If you have any questions or comments about the information presented in this submittal, please do not hesitate to call me at (915) 543-4065 or Mr. Roger Chacon, EPE's Environmental Department Manager, at (915) 543-5827.

Sincerely,
EL PASO ELECTRIC COMPANY

Andres R. Ramirez
VP – Power Generation

Enclosure

cc: Mr. Roger Chacon, Environmental Department Manager, EPE
Mr. Eric Groten, Partner, Vinson & Elkins LLP
Mr. Paul Greywall, Director, Trinity Consultants

ATTACHMENT 1: TCEQ'S AIR QUALITY ANALYSIS AUDIT

From: Oma Flores
To: Magee, Melanie
Subject: comments el paso electric oppose
Date: Wednesday, November 06, 2013 9:31:34 PM

A quien corresponda;
quisiera pedirles que tengan cosideracion de nosotros mi casa queda a menos de dos millas de donde el Paso Electric piensa construir su planta de energia electrica
ellos no tienen derecho a venir a perjudicarnos en la salud ellos no toman encuenta que los vientos que la mayoria del tiempo se dirijen a nuestra direccion, ni de los
mantos aquiferos que se pueden contaminar, y que decir de los 12 tanques de gasolina que contienen mas de 50,000 galones de gasolina cada uno que queda bas-
tante serca como para peligrar nuestras vidas en caso de un axcidente . y que derecho tienen en benir a devaluar mi propiedad el unico patrimonio que tenemos my
familia y yo ustedes son la unica esperanza que tenemos esta comunidad de que ese Monopolio sin escrupulos de Paso Electric bengan a poner en riesgo nuestra
salud y integridad fisica por su falta de etica y no poner una planta que no contamine existen muchas otras alternatibas que pueden construir menos esa planta que contamina el medio ambiente, nuestra comunidad porfavor interbengan en nueestro favor gracias

Guillermina Flores
Gracias

From:	Omar Flores
To:	Magee, Melanie
Subject:	comments
Date:	Wednesday, November 06, 2013 8:37:01 PM
Attachments:	real final far east el paso conclusion.docx

The effects on human health from the natural gas power-plant

Elderly, adults, adolescent's, children, infants.

Omar Flores

Community College Mission Del Paso.

El Paso, Texas.

i. Intro- what is being proposed?

A- An 88 megawatt power plant, simple-cycle aero-derivative combustion turbines powered by nature gas.

B- It will be located on Montana avenue & Flagger Street.

ii. Describing the community.

a- It consists of 7,000 homes.

b- An average of 4 people in each family household.

c- 25% of retired veterans who are senior citizens.

d- 25% are young children and adolescents under the age of 18 years.

e- 50% are adults averaging from 18-60 years of age

f- A volunteer fire department station with 2 out of 3 fire trucks working properly.

g- 4 public schools in a 2 mile radius.

h- A company named Magellan range capacity is from 50,000 to 400,000 gallons. There are about 25 tanks in that storage terminal. Range capacity is from 50,000 to 400,000 gallons.

iii. Down side effects from the power plant

a. Water issue, it will consume 800,000 gallons of water a year.

b. Air contamination

c. Housing value, within two miles will decrease between four and seven percent.

d. Attracts lightning during thunder storms threatening the Magellan tanks.

e. Lack of fire department coverage (not enough trucks)

f. Raise in monthly bill increase by $1.65 for every citizen and customer.

g. 115,000 volts of electric current will create electromagnetic radiation equaling the highest frequency within the electromagnetic spectrum, which means this type of radiation is known to break apart DNA and lead to cancer. Other High Frequency magnetic fields include: cosmic rays, gamma rays, x-rays, and sunlight.

iv. Advantages of the power plant.

a. A community park will be constructed for the residents.

b. Power demand will be met for the community and for the city.

Far East El Paso thesis

The El Paso Electric power plant station proposal at Montana Avenue and Flagger Street. The Haciendas del Norte community has been struggling for over two years in court. Haciendas Del Norte, and El Paso Both sides of this fight have been doing their best at trying to agree, and solve this problem. El Paso Electric has paid for a very tough lawyer that has had solid facts. Although they have a tough fighting system, Haciendas del Norte has been giving more concrete facts to city council officials about the bad effects of health, property values, dangers, and contaminations. All of our community is attending to all meeting at courts and including bringing friends and loved ones to help provide a good case, please open your heart to this research and think about what could happen.

The Proposed Plant

On the east corner of El Paso is the county of El Paso, the City of El Paso limit is coming soon and fast to this part of the area with new local businesses. Huge enterprises like Walmart, Cinemark XD, Lowe's, Home Depot, McDonald's, Burger King, Taco Bell, Peter-piper Pizza, T-Mobile, Joes haircuts, Montana Vista, Vista Market, and coming soon an outlet mall. Those are a few of the wonderful business of this side of El Paso. Would you allow a business like the Electric Company ruin chances to the new and bright El Paso? Allowing an 88 megawatt power plant, simple-cycle aero-derivative combustion turbines powered by natural gas will affect and affect negatively affect innocent people which could lead to death.

The community consists of 7,000 homes and an average of 4 people in each family house hold. Twenty five percent are retired veterans who are senior citizens over age 60, twenty percent of those seniors have breathing problems, cancer, and constantly taken to the emergency room. Another twenty-five percent are young children and adolescents from ages 1-18 years of age most of them live in the rural areas because of asthma. The last is fifty percent that consists of adults ranging from 18-60 years of age that work hard, pay taxes, and vote to support their families they love. There is a volunteer fire department about one thousand feet away from the proposed site with 2 out of 3 trucks working properly. Four public schools in a two mile radius with a total of 3,212 of children. Last is a fuel farm company named Magellan, with 25 fuel tanks with a range capacity from 50,000 to 400,000 gallons each tank is also located in this area.

The proposal Plant

The downside effects of this plant is very disturbing for me to have researched. The few main problems will be water issue because the plant will consume 800,000 gallons of water a year. El Paso is suffering though a drought at the moment, and the electric company wants to use those gallons of water for the cooling towers and turbines which will be dumped in a man-made pond that becomes a water contamination problem very soon, and bring many mosquitos to the area containing the West Nile virus. The West Nile virus is a mosquito-borne illness. Up to 80 percent of people infected with West Nile virus will have no symptoms and will recover on their own, however, some cases can cause serious illness or death.

People over 50 and those with weakened immune systems are at a higher risk of becoming ill if they become infected with the virus. In the city of El Paso, at this time last year, there were 24 confirmed cases in the El Paso area with five resulting in death. Overall, 32 confirmed cases were reported in El Paso last year with six people dying as a result of either the disease itself or due to underlying conditions, officials said. Air contamination will be a great problem. A notice of application and preliminary decision for an air-quality permit, which was published by the Texas Commission on Environmental Quality in the Oct. 15 edition of the El Paso Times, says the proposed facility will emit air contaminants in a significant amount, including carbon monoxide, nitrogen oxides and particulate matter. The facility would also emit air contaminants such as sulfur dioxide causing Respiratory irritant. Aggravates lung and heart problems. In the presence of moisture and oxygen, sulfur dioxide converts to sulfuric acid which can damage marble, iron and steel; damage crops and natural vegetation. Impairs visibility. Precursor to acid rain. Sulfuric acid the most common way for sulfuric acid to enter the body is through the respiratory system. Serious lung damage may result from inhalation exposure to sulfuric acid. When Organic compounds and ammonia enters the body as a result of breathing, swallowing or skin contact, it reacts with water to produce ammonium hydroxide. This chemical is very corrosive and damages cells in the body on contact. Housing value will decrease at a rapidly pace, in within two miles will decrease between four and seven percent. In a 1 year period the bill will increase by $19.80. "The fuel fee goes up or down depending on fuel costs," city Rep. Cortney Niland said. "But we have to look at options for some of the other fees that we can better control."

Sadly this big power-plant greatly Attracts lightning during thunder storms threatening the Magellan tanks. While we have Lack of Fire Department coverage (not enough trucks) to cover the fire damage that the Magellan tanks are exposed to. The public is also not safe in this aspect either they are exposed to 115,000 volts of electric current will create electromagnetic radiation equaling the highest frequency within the electromagnetic spectrum, which means this type of radiation is known to break apart DNA and lead to cancer. Other High Frequency magnetic fields include: cosmic rays, gamma rays, x-rays, and sunlight.

Advantages

Two great advantages had been offered to bring a park to haciendas Del north and the power demand to the city and its customers will be met and supplied when needed, if this plant will be allowed to be built.

Conclusion

The aftermath of everything is that, El Paso Electric, and Haciendas Del Norte. Have not come to a final conclusion to this proposed power-plant still presenting a major issue problem concerning the future residents of El Paso city, and the community of haciendas. There needs to be some type of agreement where both the electric company, and the haciendas community be pleased and happy to the end result. It shall not be tolerated not coming up with some other alternative to this problem. There is many other energy alternatives that can be used in a Texas desert that will be effective, and proficient.

Alternatives for El Paso Electric.

One of my solutions to this power demand is Solar Thermal energy. **Solar thermal (heat) energy** is a carbon-free, renewable alternative to the power we generate with fossil fuels like coal and gas. This isn't a thing of the future, either. Between 1984 and 1991, the United States built nine such plants in California's Mojave Desert, and today they continue to provide a combined capacity of 354 megawatts annually, power used in 500,000 Californian homes [source: Hutchinson]. Reliable power, at that. In 2008 when six days of peak demand buckled the power grid and brought electricity outages in California, those solar thermal plants continued to produce at 110 percent capacity [source: Kanellos].

Wondering where the technology's been since then? In the 1990s when prices of natural gas dropped, so did interest in solar thermal power. Today, though, the technology is poised for a comeback. It's estimated by the U.S. National Renewable Energy Laboratories that solar thermal power could provide hundreds of gig watts of electricity, equal to more than 10 percent of demand in the United States.

Shake the image of solar panels from your head there are two types of solar thermal systems: passive and active. A passive system requires no equipment, like when heat builds up inside your car when it's left parked in the sun. An active system requires some way to absorb and collect solar radiation and then store it.

Solar thermal power plants are active systems, and while there are a few types, there are a few basic similarities: Mirrors reflect and concentrate sunlight, and receivers collect that solar energy and convert it into heat energy. A generator can then be used to produce electricity from this heat energy. The most common type of solar thermal power plants, including those plants in California's Mojave Desert, use a **parabolic trough** design to collect the sun's radiation. These collectors are known as linear concentrator systems, and the largest are able to generate 80 megawatts of electricity [source: U.S. Department of Energy]. They are shaped like a half-pipe you'd see used for snowboarding or skateboarding, and have linear, parabolic-shaped reflectors covered with more than 900,000 mirrors that are north-south aligned and able to pivot to follow the sun as it moves east to west during the day. Because of its shape, this type of plant can reach operating temperatures of about 750 degrees F (400 degrees C), concentrating the sun's rays at 30 to 100 times their normal intensity onto heat-transfer-fluid or water/steam filled pipes [source: Energy Information Administration]. The hot fluid is used to produce steam, and the steam then spins a turbine that powers a generator to make electricity. Solar thermal systems are a promising renewable energy solution -- the sun is an abundant resource that’s why it would be great to have this alternative in the city of El Paso.

From:	Paul Svihla
To:	Magee, Melanie
Subject:	El Paso Electric Power Station
Date:	Saturday, October 26, 2013 3:37:14 PM

Ms. Magee,

I am writing you today as a resident of the Homestead Meadows North, which is a community that will be affected by the electric company's proposed power station that is to be located near Montana Ave in El Paso, Texas. This Power Plant is a bad idea and with your help this project will not go as planned.

Regards,

Paul Svihla

From:	Raul Issa
To:	Magee, Melanie
Cc:	Risher Gilbert
Subject:	Comment letter- Permit-PSD-TX-1290-GHG- El Paso Electric Company
Date:	Wednesday, December 04, 2013 2:43:42 PM
Attachments:	ltr to EPA- MPS- 12-03-13.pdf FINAL Exhibit D- Powers- 140 million.pdf FINAL Exhibit A.pdf FINAL Exhibit B.pdf FINAL Exhibit C.pdf FINAL Exhibit C-1.pdf

Ms. Magee,

Please review the attached comment letter we are submitting on behalf of our client CSM Realty Holdings, II Ltd. concerning the above referenced matter.

This email contains the first half of the exhibits to our letter. I will send the remaining exhibits in a second email. Thank you.

Raul Issa
Paralegal to Risher Gilbert

Raul Issa, Certified Paralegal
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December 3, 2013

Ms. Melanie Magee
Air Permits Section (R6 PD-R)
U.S. EPA Region 6
1445 Ross Avenue, Suite 1200
Dallas, Texas 75202

Via email and USPS

Re: El Paso Electric Company, Montana Power Station
Permit PSD-TX-1290-GHG

Dear Ms. Magee:

Thank you for the opportunity to comment on the above referenced matter. Our firm represents CSM Realty Holdings II, Ltd. (CSM), the owner of the parcel of land that shares the over 4,000 lineal foot easterly boundary of the Montana Power Station site. This landowner will be directly impacted by the El Paso Electric Company (EPEC) proposed power plant, its required infrastructure and transmission corridors.

The Montana Power Station Site is subject to the greenhouse gas Prevention of Significant Deterioration (PSD) regulations. EPA Region 6 has received from EPEC a PSD permit application for Greenhouse Gas (GHG) emissions from the proposed power station. The MPS will have four turbines together producing 400 MW of electric power. The Statement of Basis (SOB) has summarized the plant to include (i) four natural gas-fired turbines and associated equipment including cooling towers; (ii) a firewater pump engine; (iii) ammonia storage tanks and unloading system; (iv) circuit breakers; and (v) a diesel storage tank. Per the SOB the draft permit, if finalized as proposed, would authorize GHG emissions from the: (a.) four turbines; (b) firewater pump engine; (c) circuit breakers; (d) maintenance, startup and shut down emissions; and (e) fugitive leak emissions. The remaining units are not considered by EPA to be potential GHG emission sources.

Project Description. The SOB states that the MPS is a greenfield site (page 5), which statement conjures up an image far different from the actual site. The northerly boundary of the site is a federal military reservation where military operations take place and where there is possible unexploded ordnance. This adjacent land is referred to as the 'South Training Areas' by the Army. To the south of the MPS site is a very large industrial operation known as the

Magellan Pipeline Terminal. This terminal includes a 5-bay truck loading rack and 22 large storage tanks, and is by far the most visible landmark along the state highway known as Montana Avenue. The tanks are estimated to hold some 900,000 barrels of flammable fuels (almost 38 million gallons assuming 42 gallons per barrel) of flammable fuels (**Exhibit "A"** -Attachment 2A to Zephyr Environmental spill report for Magellan attached to the January 16, 2012 AMEC Phase I Environmental Site Assessment performed for EPEC on 75 Acre Magellan Parcel). In addition to the tanks, there are industrial oil and gas pipelines along the northerly boundary of the MPS and going through the site to the Magellan Pipeline Terminal. **(Exhibit "B"**- AMEC Phase I ESA Report pgs. 13, 14, 15, 18, 22). To the immediate west of the MPS site are historical *colonias,* a term with which Region 6 is very familiar because of Region 6's support of the extension of water to numerous colonias in El Paso County. Immediately to the east of the MPS site is the property of CSM. (See **Exhibit "C"**- Map of Area and **"C-1"**- highlighting easements).

Region 6 Rejected Fugitive Emission Leak Detection and Repair (LDAR) and Remote Sensing Without Doing Site-Specific Analysis

The MPS will be close to EPEC diesel tanks, the EPEC new large operations and maintenance center and the underground oil and gas lines located along and through the site. All of these tanks, lines and O & M activities are in addition to the operation of the power plant. These operations are within the shadows of the adjacent storage tanks containing approximately 38 million gallons of flammable fuels. Thus it is imperative that all gas emissions from the MPS are timely, consistently and accurately monitored, measured and are immediately addressed. The results of this monitoring should be retained and made available to landowners and residents in the area.

The SOB acknowledges the availability of instrument leak detection and repair technology (LDAR) for monitoring leaks and emissions of methane and carbon dioxide (pgs 23, 24). However the SOB rejects the best available technology for controlling the natural gas fugitive emissions. The SOB identifies LDAR analyzers and remote sensing using infrared imaging as effective technologies. The SOB then considers the cheaper control of only Auditory/Visual/Olfactory (AVO) monitoring which is less effective. The SOB concludes that LDAR is "not economically practicable." (SOB at p.24.) The SOB lacks any quantification of the cost of LDAR, and makes an unsubstantiated statement that "AVO monitoring is effective due to the frequency of observation opportunities." Just because one has the 'opportunity' to observe does not mean one will observe. Each human's auditory perception, sense of smell and clarity of sight can vary greatly. The reasoning in the SOB assumes the absence of plant operational ambient noises, distracted employees, and simple human failure to observe. How can AVO monitoring be effective when employees are assigned to other areas of the plant or must work on more immediate work taking precedent over observation of possible emissions? Has EPEC provided to EPA the plant footprint and site plan components to be able to evaluate the practical challenges of AVO in light of distance of worker stations and obstruction of visual corridors to the areas where emissions may occur?

We submit that the Region 6 rejection of LDAR and remote sensing does not comply with the required BACT analysis. Step 4 of the BACT analysis requires ranking the control technologies in the order of most effective to least effective. In Step 4 the SOB first lists LDAR and remote sensing of piping fugitive emission before AVO but rejects LDAR and remote sensing as "not economically practicable"... (pg 24) The SOB does not provide any incremental cost analysis or any analysis showing that installing LDAR or remote sensing would be disproportionately expensive compared to other facilities. There is no support for the conclusion that installing and operating LDAR or remote sensing would cause uniquely excessive costs at the MPS compared to other electric generating facilities. In sum, there is no basis for Region 6 to reject the most efficient and lowest GHG emitting technology based on adverse economic impacts. Because of the magnitude of potential danger if the human observations fail, it is especially important that this careful cost analysis be conducted.

BACT Requires a Dry-Hybrid System to be Evaluated. The SOB notes that GE LMS 100 offers an option of wet or dry system intercoolers, and that EPEC chose wet. (pg 17) Under BACT a dry system should be more thoroughly analyzed and a hybrid system should also be considered and evaluated. Because of the extremely limited water in the El Paso region and the exacerbating impact of the current drought of record, the true cost-both environmentally and monetarily- of the wet system is much greater than in other regions. EPEC should not be permitted to waste a precious natural resource critical to all residents in order to save EPEC shareholders money. A system that uses less water must be more carefully examined.

EPEC will be using an evaporative cooling system to cool the incoming combustion turbine air in order to increase the combustion air mass flow. This will involve the consumption of 140 million gallons of water a year according to the testimony of William Powers, P.E. in TCEQ Docket No. 2012-2608-AIR (**Exhibit "D"**). Because of the herculean and sacrificial efforts of El Pasoans to conserve water and reduce their per capita usage, this 140 million gallons a year is the equivalent of the water used indoors and outdoors for an entire year by over 1,100 separate El Paso households (**Exhibit "E"**). (The calculation is as follows: 325 gallons/house/day x 365 days/year= 118,625 gallons/house/year; 140 million gallons per year used by the MPS divided by 118,625 gallons/house/year = 1,180.2 households).

The New Source Review Workshop Manual (Draft October 1990) states that the analysis of environmental impacts should be made on a consideration of site-specific circumstances (pg B47). Water usage that is justified in a water rich region is not justified in a desert region where water is the most precious and critical environmental resource. Water is so scarce in the El Paso region that federal funds helped fund the largest inland desalination plant off of Montana and fairly close to this MPS site. The plant includes the TecH$_2$O Center that emphasizes the importance of water conservation and management of the region's endangered water resources. In a typical year El Paso receives approximately 9 inches of rain, which is approximately 25 fewer inches of rain than Dallas and 41 fewer than Houston. El Paso is in an historical drought of record placing heavy demands on already scarce water resources. Last summer the Elephant Butte reservoir from which El Paso receives its allocation of surface water dropped to about 3%

of capacity (http://earthobservatory.nasa.gov/IOTD/view.php?id=81714). In the last irrigation season the farmers in El Paso County were allocated only half an acre foot per acre of land, when the normal allocation is 4 acre foot per acre. The normal irrigation season is 7 months, from mid-March to mid-October. In 2013 releases could only be made from June 1 to July 17, a mere 6 weeks. The MPS should be required to use a dry or a dry-Hybrid system instead of a wet system.

Need for Environmental Justice Analysis. When a new industrial plant with environmental impacts is to be located in a minority and low-income community that has already absorbed the adverse impacts of heavy industry, an environmental justice analysis is imperative. The EPA should protect disadvantaged communities from being taken advantage of by those with the resources to keep these same industrial uses and emissions from their own back yards. We submit that the facts reflect that the adverse effects from the Montana Power Station on the environmental and human health conditions of the minority and low-income community within which it is located is disproportionate to other higher income and more educated areas of El Paso.

According to the U.S. Army, the location of the MPS is in zip code 79938, and is in an identified Minority and Poverty Area (**Exhibit "F"**- Figure 3-7 entitled 'Potential Environmental Justice Census Tracts' attached to the Draft Environmental Impact Statement of the Army for a Waste-to-Energy plant). Per the U.S. Census Bureau 2007-2011 American Community Survey 5-year Estimates (ACS), over 77% speak Spanish at home and more than 30% do not speak English very well (**Exhibits "G-1"**). Twenty one percent of the households in this 79938 zip code are making less than $25,000, which is below the poverty level of $27,570 for a family of 5. Over 10% of households in 79938 are making less than $15,000, which is below the poverty level of $19,530 for a family of 3 (**Exhibits "G-2"**. Per the ACS 16% have less than a 9th grade education and 27.3% of the residents in 79938 do not have a high school diploma. Less than 13% have a bachelor's degree (**Exhibit "G-1"**).

In the EPA Region 6 response dated June 28, 2013 to the above mentioned DEIS for a Ft. Bliss proposed WTE plant to be located immediately north of the MPS site the EPA said that the location has the potential to raise "***major*** environmental justice issues" (emphasis added). (**Exhibit "H"**) In addition, the EPA noted that the location of the proposed WTE plant is "adjacent to an identified Minority and Poverty Area". On **Exhibit "F"** is the approximate location of the MPS marked on Figure 3-7 of the DEIS to which the EPA was referring. The EPA rated the DEIS as EC-2, indicating that the DEIS did not have sufficient analysis concerning environmental justice, among other issues. (**Exhibit "H"**- page 3 of the EPA's Detailed Comments on the DEIS in June 28, 2013 letter to Ft. Bliss). The need for a thorough environmental justice analysis is particularly critical because of the existing large tank terminal, large pipeline corridors and operations, and military activity in the immediate area of the MPS.

The SOB acknowledges that the EAB has held environmental justice issues ***must be considered*** in connection with the issuance of federal PSD permits issued by EPA Regional Offices [emphasis added](pg 26). But the SOB subsequently tries to justify avoiding any EJ analysis in the present case by making the following observations: 1) the absence of National Ambient Air Quality Standard for GHGs; 2) the impact of GHG emissions is far-reaching and multi-dimensional; 3) evaluation of climate change risks and impacts are typically larger than emissions from individual projects; 4) the impossibility of quantifying the exact impacts attributable to a specific GHG source. Springing from these observations the SOB leap-frogs to the conclusion that any EJ analysis is unnecessary because it would not be meaningful to evaluate impacts of GHG emissions on a local community (pg 26).

It is clear that 'but for' the new power plant the GHG emissions that require a federal PSD permit would not exist. However the SOB advocates an exception to the requirement of an EJ analysis based on the fact that only GHG emissions are being regulated and not other types of emissions. This slippery slope implies that disadvantaged communities should not be entitled to environmental justice when only methane, carbon dioxide, nitrous oxide, ozone, water vapor and chlorofluorocarbons are emitted. We believe this violates the spirit and intent of Executive Order 12898 and the specific holding of the EPA's Environmental Appeals Board as to PSD permits issued by the EPA. It is also inconsistent with Region 6's own recent position with PSD permits for GHG emissions. Region 6 even conducted an (albeit brief) environmental justice analysis on a PSD permit for GHG emissions for four new natural gas processing plants in Jackson County, Texas as recently as March of 2012. (See PSD-TX-1264-GHG).

Cumulative Impacts. The EPA should not be allowed to put on blinders so that only an isolated and narrow impact of the MPS on a disadvantaged community is reviewed. The geographic area next to the MPS includes a 148 acre Magellan Pipeline terminal that fronts on Montana Avenue and presently contains 22 large capacity tanks holding flammable fuels. The MPS plant with its large overhead transmission lines and its related operations will consume almost the entire adjacent 264 acre parcel acquired by El Paso Electric Company from the tank terminal owners. In addition to the planned large electrical power generating plant the same 264 acres will be the location of a large support operations, maintenance and warehouse center. It appears that this center is intended to combine all of the other support and maintenance locations of EPEC, and will employ approximately 235 employees (EPEC website: http://www.epelectric.com/about-el-paso-electric/epes-new-distribution-operations-service-center). The vehicles bringing these employees to and from work will bring further emissions into the neighborhood. Some of the equipment used in this operations and maintenance center will likely have diesel emissions. The MPS will require five 115 KV transmission circuits in possibly 3 transmission corridors of between 50 and 75 feet in width for long distances to and from these facilities. The ***average*** height of the transmission structures will be approximately 88 feet (about 8 stories) above ground and the average span of each pole is 450 feet (**Exhibit "I"**). Further, in order to build the operations center there will be about 200 construction workers traveling back and forth to the area, and large construction equipment operating in the area project well over a year (see El Paso Times article posted 10-26-13 at the following link: http://www.elpasotimes.com/news/ci_24391490/works-starts-el-paso-electrics-new-38-million).

Vehicle emissions include hydrocarbons, carbon monoxide, nitrogen oxides, particulate matter, sulfur oxide and VOC's. All of these emissions will be in addition to the air emissions from the plant itself. The cumulative impact of these existing and future heavy industrial uses will exceed the tipping point, will have an adverse impact on the environment, and will have a disproportionate impact on the health, safety and welfare of the residents and other landowners in the area.

Conclusion. Any technical evaluation of new emissions is fundamentally at fault if it does not put the new emissions within the existing land use, minority/poverty and natural resource context of the emission site. The PSD permitting process with new source review must determine what is the best technology available to control the new emissions. The best technology to use in a desert region in a drought of record should be different than in a non-desert region. The best technology evaluation in a location next to large pressurized third party pipeline corridors and adjacent to a 148 acre tank terminal containing 38 million gallons of flammable liquids should be different that in a true greenfield. The minority and poverty data around the site requires a thorough environmental justice analysis. We appreciate your consideration of these issues.

Sincerely yours,
THE GILBERT LAW FIRM, P.C.

Risher S. Gilbert

Enclosures per Attached List of Exhibits
cc: CSM

List of Exhibits

Exhibit A- Attachment 2A to Zephyr Environmental spill report for Magellan attached to 01-16-12 AMEC Phase I ESA

Exhibit B- AMEC Phase I ESA for 75 acre parcel, pages 13, 14, 15, 18, 22

Exhibit C- page 33 of AMEC Phase I ESA for 150 acre parcel

Exhibit C-1- map showing pipeline easements

Exhibit D- Excerpt from Prefiled Testimony of William Powers, P.E., SOAH DOCKET 532-13-1520, TCEQ Docket 2012-2608-AIR

Exhibit E- Excerpt from Texas Water Development Board Technical Note 12-01, dated November 2012

Exhibit F- Figure 3-7 from Ft. Bliss Draft EIS

Exhibit G-1- U.S. Census Bureau Selected Social Characteristics for zip code 79938

Exhibit G-2- U.S. Census Bureau Selected Economic Characteristics for zip code 79938

Exhibit H- EPA letter commenting on Ft. Bliss EIS, dated June 28, 2013

Exhibit I- El Paso Electric information on height of transmission lines

SOAH DOCKET NO. 582-13-1520
TCEQ DOCKET NO. 2012-2608-AIR

IN THE MATTER OF EL PASO ELECTRIC COMPANY APPLICATION FOR AIR QUALITY PERMIT NOS. 102294 AND PSD-TX-1290	§ § § § § § §	**BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS**

PREFILED TESTIMONY

OF

WILLIAM POWERS, P.E.

FOR

ALIGNED PROTESTANTS RAFAEL CARRASCO AND

FAR EAST EL PASO CITIZENS UNITED

MAY 17, 2013

EXHIBIT D

Q. DOES AIR COOLING INCREASE THE OPERATING COST OF THE LMS100?

A. No. The cooling towers at the Montana Power Station would require up to about 140 million gallons per year of raw water, and generate up to about 16 million gallons per year of wastewater. The cooling towers would also require an expenditure of approximately $370,000 per year to pay City of El Paso raw water supply and wastewater discharge fees.[48,49,50]

Q. DOES AIR COOLING INCREASE THE ENERGY CONSUMPTION OF THE LMS100?

A. The fan power demand for a 10 °F approach temperature fin-fan air cooler for a single LMS100 would range from 0.8 to 1.1 MW, depending on the air cooling approach temperature selected (either 20 °F or 10 °F).[51] No fan power would be necessary at or below an ambient temperature of 40 °F according to LMS100 manufacturer General Electric. A cooling tower for two LMS100 would have a pump power demand of about

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Therefore cost of 220 MMBtu/hr fin-fan air cooler with 20 °F approach temperature for two LMS100 units would be: (220 MMBtu/hr)/(150 MMBtu/hr)($1.9 million) = $2.8 million.

[48] California Energy Commission, *Bullard Energy Center Application for Certification* (two LMS100 units), Docket No. 06-AFC-08, November 6, 2006, Table 3.4-2, p. 3-13. Annual average cooling tower water consumption, for two LMS100s at 57% annual design capacity factor = 219 acre-ft/yr (71 million gallons per year). Cooling tower blowdown to wastewater treatment, at 9 cycles of concentration per Montana Power Station Application, would be approximately one-ninth of the total cooling tower water consumption: (71 million gallons per year/9) = 8 million gallons per year.

[49] Cost of cooling tower makeup water, assuming it supplied by the City of El Paso, would be $1.56/CCF. (http://www.epwu.org/services/water_rates.html). "CCF" is 100 cubic feet of water, which equals 750 gallons. City of El Paso charges a 1.15× premium for customers outside of the city limits (Montana Power Station is outside the city limits). Annual cooling tower makeup water cost for two LMS100s = (71 million gallons/yr)($1.56/750 gallons)(1.15) = $169,832/yr (two LMS100s).

[50] Cost of cooling tower wastewater discharge, assuming it received by the City of El Paso, would be $1.38/CCF (http://www.epwu.org/wastewater/wastewater_rates.html). "CCF" is 100 cubic feet of water, which equals 750 gallons. Annual cooling tower makeup water cost for two LMS100s = (8 million gallons/yr)($1.38/750 gallons) = $14,720/yr (two LMS100s).

[51] B. Powers – Powers Engineering, letter report - Big West CFP DEIR Is Deficient in Its Failure to Analyze Air-Cooled Heat Exchanger as an Alternative to Cooling Tower, prepared for Adams Broadwell Joseph & Cardozo, March 27, 2007. Fan power demand for 150 MMBtu/hr fin-fan air cooler ranges from 1.1 to 1.6 MW. Heat rejection requirement of one LMS100 is 105 MMBtu/hr. Therefore fan power requirement of fin-fan cooler for one LMS100 is: (105 MMBtu/hr/150 MMBtu/hr) x (1.1 MW to 1.6 MW) = 0.8 MW to 1.1 MW.

70 kW and a fan power demand of about 335 kW.[52] This equals a cooling tower power demand of about 0.2 MW (200 kW) per LMS100.

Q. WHAT IS THE ADDITIONAL POWER DEMAND OF AIR COOLING FOR THE LMS100?

A. The additional power demand would be about 0.6 to 0.9 MW.

Q. WHAT IS THE COST OF THIS ADDITIONAL POWER DEMAND?

A. Assuming a cost of electricity generation by Montana Power Station of $30/MW-hr and a 57 percent capacity factor, the cost of the annual additional power demand would range from $30/MW-hr x 0.57 x 8,760 hr/yr x 0.6 MW = ~$90,000/yr, to $30/MW-hr x 0.57 x 8,760 hr/yr x 0.9 MW = ~$135,000/yr

Q. DOES AIR COOLING REDUCE THE ENVIRONMENTAL IMPACTS OF THE LMS100?

A. Yes. Use of air cooling would eliminate up to 140 million gallons per year of City of El Paso raw water consumption, and also eliminate up to 16 million gallons per year of wastewater that would be discharged to the City of El Paso wastewater treatment system.

Q. MR. POWERS, WHAT IS YOUR ULTIMATE CONCLUSION ABOUT THE COOLING TOWER PM BACT ANALYSIS?

A. The cooling tower PM emissions impact could be eliminated by specifying air cooling for the Montana Power Station LMS100 units. The annualized cost of air cooling and wet cooling are comparable, and use of air cooling would eliminate 140 million gallons per year of water consumption at Montana Power Station.

C. CARBON MONOXIDE

Q. MR. POWERS, LET'S MOVE ON TO THE CO BACT ANALYSIS. WHAT DOES EL PASO ELECTRIC POWER PROPOSE AS BACT FOR CO?

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[52] California Energy Commission, *Bullard Energy Center Application for Certification* (two LMS100 units), Docket No. 06-AFC-08, November 6, 2006, Table 3.4-1, p. 3-4. Cooling tower flow rate is 13,800 gpm. Hydraulic head is 22 feet. Thererfore pump demand = [(13,800 gpm)(22 feet)]/(3,960 × 0.8) = 96 hp (71 kW). Fan power requirement is 3 fans x 150 hp = 450 hp (335 kW). Total power demand = ~400 kW (0.4 MW). Cooling tower demand per LMS100 = 0.4 MW/2 = 0.2 MW.

T/F/IHW 57055 CO
ARTS CCN 1453 0237 RP
PROJ. MGR. G Meyer
* to assign new PM

AFFECTED PROPERTY ASSESSMENT REPORT

FOR
MAGELLAN EL PASO TERMINAL TANK 005 BASIN AREA RELEASE
13551 MONTANA AVENUE
EL PASO, TEXAS

Received
DEC 10 2010
Remediation Division
Corrective Action

Prepared for:

MAGELLAN PIPELINE TERMINALS, L.P.
ONE WILLIAMS CENTER, MD 27-3
PO BOX 22186
TULSA, OKLAHOMA, 74131

Prepared by:

ZEPHYR ENVIRONMENTAL CORPORATION
2600 VIA FORTUNA, SUITE 450
AUSTIN, TEXAS 78746
(512) 329-5544

DECEMBER 2010

zephyr

EXHIBIT "A"

ATTACHMENT 2A – TIER I EXCLUSION CHECKLIST

PART I. Affected Property Identification and Background Information

1) Provide a description of the specific area of the response action and the nature of the release. Include estimated acreage of the affected property and the facility property, and a description of the type of facility and/or operation associated with the affected property. Also describe the location of the affected property with respect to the facility property boundaries and public roadways.

The property associated with this affected property assessment is the Magellan Pipeline Terminals, L.P. (Magellan) El Paso Terminal facility located at 13551 Montana Avenue in El Paso, El Paso County, Texas. The property is comprised of 525 acres, of which 90 acres is occupied by a terminal facility, owned and operated by Magellan of Tulsa Oklahoma. The general land use at the on-site property is industrial. Magellan operates under the primary Standard Industrial Classification Code (SIC) 4613, refined petroleum pipelines. *The terminal facility is comprised of a 5-bay truck loading rack and multiple aboveground storage tanks totaling over 900,000 barrels of storage. The terminal receives refined motor fuel products (e.g., gasoline and diesel) from Gulf Coast refineries through a 700-mile, common carrier pipeline. There are no plans to change the future land use of the on-site property. The affected property is located on the southwest side of Tank 005 within the secondary containment dikes for this aboveground storage tank, and is approximately 460 feet north of the southern property boundary (Montana Avenue) and approximately 1,150 feet east of the facility's western fence line. The affected property covers an area of about 40' by 40'(~0.04 acres).*

On May 8, 2008, an estimated 275 gallons of diesel fuel was released to surface soils in the vicinity of Tank 005 at the El Paso Terminal. Magellan reported the spill to the State Emergency Response Commission/Texas Commission on Environmental Quality (SERC/TCEQ) within 24 hours and provided a written notification letter regarding the incident on June 6. Free-phase product was recovered and affected soil removed as a response action. A second notification was provided to the TCEQ on Saturday, May 10, 2008 due to a subsequent release, apparently from the same piping component, resulting in further impacts to the spill area. It was estimated that 175 gallons diesel fuel was released during the second incident. Between these two spills, approximately 75 gallons of diesel fuel was recovered and around 150 cubic yards of affected soil excavated. The release was entirely contained onsite.

A defective 3/8" pipe nipple and valve body utilized for pressure/flow regulation on the Tank 005 discharge pipeline was identified as the cause of the spills. These components were replaced to circumvent any additional releases. A written notification letter was submitted to the TCEQ in regards to this incident on June 6, 2008, in which Magellan requested an extension of up to six months in accordance with the requirements of 30 TAC §327.5(C)(2) to further attempt completion of the spill response action.

A bioremediation agent was applied to the spill area in an attempt to reduce COC concentrations to below the method quantitation limits (MQLs) and complete the §327 response action. The analytical data for the spill response samples collected several days following the

PHASE I ENVIRONMENTAL SITE ASSESSMENT
75 Acre Magellan Parcel
El Paso, Texas

AMEC REF. NO. 1167171140

Submitted To:

El Paso Electric Company
Environmental Affairs Department
P.O. Box 982
El Paso, TX 79960

Submitted By:

AMEC Environment & Infrastructure, Inc.
125 Montoya Road
El Paso, Texas 79932

January 16, 2012

EXHIBIT "B"

2.2 HISTORY OF PROPERTY USE

2.2.1 REVIEW OF AERIAL PHOTOGRAPHS

Records of historic land use were found in aerial photographs taken in 1936, 1956, 1967, 1974, 1979, 1988, 1996, 2004, 2005, and 2008. Aerial photographs provided by Environmental Data Resources, Inc. (EDR) were compiled from various sources including the Texas Department of Transportation (TxDOT), the Agricultural Stabilization and Conservation Service (ASCS), the United States Department of Agriculture (USDA), the United States Geological Survey (USGS) and EDR. Additionally, aerial photography ranging from 1996 to 2010 was reviewed online Google Earth Pro®. Select aerial photographs reviewed are included in ***Appendix C***.

The subject site and the surrounding area appear as undeveloped desert terrain with sparse vegetation in all photographs from 1936 to 1996. Montana Avenue (Highway 62/180) appears south of the site in all photographs, however, it is unclear if it is paved in 1936. In the 1936 photograph Zaragoza Street is visible, but it does not appear to be paved. An unpaved road crossing the site trending north-south can be seen starting in 1956 and is visible in all subsequent photographs.

The 1974 aerial photograph continues to show the subject site and as undeveloped desert terrain. A faint trail paralleling the north-south road can be seen a few hundred feet to the east of the road bisecting the property (this may be the location of a near-surface water line identified on the site during the reconnaissance). An east-west trending scar can be seen crossing the northern portion of the site area in the 1974 aerial photographs and may mark the location of a later pipeline easement.

The east-west alignment is less visible in the 1979 aerial photograph. Signs of excavations to the north and west of the subject site can be seen suggesting possible undocumented/unregulated activities being conducted by 1979 at the subject site. Flagger Street is visible in this photograph as is the Nations South Well.

The first development other than roadways can be seen in the 1984 aerial photograph, as a drive-in theater can be seen south of Montana Avenue. It appears that dumping in the vicinity of the well (on Fort Bliss/DOD property) had occurred by 1984. According to Fort Bliss representatives, the material found at this area consists of piles of "compost type material' with scattered piles of miscellaneous household debris.

The 1988 aerial photograph shows additional roadways and evidence of surface dumping on parcels to the west of the site and additional development on parcels along Montana Avenue and near Flagger can be seen.

In the 2004 photograph the site remains undeveloped, but property abutting the site to the southwest has been developed as a petroleum bulk storage facility and pipeline terminal, currently owned by Magellan. An east-west trending pipeline easement is prominently visible bounding the northern edge of the site along Frankie Lane. Significant earthwork activities can be seen on adjacent properties to the west. The 2004 aerial photograph shows the first clear modification of the site by activities other than roadway construction, as portions of the extreme western margin and the west end of the southern half of the property have been graded in an area where pipeline easements now exist. The remainder of the site remains as generally undeveloped lands.

Aerial photographs from 2005 to 2010 are very similar to the 2004 photograph and indicate no further significant development of the subject property. Properties in the vicinity continue to develop with a combination of scattered residential, bulk petroleum and commercial facilities.

2.2.2 REVIEW OF FIRE INSURANCE MAPS

A request for available Sanborn Fire Insurance maps was made to EDR, Inc. Based on a response from EDR, Inc., Sanborn map coverage of the subject site area was not found. A copy of the Sanborn unmapped property certificate supplied by EDR is presented in ***Appendix D.***

2.2.3 REVIEW OF PROPERTY TAX FILES

AMEC reviewed available EPCAD information for the site. Based on available information, the current owner of the site is identified as Magellan Asset Services LP. The appraisal information reviewed list the subject property as account number 208822 and indicates the property consists of approximately 413-acres of land out of which the subject site occupies approximately 75+ acres. The tax records indicate no existing improvements.

A copy of the account record from EPCAD is included as ***Appendix B***.

2.2.4 REVIEW OF RECORDED LAND TITLE RECORDS

Title and easement information for the subject property was provided by the client during earlier studies on adjacent parcels, but which are applicable to this study. Selected portions of these documents are included in ***Appendix B.***

According to title records, the subject property or portions of the property have been owned or leased by the following since 1940:

- The Texas Pacific Land Trust, including various individuals as trustees
- AT&T – Right of Way and Easement Agreement (1947)
- P.J. Wieland (1954) – Trustee for Texas Pacific Land Trust
- TXL Oil Corporation (Texas Pacific Land Trust subsidiary) – Mineral Deed (1954)
- Maurice Meyer Jr. and George M. Crawford as Trustees for the Texas Pacific Land Trust (1955)
- Texaco Inc– General Indenture of Conveyance, Assignment, and Transfer (1962)
- El Paso Electric Company– Easement Agreement (1974-2007)
- DSE Pipeline – Pipe Line Easement (1995)
- Axis Gas Corporation – Assignment and Bill of Sale; Novation Agreement; and Special Warranty Deed (1996)
- Longhorn Partners Pipeline, L.P. – Special Warranty Deed (1998)

- Longhorn Partners Pipeline, L.P. and Magellan Pipeline Terminals, L.P. (1998)
- Phillips Texas Pipeline Company, LTD – Right of Way Assignment (1999)
- Texas Gas Service Company – Easement Agreement (2008)
- Longhorn Partners Pipeline, L.P. – Assignment, Conveyance and Bill of Sale (2008)
- Valero Terminaling and Distribution Company – Assignment and Assumption Agreement (2008)
- Magellan Pipeline Terminals, L.P. (2009)
- P.M.I Services North America, Inc. – Memorandum of Terminal Lease and Pipeline Easement (2009)

There were no environmental liens identified for the subject property. Past ownership clearly indicates past use of portions of the subject property and adjacent lands for petroleum distribution/conveyance.

2.2.5 USGS TOPOGRAPHIC MAPS

Topographic maps from 1908, 1944, 1948, 1955, 1976, 1995, and 2010 were reviewed to gather supplemental data regarding on-site development and nearby geographic features. The topographic maps from 1908 through 1995 were obtained from EDR and the topographic map 2010 was obtained from the USGS website. The most recent topographic map (2010) is presented as ***Figure 1***, historic topographic maps are provided in ***Appendix E***.

According to the topographic maps reviewed the elevation of the subject property is approximately 4015 to 4020 feet above mean sea level (msl). The area appears to be centered on a topographic depression (graben) with only limited relief.

The historic topographic map from 1908 does not depict any structures or roads at or near the subject site location.

The 1944 topographic map does not depict any structures at or near the subject site location. The Nations South Well is located north of the site and Montana Avenue (US 62/180) and Zaragoza Street are shown as paved roads to the south of the subject site. A two-track road leading from Montana Avenue (labeled as Carlsbad Highway) northward to the Nations South Well and beyond can be seen at the location of the subject site.

The 1948 and 1955 topographic maps show improvements to the north-south road, but it is still likely unpaved at this time. A two-track road can be seen parallel to the roadway and may mark the location of a water line which crosses the property.

The 1976 topographic map does not indicate any significant change to the subject site however, development can be observed to the west and east of the subject site and to the immediate north a boundary for a military reservation (Fort Bliss) is now visible. Flagger Road can be seen for the first time, as well as a grid work of roads to the east and west of the subject property.

classified in the Hueco Series. The Hueco components consist of moderately deep well drained soils that have permeability ranging from moderately low to moderately high. The Hueco series soils are formed in coarse-loamy alluvium material. The profiles within this series consist of various coarse – fine sandy loams. Soils noted in the field include windblown sands overlying calcium carbonate indurated silts, clays and sands (caliche). Silty sands, sands and some gravels occur at depth in the basin filling Quaternary sediments beneath the site. Quaternary/Late Tertiary basin filling materials (clay, sand, silt, gravel) underlie the site to depths of several hundred feet or more. Localized faulting associated with basin extension exhibiting Quaternary expression is known in the area (Keaton & Barnes, 1993; Seager, 1980).

3.3 HYDROGEOLOGIC SETTING

Water for domestic/commercial use in the vicinity of the subject site is derived from a combination of surface water from the Rio Grande Aquifer and from wells in the Hueco Bolson. Groundwater beneath the site is known to exist in unconfined aquifers associated with geologically recent Miocene-Pleistocene basin filling sediments of the Hueco Bolson. Based on nearby well data included in the EDR report, the depth to groundwater at the subject site is estimated to be on the order of 450 to 500 feet below the existing ground surface. This information is included in the EDR report presented in ***Appendix H,*** which includes well data and depth to water information for reported wells in the vicinity. Although no site specific groundwater flow direction information was obtained during this assessment, the groundwater flow direction in 2002 in the general area of the subject site was towards the southwest (Hutchison, 2006). Shallower perched groundwater is known to occur throughout the Hueco Bolson at depths significantly shallower than 200 feet. No groundwater was encountered to depths of 30 feet in studies conducted concurrently with this evaluation.

4.0 INFORMATION FROM SITE RECONNAISSANCE

4.1 CURRENT SITE USE AND DESCRIPTION OF IMPROVEMENTS

A plan showing the general site layout is presented in ***Figure 2, 3 and 4***. Selected photographs of current site conditions are included in ***Appendix I***.

The site is primarily unimproved desert land with the exception of a pipeline easement crossing the southern third of the property (see ***Figure 2, 3 and 4***. An unpaved road bisects the property, running north to south, and a power transmission line parallels the road. Unpaved roads also mark the northern and extreme western margins of the site. A power line also exists just north of the unpaved road at the north end of the property.

A pipeline easement starts at Montana Avenue, crosses the site trending northwest to the northeastern corner of the existing Magallen yard and later forms the western margin of the site. These easements, as well as the pipeline easement at the north end of the property contain several petroleum lines marked by a graded surface and pipeline markers.

4.20 OTHER CONDITIONS OF CONCERN

Several petroleum pipelines hold easements in areas crossing and adjoining the subject property including P.M.C.I., Magallen and Buckeye Development. No indication of a release from pipelines within the easements that bound the site or cross the southern third of the site were identified during our site reconnaissance, our review of the regulatory database or in conversations with Magellan.

No other conditions of environmental concern were noted on the subject site during the site visit or review of background information. Adjacent property use by the Magallen bulk is discussed below.

4.21 CURRENT USE OF ADJACENT PROPERTIES

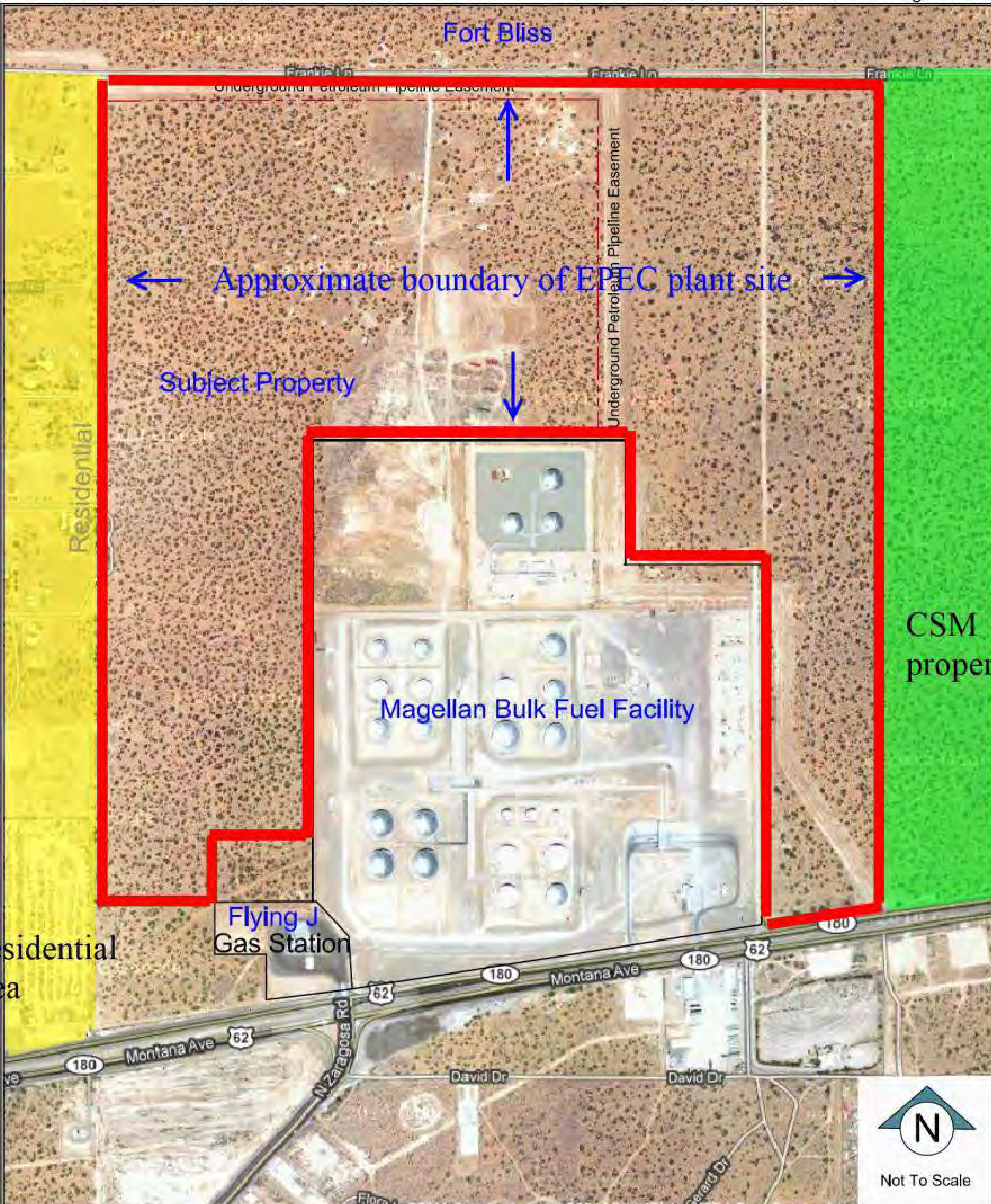
A cursory reconnaissance of adjoining properties was performed to identify land use and the potential for adverse conditions which may impact the subject parcel. Adjacent parcels were observed from legal boundaries or from legally accessible areas on the adjoining property.
The Fort Bliss military reservation is located beyond the pipeline easement and dirt road north of the subject site. Montana Avenue (US Highway 62/180) runs east and west approximately immediately south of the subject site's southern boundary.

A large portion of the site abuts the Magellan bulk fuel storage facility, which is known to store and transport a variety of petroleum products (primarily gasoline and diesel). Maintenance and yard operations were noted during our reconnaissance and a drum storage area exists at the northeast corner of the yard, in close proximity to the site's western property line.

Information concerning the construction of the aboveground fuel storage tanks at the Magellan Fuel Terminal was provided by Magellan via EPE. According to a Magellan representative "the Magellan owned tanks and facilities were built to API 650 and the DOT code at the time and they are inspected and repaired to API 653 and DOT 195"." Additionally the Magellan representative stated that "all Magellan owned tanks have had an API 653 out of service inspection performed on them and to the best of their knowledge the facility had not experienced any leaks from any of the Magellan tanks". Furthermore they stated that "all Magellan-owned tanks have concrete ring walls with leak prevention barriers (clay liners or HDPE liners) with leak detection ports through the ring walls and that all of the Magellan tanks (with the exception of Tanks 8 and 10) have internal epoxy linings".

5.0 REGULATORY RECORDS REVIEW

Available federal and state listings of locations on or near the project site subject to environmental regulation or investigation, provided by Environmental Data Resources, Inc. (EDR), were reviewed for this project. Additionally AMEC conducted a supplemental regulatory record search of the El Paso Terminal. A copy of the report generated by EDR and selected regulatory records for the El Paso Terminal are presented in ***Appendix H*** and ***Appendix J*** respectively.



Phase I Environmental Site Assessment Vacant Parcel Near Flagger & Montana Intersection Flagger and Montana - El Paso, Texas AMEC Job No. 1167171048	Figure 2 Site Plan	amec Earth & Environmental Drawing by: C. Gallegos Checked by: S. Gandara File No.: 1167171048 Figure 2

EXHIBIT "C"

Phase I Environmental Site Assessment Vacant Parcel Near Flagger & Montana Intersection Flagger and Montana - El Paso, Texas AMEC Job No. 1167171048	Figure 2 Site Plan	amec Earth & Environmental Drawing by: C. Gallegos Checked by: S. Gandara File No.: 1167171048 Figure 2

From: Raul Issa
To: Magee, Melanie
Cc: Risher Gilbert
Subject: Comment letter- Permit-PSD-TX-1290-GHG- El Paso Electric Company
Date: Wednesday, December 04, 2013 2:44:49 PM
Attachments: FINAL Exhibit I.pdf
FINAL Exhibit E- household water use.pdf
FINAL Exhibit F- map.pdf
FINAL Exhibit G-1.pdf
FINAL Exhibit G-2.pdf
FINAL Exhibit H.pdf

Ms. Magee,
This email contains the rest of the exhibits to our letter concerning the above referenced matter. Kindly reply so I know you have received all files: the letter PDF and Exhibits A through I.

We have also sent the comment letter and exhibits via certified mail. Please contact me if you have any questions or comments.

Thank you.

Raul Issa
Paralegal to Risher Gilbert

Raul Issa, Certified Paralegal
The Gilbert Law Firm
201 E. Main, Suite 1501
El Paso, TX 79901
915-532-6622
fax: 915-541-6490

The Electric Company

El Paso Electric

Contact Information:

Lawrence Thoenen

P.O. Box 982

El Paso, Texas

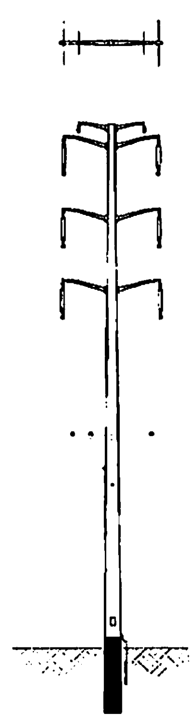
79960-0982

(915) 543-5811

Purpose & Benefits:

El Paso Electric (EPE) is currently planning for the construction of the new Montana Power Station (MPS) on El Paso's East side. The plant will be located behind 13351 Montana Avenue, near the intersection of US Hwy. 62/180 and FM 659, Zaragoza Rd.

- EPE has identified the need to construct five 115kV transmission circuits in possibly 3 corridors from this site.
- This Project will be completed in 2 phases:
    - **Phase 1** will include the construction of two 115kV double circuit transmission lines from MPS. The first line will intercept EPE's existing Caliente to Coyote 115kV line located to south of MPS. The second line will be built from MPS to EPE's Caliente Substation located west of MPS. These new line segments will be approximately 1 mile and 3 miles in length, respectively.
    - **Phase 2** will include the construction of one new 115kV transmission line from MPS and will tie into EPE's existing Montwood Substation located approximately 6.2 miles south and west of MPS.



Project Timeline:

Develop potential routes: Winter 2012

Open House Meeting: March 2013

Submit Applications to PUCT: Spring 2013

Phase 1 Construction Begins: Fall 2013

Phase 1 In-Service Date: Winter 2014

Phase 2 Construction Begins: Summer 2014

Phase 2 In-Service Date: Fall 2014

Construction Overview:

Single Pole: Winter 2012

- Average spans, 450 feet
- Average Pole heights, 88 feet
- Easement width, approximately 50-75 feet
- These poles will be direct embedded

EXHIBIT I

El Paso Electric

Typical Routing Considerations:

•Overall length
•Access and terrain
•Number of parcels crossed
•Visibility of the line to the public
•Length parallel to existing features such as pipelines, transmission lines, existing roads and section lines, etc.
•Proximity to:

- Residences
- Businesses
- Public facilities (churches, schools, cemeteries, etc.)
- Historic and archaeological sites
- New and planned developments
- Airport and airstrips
- Federal and state lands
- Conservation areas

•Crossing of:

- Pasture/grassland
- Streams
- Roads

Real Estate FAQs:

- ***What is an easement?***
  A permanent land right acquired to use land for special purpose(s).
- ***What rights will be needed for the transmission line construction?***
  Access for surveying and inspections, constructing, operating, and maintaining a transmission line across a defined strip of the right-of-way easement.
- ***What are the main building and use restrictions in the easement?***
  1) No constructing of permanent structures
  2) No planting of vegetation that exceeds 10 feet of height at maturity
- ***Who will be talking to me about the easement on my property?***
  Agents working on behalf of EPE will call you to set up an appointment to meet with you and discuss the project and the easement across your property.
- ***What happens if my property is damaged during the surveying or construction process?***
  Contractors try to minimize any damage to property. A Right-of-Way agent will inspect each parcel with the property owner and/or tenant to restore and/or settle any damage to crops, fences, or related property.

Land Acquisition Process:

1. Public Open Houses
2. Route Selection
3. Right of Entry
4. Survey and Inspections
5. Valuation Study
6. Create Easement Packages
7. Acquisition Negotiation
8. Recording of Interest
9. Construction Coordination
10. Post Construction Inspection
11. Final Settlement

Texas Water Development Board

Technical Note 12-01

The Grass Is Always Greener… Outdoor Residential Water Use in Texas

by

Sam Marie Hermitte, M.A. and Robert E. Mace, Ph.D., P.G.

November 2012

EXHIBIT E

Table 3: Annual average water use by city for 2004 through 2011.

	City	Indoor use (gallons)	Outdoor use (gallons)	Outdoor use as a percentage of total use	Gallons per household per day for indoor use (gallons)	Gallons per household per day for outdoor use (gallons)
1	Amarillo	4,203,333,000	3,110,188,125	42	194	143
2	Arlington	6,579,447,000	3,806,411,375	36	198	114
3	Austin	11,532,894,150	5,879,032,288	33	176	89
4	College Station*	1,510,618,286	922,872,143	38	-	-
5	Corpus Christi	4,983,501,000	1,839,473,375	26	179	66
6	Dallas	16,293,358,200	11,668,235,723	41	173	125
7	El Paso	12,676,702,014	6,231,936,280	33	220	105
8	Fort Worth	11,576,921,511	6,819,864,226	37	166	97
9	Garland	4,398,659,640	2,234,119,198	33	198	100
10	Houston	22,287,783,000	5,629,024,250	20	148	37
11	Katy	281,554,500	202,737,375	40	188	135
12	Laredo	5,013,600,000	1,707,862,500	25	265	93
13	Lubbock	4,332,784,500	2,341,568,000	36	177	96
14	Odessa	2,327,562,000	1,358,331,500	37	205	119
15	Pflugerville	558,544,200	393,038,375	39	219	152
16	San Antonio**	23,242,411,406	7,713,879,696	25	202	67
17	Tyler	1,682,887,500	1,937,568,750	53	171	195
	City average			*35*	*192*	*108*
	City median			*36*	*191*	*102*
	Statewide average			*31*	*181*	*86*

* College Station changed its method of calculating single-family residential connections between 2008 and 2009. Consequently, we omitted gallons per household calculations for this city as the data was inconsistent.

** San Antonio Water System staff indicated that monthly totals for the 2009 through 2011 period have not been adjusted to reflect changes in final billing figures recognized at the end of each calendar year. Adjustments typically result in a 1 to 2 percent change to annual totals and are caused by billing errors, meter reading errors, and adjustments due to leakage.

- *Statewide average,* the best metric of the state as a whole, represents the average of the cities' values after each city is weighted by its population.

Though Phase II of the study involved a limited subset of Texas cities, the statewide annual averages for outdoor use as a percentage of total use were comparable to Phase I averages for the 2004 to 2008 study period (compare Table 4 to Table 2). For three of the five years, the statewide average was 2 percentage points lower in Phase II than in Phase I, and for the remaining two years the reductions in

DP02

SELECTED SOCIAL CHARACTERISTICS IN THE UNITED STATES

2007-2011 American Community Survey 5-Year Estimates

Supporting documentation on code lists, subject definitions, data accuracy, and statistical testing can be found on the American Community Survey website in the Data and Documentation section.

Sample size and data quality measures (including coverage rates, allocation rates, and response rates) can be found on the American Community Survey website in the Methodology section.

Although the American Community Survey (ACS) produces population, demographic and housing unit estimates, it is the Census Bureau's Population Estimates Program that produces and disseminates the official estimates of the population for the nation, states, counties, cities and towns and estimates of housing units for states and counties.

Subject	ZCTA5 79938			
	Estimate	Margin of Error	Percent	Percent Margin of Error
HOUSEHOLDS BY TYPE				
Total households	12,952	+/-357	12,952	(X)
Family households (families)	11,423	+/-402	88.2%	+/-2.1
With own children under 18 years	8,048	+/-490	62.1%	+/-2.9
Married-couple family	8,840	+/-537	68.3%	+/-3.8
With own children under 18 years	6,363	+/-553	49.1%	+/-3.9
Male householder, no wife present, family	836	+/-274	6.5%	+/-2.1
With own children under 18 years	323	+/-191	2.5%	+/-1.5
Female householder, no husband present, family	1,747	+/-312	13.5%	+/-2.4
With own children under 18 years	1,362	+/-313	10.5%	+/-2.4
Nonfamily households	1,529	+/-273	11.8%	+/-2.1
Householder living alone	1,201	+/-244	9.3%	+/-1.9
65 years and over	238	+/-111	1.8%	+/-0.9
Households with one or more people under 18 years	8,916	+/-507	68.8%	+/-3.0
Households with one or more people 65 years and over	1,551	+/-286	12.0%	+/-2.2
Average household size	3.79	+/-0.13	(X)	(X)
Average family size	4.04	+/-0.14	(X)	(X)
RELATIONSHIP				
Population in households	49,054	+/-2,037	49,054	(X)
Householder	12,952	+/-357	26.4%	+/-0.9
Spouse	8,916	+/-531	18.2%	+/-1.0
Child	20,740	+/-1,248	42.3%	+/-1.5
Other relatives	5,020	+/-882	10.2%	+/-1.6
Nonrelatives	1,426	+/-378	2.9%	+/-0.7
Unmarried partner	592	+/-187	1.2%	+/-0.4
MARITAL STATUS				
Males 15 years and over	18,616	+/-1,086	18,616	(X)
Never married	6,233	+/-764	33.5%	+/-3.0
Now married, except separated	10,328	+/-627	55.5%	+/-3.1
Separated	484	+/-214	2.6%	+/-1.1
Widowed	288	+/-135	1.5%	+/-0.7

EXHIBIT "G-1"

Subject	ZCTA5 79938			
	Estimate	Margin of Error	Percent	Percent Margin of Error
Divorced	1,283	+/-309	6.9%	+/-1.5
Females 15 years and over	17,444	+/-871	17,444	(X)
Never married	4,586	+/-702	26.3%	+/-3.0
Now married, except separated	9,974	+/-494	57.2%	+/-3.6
Separated	547	+/-258	3.1%	+/-1.5
Widowed	1,118	+/-304	6.4%	+/-1.7
Divorced	1,219	+/-275	7.0%	+/-1.5
FERTILITY				
Number of women 15 to 50 years old who had a birth in the past 12 months	994	+/-246	994	(X)
Unmarried women (widowed, divorced, and never married)	138	+/-111	13.9%	+/-10.1
Per 1,000 unmarried women	26	+/-21	(X)	(X)
Per 1,000 women 15 to 50 years old	71	+/-17	(X)	(X)
Per 1,000 women 15 to 19 years old	13	+/-17	(X)	(X)
Per 1,000 women 20 to 34 years old	139	+/-37	(X)	(X)
Per 1,000 women 35 to 50 years old	28	+/-18	(X)	(X)
GRANDPARENTS				
Number of grandparents living with own grandchildren under 18 years	2,614	+/-626	2,614	(X)
Responsible for grandchildren	859	+/-329	32.9%	+/-11.3
Years responsible for grandchildren				
Less than 1 year	66	+/-68	2.5%	+/-2.6
1 or 2 years	259	+/-211	9.9%	+/-7.6
3 or 4 years	246	+/-170	9.4%	+/-6.4
5 or more years	288	+/-164	11.0%	+/-6.3
Number of grandparents responsible for own grandchildren under 18 years	859	+/-329	859	(X)
Who are female	501	+/-200	58.3%	+/-6.7
Who are married	787	+/-325	91.6%	+/-7.2
SCHOOL ENROLLMENT				
Population 3 years and over enrolled in school	18,627	+/-1,084	18,627	(X)
Nursery school, preschool	1,223	+/-319	6.6%	+/-1.7
Kindergarten	908	+/-235	4.9%	+/-1.2
Elementary school (grades 1-8)	8,445	+/-746	45.3%	+/-2.9
High school (grades 9-12)	3,895	+/-599	20.9%	+/-3.0
College or graduate school	4,156	+/-525	22.3%	+/-2.5
EDUCATIONAL ATTAINMENT				
Population 25 years and over	27,777	+/-1,070	27,777	(X)
Less than 9th grade	4,437	+/-544	16.0%	+/-1.8
9th to 12th grade, no diploma	3,148	+/-506	11.3%	+/-1.7
High school graduate (includes equivalency)	6,969	+/-759	25.1%	+/-2.3
Some college, no degree	6,454	+/-716	23.2%	+/-2.6
Associate's degree	1,935	+/-339	7.0%	+/-1.2
Bachelor's degree	3,558	+/-445	12.8%	+/-1.5
Graduate or professional degree	1,276	+/-267	4.6%	+/-1.0
Percent high school graduate or higher	(X)	(X)	72.7%	+/-2.3
Percent bachelor's degree or higher	(X)	(X)	17.4%	+/-1.8
VETERAN STATUS				
Civilian population 18 years and over	32,301	+/-1,192	32,301	(X)
Civilian veterans	2,197	+/-355	6.8%	+/-1.2

Subject	ZCTA5 79938			
	Estimate	Margin of Error	Percent	Percent Margin of Error
DISABILITY STATUS OF THE CIVILIAN NONINSTITUTIONALIZED POPULATION				
Total Civilian Noninstitutionalized Population	(X)	(X)	(X)	(X)
With a disability	(X)	(X)	(X)	(X)
Under 18 years	(X)	(X)	(X)	(X)
With a disability	(X)	(X)	(X)	(X)
18 to 64 years	(X)	(X)	(X)	(X)
With a disability	(X)	(X)	(X)	(X)
65 years and over	(X)	(X)	(X)	(X)
With a disability	(X)	(X)	(X)	(X)
RESIDENCE 1 YEAR AGO				
Population 1 year and over	50,534	+/-2,173	50,534	(X)
Same house	42,869	+/-1,940	84.8%	+/-2.7
Different house in the U.S.	7,222	+/-1,443	14.3%	+/-2.6
Same county	4,944	+/-1,367	9.8%	+/-2.6
Different county	2,278	+/-667	4.5%	+/-1.3
Same state	1,026	+/-332	2.0%	+/-0.6
Different state	1,252	+/-556	2.5%	+/-1.1
Abroad	443	+/-190	0.9%	+/-0.4
PLACE OF BIRTH				
Total population	51,367	+/-2,206	51,367	(X)
Native	35,885	+/-1,810	69.9%	+/-1.9
Born in United States	34,859	+/-1,774	67.9%	+/-1.9
State of residence	27,265	+/-1,642	53.1%	+/-2.2
Different state	7,594	+/-890	14.8%	+/-1.6
Born in Puerto Rico, U.S. Island areas, or born abroad to American parent(s)	1,026	+/-258	2.0%	+/-0.5
Foreign born	15,482	+/-1,207	30.1%	+/-1.9
U.S. CITIZENSHIP STATUS				
Foreign-born population	15,482	+/-1,207	15,482	(X)
Naturalized U.S. citizen	5,596	+/-647	36.1%	+/-3.6
Not a U.S. citizen	9,886	+/-1,025	63.9%	+/-3.6
YEAR OF ENTRY				
Population born outside the United States	16,508	+/-1,208	16,508	(X)
Native	1,026	+/-258	1,026	(X)
Entered 2000 or later	240	+/-116	23.4%	+/-9.3
Entered before 2000	786	+/-215	76.6%	+/-9.3
Foreign born	15,482	+/-1,207	15,482	(X)
Entered 2000 or later	3,999	+/-750	25.8%	+/-4.0
Entered before 2000	11,483	+/-967	74.2%	+/-4.0
WORLD REGION OF BIRTH OF FOREIGN BORN				
Foreign-born population, excluding population born at sea	15,482	+/-1,207	15,482	(X)
Europe	98	+/-52	0.6%	+/-0.3
Asia	284	+/-134	1.8%	+/-0.8
Africa	8	+/-14	0.1%	+/-0.1
Oceania	5	+/-8	0.0%	+/-0.1
Latin America	15,074	+/-1,168	97.4%	+/-0.9
Northern America	13	+/-21	0.1%	+/-0.1

Subject	ZCTA5 79938			
	Estimate	Margin of Error	Percent	Percent Margin of Error
LANGUAGE SPOKEN AT HOME				
Population 5 years and over	46,440	+/-1,869	46,440	(X)
English only	10,019	+/-1,147	21.6%	+/-2.3
Language other than English	36,421	+/-1,842	78.4%	+/-2.3
Speak English less than "very well"	14,712	+/-1,214	31.7%	+/-2.1
Spanish	35,957	+/-1,818	77.4%	+/-2.4
Speak English less than "very well"	14,477	+/-1,182	31.2%	+/-2.1
Other Indo-European languages	202	+/-118	0.4%	+/-0.3
Speak English less than "very well"	78	+/-66	0.2%	+/-0.1
Asian and Pacific Islander languages	257	+/-128	0.6%	+/-0.3
Speak English less than "very well"	157	+/-119	0.3%	+/-0.3
Other languages	5	+/-8	0.0%	+/-0.1
Speak English less than "very well"	0	+/-95	0.0%	+/-0.1
ANCESTRY				
Total population	51,367	+/-2,206	51,367	(X)
American	1,060	+/-388	2.1%	+/-0.7
Arab	0	+/-95	0.0%	+/-0.1
Czech	15	+/-22	0.0%	+/-0.1
Danish	18	+/-27	0.0%	+/-0.1
Dutch	46	+/-33	0.1%	+/-0.1
English	533	+/-214	1.0%	+/-0.4
French (except Basque)	275	+/-125	0.5%	+/-0.2
French Canadian	0	+/-95	0.0%	+/-0.1
German	1,143	+/-297	2.2%	+/-0.6
Greek	0	+/-95	0.0%	+/-0.1
Hungarian	0	+/-95	0.0%	+/-0.1
Irish	910	+/-299	1.8%	+/-0.6
Italian	221	+/-129	0.4%	+/-0.2
Lithuanian	0	+/-95	0.0%	+/-0.1
Norwegian	17	+/-27	0.0%	+/-0.1
Polish	152	+/-104	0.3%	+/-0.2
Portuguese	18	+/-28	0.0%	+/-0.1
Russian	41	+/-64	0.1%	+/-0.1
Scotch-Irish	58	+/-51	0.1%	+/-0.1
Scottish	89	+/-51	0.2%	+/-0.1
Slovak	50	+/-67	0.1%	+/-0.1
Subsaharan African	95	+/-101	0.2%	+/-0.2
Swedish	0	+/-95	0.0%	+/-0.1
Swiss	26	+/-40	0.1%	+/-0.1
Ukrainian	17	+/-27	0.0%	+/-0.1
Welsh	57	+/-62	0.1%	+/-0.1
West Indian (excluding Hispanic origin groups)	145	+/-118	0.3%	+/-0.2

Data are based on a sample and are subject to sampling variability. The degree of uncertainty for an estimate arising from sampling variability is represented through the use of a margin of error. The value shown here is the 90 percent margin of error. The margin of error can be interpreted roughly as providing a 90 percent probability that the interval defined by the estimate minus the margin of error and the estimate plus the margin of error (the lower and upper confidence bounds) contains the true value. In addition to sampling variability, the ACS estimates are subject to nonsampling error (for a discussion of nonsampling variability, see Accuracy of the Data). The effect of nonsampling error is not represented in these tables.

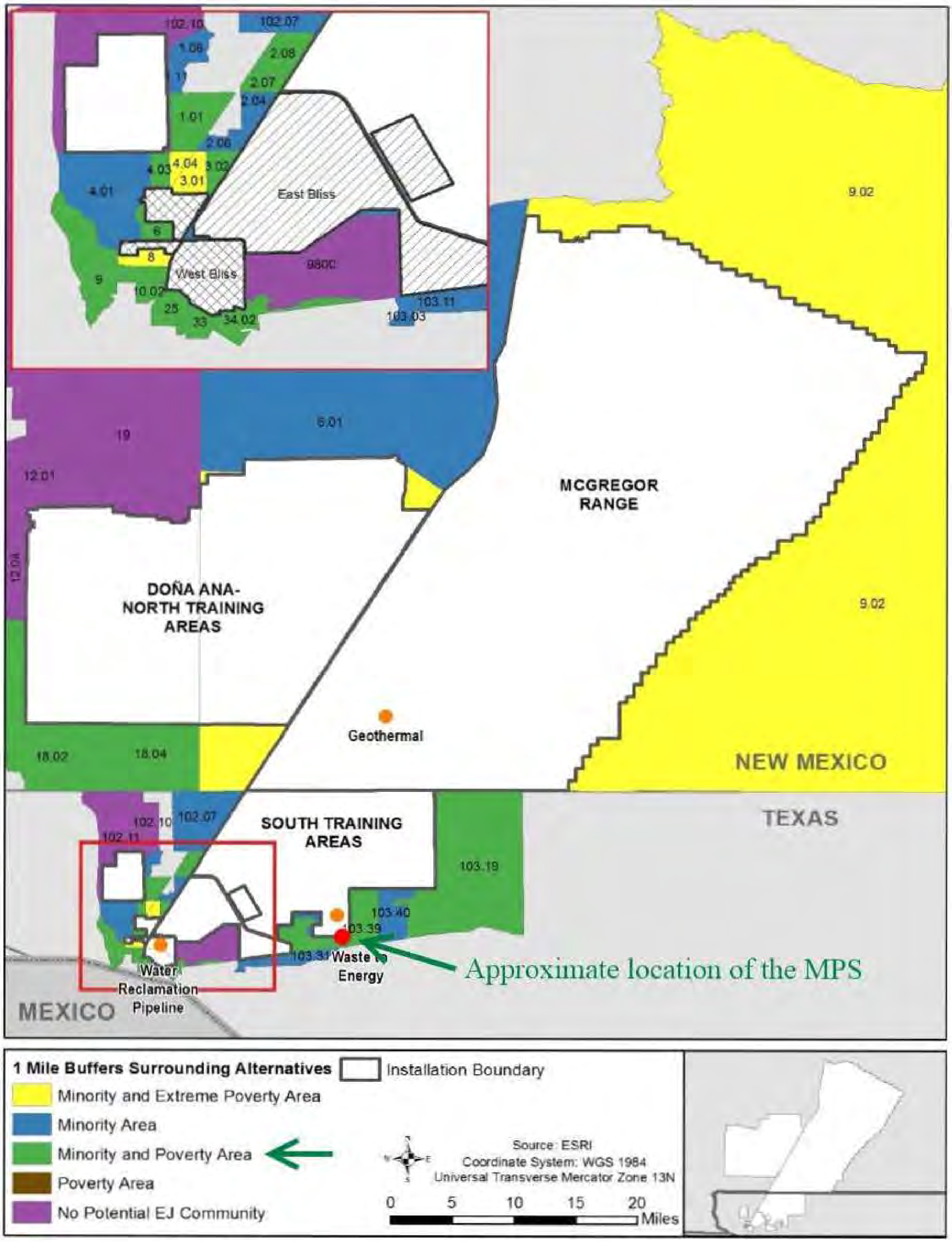
While the 2007-2011 American Community Survey (ACS) data generally reflect the December 2009 Office of Management and Budget (OMB) definitions of metropolitan and micropolitan statistical areas; in certain instances the names, codes, and boundaries of the principal cities shown in ACS tables may differ from the OMB definitions due to differences in the effective dates of the geographic entities.

Estimates of urban and rural population, housing units, and characteristics reflect boundaries of urban areas defined based on Census 2000 data. Boundaries for urban areas have not been updated since Census 2000. As a result, data for urban and rural areas from the ACS do not necessarily reflect the results of ongoing urbanization.

Source: U.S. Census Bureau, 2007-2011 American Community Survey

Explanation of Symbols:

1. An '**' entry in the margin of error column indicates that either no sample observations or too few sample observations were available to compute a standard error and thus the margin of error. A statistical test is not appropriate.
2. An '-' entry in the estimate column indicates that either no sample observations or too few sample observations were available to compute an estimate, or a ratio of medians cannot be calculated because one or both of the median estimates falls in the lowest interval or upper interval of an open-ended distribution.
3. An '-' following a median estimate means the median falls in the lowest interval of an open-ended distribution.
4. An '+' following a median estimate means the median falls in the upper interval of an open-ended distribution.
5. An '***' entry in the margin of error column indicates that the median falls in the lowest interval or upper interval of an open-ended distribution. A statistical test is not appropriate.
6. An '*****' entry in the margin of error column indicates that the estimate is controlled. A statistical test for sampling variability is not appropriate.
7. An 'N' entry in the estimate and margin of error columns indicates that data for this geographic area cannot be displayed because the number of sample cases is too small.
8. An '(X)' means that the estimate is not applicable or not available.



Source: U.S. Department of Commerce (2010c,d)

Figure 3-7. Potential Environmental Justice Census Tracts

EXHIBIT "F"

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
Region 6
1445 Ross Avenue, Suite 1200
Dallas, TX 75202-2733

June 28, 2013

Dr. John Kipp
Fort Bliss Directorate of Public Works
Attention: IMBL-PWE (Kipp)
Building 624 Pleasonton Road
Fort Bliss, Texas 79916

In accordance with our responsibilities under Section 309 of the Clean Air Act (CAA), the National Environmental Policy Act (NEPA), and the Council on Environmental Quality (CEQ) regulations for implementing NEPA, the U.S. Environmental Protection Agency (EPA) Region 6 office in Dallas, Texas, has completed its review of the Draft Environmental Impact Statement (DEIS) for the Implementation of Energy, Water, and Solid Waste Sustainability Initiatives (Net Zero) at Fort Bliss, Texas and New Mexico prepared by the United States Army (Army). The purpose of the proposed action is to implement Net Zero initiatives at Fort Bliss to meet Army mandates for renewable energy production, water conservation, and solid waste reduction.

EPA rates the DEIS as "EC-2" i.e., EPA has "environmental concerns and requests additional information" in the Final EIS (FEIS). The EPA's Rating System Criteria can be found here: http://www.epa.gov/oecaerth/nepa/comments/ratings.html. The "EC" rating is based on potential impacts to natural and cultural resources. The "2" indicates the DEIS does not contain sufficient analysis and information concerning environmental justice, water use, cultural resources, air impacts, and energy consumption. Detailed comments are enclosed with this letter which clearly identifies our concerns and the informational needs requested for incorporation into the Final EIS (FEIS). Responses to comments should be placed in a dedicated section of the FEIS and should include the specific location where the revision, if any, was made. If no revision was made, a clear explanation should be included.

EPA appreciates the opportunity to review the DEIS. Please send our office two copies of the FEIS, and an internet link, when it is sent to the Office of Federal Activities, EPA (Mail Code 2252A), Ariel Rios Federal Building, 1200 Pennsylvania Ave, N.W., Washington, D.C. 20004. Our classification will be published on the EPA website, www.epa.gov, according to our responsibility under Section 309 of the CAA to inform the public of our views on the proposed Federal action. If you have any questions or concerns, I can be reached at 214-665-8006, or contact Keith Hayden of my staff at hayden.keith@epa.gov or 214-665-2133.

Sincerely,

Rhonda Smith

Rhonda Smith
Chief, Office of Planning
And Coordination

Enclosure

EXHIBIT "H"

**DETAILED COMMENTS ON THE
DRAFT ENVIRONMENTAL IMPACT STATEMENT
FOR THE
IMPLEMENTATION OF ENERGY, WATER, AND SOLID WASTE SUSTAINABILITY
INITIATIVES (NET ZERO) AT FORT BLISS, TEXAS AND NEW MEXICO**

BACKGROUND: Fort Bliss is seeking to manage installation operations, material, and resources, with a goal of achieving Net Zero status for energy use, water use, and solid waste generation. A Net Zero energy installation produces as much energy on-site as it uses over the course of a year. A Net Zero water installation limits the consumption of water resources and returns water back to the same watershed from which it was withdrawn. A Net Zero waste installation reduces waste generation, reuses materials, and recovers waste streams so that the installation produces no landfill waste over the course of a year. The Army currently faces significant challenges in meeting its energy and water supply requirements, both domestically and abroad. Addressing these challenges is operationally necessary, financially prudent, and essential to Army mission accomplishment. Fort Bliss seeks to improve the installations long term sustainability through anticipated cost reductions; while improving quality of life, relationships with local communities, and preserving options for the Army's future.

AIR QUALITY

Environmental Consequences of Alternatives; page 3-12:

Fort Bliss is located in close proximity to the major population centers of El Paso, Texas and Ciudad Juarez, Chihuahua, Mexico. In order to reduce potential short-term air quality impacts associated with construction activities of the various alternatives, EPA asks the agencies responsible for the project implement the following recommendations.

Recommendations:

- The agencies responsible for the project should include a Construction Emissions Mitigation Plan and adopt this plan in the Record of Decision (ROD). In addition to all applicable local, state, or federal requirements, the EPA recommends that the following mitigation measures be included in the Construction Emissions Mitigation Plan in order to reduce impacts associated with emissions of NOx, CO, PM, SO_2, and other pollutants from construction-related activities:

Fugitive Dust Source Controls:

- Stabilize open storage piles and disturbed areas by covering and/or applying water or chemical/organic dust palliative where appropriate at active and inactive sites during workdays, weekends, holidays, and windy conditions;
- Install wind fencing and phase grading operations where appropriate, and operate water trucks for stabilization of surfaces under windy conditions; and
- Prevent spillage when hauling material and operating non-earthmoving equipment and limit speeds to 15 miles per hour. Limit speed of earth-moving equipment to 10 mph.

Mobile and Stationary Source Controls:

- Plan construction scheduling to minimize vehicle trips;

- Limit idling of heavy equipment to less than 5 minutes and verify through unscheduled inspections;
- Maintain and tune engines per manufacturer's specifications to perform at EPA certification levels, prevent tampering, and conduct unscheduled inspections to ensure these measures are followed;
- Consider use of construction equipment meeting EPA's Tier 4 engine standards. However, lacking availability of such non-road construction equipment that meets these standards, we would suggest use of EPA-verified particulate traps, oxidation catalysts and other appropriate controls where suitable to reduce emissions of diesel particulate matter and other pollutants at the construction site; and
- Consider alternative fuels and energy sources such as natural gas and electricity (plug-in or battery).

Administrative controls:

- Prepare an inventory of all equipment prior to construction and identify the suitability of add-on emission controls for each piece of equipment before groundbreaking;
- Develop a construction traffic and parking management plan that maintains traffic flow and plan construction to minimize vehicle trips; and
- Identify sensitive receptors in the project area, such as children, elderly, and infirmed, and specify the means by which impacts to these populations will be minimized (e.g. locate construction equipment and staging zones away from sensitive receptors and building air intakes).

Appendix C – Draft Air Quality Technical Study; page 3

This section states "the USEPA also has classified Doña Ana and Otero counties in New Mexico (40 CFR 81.332) for criteria pollutants. A portion of Doña Ana County (Anthony, New Mexico) is designated as moderate non-attainment for PM10." This section primarily discusses counties that are designated nonattainment or maintenance of National Ambient Air Quality Standards (NAAQS) in 40 CFR 81.332), whereas Otero county is currently designated as "Unclassifiable/Attainment" for all NAAQS, and is not included in the Doña Ana County/Anthony Quadrangle PM_{10} "Nonattainment" designation.

Recommendation:

- Clarify the classification that is being referred to regarding Otero County.

ENERGY DEMAND AND GENERATION

Energy Supply; page 3-64

According to 2015 use estimates, both average energy and peak energy use are projected to double from 2010 usage. This estimate came from a bullet point contained in an August 2011 newsletter published by Fort Bliss. It is unclear what information the newsletter used to arrive at the 2015 energy use estimates.

Recommendation:

- Cite the information source or study used to calculate the 2015 energy estimates for Fort Bliss. Highlight the expected changes at fort Bliss that would cause energy use to double from 2010 - 2015.

SOCIOECONOMICS AND ENVIRONMENTAL JUSTICE

Alternative 3 – Water Reclamation Pipeline; page 3-126

The construction of a Water Reclamation Pipeline has the potential to raise major environmental justice issues. The DEIS makes conclusions regarding the potential impacts to low income or minority populations of Alternative 3, but does not provide analysis or information to support such a conclusion.

Alternative 4 – Waste to Energy Plant; page 3-128

The construction of a waste to energy (WTE) facility has the potential to raise major environmental justice issues. The proposed location of the WTE facility is adjacent to an identified Minority and Poverty Area (Figure 3-7). Some information is provided to support the conclusion regarding impacts to low income or minority communities; however, there is no relevant public health and industry data concerning the potential for exposure (direct, indirect, and cumulative) from WTE facility activities to human health or environmental hazards in the potentially affected populations.

The DEIS states that at least 100 fully loaded garbage trucks would be delivered daily for combustion to the WTE facility and another 30 trucks a day of ash would be leaving daily. The DEIS does not evaluate the potential for noise, odor, flies, debris and ash from truck traffic on minority or low income communities in proximity to the facility. The DEIS explains some economic benefits of Zero Net initiative, but does not describe whether the residents (particularly minority or poverty communities) adjacent or nearby would benefit from the project.

4.3.10 Socioeconomic and Environmental Justice Cumulative Impacts; page 4-33

The cumulative impacts chapter contains summary statements that are not supported with analysis, documentation, or information. For example, page 4-33 states "Since implementation of this alternative is not expected to have a disproportionately high and adverse human health or environmental effect on minority, low-income, or younger segments of the local population, it would not cause cumulative impacts for the purposes of environmental justice when considered with any other actions in the area".

Recommendation:

- The Army should provide a more detailed level of analysis, particularly for Alternatives 3 and 4, potential cumulative impacts, and potential direct impacts. The analysis should include:
  - historical environmental stressors on these communities,
  - health impacts of past, present or reasonably foreseeable future actions, and
  - environmental and health impacts of the alternatives on identified environmental justice communities.

GENERAL COMMENTS

Consultation with Tribes

No documentation was provided in the DEIS showing the Army sent letters to Tribes, or their responses. Also, the document indicates that Tribes were identified and contacted for the limited purpose of National Historic Preservation Act (NHPA) discussion, or other concerns of a limited scope. Due to the nature of the project, it appears it could affect tribal resources (including natural resources), citizens or government services.

Recommendation:

- Send the DEIS to the following Tribes: Tonkawa Tribe of Oklahoma, the Wichita and Affiliated Tribes of Oklahoma, Cheyenne/Arapaho Tribes, Apache Tribe of Oklahoma, Ponca Tribe of Oklahoma, and Jicarilla Apache Tribe (New Mexico). These Tribes practice religious ceremonies similar to the Tribes already identified in the DEIS and may have a historical or cultural connection to the El Paso/Ft Bliss ROI. Similarly, the Arizona State Historic Preservation Officer (SHPO) and the Arizona Apache Tribes, such as, the White Mountain and San Carlos Apache should be contacted.

- Identify all potentially affected tribes, resources and tribal communities, potentially applicable treaties, laws, policies, legal responsibilities and duties. Contact and, as appropriate, initiate consultation with Tribes concerning the potential effects of the alternatives. Provide an appendix that includes letters sent from the Army to Tribes for the purposes of NHPA and consultation under E.O. 13175, and the responses from Tribes.

Other Consultations

Due to potential impacts to air quality, water quality and quantity, threatened and endangered species, migratory birds, and cultural, historical, and archeological resources; consultation with applicable local, regional, state, tribal, and federal agencies or governments is required.

Recommendation:

- In a dedicated section of the Final EIS include all correspondence between the Army and all applicable local, regional, state, tribal, and federal agencies or governments.

Affected Environment and Environmental Consequences; page 3-1

All of the alternatives are in the planning stage of development and implementation, and many details about each alternative need to be identified and assessed before the impacts of the alternatives can be adequately evaluated.

Recommendation:

- EPA recommends that analysis for each of the alternatives be provided in the form of a supplemental environmental analysis or tiered off of this DEIS. This would allow proper evaluation of, and comment on, the alternatives before progressing to the Final EIS stage.

Potential Mitigation and Monitoring; page 5-1

The best management practices (BMP's) and mitigation proposed in the DEIS are vaguely described and phrased in ways that diminish the certainty of their implementation. Phrases, such as, "could be used", "potentially", and may be implemented" do not qualify as mitigation. Similarly, stating that BMP's will be used to lessen impacts; and then offering vague BMP's which are not linked to specific impacts is not mitigation.

Recommendation:

- The DEIS needs to definitively state what BMP's and mitigation measures will be implemented, and then relate those BMP's and mitigation measures to a potential impact.

From: Travis Ritchie
To: Magee, Melanie
Subject: Request for Extension to file El Paso Montana Power Station Comments
Date: Thursday, October 17, 2013 2:25:56 PM

Ms. Magee,
I'm writing to request a one-week extension until October 29, 2013 to file public comments on the draft PSD permit for El Paso Electric Company's Montana Power Station (PSD-TX-1290-GHG). Our expert consultants have run into a bit of trouble recovering some of the data that we intend to provide in our comments from some government websites. I believe that issue has been resolved on our side, but we are a bit behind in drafting our comments. I would appreciate any accommodation you could provide to extend the deadline.

Thank you in advance.
Travis Ritchie

ps - I am very glad that EPA is back up and running, and I understand that you are probably digging out from under a mountain of emails and delayed tasks. I hope the transition back to normal operations proceeds smoothly and quickly.

--
Travis Ritchie
Associate Attorney
Sierra Club Environmental Law Program
85 Second Street, 2nd Floor
San Francisco, CA 94105
415-977-5727
travis.ritchie@sierraclub.org

From:	Enrique Valdivia
To:	Magee, Melanie
Cc:	amy@savagejohnson.com; vcarbajal@trla.org
Subject:	Request for Public Meeting by Far East El Paso Citizens United
Date:	Tuesday, October 15, 2013 3:41:19 PM
Importance:	High

Dear Ms. Magee,

Texas Rio Grande Legal Aid (TRLA) represents Far East El Paso Citizens United and its members in the matter of El Paso Electric's proposed Montana Power Station. On behalf of Far East El Paso Citizens United we request that EPA hold a public meeting on the Prevention of Significant Deterioration (PSD) permit application for the El Paso Electric Company, Montana Power Station and EPA's proposed greenhouse gas permit for same. This proposed plant has drawn national as well as local attention (See http://www.nytimes.com/2013/04/05/us/in-texas-montana-vista-is-set-to-fight-power-plant.html). The issues we propose to raise at the hearing include the appropriateness of the selection of simple cycle turbines for this project as well as the project's BACT analysis, hours of operation, the number of start ups and shut downs, and the GHG permitting of four turbines.

Should you have any questions regarding this request please do not hesitate to contact me. My direct number is 210-212-3707.

Sincerely,

Enrique Valdivia

enrique valdivia
texas rio grande legal aid
1111 north main
san antonio, texas 78212

210-212-3700

From:	Rivera Ernestina (JuP1/CLP2)
To:	Magee, Melanie
Cc:	Rivera Ernestina (JuP1/CLP2)
Subject:	El Paso, Texas: El Paso Electric Power Plant
Date:	Monday, October 28, 2013 11:27:33 AM

To whom it may concern:

Please accept these comments as formal.

My name is Ernestina Rivera Villarreal. I have lived in East El Paso for 13 years now. I am writing to you to request your support to stop the building of the Power Plants in this area. I have two kids and are concerned about their health. The proven damages behind these Power Plants does exist and should not be taken lightly. El Paso Electric has the opportunity to build such facilities in many areas of El Paso that are not close to residential areas, but chose not to. Please support us in this movement. The contamination behind such facility is dangerous, why can't El Paso Electric build far away from residential areas.

Please support us.

Thank you

Ernestina Rivera Villarreal

From:	Sara Gossett
To:	Magee, Melanie
Subject:	No to power plant!
Date:	Saturday, October 26, 2013 3:30:22 PM

Dear Ms. Magee,

I am a resident of Homestead Meadows North, a community that will be directly effected by the Electric Company's proposed Power Station and Facility Complex to be located near Montana Avenue in El Paso, Texas.

This letter is to voice my opinion of the addition of four combustion turbines - NO! This is a bad idea! They will sit right next to 25 huge fuel tanks!

Sincerely,
Sara Svihla

Sent from my iPhone

From:	Sheri Gossett
To:	Magee, Melanie
Subject:	El Paso Electric Montana Power Station
Date:	Saturday, October 26, 2013 2:11:57 PM

I am opposed to the electric company considering a natural gas fueled power plant for several reasons. The amount of water needed to operate such a plant is outrageous considering it is in the middle of the desert where water is such a precious resource. The high evaporation rate in this area only compounds the problem. West Nile virus or the pesticides needed to avoid the virus is also a concern. El Paso is so much more conducive to wind and especially solar power.

I am also opposed to the location of the power plant in an established neighborhood with thousands of homes, hundreds of businesses, and a dozen public schools within a ten mile radius. The proposed site is directly adjacent to a fuel storage tank field that threatens the safety of nearby residents. If an accident happens at the plant or with the transmission lines it could be disastrous to the community.

The EPA was established to monitor environmental injustices. In your review you take into consideration the effect of air quality on endangered species and historical sites. Not much was noted about human life. The vast majority of the people in the community are economically and educationally disadvantaged and do not have the resources to relocate. I believe they were taken advantage of. Who will protect the people, if not the EPA?

Many of the people there moved to the county for relief from the city's pollution as they have asthma and other respiratory ailments. El Paso is known for it's fragile air quality with it's proximity to Juarez, that has no regulations, and the major interstate that runs through town carrying people east and west. The environment's natural tendency for air conversions that traps the pollution in the lower elevations makes the problem worse. I am sure that the numbers in the Electric Company's application meet the acceptable standard for emissions. But does it take into account that it will be adding to what is already there?

There are alternatives to a natural gas fueled power plant. There are alternative locations for a new electric generation station. I am not a researcher, an engineer, a scientist, or an expert in this field. I am just a woman who has lived there for over 30 years, raised her children there, and like many others, have enjoyed the beauty of the desert. We cherish the wildlife, the peace and quiet, the immense night sky, and the clean fresh air. We are relying on a federal agency to take everything into consideration and to do what's best.

Thank you,
Sheri Gossett

From:	Shirley Moreno
To:	Magee, Melanie
Subject:	Montana Power Station
Date:	Tuesday, December 03, 2013 12:06:47 PM

El Paso Electric has not justified the need for an additional power plant. Fort Bliss is going to Net Zero generation of electricity. Fort Bliss will generate it's own energy. This means that their need for electricity for El Paso Electric will be reduced. Population growth will not justify the need for an additional power plant.

My family has resided in the Haciendas Del Norte Estates Edition, which is located off of Flager (east of proposed site) for over 20 years. We selected this area because of its proximity to nothing, which translates into CLEAN AIR AND NO NOISE POLLUTION. We could have selected any other area but chose this one. My family's health was the first reason we chose this area, with some family health issues this area of clean air was the best thing for us. Aside from that we also kept into prospective the raising of our children, this area is less traveled. I intend to stay in this location at this point, however should I decide to sell I am very concerned with the loss of property value based on a power plant in our area. I also look into the second generation, my grandchildren, I want to ensure that they too will have a CLEAN area to grow in, as well as a quite area. I do not feel that it is fair that I take all this into consideration years ago and now a power plant can just pop in. They too could have anticipated where they thought they would have needed to place a power plant years ago just like all of us did. My health and the health of my family are of extreme importance. I would think that the electric company would have thought this process out years ago, maybe now they need to look into an area further east that is not populated or place the power plant where the need is, south of Montana Street.

Thank you for your time.

Shirley Moreno
[redacted]

From:	Travis Ritchie
To:	Magee, Melanie
Cc:	Tomasovic, Brian; Derek Nelson
Subject:	Sierra Club Comments re Montana Power Station - PSD-TX-1290-GHG (Email 1 of 2)
Date:	Wednesday, December 04, 2013 9:32:50 PM
Attachments:	Ex. 1 GE Spec for LMS 100.pdf Ex. 2 SGT6-5000F Application Overview.pdf Ex. 3 Fast-Cycling Towards Bigger Profits.pdf Ex. 4 Gas Turbine Combined Cycle Fast Start - The Physics Behind the Concept.pdf Ex. 5 October 18, 2013 Letter from Rich Batey to Travis Ritchie.pdf Ex. 6 2013 GTW Handbook Price List (Excerpt).pdf Ex. 7 NRG's California El Segundo Natgas Power Plant Enters Service.pdf Ex. 8 Salem Plant Press Release.pdf Sierra Club Comments on Montana Power Station 12-4-13.pdf

Ms. Magee,
Please find attached Sierra Club's Comments on the proposed Montana Power Station, Permit No. PSD-TX-1290-GHG, and Sierra Club Exhibits 1-16. Due to file size, Sierra Club is submitting these comments in two emails. We are also providing a courtesy hard copy of the comments and exhibits.

Sierra Club is submitting these comments today in accordance with the deadline to provide public comments. However, Sierra Club requests that you withhold publicly posting these comments for the time being while Sierra Club continues to review issues related to this facility.

Please let me know if you have any trouble receiving the comments and attached exhibits.
Thank you.
Travis Ritchie

--
Travis Ritchie
Associate Attorney
Sierra Club Environmental Law Program
85 Second Street, 2nd Floor
San Francisco, CA 94105
415-977-5727
travis.ritchie@sierraclub.org

Exhibit 1

GE Spec for LMS 100

GE Energy

New High Efficiency Simple Cycle Gas Turbine – GE's LMS100™

imagination at work

Authored by:
Michael J. Reale
LMS100™ Platform Manager

GER-4222A (06/04)

New High Efficiency Simple Cycle Gas Turbine – GE's LMS100™

Contents:

New High Efficiency Simple Cycle Gas Turbine – GE's LMS100™

Abstract

GE has introduced the first modern production gas turbine in the power generation industry to employ off-engine intercooling technology with the use of an external heat exchanger, the LMS100™. This gas turbine provides the highest simple cycle efficiency in the Industry today and comes on the heels of GE's introduction of the highest combined cycle gas turbine system, the MS9001H. The LMS100™ system combines frame and aeroderivative gas turbine technology for gas fired power generation. This marriage provides customers with cyclic capability without maintenance impact, high simple cycle efficiency, fast starts, high availability and reliability, at low installed cost. The unique feature of this system is the use of intercooling within the compression section of the gas turbine, leveraging technology that has been used extensively in the gas and air compressor industry. Application of this technology to gas turbines has been evaluated by GE and others extensively over many years although it has never been commercialized for large power generation applications. In the past five years, GE has successfully used the SPRINT® patented spray intercooling, evaporative cooling technology between the low and high pressure compressors of the LM6000™ gas turbine, the most popular aeroderivative gas turbine in the 40 to 50MW range. GE's development of high pressure ratio aircraft gas turbines, like the GE90®, has provided the needed technology to take intercooling to production. The LMS100™ gas turbine intercooling technology provides outputs above 100MW, reaching simple cycle thermal efficiencies in excess of 46%. This represents a 10% increase over GE's most efficient simple cycle gas turbine available today, the LM6000™.

Introduction

GE chose the intercooled cycle to meet customers' need for high simple cycle efficiency. The approach to developing an intercooled gas turbine is the result of years of intercooled cycle evaluation along with knowledge developed with operation of SPRINT® technology. Matching current technology with customer requirements results in a system approach to achieving a significant improvement in simple cycle efficiency.

The development program requirement was to use existing and proven technology from both GE Transportation (formerly GE Aircraft Engines) and GE Energy (formerly GE Power Systems), and combine them into a system that provides superior simple cycle performance at competitive installed cost. All component designs and materials, including the intercooler system, have been successfully operated in similar or more severe applications. The combination of these components and systems for a production gas turbine is new in the power generation industry.

The GE Transportation CF6-80C2/80E gas turbine provided the best platform from which to develop this new product. With over 100 million hours of operating experience in both aircraft engines and industrial applications, through the LM6000™ gas turbine, the CF6® gas turbine fits the targeted size class. The intercooling process allowed for a significant increase in mass flow compared to the current LM™ product capability. Therefore, GE Energy frame units were investigated for potential Low Pressure Compressors (LPC) due to their higher mass flow designs. The MS6001FA (6FA) gas turbine compressor operates at 460 lbm/sec (209 kg/sec) and provides the best match with the CF6-80C2 High Pressure Compressor (HPC) to meet the cycle needs.

The LMS100™ system includes a 3-spool gas turbine that uses an intercooler between the LPC and the HPC as shown in Fig. 1.

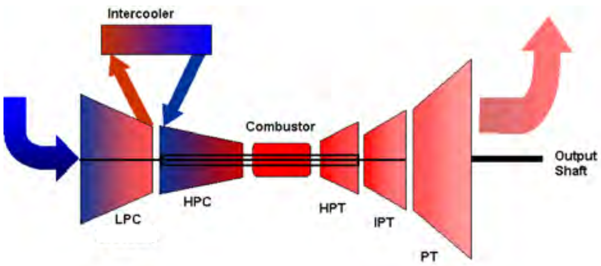


Fig. 1. LMS100™ GT Configuration

Intercooling provides significant benefits to the Brayton cycle by reducing the work of compression for the HPC, which allows for higher pressure ratios, thus increasing overall efficiency. The cycle pressure ratio is 42:1. The reduced inlet temperature for the HPC allows increased mass flow resulting in higher specific power. The lower resultant compressor discharge temperature provides colder cooling air to the turbines, which in turn allows increased firing temperatures at metal temperatures equivalent to the LM6000™ gas turbine producing increased efficiency. The LMS100™ system is a 2550°F (1380°C) firing temperature class design.

This product is particularly attractive for the peaking and mid-range dispatch applications where cyclic operation is required and efficiency becomes more important with increasing dispatch. With an aeroderivative core the LMS100™ system will operate in cyclic duty without maintenance impact. The extraordinary efficiency also provides unique capability for cogeneration applications due to the very high power-to-thermal energy ratio. Simple cycle baseload applications will benefit from the high efficiency, high availability, maintainability and low first cost.

GE, together with its program participants Avio, S.p.A., Volvo Aero Corporation and Sumitomo Corporation, are creating a product that changes the game in power generation.

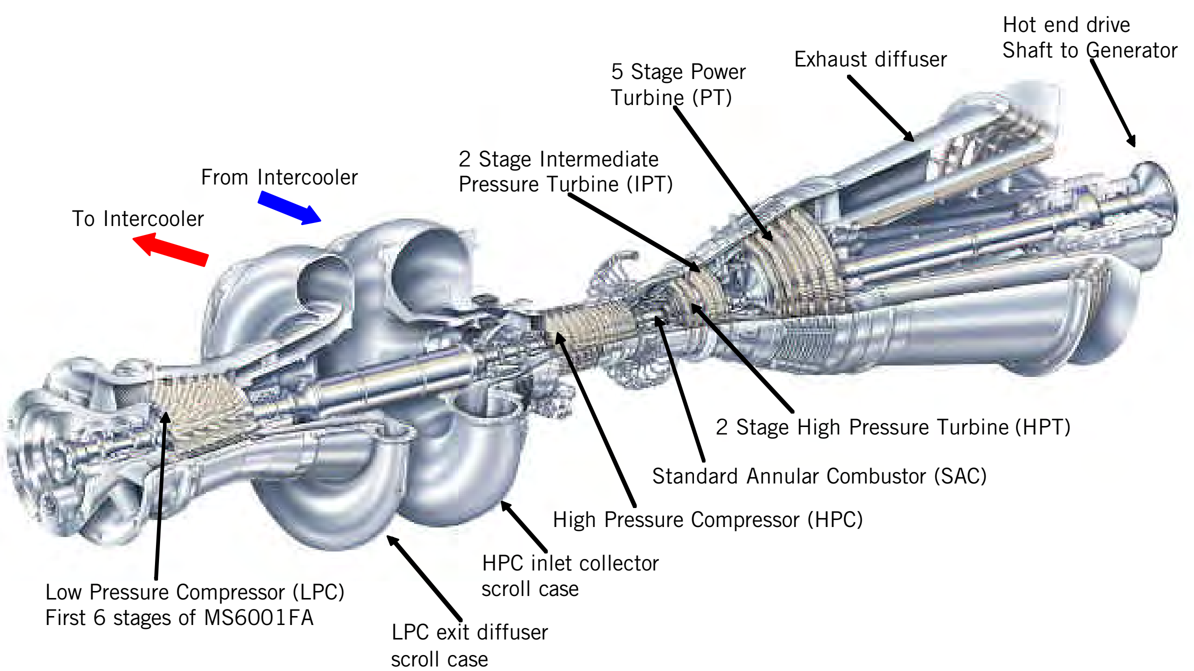


Fig. 2. LMS100™ Gas Turbine

Gas Turbine Design

The LMS100™ system combines the GE Energy FA compressor technology with GE Transportation CF6®/LM6000™ technology providing the best of both worlds to power generation customers. Fig. 2 shows the gas turbine architecture.

The LPC, which comprises the first 6 stages of the 6FA, pumps 460 lb/sec (209 kg/sec) of airflow (1.7 X the LM6000™ airflow). This flow rate matched the capability of the core engine in the intercooled cycle, making it an ideal choice. The LMS100™ system LPC operates at the same design speed as the 6FA, thereby reducing development requirements and risk. The compressor discharges through an exit guide vane and diffuser into an aerodynamically designed scroll case. The scroll case is designed to minimize pressure losses and has been validated through 1/6 scale model testing. Air leaving the scroll case is delivered to the intercooler through stainless steel piping.

Air exiting the intercooler is directed to the HPC inlet scroll case. Like the LPC exit scroll case, the HPC inlet collector scroll case is aerodynamically designed for low pressure loss. This scroll case is mechanically isolated from the HPC by an expansion bellows to eliminate loading on the case from thermal growth of the core engine.

The HPC discharges into the combustor at ~250°F (140°C) lower than the LM6000™ aeroderivative gas turbine. The combination of lower inlet temperature and less work per unit of mass flow results in a higher pressure ratio and lower discharge temperature, providing significant margin for existing material limits. The HPC airfoils and casing have been strengthened for this high pressure condition.

The combustor system will be available in two configurations: the Single Annular Combustor (SAC) is an aircraft style single dome system with water or steam injection for NOx control to 25 ppm; and the Dry Low Emissions-2 (DLE2) configuration, which is a multi-dome lean premixed design, operating dry to 25 ppm NOx and CO. The DLE2 is a new design based on the proven LM™ DLE combustor technology and the latest GE Transportation low emissions technology derived from the GE90® and CFM56® gas turbines. GE Global Research Center (GRC) is supporting the development program by providing technical expertise and conducting rig testing for the DLE2 combustor system.

The HPT module contains the latest airfoil, rotor, cooling design and materials from the CF6-80C2 and -80E aircraft engines. This design provides increased cooling flow to the critical areas of the HPT, which, in conjunction with the lower cooling flow temperatures, provides increased firing temperature capability.

The IPT drives the LPC through a mid-shaft and flexible coupling. The mid-shaft is the same design as the CF6-80C2/LM6000™. The flexible coupling is the same design used on the LM2500™ marine gas turbine on the U.S. Navy DDG-51 Destroyers. The IPT rotor and stator components are being designed, manufactured and assembled by Avio, S.p.A. as a program participant in the development of the LMS100™ system. Volvo Aero Corporation as a program participant manufactures the Intermediate Turbine Mid-Frame (TMF) and also assembles the liners, bearings and seals.

The IPT rotor/stator assembly and mid-shaft are assembled to the core engine to create the 'Supercore.' This Supercore assembly can be replaced in the field within a 24-hour period.

Lease pool Supercores will be available allowing continued operation during overhaul periods or unscheduled events.

The Power Turbine (PT) is a 5-stage design based on the LM6000™ and CF6-80C2 designs. Avio, S.p.A. is designing the PT for GE Transportation and manufacturing many of the components. Volvo Aero Corporation is designing and manufacturing the PT case. The Turbine Rear Frame (TRF) that supports the PT rotor/stator assembly and the Power Turbine Shaft Assembly (PTSA) is based on GE Energy's frame technology. The PTSA consists of a rotor and hydrodynamic tilt-pad bearings, including a thrust bearing. This system was designed by GE Energy based on extensive frame gas turbine experience. The PT rotor/stator assembly is connected to the PTSA forming a free PT (aerodynamically coupled to the Supercore), which is connected to the generator via a flexible coupling.

The diffuser and exhaust collector combination was a collaborative design effort with the aero design provided by GE Transportation and the mechanical design provided by GE Energy. GE Transportation's experience with marine modules and GE Energy's experience with E and F technology diffuser/collector designs were incorporated.

Intercooler System Design

The intercooler system consists of a heat exchanger, piping, bellows expansion joints, moisture separator and variable bleed valve (VBV) system. All process air wetted components are made of stainless steel. The LMS100™ system will be offered with two types of intercooling systems, a wet system that uses an evaporative cooling tower and a dry system (no water required).

The wet system uses an air-to-water heat exchanger of the tube and shell design, as shown in Fig. 3.

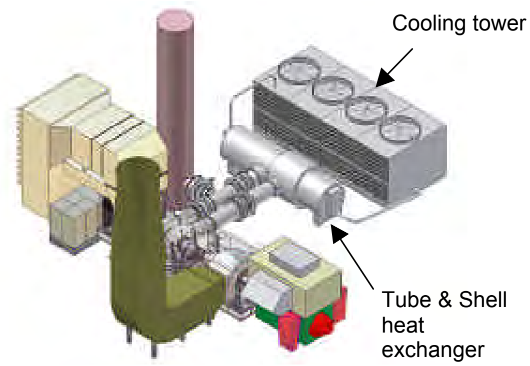


Fig. 3. LMS100™ Wet Intercooler System

The tube and shell heat exchanger is used extensively throughout the compressed air and oil & gas industries, among others. The design conditions are well within industry standards of similar-sized heat exchangers with significant industrial operating experience. This design is in general conformance with API 660 and TEMA C requirements.

The intercooler lies horizontal on supports at grade level, making maintenance very easy. Applications that have rivers, lakes or the ocean nearby can take advantage of the available cooling water. This design provides plant layout flexibility. In multi-unit sites a series of evaporative cooling towers can be constructed together, away from the GT, if desirable, to optimize the plant design.

An optional configuration using closed loop secondary cooling to a finned tube heat exchanger (replacing the evaporative cooling towers) will also be available (See Fig. 4). This design uses the same primary heat exchanger (tube and shell), piping, bellows expansion joints and VBV system, providing commonality across product configurations. The secondary cooling system can be water or glycol. This system is beneficial in cold and temperate climates or where water is scarce or expensive.

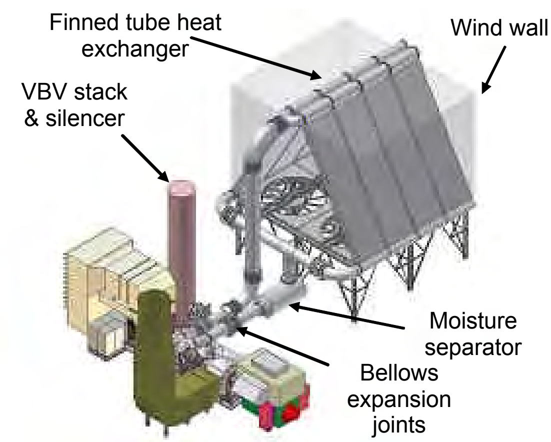


Fig. 4. LMS100™ Dry Intercooler System with Air-to-Air Heat Exchanger

An alternate dry intercooler system is being developed for future applications, and uses an air-to-air heat exchanger constructed with panels of finned tubes connected to a header manifold. This design is the same as that used with typical air-cooled systems in the industry. The main difference is mounting these panels in an A-frame configuration. This configuration is typically used with steam condensers and provides space advantages together with improved condensate drainage. The material selection, design and construction of this system are in general conformance with American Petroleum Institute (API) Standard 661 and are proven through millions of hours of operation in similar conditions.

The air-to-air system has advantages in cold weather operation since it does not require water and therefore winterization. Maintenance requirements are very low since this system has very few moving parts. In fact, below 40°F (4°C) the fans are not required, thereby eliminating the parasitic loss. In high ambient climates the performance of the air-to-air system can be enhanced with an evaporative cooling system integrated with the heat exchanger. This provides equivalent performance to the air-to-water system. Water usage will be low and intermittent since it would only be used during the peak temperature periods, resulting in a very low yearly consumption.

Package Design

The gas turbine is assembled inside a structural enclosure, which provides protection from the environment while also reducing noise (see Fig. 5). Many customer-sensing sessions were held to determine the package design requirements, which resulted in a design that has easy access for maintenance, quick replacement of the Supercore, high reliability and low installation time. Package design lessons learned from the highly successful LM6000™ gas turbine and GE's experiences with the 9H installation at Baglan Bay have been incorporated into the LMS100™ system package design. The complete GT driver package can be shipped by truck. This design significantly reduces installation time and increases reliability.

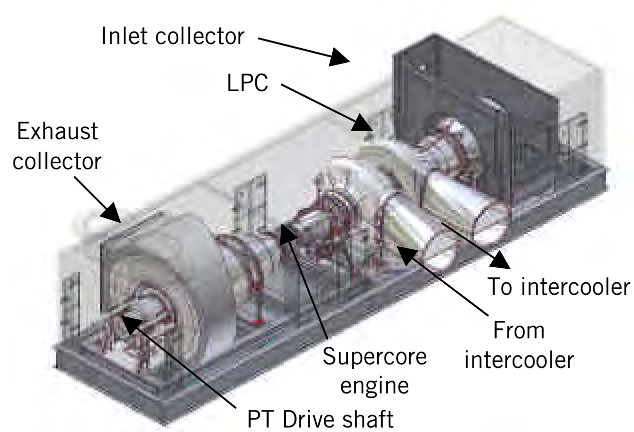


Fig. 5. LMS100™ System GT Driver Package

The auxiliary systems are mounted on a single skid in front of the GT driver package. This skid is pre-assembled and factory tested prior to shipment. The auxiliary skid connects with the base plate through short, flexible connectors. This design improves reliability and reduces interconnects and site installation cost (see Fig. 6).

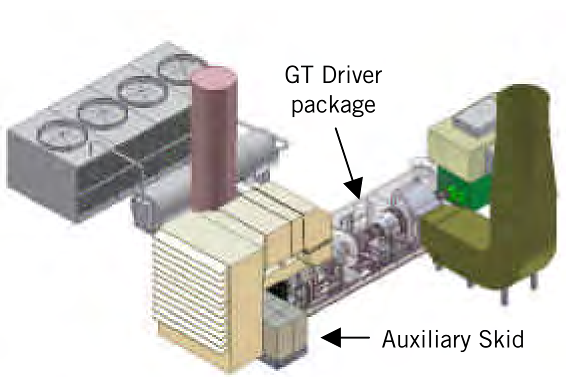


Fig. 6. LMS100™ System Auxiliary Skid Location

The control system design is a collaboration of GE Transportation and GE Energy. It employs triple processors that can be replaced on-line with redundant instrumentations and sensors. The use of GE Transportation's synthetic modeling will provide a third level of redundancy based on the successful Full Authority Digital Electronic Control (FADEC) design used in flight engines. The control system is GE Energy's new Mark VI, which will be first deployed on the LM6000™ gas turbine in late 2004 (ahead of the LMS100™ system).

The inlet system is the MS6001FA design with minor modifications to adjust for the elimination of the front-mounted generator and ventilation requirements.

The exhaust systems and intercooler systems are designed for right- or left-handed installation.

Reliability and Maintainability

The LMS100™ system is designed for high reliability and leverages LM™ and GE Energy frame technology and experience, along with GE Transportation technology. The use of Six Sigma processes and methods, and Failure Modes and Effects Analysis (FMEA) for all systems identified areas requiring redundancy or technology improvements. The LMS100™ system will consist of a single package and control system design from GE Energy, greatly enhancing reliability through commonality and simplicity.

The control system employs remote I/O (Input/Output) with the use of fiber optics for signal transmission between the package and control system. These connections are typically installed during site construction and have in the past been the source of many shutdowns due to Electro Magnetic Interference (EMI). The LMS100™ design reduces the number of these signal interconnects by 90% and eliminates EMI concerns with the use of fiber optic cables. In addition, the auxiliary skid design and location reduce the mechanical interconnects by 25%, further improving reliability. The use of an integrated system approach based on the latest reliability technology of the GE Transportation flight engine and GE Energy Frame GT will drive the Mean Time Between Forced Outages (MTBFO) of the LMS100™ system up to the best frame gas turbine rate.

The LMS100™ system has the same maintenance philosophy as aeroderivative gas turbines – modular design for field replacement. Design maintenance intervals are the same as the LM6000™ – 25,000 hours hot section repair and 50,000 hours overhaul intervals.

The LPC requires very little maintenance with only periodic borescope inspections at the same time as the core engine. No other significant maintenance is required.

The Supercore requires combustor, HPT airfoils and IPT airfoils inspection and on-condition repair or replacement at 25,000 hours. This can be accomplished on-site within a 4-day period. The package is designed for 24-hour removal and replacement of the Supercore. Rotable modules for the combustor, HPT and IPT will be used to replace existing hardware. The Supercore and PT rotor/stator module will be returned to the Depot for the 50,000-hour overhaul. During this period a leased Supercore and PT rotor/stator module will be available to continue revenue operation. The LMS100™ core is compatible with existing LM6000™ Depot capabilities.

The PT rotor/stator assembly only requires on-condition maintenance action at 50,000 hours. This module can be removed after the Supercore is removed and replaced with a new module or a leased module during this period.

The PT shaft assembly, like the LPC, needs periodic inspection only.

Configurations

The LMS100™ system is available as a Gas Turbine Generator set (GTG), which includes the complete intercooler system. An LMS100™ Simple Cycle power plant will also be offered. GTGs will be offered with several choices of combustor configurations as shown in Table 1.

The GTG is available for 50 and 60 Hz applications and does not require the use of a gearbox.

Air-to-air or air-to-water intercooler systems are available with any of the configurations to best match the site conditions.

Product Offering	Fuel Type	Diluent	NOx Level	Power Augmentation
LMS100PA-SAC (50 or 60 Hz)	Gas or Dual	Water	25	None
LMS100PA-SAC (50 or 60 Hz)	Gas	Steam	25	None
LMS100PA-SAC STIG (50 or 60 Hz)	Gas	Steam	25	Steam
LMS100PB-DLE2 (50 or 60 Hz)	Gas	None	25	None

Table 1. LMS100™ System Product Configurations

Optional kits will be made available for cold weather applications and power augmentation for hot ambient when using the air-to-air intercooler system.

All 50 Hz units will meet the requirements of applicable European directives (e.g. ATEX, PEDS, etc.).

The generator is available in an air-cooled or TWAC configuration and is dual rated (50 and 60 Hz). Sumitomo Corporation is a program participant in development of the LMS100™ system and will be supplying a portion of the production generators. Brush or others will supply generators not supplied by Sumitomo.

The GTG will be rated for 85-dBA average at 3 feet (1 meter). An option for 80-dBA average at 3 feet (1 meter) will be available.

Performance

The LMS100™ system cycle incorporates an intercooled compressor system. LPC discharge air is cooled prior to entering the HPC. This raises the specific work of the cycle from 150(kW/pps) to 210+(kW/pps). The LMS100™ system represents a significant shift in current power generation gas turbine technology (see Fig. 7 – data from Ref. 1).

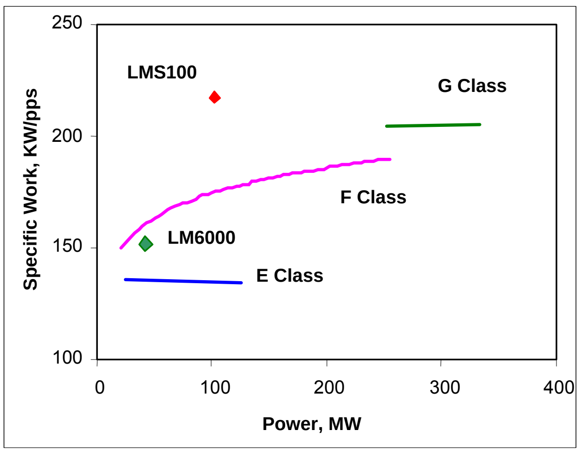


Fig. 7. LMS100™ System Specific Work vs. Other Technology

As the specific work increases for a given power the gas turbine can produce this power in a smaller turbine. This increase in technical capability leads to reduced cost. The LMS100™ system changes the game by shifting the technology curve to provide higher efficiency and power in a smaller gas turbine for its class (i.e. relative firing temperature level).

The cycle design was based on matching the existing GE Transportation CF6-80C2 compressor with available GE Energy compressor designs. The firing temperature was increased to the point allowed by the cooled high pressure air to maintain the same maximum metal temperatures as the LM6000™ gas turbine. The result is a design compression ratio of 42:1 and a firing temperature class of 2550°F (1380°C) that produces greater than 46% simple cycle gas turbine shaft efficiency. This represents a 10% increase over GE's highest efficiency gas turbine available in the Industry today – the LM6000™ gas turbine @42% (see Fig. 8 – data from Ref. 1).

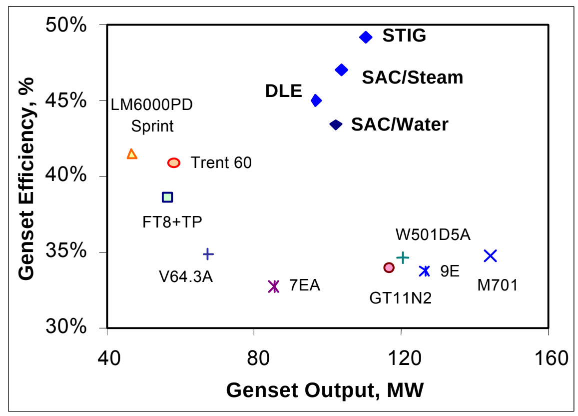


Fig. 8. LMS100™ System Competitive Positions

Intercooling provides unique attributes to the cycle. The ability to control the HPC inlet temperature to a desired temperature regardless of ambient temperatures provides operational flexibility and improved performance. The LMS100™ system with the SAC combustion system maintains a high power level up to an ambient temperature of ~80°F (27°C) (see Fig. 9). The lapse rate (rate of power reduction vs. ambient temperature) from 59°F (15°C) to 90°F (32°C) is only 2%, which is significantly less than a typical aeroderivative (~22%) or frame gas turbine (~12%).

The LMS100™ system has been designed for 50 and 60 Hz operations without the need for a speed reduction gearbox. This is achieved by providing a different PT Stage 1 nozzle for each speed that is mounted between the Supercore and PT. The PT design point is optimized to provide the best performance at both 3000 and 3600 rpm operating speeds. Fig. 9 shows that there is a very small difference in performance between the two operating speeds.

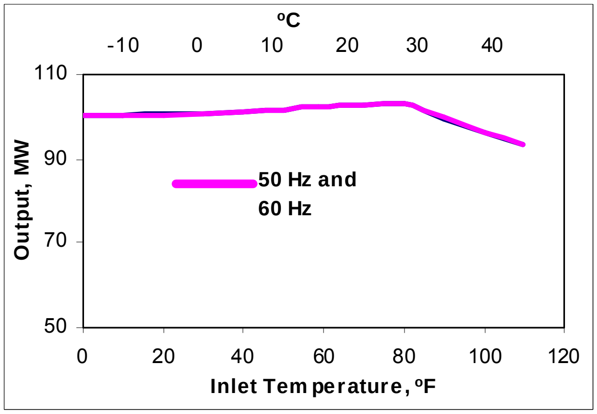


Fig. 9. LMS100™ System SAC Performance

Most countries today have increased their focus on environmental impact of new power plants and desire low emissions. Even with the high firing temperatures and pressures, the LMS100™ system is capable of 25ppm NOx at 15% O_2 dry. Table 1 shows the emission levels for each configuration. The 25 ppm NOx emissions from an LMS100™ system represent a 30% reduction in pounds of NOx/kWh relative to LM6000™ levels. The high cycle efficiency results in low exhaust temperatures and the ability to use lower temperature SCRs (Selective Catalytic Reduction).

Another unique characteristic of the LMS100™ system is the ability to achieve high part-power efficiency. Fig. 10 shows the part-power efficiency versus load. It should be noted that at 50% load the LMS100™ system heat rate (~40% efficiency) is better than most gas turbines at baseload. Also, the 59ºF (15ºC) and 90ºF (32ºC) curves are identical.

The LMS100™ system will be available in a STIG (steam injection for power augmentation) configuration providing significant efficiency improvements and power augmentation. Figs. 11 and 12 show the power output at the generator terminals and heat rate, respectively.

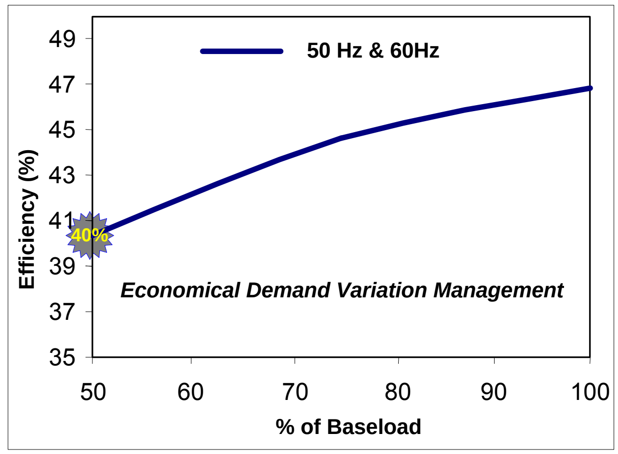


Fig. 10. LMS100™ System Part-Power Efficiency

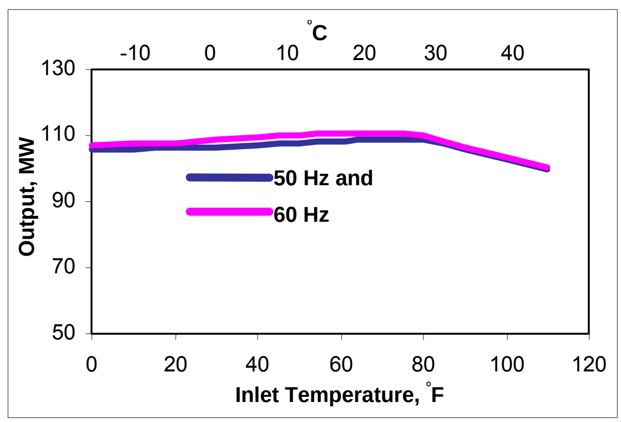


Fig. 11. LMS100™ System STIG Electric Power vs $T_{ambient}$

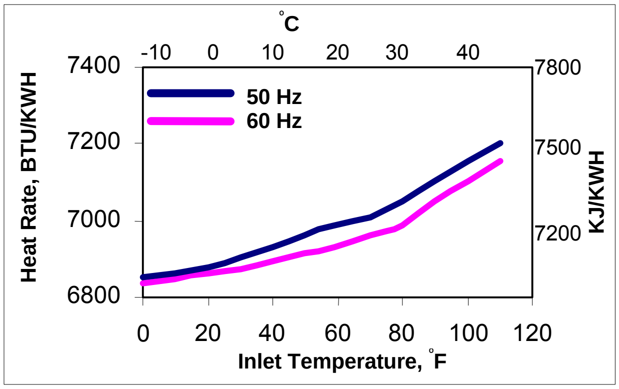


Fig. 12. LMS100™ System STIG Heat Rate (LHV) vs $T_{ambient}$

The use of STIG can be varied from full STIG to steam injection for NOx reduction only. The later allows steam production for process if needed. Fig. 13 – data from Ref. 1, compares the electrical power and steam production (@ 165 psi/365°F, 11.3 bar/185°C) of different technologies with the LMS100™ system variable STIG performance.

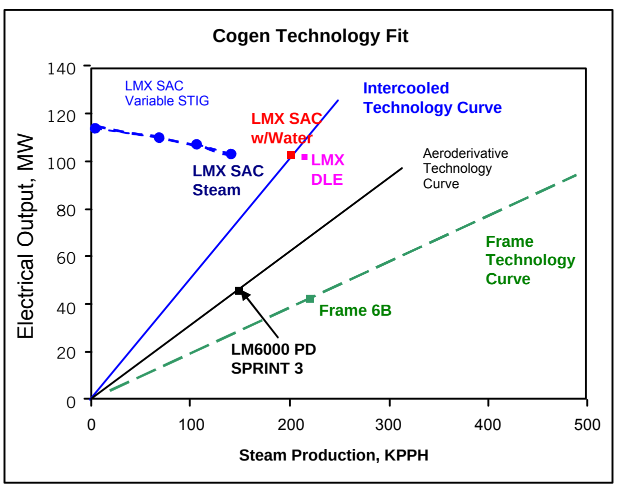


Fig. 13. LMS100™ System Variable STIG for Cogen

A unique characteristic of the LMS100™ system is that at >2X the power of the LM6000™ gas turbine it provides approximately the same steam flow. This steam-to-process can be varied to match heating or cooling needs for winter or summer, respectively. During the peak season, when power is needed and electricity prices are high, the steam can be injected into the gas turbine to efficiently produce additional power. During other periods the steam can be used for process. This characteristic provides flexibility to the customer and economic operation under varying conditions.

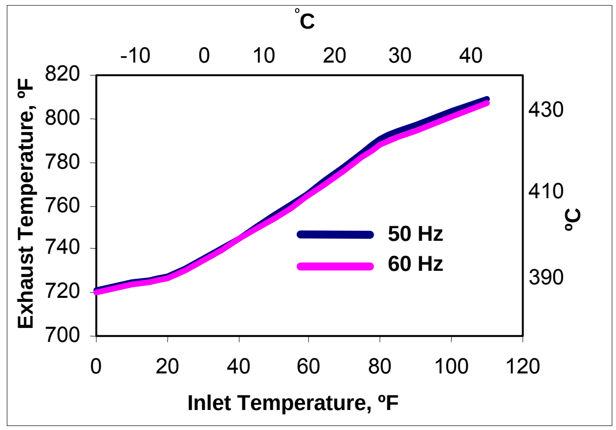


Fig. 14. LMS100™ System Exhaust Temperatures

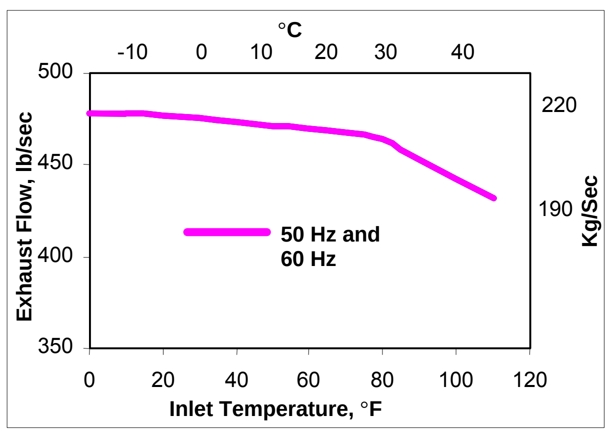


Fig. 15. LMS100™ System Exhaust Flow

The LMS100™ system cycle results in low exhaust temperature due to the high efficiency (see Figs. 14 and 15). Good combined cycle efficiency can be achieved with a much smaller steam plant than other gas turbines.

Table 2 shows a summary of the LMS100™ system configurations and their performance. The product flexibility provides the customer with multiple configurations to match their needs while at the same time delivering outstanding performance.

	Power (Mwe) 60 HZ	Heat Rate (BTU/KWh) 60 Hz	Power (Mwe) 50 HZ	Heat Rate (KJ/KWh) 50 Hz
DLE	98.7	7509	99.0	7921
SAC w/Water	102.6	7813	102.5	8247
SAC w/Steam	104.5	7167	102.2	7603
STIG	112.2	6845	110.8	7263

Table 2. LMS100™ System Generator Terminal Performance

(ISO 59ºF/15ºC, 60% RH, zero losses, sea level)

Simple Cycle

The LMS100™ system was primarily designed for simple cycle mid-range dispatch. However, due to its high specific work, it has low installed cost, and with no cyclic impact on maintenance cost, it is also competitive in peaking applications. In the 100 to 160MW peaking power range, the LMS100™ system provides the lowest cost-of-electricity (COE). Fig. 16 shows the range of dispatch and power demand over which the LMS100™ system serves as an economical product choice. This evaluation was based on COE analysis at $5.00/MMBTU (HHV).

The LMS100™ will be available in a DLE configuration. This configuration with a dry intercooler system will provide an environmental simple cycle power plant combining high efficiency, low mass emissions rate and without the usage of water.

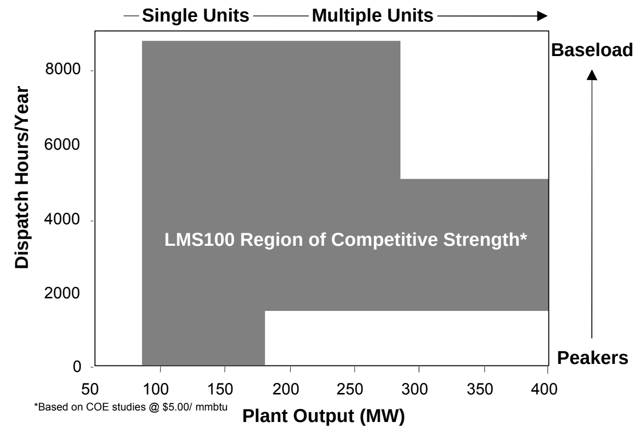


Fig. 16. LMS100™ System Competitive Regions

In simple cycle applications all frame and aeroderivative gas turbines require tempering fans in the exhaust to bring the exhaust temperature within the SCR material capability. The exhaust temperature (shown in Fig. 14) of the LMS100™ system is low enough to eliminate the requirement for tempering fans and allows use of lower cost SCRs.

Many peaking units are operated in hot ambient conditions to help meet the power demand when air conditioning use is at its maximum. High ambient temperatures usually mean lower power for gas turbines. Customers tend to evaluate gas turbines at 90ºF (32ºC) for these applications. Typically, inlet chilling is employed on aeroderivatives or evaporative cooling for heavy duty and aeroderivative engines to reduce the inlet temperature and increase power. This adds fixed cost to the power plant along with the variable cost adder for water usage. The power versus temperature profile for the LMS100™ system in

Fig. 9 shows power to be increasing to 80°F (27°C) and shows a lower lapse rate beyond that point versus other gas turbines. This eliminates the need for inlet chilling thereby reducing the product cost and parasitic losses. Evaporative cooling can be used above this point for additional power gain.

Simple cycle gas turbines, especially aeroderivatives, are typically used to support the grid by providing quick start (10 minutes to full power) and load following capability. The LMS100™ system is the only gas turbine in its size class with both of these capabilities. High part-power efficiency, as shown in Fig. 10, enhances load following by improving LMS100™ system operating economics.

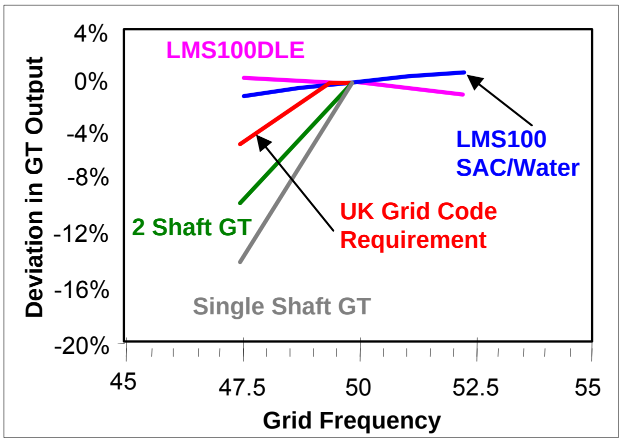


Fig. 17. LMS100™ System Gas Turbine Grid Frequency Variations

Many countries require off-frequency operation without significant power loss in order to support the grid system. The United Kingdom grid code permits no reduction in power for 1% reduction in grid frequency (49.5 Hz) and 5% reduction in power for an additional 5% reduction in grid frequency (47 Hz). Fig. 17 shows the impact of grid frequency variation on 3 different gas turbines: a single shaft, a 2-shaft and the LMS100™ system. Typically, a single and 2-shaft engine will need to derate power in order to meet the UK code requirements.

The LMS100™ system can operate with very little power variation for up to 5% grid frequency variation. This product is uniquely capable of supporting the grid in times of high demand and load fluctuations.

Combined Heat and Power

Combined Heat and Power (CHP) applications commonly use gas turbines. The exhaust energy is used to make steam for manufacturing processes and absorption chilling for air conditioning, among others. The LMS100™ system provides a unique characteristic for CHP applications. As shown in Fig. 13, the higher power-to-steam ratio can meet the demands served by 40-50MW aeroderivative and frame gas turbines and provide more than twice the power. From the opposite view, at 100MW the LMS100™ system can provide a lower amount of steam without suffering the significant efficiency reduction seen with similar size gas turbines at this steam flow. This characteristic creates opportunities for economical operation in conjunction with lower steam demand.

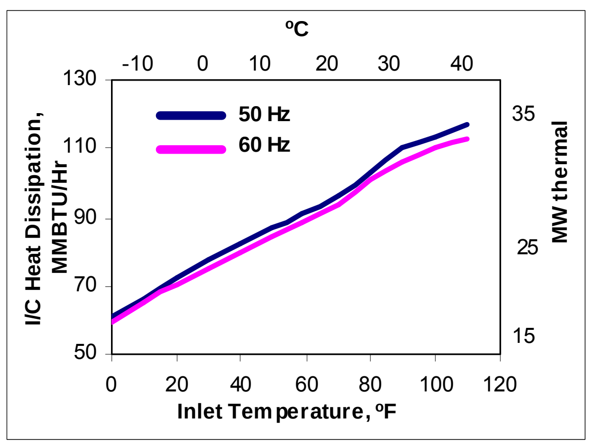


Fig. 18. LMS100™ System Intercooler Heat Rejections

Fig. 18 shows the intercooler heat dissipation, which ranges from 20-30MW of thermal energy. With an air-to-water intercooler system, the energy can be captured for low-grade steam or other applications, significantly raising the plant efficiency level. Using exhaust and intercooler energy, an LMS100™ plant will have >85% thermal efficiency.

Combined Cycle

Even though the LMS100™ system was aimed at the mid-range dispatch segment, it is also attractive in the combined cycle segment. Frame gas turbines tend to have high combined cycle efficiency due to their high exhaust temperatures. In the 80-160MW class, combined cycle efficiencies range from 51–54%. The LMS100™ system produces 120MW at 53.8% efficiency in combined cycle.

A combined cycle plant based on a frame type gas turbine produces 60-70% of the total plant power from the gas turbine and 30-40% from the steam turbine. In combined cycle the LMS100™ system produces 85-90% of the total plant power from the gas turbine and 10-15% from the steam turbine. This results in a lower installed cost for the steam plant.

The lower exhaust temperature of the LMS100™ system also allows significantly more power from exhaust system duct firing for peaking applications. Typical frame gas turbines exhaust at 1000°F-1150°F (538°C-621°C) which leaves 300°F-350°F (149°C-177°C) for duct firing. With the LMS100™ exhaust temperatures at <825°F (440°C) and duct-firing capability to 1450°F (788°C) (material limit) an additional 30MW can be produced.

Core Test

The LMS100™ core engine will test in GE Transportation's high altitude test cell in June 2004. This facility provides the required mass flow at >35 psi (>2 bar) approaching the core inlet conditions. The compressor and turbine rotor and airfoils will be fully instrumented. The core engine test will use a SAC dual fuel combustor configuration with water injection. Testing will be conducted on both gas and liquid fuel. This test will validate HPC and HPT aeromechanics, combustor characteristics, starting and part load characteristics, rotor mechanical design and aero thermal conditions, along with preliminary performance. More than 1,500 sensors will be measured during this test.

Full Load Test

The full load test will consist of validating performance (net electrical) of the gas turbine intercooler system with the production engine configuration and air-cooled generator. All mechanical systems and component designs will be validated together with the control system. The gas turbine will be operated in both steady state and transient conditions.

The full load test will be conducted at GE Energy's aeroderivative facility in Jacintoport, Texas, in the first half of 2005. The test will include a full simple cycle power plant operated to design point conditions. Power will be dissipated to air-cooled load (resistor) banks. The gas turbine will use a SAC dual fuel combustion system with water injection.

The LPC, mid-shaft, IPT and PT rotors and airfoils will be fully instrumented. The intercooler system, package and sub-systems will also be instrumented to validate design calculations. In total, over 3,000 sensors will be recorded.

After testing is complete, the Supercore and PT rotor/stator assemblies will be replaced with production (uninstrumented) hardware. The complete system will be shipped to the demonstration customer site for endurance testing. This site will be the "Fleet Leader," providing early evaluation of product reliability.

Schedule

The first production GTG will be available for shipment from GE Energy's aeroderivative facility in Jacintoport, Texas, in the second half of 2005. Configurations available at this time will be SAC gas fuel, with water or steam injection, or dual fuel with water injection. Both configurations will be available for 50 and 60 Hz applications. STIG will be available in the first half of 2006. The DLE2 combustion system development is scheduled to be complete in early 2006. Therefore, a LMS100™ system configured with DLE2 combustor in 50 or 60 Hz will be available in the second half of 2006.

Summary

The LMS100™ system provides significant benefits to power generation operators as shown in Table 3. The LMS100™ system represents a significant change in power generation technology. The marriage of frame technology and aircraft engine technology has produced unparalleled simple cycle efficiency and power generation flexibility. GE is the only company with the technology base and product experience to bring this innovative product to the power generation industry.

- High simple cycle efficiency over a wide load range
- Low lapse rate for sustained hot day power
- Low specific emissions (mass/kWh)
- 50 or 60 Hz capability without a gearbox
- Fuel flexibility – multiple combustor configurations
- Flexible power augmentation
- Designed for cyclic operation:
  - No maintenance cost impact
- 10-minute start to full power
  - Improves average efficiency in cyclic applications
  - Potential for spinning reserves credit
  - Low start-up and shutdown emissions
- Load following capability
- Synchronous condenser operation
- High availability:
  - Enabled by modular design
  - Rotable modules
  - Supercore and PT lease pool
- Low maintenance cost
- Designed for high reliability
- Flexible plant layout
  - Left- or right-hand exhaust and/or intercooler installation
- Operates economically across a wide range of dispatched hours

Table 3. LMS100™ Customer Benefits

References:

1) Gas Turbine World (GTW); "2003 GTW Handbook," Volume 23

LMS100 is a trademark of GE Energy.

GE90, CF6 and LM2500 are registered trademarks of General Electric Company.

LM6000 is a trademark of General Electric Company.

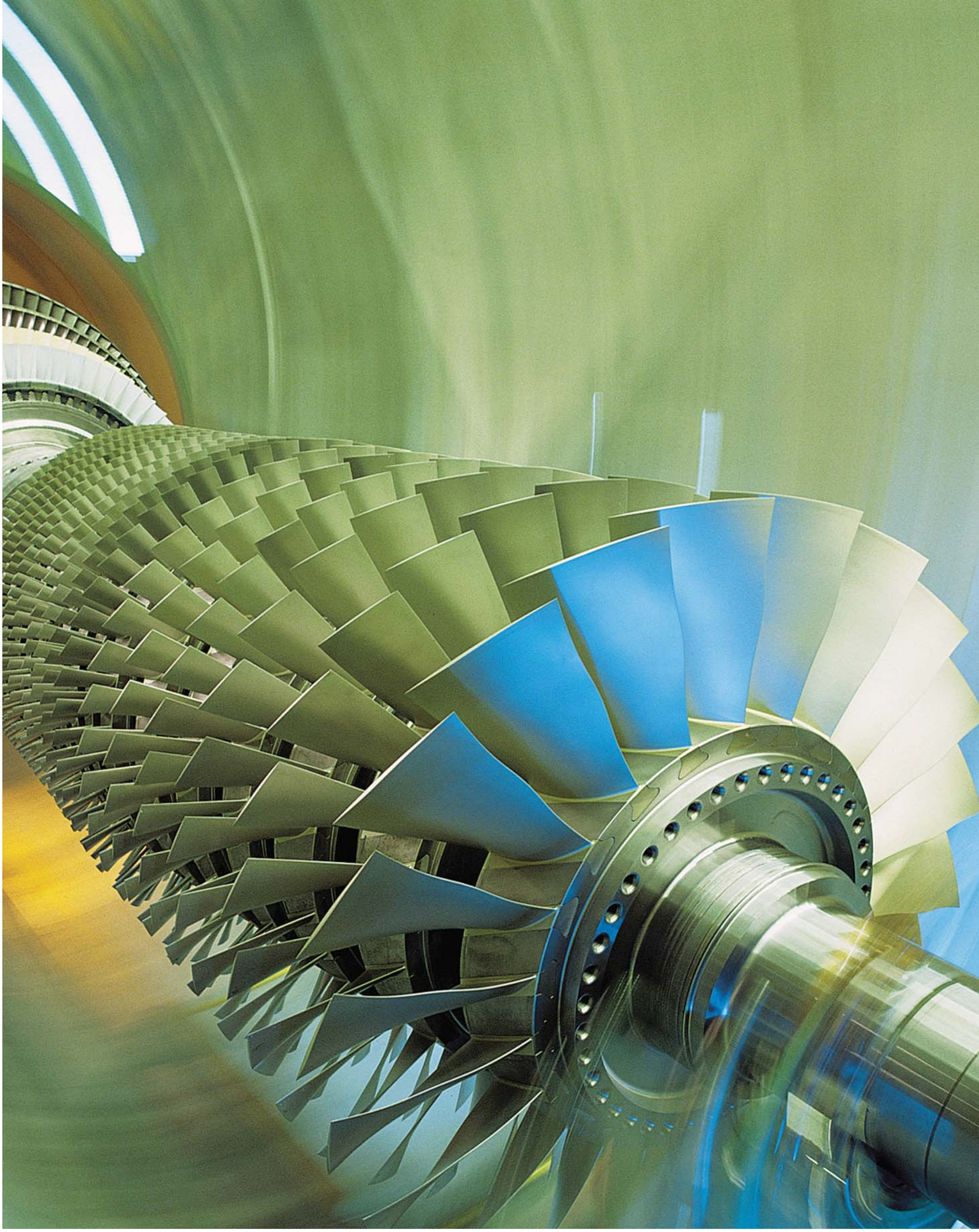
MS6001 is a trademark of GE Energy.

CFM56 is a registered trademark of CFM International, a joint company of Snecma Moteurs, France, and General Electric Company.

SPRINT is a registered trademark of General Electric Company.

Exhibit 2

SGT6-5000F Application Overview



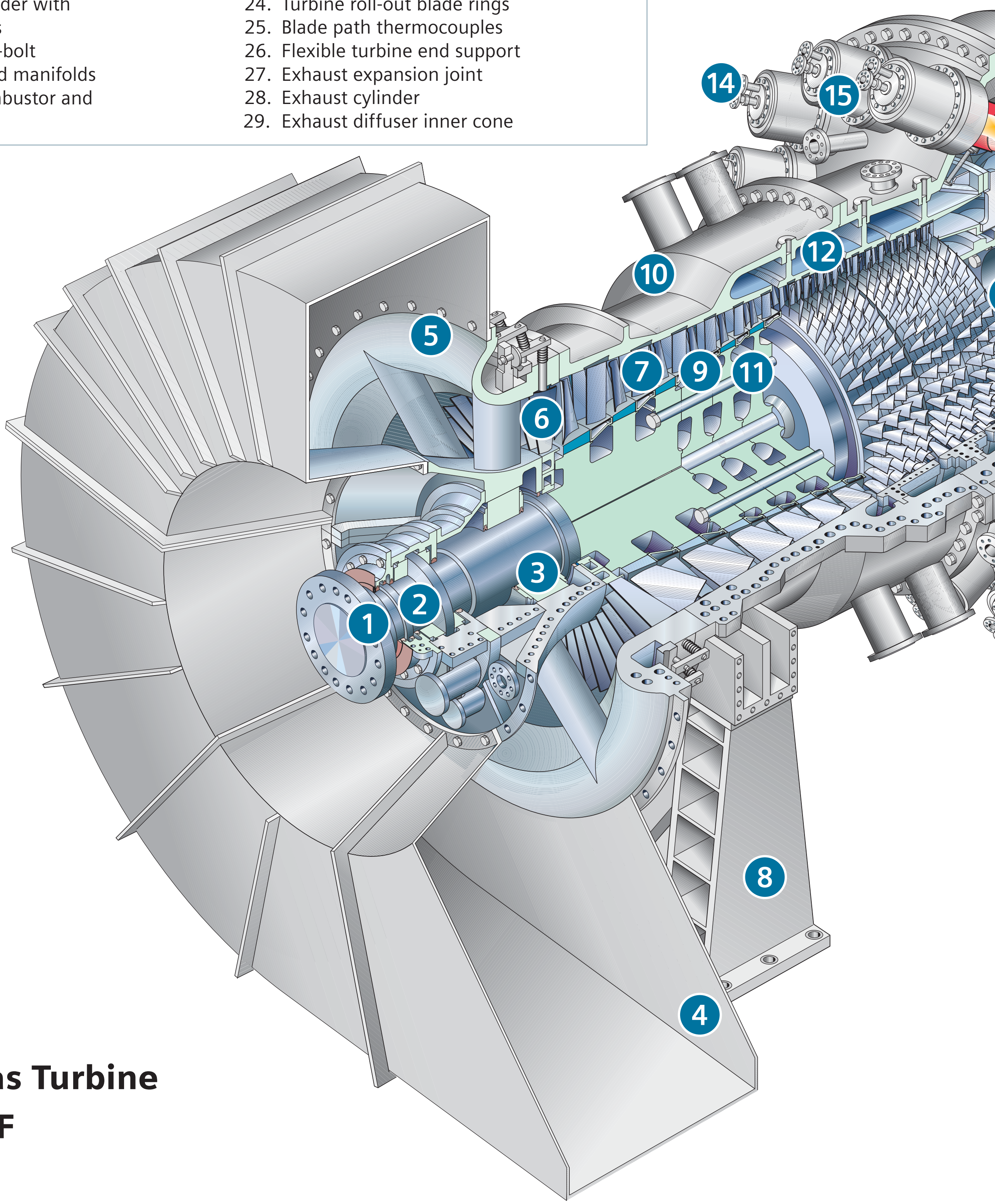
Siemens Gas Turbine SGT6-5000F Application Overview

Answers for energy.

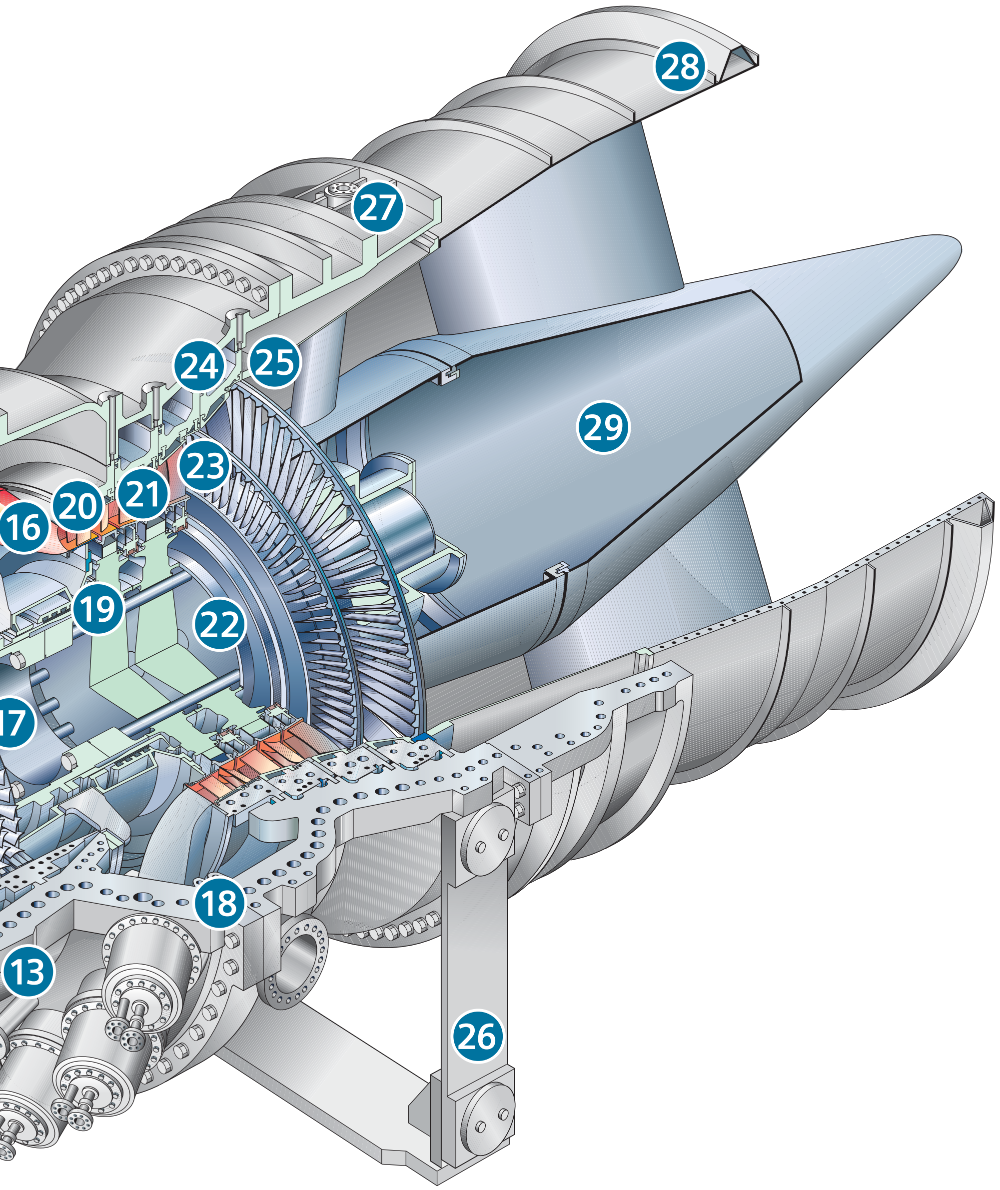
SIEMENS

Key:

1. Generator coupling
2. Thrust bearing
3. Journal bearing
4. Inlet air duct
5. Inlet cylinder
6. Variable inlet guide vane
7. Compressor rotating blades
8. Fixed compressor end support
9. Compressor diaphragms with labyrinth seals
10. Compressor cylinder with borescope access
11. Compressor thru-bolt
12. Compressor bleed manifolds
13. Compressor, combustor and turbine cylinder
14. Fuel nozzles
15. Combustor baskets
16. Combustor transitions
17. Torque tube/air separator
18. Engine horizontal joint
19. Turbine disc thru-bolts
20. Individual first-stage stationary vanes
21. Turbine multivane diaphragms
22. Turbine discs
23. Turbine rotating blades
24. Turbine roll-out blade rings
25. Blade path thermocouples
26. Flexible turbine end support
27. Exhaust expansion joint
28. Exhaust cylinder
29. Exhaust diffuser inner cone



Siemens Gas Turbine SGT6-5000F



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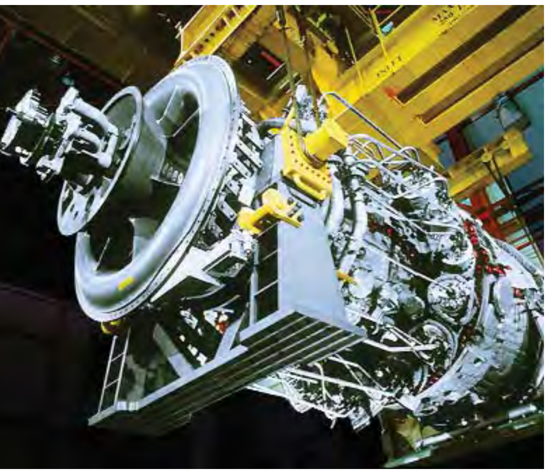
SGT6-5000F application overview



Siemens Gas Turbine engine SGT6-5000F

The advanced technology of the SGT6-5000F* gas turbine continues to satisfy the worldwide needs of the power generation marketplace for 60 Hz projects. Siemens introduced the first unit in the W501 series in 1968. Since that time over 560 units of Siemens Gas Turbines (SGT™) have been sold. Siemens evolutionary design philosophy maintains continuity by building on our proven gas turbine technology. To attain high engine reliability, upgrades or new engine designs are based on technologies proven by engine operation or by extensive component testing.

The SGT6-5000F gas turbine exemplifies this evolutionary process. This SGT6-5000F gas turbine combines the efficient, proven design concepts of the W501D5 with the addition of advanced cooling technologies and improved compressor construction. The advanced cooling technologies allow higher flow path gas temperatures while keeping metal temperatures at the level of previous engines. The technology upgrades applied to the SGT6-5000F gas turbine have resulted in an engine with a rated output that is among the highest of the "F" class gas turbines. The SGT6-5000F gas turbine fleet has achieved over 3.4 million hours of reliable operation and net combined cycle efficiencies of 57%.

This gas turbine is ideally suited for simple cycle and heat recovery applications including Integrated Gasification Combined Cycle (IGCC), cogeneration, combined cycle and repowering. Flexible fuel capabilities include natural gas, LNG, distillate oil, syngas and other fuels, such as low- or medium-Btu gas.

The low emissions SGT6-5000F gas turbine engine consists of a 16-stage axial-flow compressor, a combustion system composed of 16 can-annular combustors and a 4-stage turbine. Packaged with the generator and other auxiliary modules the SGT6-PAC 5000F** power generation system provides economical power for peaking duty, operational flexibility and load following capabilities for intermediate duty, while maintaining high efficiencies for continuous service. Regardless of the application, the SGT6-5000F gas turbine is the basic building block for a wide variety of power generation systems.

Siemens Simple Cycle applications

The Siemens Simple Cycle (SSC™) SGT6-PAC 5000F power plant, nominally rated at 196 MW, is a self-contained, electric power generating system suited for simple cycle applications. The design of the SGT6-PAC 5000F includes over 50 years of experience in gas turbine technology and power plant design. These following proven features, incorporated into the SGT6-PAC 5000F power plant include:

- Factory assembled fuel, auxiliary, lubricating and electrical packages
- Walk-around enclosures for turbine and auxiliary packages
- Microprocessor-based distributed control system
- Air-cooled generator
- Normal start time - 29.5 minutes to base load
- Optional fast start - 10 minutes to 150 MW.

** SGT6-5000F gas turbine engine was formerly called the W501F.*

*** SGT6-PAC 5000F power plant was formerly called the W501F Econopac.*

SGT6-5000F application overview

Siemens Combined Cycle applications

Siemens has more than three decades of experience in combined cycle plant design. Our first combined cycle experience came in the early 1960s with the installation of the West Texas Utilities plant using a W301, a 30 MW gas turbine. The second generation of combined cycle plants were the PACE (Power at Combined Efficiencies) plants introduced in the early 1970s. The PACE plants used an earlier W501 model, the W501B, as their prime mover and were pre-engineered, standardized combined cycle plants.

The Siemens Combined Cycle (SCC™) SCC6-5000F plant*** design (as shown in Figure 1) is built on the strong knowledge base derived from these previous design efforts. With 1x1 (~293 MW), 2x1 (~591 MW) and 3x1 (~885 MW) configurations, the SCC6-5000F family of combined cycle plants is sized to meet the various base and cyclic load requirements of utilities, independent power producers (IPPs) and merchant plant operators. The development of these designs allows for cost-effective plants that require minimal project specific engineering.

Project capabilities

Siemens is experienced in producing successful power projects. Our comprehensive scope of capabilities includes:

- Total turnkey power plants
- Integrated project management
- Plant engineering and design
- Plant permitting assistance
- Equipment installation
- Plant operation and maintenance.

When we take responsibility for a project, or any portion of it, an integrated project management approach is applied to the task. The planning techniques used are among the most advanced in the industry. Project goals are clearly developed and well communicated. Work packages are created which include drawings, material lists and sign-off sheets. Personal accountability means a personal commitment to quality. Siemens has achieved an impressive record for building plants on schedule and within budget.

Figure 1 - SCC6-5000F combined cycle plant design

*** *SCC6-5000F combined cycle power plant was formerly called the W501F combined cycle plant.*

Service and support

A global network for service and support

Siemens is equally committed to providing comprehensive service programs that truly support and optimize the performance of your equipment. We begin with technical assistance provided during the installation and start-up of your equipment and continue with a multitude of service options. These include turnkey maintenance inspections, technical field assistance, modernizations and upgrades, repair and refurbishment and control system service and upgrades.

We have established a powerful and responsive service network with more than 4,000 field engineers and technicians in regional service offices around the globe. So wherever you are, wherever your plant is located, we speak the language, we know the market and we are available when you need us...with rapid-response solutions that translate into measurable benefits for you.

Total Maintenance Services

Our comprehensive service approach also means that we have the ability to track unit trends in our global fleet through leading edge diagnostics technology to ensure maximum unit performance and availability. Total Maintenance Services (TMS) is a structured outage planning, implementation and lessons-learned process. It enables our customers to receive regular notifications of the latest engine design improvements and upgrades as well as notices regarding inspection and maintenance activities. Pre-outage planning is a standard feature to ensure preparedness by identifying necessary parts, modifications and upgrades that are available, new training programs, addressing customer questions and concerns, and offering a comprehensive scope of recommendations.

By analyzing data and trends from the entire operating fleet, we can identify and prevent issues before they impact your plant performance. The constant flow of information and documented pre-outage planning initiatives enable our customers to be better informed and prepared for a more efficient and timely outage that meets their goals of unit reliability, outage duration and budget.

Service programs

Our Service Agreements link performance with customer objectives, providing turnkey outage services as well as parts and repairs for scheduled and unscheduled maintenance.

This performance-based contract approach provides incentive for both parties to benefit from on-time completion, high-quality maintenance, project management and advanced, remote monitoring and diagnostics systems. A dedicated program manager is on-call to provide support and a dedicated team of locally based district managers, home office personnel and factory-trained technicians understand and are closely aligned to your objectives. Our flexible service approach enables us to work with you to create a service program that truly meets your requirements.

We want to develop an ongoing partnership to help ensure your project's long-term success. We are committed to serving our customers well after plant commissioning. That is why we offer comprehensive service options, backed by a global network of resources, to support your equipment throughout its entire life-cycle.

Power Diagnostics services

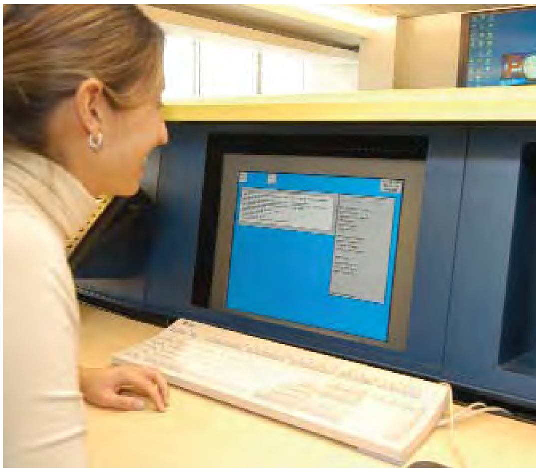
Power Diagnostics

Siemens has provided diagnostic systems design and implementation since the early 1980s. Whether you are a plant owner or operator, our Power Diagnostics® services can help you maximize your plant performance, availability and profitability.

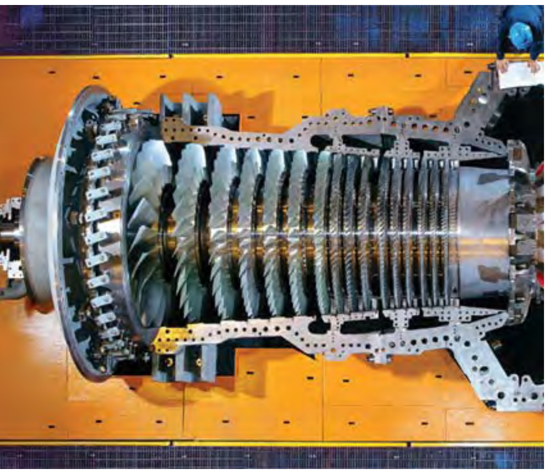
Your power business is unique; accordingly, your business requirements demand the most innovative and effective solutions available. We meet these challenging requirements with one of the most effective monitoring and diagnostics services available to power plant owners. Our Power Diagnostics approach keeps your plant connected to our vast engineering expertise. Data acquired by acquisition systems is transmitted to the Power Diagnostics Center to be analyzed and processed by specialists and engineers. This engineering knowledge, combined with the use of sophisticated tools, provides trending and analysis capabilities to address a broad range of operating needs specific to each customer. This approach facilitates continuous improvement of our solutions to help you enhance your plant's availability and reliability.

Our Power Diagnostics Centers in the United States and Germany are monitored around the clock with experienced professionals who understand the complexity of your turbine systems and the demands placed on them. These highly skilled and trained engineers recognize the importance you place on keeping your plant on-line to meet business demands. If an abnormal trend is detected, your data will be analyzed, compared to our vast historical operating fleet database, and presented in an understandable manner to your plant staff for timely trend assessment. Analysis results also can help you to schedule outages with more precision. If required, quick-response technical resources also can be dispatched for on-site problem resolution.

To help you optimize your plant operating availability and enhance your bottom line, Power Diagnostics is invaluable in assisting with the detection of impending operational problems, thereby helping to minimize unplanned outages and maximize power generation availability.



SGT6-5000F gas turbine



General description

Designed for both simple and combined cycle applications, the SGT6-5000F gas turbine can operate on conventional gas turbine fuels and a wide range of alternate fuels subject to review by Siemens. The gas turbine consists of a 16-stage, high efficiency axial compressor, combustion chamber equipped with 16 Dry Low NO_x (DLN) emissions or conventional combustors arranged in a circular array around the engine centerline, and a 4-stage reaction type turbine. The gas turbine is coupled directly to the generator at the compressor end.

Ambient air is drawn through the inlet manifold and inlet casing into the compressor. It is pressurized to approximately 16 atmospheres and guided into the combustors, where it is mixed with fuel and ignited, raising the temperature of the mixture. The compressed and heated mixture (gas) then expands through the turbine, dropping in pressure and temperature as the heat energy is converted into mechanical work. A portion of the power developed by the turbine is used for driving the compressor, with the balance of power used to drive the generator. Expanded gases are then exhausted into the atmosphere through an exhaust stack for a simple cycle application or through a Heat Recovery Steam Generator (HRSG) and exhaust stack in a combined cycle application.

Design features

SGT6-5000F gas turbine features, such as cold-end generator drive, two-bearing design, horizontally split casings, can-annular combustors and tangential strut supports have been used in this gas turbine family since the early 1950s.

The axial exhaust concept, introduced in 1970 on the W501AA, improves performance and provides greater flexibility for multiple unit plant arrangements especially when applied to combined cycle power plants.

Design features summary:

- A two-bearing rotor used to simplify alignment
- Bearings that operate at below atmospheric pressure to prevent shaft seal leakage
- Readily accessible bearings that can be removed and replaced without lifting the gas turbine covers
- Compressor blades that can be removed for inspection and reinstalled without disturbing blades in other rows and without removing the rotor from its casing
- Low temperature environment of the exhaust bearing permits the use of less expensive and readily available lubricating oil
- Individual turbine blades that can be removed for inspection or replacement with the rotor in place and without disturbing other blades
- Compressor diaphragms and turbine blade rings that can be taken out for inspection or be replaced with the rotor in place
- Field balancing, two end and one center balance planes are easily accessible
- Multiple boroscopic inspection ports in the compressor and turbine flow paths to permit inspection of the blading without lifting covers
- Turbine supports for free expansion and contraction due to temperature changes without disturbing the shaft alignment
- Cooling circuits designed to protect the gas turbine parts from the high temperature gas stream for better reliability and longer life
- A tangential strut support system for the turbine-end bearing – a Siemens patented feature – for maintaining the bearing on centerline for all conditions of load and temperature.

SGT6-5000F gas turbine

Major assemblies

Casings

Engine casings are horizontally split to facilitate maintenance with the rotor in place. Inlet casings are cast from nodular iron or fabricated from cast steel. The compressor section casings are cast steel while the combustor, turbine and exhaust casings are alloy steel.

Eight radial struts support the inlet bearing housing while six tangential struts support the exhaust-end bearing housing. Airfoil-shaped covers protect the tangential struts from the blade path gases and support the inner and outer diffuser cones.

Tangential struts maintain alignment of the bearing housing by rotating it, as required, to accommodate thermal expansion. Individual inner casings (blade rings) are used for each turbine stationary stage and can be readily replaced or serviced with the rotor in place. Similar blade rings are in the compressor for stages seven through sixteen. The blade rings have a thermal response independent of the outer casing, thereby permitting the blade rings to remain concentric to the rotor. This allows for a minimum clearance between rotating and stationary airfoils in order to increase flowpath efficiency.

Rotor assembly

The rotor consists of the compressor and turbine rotor components bolted together and supported by two tilting-pad bearings. A direct lubricated, double acting thrust bearing located at the compressor end of the gas turbine accommodates engine thrust. The compressor rotor is comprised of multiple discs equipped with load carrying keys between discs, aligned using a spigot fit and clamped together by 12 through bolts.

The turbine rotor is made up of interlocking discs using CURVIC® couplings that are held together by 12 through bolts. The CURVIC couplings consist of mating curved teeth that are located around the circumference of adjacent disc faces, which interlock and provide precise alignment and torque carrying abilities. This proven turbine rotor design has accrued millions of hours of reliable service in all sizes of our gas turbines.

Any turbine or compressor blade can be removed for inspection and replaced without lifting the rotor.

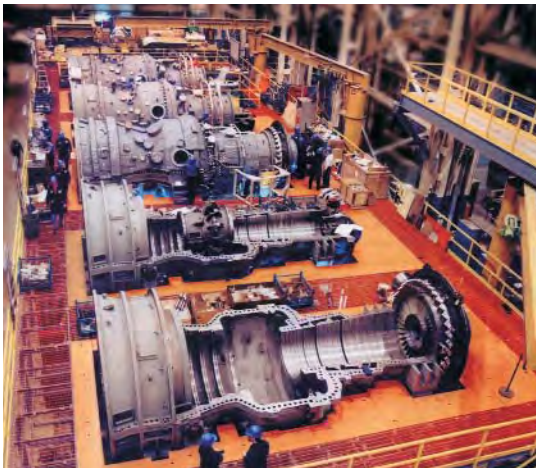
Air inlet system and compressor

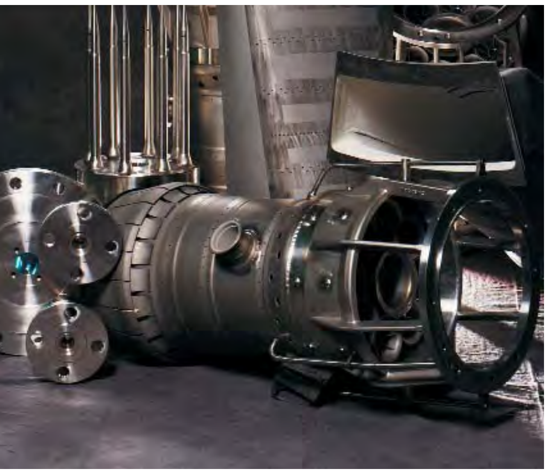
The air inlet system, consisting of the inlet filter, inlet silencer and associated ductwork, delivers air to the compressor. The compressor is a 16-stage axial flow design and achieves a 17-to-1 pressure ratio. Inter-stage bleeds for starting and cooling flows are located at the 6th, 10th and 13th stages. The compressor is equipped with one stage of variable inlet guide vanes to improve the compressor low speed surge characteristics and part load performance in combined cycle applications.

The compressor blade path design is based on an advanced three-dimensional flow field analysis computer model. All rotor blades incorporate an improved root design that has flat contact faces (as do the turbine blade roots), which allows the blades to be removed in the field with the rotor in place. The blades of the first six stages are 17-4 pH (17% Cr precipitation hardened stainless steel). Rows seven through sixteen blades use AISI 616 stainless steel.

Each stage of stationary airfoils consists of two 180° diaphragms for easy removal. An inner shroud sealing system is used on the SGT6-5000F gas turbine. The seals are supported by machined seal rings, which can be removed to facilitate inspection and maintenance of shrouds and seals. One row of exit guide vanes is used to direct the flow leaving the compressor. Stationary airfoils and shrouds utilize corrosion and heat-resistant stainless steel throughout.

Compressor rotating and stationary airfoils are coated to improve aerodynamic performance and provide corrosion protection.





Combustion system

The combustion system consists of 16 can-annular, dry low emissions (25 ppm or 9 ppm NO_X systems are available) or conventional combustors.

The presence or absence of flame and the uniformity of the fuel distribution between combustors are monitored by thermocouples located downstream of the last stage turbine blades. These can also detect combustor malfunctions when at load. Ultraviolet detectors are used to sense ignition during starting.

Transition ducts, one for each combustor, direct the hot gases from the combustors to the turbine blade path. The transitions are air-cooled and the same design is used in both simple and combined cycle applications.

Turbine section

The turbine design of the SGT6-5000F gas turbine maintains moderate aerodynamic loading by the use of a 4-stage turbine. Furthermore, improvements in aerodynamic airfoil shapes have been made possible by using a fully three-dimensional flow analysis computer model. A sophisticated airfoil design approach was utilized to target high aerodynamic efficiency.

The 1st and 2nd stages on the turbine rotor contain 72 and 66 freestanding blades, respectively. The 3rd and 4th stages contain 112 and 84 blades, which incorporate integral Z-tip shrouds. The shrouding of blades allows increases in mass flow and thus an increase in the power output. The shrouded blade design prevents flow induced non-synchronous vibration due to aero-elastic interaction between blade structure and flow.

The 1st and 2nd stage rotating blades are precision cast of equiaxed IN-738. The 3rd and 4th stage rotating blades are precision cast of equiaxed CM-247. All rows have long blade root extensions to minimize the stress concentration factor that results when load is transferred between cross sections of different size and shape. Roots are multiple serration type with four serrations used on the first two rows and five serrations on the last two stages.

The 1st turbine stationary row consists of 32 precision-cast, single-vane segments of ECY-768 alloy coated with thermal barrier coating (TBC) for improved thermal resistance. Consistent with previous proven W501 designs, 1st row single vanes are removable, without lifting any covers, through access ports in the combustor shell. Inner shrouds are supported from the torque tube casing to limit flexural stresses and distortion, thus maintaining control of critical 1st row vane angles. In the 2nd turbine stationary row, there are 24 two-vane segments precision-cast of ECY-768 alloy, which are also treated with TBC. The 3rd turbine stationary row consists of 16 three-vane segments and the 4th turbine stationary row consists of 14 four-vane segments. Both are precision cast of X-45.

Each row of vane segments is supported in a separate blade ring, which is keyed and supported to permit radial and axial thermal response independent of possible external cylinder displacements. Segmented isolation rings support the vane segments. Ring segments located over the rotating blades form the flow path outer annulus. Isolation and ring segments both act to limit thermal conduction between the flow path and the blade ring, thus mitigating blade ring clearance changes in the turbine section. The interstage seal housings are uniquely supported from the inner shrouds of rows 2, 3 and 4 vane segments by radial keys. This permits the thermal response of the seal housings to be independent of the more rapid thermal response of the vane segments.

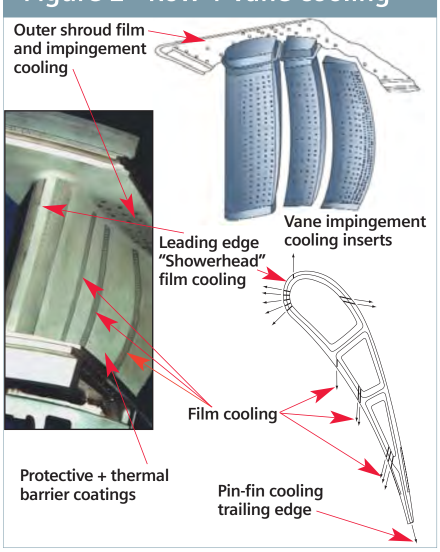
Cooling system

Comprehensive cooling methods enable the SGT6-5000F gas turbine to operate at high performance firing temperatures while using conventional materials.

Compressor bleed air from the 13th, 10th and 6th stages are used to provide cooling air to turbine blade ring cavities at the 2nd, 3rd and 4th stages, respectively. This supply of bleed air also cools the 2nd, 3rd and 4th stage vanes and ring segments and provides cooling air for the turbine interstage disc cavities to shield the interstage seals and disc faces from hot blade path gases.

Direct compressor discharge air is used to cool the 1st row vane. The 1st row vane cooling design uses state-of-the art concepts with three impingement inserts in combination with an array of film-cooling holes and a trailing edge pin-fin system. "Showerhead" cooling is used at the leading edge of the 1st row vane, while film cooling is used at selected pressure and suction side locations. This limits vane wall thermal gradients and external surface temperatures, while providing an efficient re-entry for spent cooling air. Pin-fins, used successfully for the first time on the W501D5 1st row vane, are used to increase turbulence and surface area, thereby optimizing the overall trailing edge cooling effectiveness. (See Figure 2.) The design of the 1st row vane is such that the Low Cycle Fatigue (LCF) design criteria is satisfied by control of wall thermal gradients.

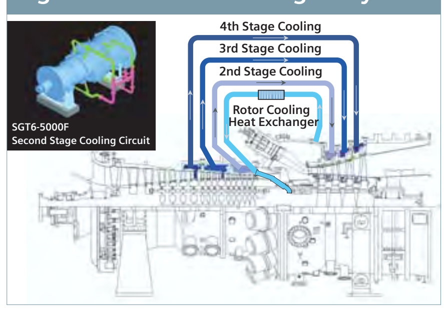
Figure 2 - Row 1 vane cooling



For the 2nd row vane, 13th stage compressor bleed air is ducted directly to the twin insert system. The 2nd row vane cooling is a less complex version of 1st row vane cooling. It uses twin impingement inserts with film-cooling holes and a trailing edge pin-fin system. Film cooling is used at one location on the suction side and at the exit of the aft insert on the pressure side.

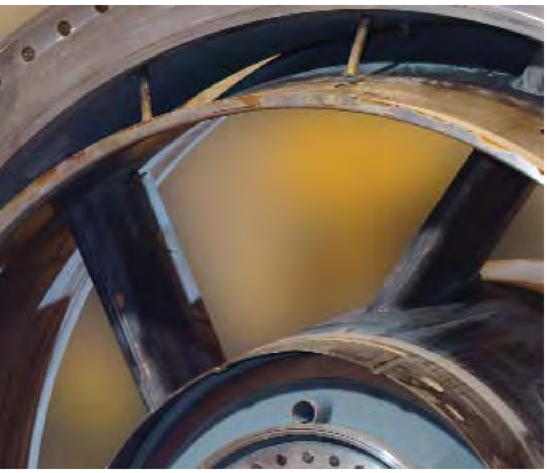
Compressor bleed air from the 10th stage is used to supply cooling air to the 3rd stage blade ring cavity. Cooling air is directed to the inlet cavity of a three-cavity multipass convective-cooled vane airfoil. Leading edge cavity flow also supplies the interstage seal and cooling system, while the third pass cavity exits at pressure side gill holes on the vane surface. The 4th stage vane is uncooled, but does transport 6th stage compressor bleed air for the 4th row inter-stage seal. (Figure 3 depicts the cooling system.)

Figure 3 - Turbine cooling air system



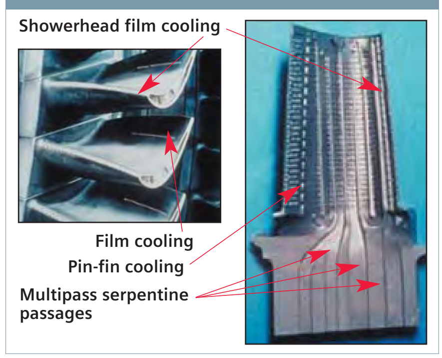
Rotor cooling air is extracted from the combustor shell. The air is externally cooled and returned to the torque tube seal housing to be used for seal air supply and for cooling of the turbine discs and 1st, 2nd and 3rd stage turbine rotor blades. This provides a blanket of protection from hot blade path gases.

The 1st stage blade is cooled by a combination of convection techniques via multipass serpentine passages and pin-fin cooling in the trailing edge exit slots. (See Figure 4, page 12.) Air supply for blade cooling is high-pressure compressor discharge air that has been cooled and returned to the turbine rotor via four supply pipes in the combustor shell. Cooling air flows outward through three slots in the root and is conveyed radially through the blade shank. Showerhead film cooling is used for the leading edge region. The 2nd row rotor blade is also precision cast and is cooled by a combination of convection



techniques via serpentine passage and pin-fin cooling in the trailing edge exit slots. The 3rd row blade is precision cast with single pass convective cooling holes.

Figure 4 - Row 1 blade cooling



The cooling system maintains the NiCrMoV turbine discs at a temperature sufficient to keep the disc below the creep range.

Exhaust cylinder section

The exhaust cylinder fabrication is composed of the bearing housing, inner and outer cones of the exhaust diffuser and outer case, all joined together by means of a strut system. The strut system consists of six bearing struts equally spaced around the circumference but positioned tangentially with respect to the bearing housing.

These struts extend from the bearing housing to the outer case. In the hot gas section of the exhaust diffuser, the bearing struts are shielded inside another set of struts, which are hollow and serve as supports for the exhaust diffuser cones. Thus, the bearing struts are protected from the hot exhaust gas by envelopes of cooler air around them. This results in a strut system that is less sensitive to transient temperatures. Growth of the outer case and struts is accommodated by bearing housing rotation.

The system provides a low stress, rigid support, capable of holding the bearing on center for variations of load and temperature.

Axial exhaust manifold section

The exhaust manifold section consists of the exhaust manifold, expansion joint with flow liner and exhaust transition. The exhaust gas flows through the manifold and flow liner into the transition and is then discharged into the stack.

The manifold acts like a muffler in which the flow is slowed down without becoming excessively turbulent. This flow stabilization further improves the gas turbine performance. All parts of the exhaust system section, with the exception of the expansion joint, are fabricated from a high strength, low alloy steel.

The exhaust manifold is composed of one outer and inner cylinder held together by means of two hollow struts. The outer cylinder has the shape of a truncated cone. The inner cylinder, in conjunction with the inner cone of the exhaust diffuser, forms an enclosed chamber around the gas turbine centerline. An access passage to this chamber and a channel for the pipe and conduit lines going to the bearing area are provided through the hollow struts.

The manifold is connected to the exhaust transition by means of an expansion joint made from a high temperature-resistant material. The expansion joint's primary function is to accommodate the axial growth of the unit due to thermal expansion and to prevent any external load from being imposed upon the exhaust manifold.

The axial exhaust configuration is ideally suited for waste heat recovery applications such as combined cycle, cogeneration and repowering.

Scope of supply definitions

SGT-PAC

- Gas turbines for fuel gas incl. auxiliaries
- Air intake/exhaust system
- Fuel gas system
  – skids
  – connecting pipes
- Gas turbine generators incl. auxiliaries
- Fire protection GT
- GT-electrical and I&C
- Options

Performance/Delivery

SCC Thermal Equipment

- **SGT-PAC**
- SST-PAC w/o condenser
  – Steam turbine incl. auxiliaries w/o piping
  – Generator incl. auxiliaries
  – ST electrical and I&C
- HRSG
- Options

Cycle optimization/ Performance wrap

SCC Power Island

- **SCC Thermal Equipment**
- Condenser incl. air removal system
- Boiler feed pumps
- Condensate pumps
- Critical valves
- Fuel pre-heater with filter, metering station, etc.
- Power Island controls
- Options

System integration/ Optimized operability

SCC Turnkey

- **SCC Power Island**
- Buildings/structures
- Cranes and HVAC (Turbine hall)
- Plant Cooling systems
- Water treatment
- Raw water system
- Waste water system
- Tanks
- Plant piping/valves
- Electrical equipment
- Plant control system
- Additional fire protection/ fighting
- Erection/commissioning
- Further options

Total EPC plant wrap

SGT-PAC

Gas turbine, generator, auxiliaries and contols for supplied scope, inlet and exhaust systems.

SCC Power Island

SGT-PAC plus HRSG, steam turbine, condenser, major pumps, critical valves and controls for supplied scope.

Remark:
Visible differences between Thermal Equipment and Power Island are small and therefore not shown

SCC Turnkey

SCC Power Island plus buildings, structures, plant cooling, power control centers, electrical, switchyard, fuel delivery, piping, plant control system, balance of plant construction, erection and commissioning.

SGT6-PAC 5000F power plant

General description

The SGT6-PAC 5000F plant is designed to provide the user with a complete power generating system. Components and subsystems are selected to form a compact plant housed within enclosures.

The SGT6-PAC 5000F plant features modular construction to facilitate shipment and field assembly. Subsystems are grouped and installed in auxiliary modules. Each module of the SGT6-PAC 5000F plant is factory assembled to the extent permitted by shipping limitations to minimize field assembly. Pipe rack assemblies that provide interconnecting piping between the standard modules are supplied, eliminating the need for extensive piping fabrication during construction.

The basic bill of materials for a SGT6-PAC 5000F plant typically includes the following equipment and assemblies:

- SGT6-5000F Gas Turbine
- Open air-cooled generator
- Brushless excitation and voltage regulator system
- Starting package
- Electrical package
- Lubricating oil system package
- Instrument air system
- Hydraulic oil system
- Gas fuel system
- Inlet air and exhaust gas systems
- Compressor water wash package
- Piping packages
- Cooling systems
- Fire protection
- Voltage transformer and surge cubicle.

Optional Equipment:

- Auxiliary transformer
- Isolated phase bus
- Evaporative cooling system
- Dual fuel combustion system
- Liquid fuel system
- Totally Enclosed Water-to-Air-Cooled (TEWAC) Generator
- Hydrogen-cooled generator
- Water injection package (supplied with liquid fuel system for NO_X control).

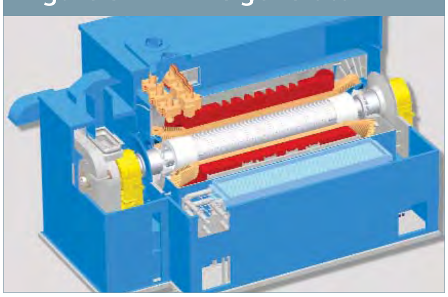
SGT6-PAC 5000F power plant

Generator

The open air-cooled (OAC) Siemens Generator (SGen™) is equipped with a cooling air filter, silencers, inlet and exhaust ducting, brushless exciter, acoustical enclosure, and necessary instrumentation. The main three-phase terminals are located on top of the acoustical enclosure at the excitation end of the generator for isolated phase interface. Internal cooling is provided via shaft-mounted axial blowers, which direct filtered ambient air through the generator's major internal components. A solid coupling connects the generator to the compressor at the cold end of the gas turbine.

Totally enclosed water-to-air-cooled (TEWAC) (as shown in Figure 5) or hydrogen-cooled generators are also options.

Figure 5 - TEWAC generator



Generator cooling system

For open air-cooled generators, the cooling air is drawn into the generator through a pad type filter and a silencing section contained in the inlet duct. The cooling air is forced through the generator via shaft-mounted blower fans located on either end of the generator shaft. As the forced air passes through the generator's major internal components, the heat is absorbed into the air and exhausted through the exhaust duct.

When selected, a TEWAC system provides a closed cooling air circuit. Cooling water is circulated through tube banks to exchange heat energy between the closed circuit generator cooling air and water. The internal active cooling paths, including the shaft-mounted blowers, are identical in both OAC and TEWAC designs. Cooling water is supplied by a fin-fan cooler or from a plant cooling water system.

Brushless excitation and voltage regulator system

The brushless exciter and voltage regulator system functions to supplies generator field excitation and controls the output of the AC generator terminal voltage. The brushless exciter has a shaft-mounted rotating armature and diode wheel. The voltage regulator supplies the stationary DC field to the brushless exciter, either under automatic or manual control. A static excitation system is an option.

Starting package

The base starting system is a modular package, with a fabricated steel bedplate and a steel enclosure for outdoor installation. The starting system includes an AC electric motor, a torque converter with charging pump, a turning gear, a turning gear motor, a clutch and associated instrumentation. The welded steel, all-weather enclosure (for outdoor application) is complete with access stairs, a door and a maintenance platform. Louvered openings on the enclosure provide natural ventilation.

An optional static starting system is available for simple cycle applications. The static start package includes a static frequency converter, a static excitation system, a two-speed turning gear (with a DC motor for slow spin and AC motor for acceleration to 120 rpm), a clutch and associated instrumentation. The static starting system is used when the fast start option, (150 MW in 10 minutes) is selected.

The starter package (whichever utilized) provides breakaway torque for initial rotation of the turbine generator, and the torque necessary for acceleration to self-sustaining speed. The starting system disengages once the unit reaches self-sustaining speed. During cool-down periods, the turning gear, a component of the starting package, provides for a slow roll of the combined turbine and generator rotor.

Auxiliary packages

Electrical package

The electrical package contains equipment necessary for sequencing, control and monitoring of the gas turbine and generator. This includes the gas turbine control system, motor control centers, generator protective relay panels, voltage regulator, fire protection system, battery and battery charger. The batteries are in an isolated section of the package and are readily accessible from the outside. Redundant HVAC units are provided in the electrical package to ensure a clean environment for the temperature sensitive electrical and control equipment.

Lubricating oil system package

The lube oil package is a factory manufactured weather-resistant skid for the lubricating oil system. The lubrication system provides clean, filtered oil at the required temperature and pressure for lubricating bearings of the gas turbine, generator and starting package. The lube oil package includes a lube oil reservoir, which provides a mounting base for the following lube oil system components:

- Main and alternate AC motor-driven pumps
- Emergency DC motor-driven pump
- Vapor extraction blowers
- Duplex filter assembly
- Accumulators.

The lube oil cooler assembly is located on top of the lube oil package roof. The lube oil system is supplied complete with interconnecting piping, valves and instrumentation.

Instrumentation air system

The turbine enclosure houses the compressed air reservoir and a pressure switch and gauge panel. The pressure switch and gauge panel contains all of the required pressure switches, gauges, regulating and safety valves, air filters and desiccants. These components clean, dry, control, monitor and direct the instrument air to various valves and instruments. For combined cycle installations, the most efficient source of compressed air is typically the plant service air compressors. For simple cycle installation, an optional reciprocating air compressor can be provided.

Hydraulic oil system

A Hydraulic Oil Power Unit (HPU) is supplied when the engine is equipped with a DLN combustion system. The HPU provides high pressure hydraulic oil to operate the gas fuel stage throttle valve and the inlet guide vane actuators. The HPU is a self-contained unit mounted on a fabricated steel skid assembly and is located outdoors adjacent to the gas turbine enclosure and the mechanical package enclosure.

The major components are:

- Stainless steel fabricated oil reservoir
- AC motor-driven high pressure charge pumps; fully redundant (2 x 100%) mounted and driven by the high pressure pump motor spindle shaft
- Hydraulic oil cooler, radiator type fan
- Filter (100% redundant duplex) housings assembly
- Safety relief valves, pressure regulating valves
- Hydraulic accumulators
- Electric immersion heaters
- Instrumentation for local and remote monitoring of pressure and temperature
- Interconnect tubing assemblies (stainless steel).

Gas fuel system

The principal components of the gas fuel system are located inside the turbine enclosure. For the base unheated fuel design, the fuel filter/separator is installed outdoors adjacent to the gas turbine enclosure. The piping assemblies and valves are supplied as spool sections for field erection. The major components of the base fuel system include:

- Fuel filter/separator system
- Fuel throttle valves for each fuel stage with associated instrumentation
- Overspeed trip and shut off valve(s)

Auxiliary packages

- Main pressure control valve and start pressure regulating valve
- Vent valve
- Fuel flow monitoring orifices with associated instrumentation.

Instrumentation to monitor the critical parameters is centralized and mounted on a fuel control panel located inside the turbine enclosure. Pressure gauges to locally monitor the fuel pressure are typically located on this panel. Field installed inter-connecting piping assemblies that direct the fuel to the turbine-mounted fuel manifolds are supplied.

For the optional heated fuel design, an additional filter/separator for the pilot stage and a pilot overspeed trip/shut off valve are supplied. The pilot filter separator is also located outdoors adjacent to the turbine enclosure.

The heated fuel option is typically applied in combined cycle applications. The fuel is heated using a low energy water source thus utilizing energy to improve the net combined cycle efficiency.

Liquid fuel system (optional)

For liquid fuel applications (either dual or single fuel), a liquid fuel system is supplied. The liquid fuel system consists of factory-assembled components, including an AC motor-driven fuel pump, a suction side duplex fuel filter with transfer valve, and a control valve, installed on a bedplate. Interconnecting piping to this gas turbine is also included.

Liquid fuel/water injection system (optional)

When a liquid fuel system is required, a factory-assembled demineralized water injection skid is furnished. This water injection skid is assembled on a bedplate and includes an AC motor-driven injection pump with suction strainer, manifolds, control valves and instrumentation.

When liquid fuel and water injection systems are required, an additional skid for the primary fuel and water scheduling components is provided and is located inside the turbine enclosure. In a typical liquid fuel installation, this skid contains liquid fuel flow dividers, liquid fuel control valves, water injection valves and a local instrument panel.

Air inlet and exhaust gas systems

Air that is drawn into the gas turbine is filtered via a two-stage pad filter. A self-cleaning pulse filter is also an available option. After passing through the filter, the inlet air duct guides the air into the compressor inlet manifold. This manifold is designed to provide a smooth flow pattern into the axial flow compressor. An inlet silencer provides sound attenuation. After passing through the combustor and turbine section, combustion gas discharges axially through a transition section and into an exhaust stack for simple cycle applications.

In combined cycle applications, the exhaust transitions direct the exhaust gases into the HRSG before exiting the stack.

Compressor water wash package

The compressor water wash package is provided for both on-line and off-line compressor cleaning. This package incorporates an AC motor-driven pump, an eductor for detergent injection, piping, valves, orifices, interconnecting piping and a detergent storage tank assembled on a bedplate.

Piping packages

SGT6-PAC 5000F plant piping is designed and manufactured to minimize field work. Each of the major pipe modules is factory assembled to reduce field connections.

The turbine pipe package is located adjacent to the gas turbine and in the gas turbine enclosure. It contains valves and piping assemblies for the turbine cooling air system and the lube oil system. The rotor cooling bleed valve is also located within the turbine piping package.

Auxiliary packages

Cooling systems

Lube oil cooler

An air-to-oil fin-fan lube oil cooler (water-to-oil cooler, optional) and the associated temperature control valve are mounted on top of the lube oil package roof. The temperature control valve maintains the lube oil temperature within the design range by controlling the flow of oil through the cooler.

Rotor air cooler

Rotor cooling air is extracted from the combustor shell, cooled by an external cooler, and introduced into the turbine section to be used for sealing purposes and to cool the appropriate rotating discs and rotating blades.

The rotor air cooler system supplied for simple cycle applications is an air-to-air fin-fan heat exchanger fitted with a variable speed motor-driven fan. The energy removed from the cooling air is released to the surrounding air.

For SCC6-PAC 5000F package or SCC6-5000F Turnkey combined cycle applications, the rotor air cooling system may include an air-to-water heat exchanger (kettle boiler) instead of a fin-fan cooler. With the kettle boiler, the energy removed from the cooling air is recovered and used to produce low-pressure steam. This steam is introduced into the steam circuit to improve the plant efficiency.

Fire protection system

The fire protection system gives a visual indication of actuation at the local control panel. There are two independent systems:

- An automatically actuated dry chemical system is provided for the exhaust bearing area of the turbine. The system consists of temperature sensing devices, spray nozzles, a dry chemical tank, interconnecting piping and wiring.
- The FM-200® fire suppressant system is provided for total flooding protection of the turbine enclosure and the electrical control package in accordance with the U.S. National Fire Protection Agency standards.
- The CO_2-based fire suppressant system is also available as an option.

VT and surge cubicle

A Voltage Transformer (VT) and surge cubicle is provided as a separate unit for connection to an isolated phase bus. It contains two three-phase sets of voltage transformers and one set of surge arresters.

Auxiliary transformers (optional)

The optional auxiliary power transformer may be included as part of the SGT6-PAC 5000F bill of material.

Isolated phase bus (optional)

The optional isolated phase bus, located at the starting package end of the gas turbine unit, carries power from the generator terminals to the customer connection. The VT and surge cubicle connects to the bus assembly.

Figure 6 - SGT6-PAC 5000F arrangement diagram

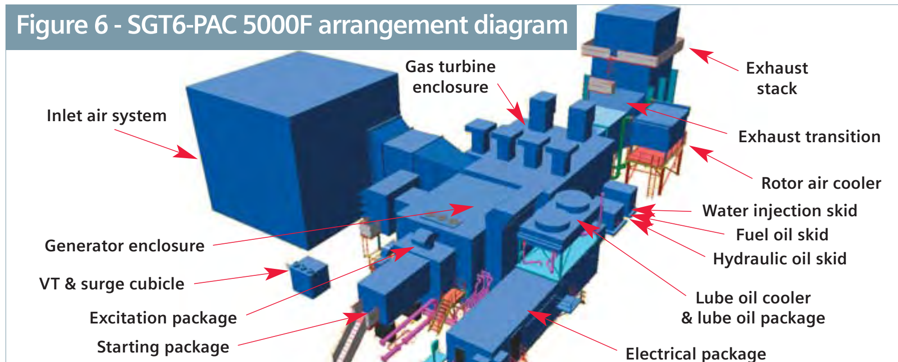
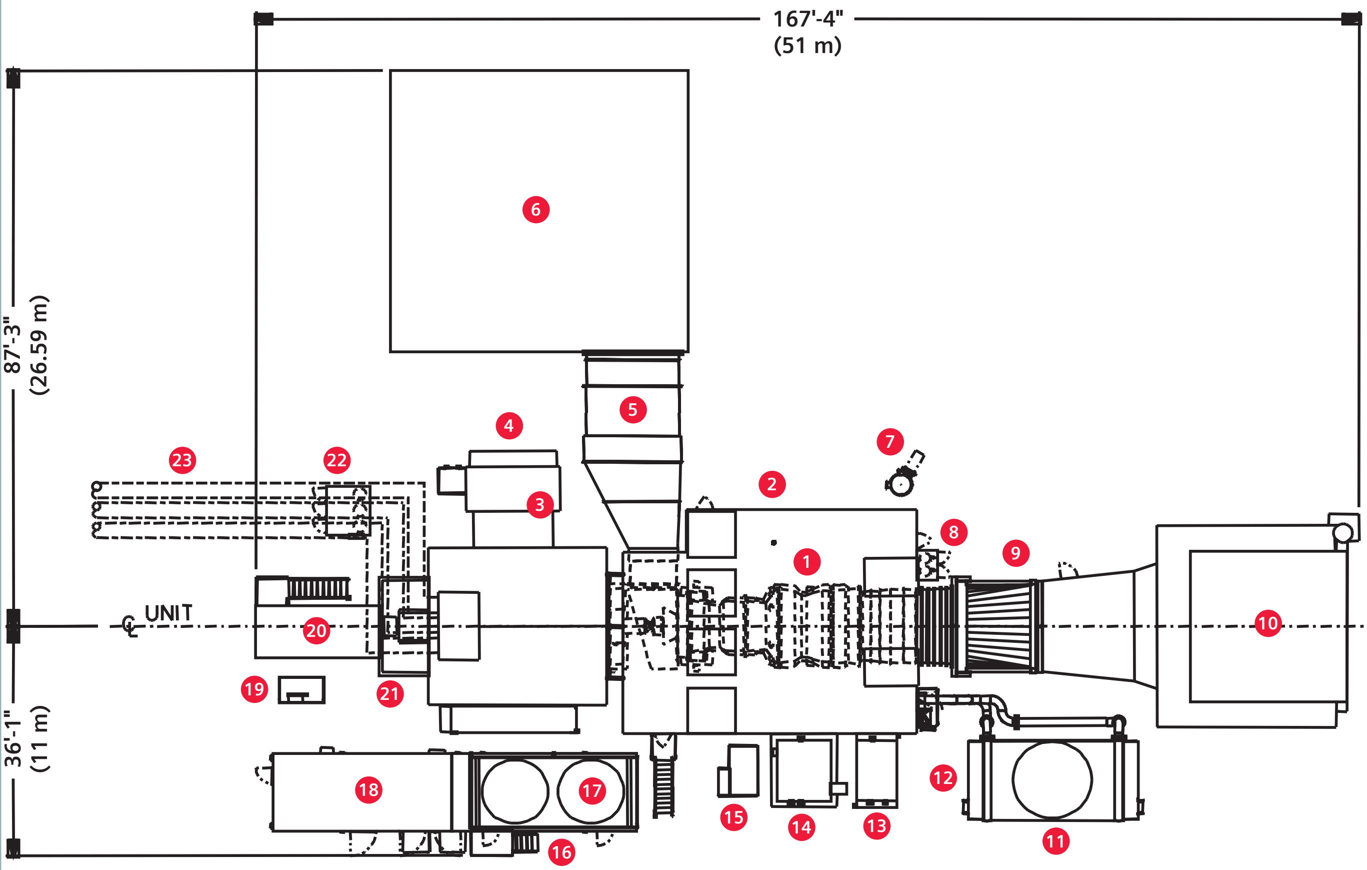


Figure 6 - SGT6-PAC 5000F simple cycle arrangement diagram depicts the location of the major components described above.

SGT6-PAC 5000F plant arrangement diagram

Figure 7 - SGT6-PAC 5000F simple cycle plant general arrangement drawing



Key:

1. Gas turbine (GT)
2. GT enclosure
3. Generator (OAC)
4. Generator air inlet filter
5. Turbine air inlet duct and silencer
6. Turbine air inlet filter
7. Fuel gas main filter/separator
8. FM-200® fire protection
9. Exhaust transition
10. Exhaust stack
11. Rotor air cooler (fin-fan)
12. Dry chemical cabinet
13. Water injection pump skid
14. Fuel oil pump skid
15. Hydraulic supply skid
16. Lube oil package
17. Lube oil cooler (fin-fan)
18. Electrical package
19. Compressor wash skid
20. Starting package
21. Brushless excitation
22. VT & surge cubicle
23. Isolated phase bus duct (by others)

Comment: Items 13 and 14 only required with Dual Fuel.

Notes: The equipment shown is representative information. This design is subject to change at the discretion of Siemens. All dimensions shown are in feet and inches (metric).

SGT6-PAC 5000F simple cycle performance

Following is the net reference performance for the SGT6-PAC 5000F power plant.

Conditions: Natural gas or liquid fuel meeting Siemens' fuel specifications. Elevation: sea level; 14.696 psia barometric pressure, 60% relative humidity, 59 °F (15 °C) inlet air temperature, 3.4 in. water (87 mm water) inlet loss, 5 in. water (127 mm water) exhaust loss, air-cooled generator and .90 power factor (pf).

Combustor type	DLN Dry	Conventional Water injection	Conventional Steam injection	DLN* Steam augmentation
Fuel	Natural gas	Natural gas	Natural gas	Natural gas
Net power output (kW)	196,000	207,790	215,650	219,400
Net heat rate (Btu/kWh) (LHV)	9,059	9,442	8,736	8,846
Net heat rate (kJ/kWh) (LHV)	9,557	9,961	9,217	9,333
Exhaust temperature (°F/ °C)	1,079/582	1,052/567	1,072/578	1,092/589
Exhaust flow (lb/hr)	3,988,800	4,105,581	4,123,828	4,120,363
Exhaust flow (kg/hr)	1,809,308	1,862,279	1,870,556	1,868,984
Fuel flow (lb/hr)	82,542	91,205	87,579	90,272
Fuel flow (kg/hr)	37,441	41,370	39,726	40,947
Fuel	Liquid	Liquid	Liquid	Liquid**
Net power output (kW)	186,650	193,417	206,244	
Net heat rate (Btu/kWh) (LHV)	9,451	9,674	8,879	
Net heat rate (kJ/kWh) (LHV)	9,972	10,206	9,368	
Exhaust temperature (°F/ °C)	1,048/584	1,033/556	1,054/568	
Exhaust flow (lb/hr)	4,030,920	4,100,167	4,143,902	
Exhaust flow (kg/hr)	1,828,413	1,859,824	1,879,662	
Fuel flow (lb/hr)	95,361	101,146	98,999	
Fuel flow (kg/hr)	43,255	45,879	44,906	

* Steam injected through the combustor section casing into the compressor discharge air to increase output.

** Steam augmentation with liquid fuel available on a case-by-case basis.

Correction curves

To estimate thermal performance of the SGT6-PAC 5000F plant at conditions other than those noted above, the following correction curves are provided:

- Correction for compressor inlet temperature (Figure 8)
- Correction for excess exhaust pressure loss (Figure 9)
- Correction for excess inlet pressure loss (Figure 10)
- Correction for barometric pressure* (Figure 11)

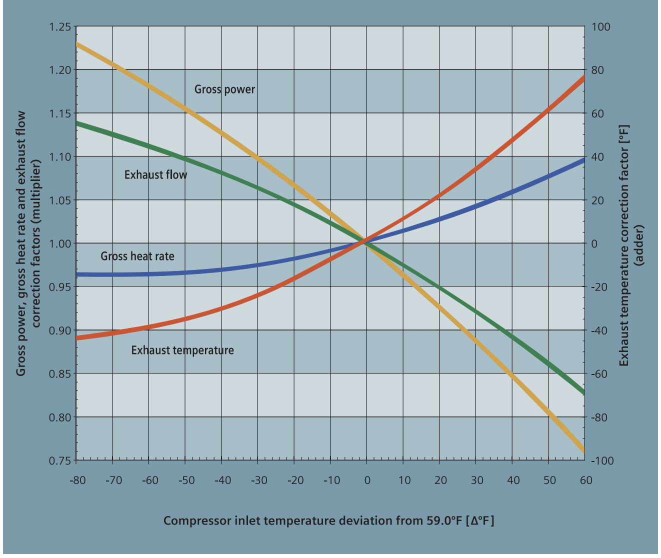
  *Barometric pressure (BP) can be calculated from the site elevation (ELE) using: $BP = 7.08601\ E\text{-}09 \times ELE^2 - 5.29221\ E\text{-}04 \times ELE + 14.696$

SGT6-PAC 5000F simple cycle performance

Correction curves

To estimate thermal performance of the SGT6-PAC 5000F at conditions other than those noted, the following correction curves may be used:

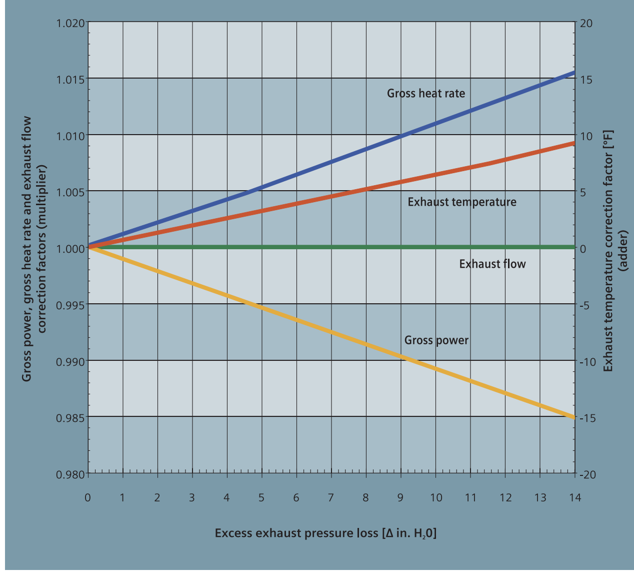
Figure 8 - SGT6-PAC 5000F simple cycle turnkey plant corrections for variations in compressor inlet temperature deviation



Conditions:

Gas fuel: 100% CH_4 | Barometric pressure: 14.696 psia | Compressor inlet temperature: 59°F | Inlet total pressure loss: 3.4 in. H_2O | Compressor inlet relative humidity: 60% | Exhaust static pressure loss: 5.0 in. H_2O

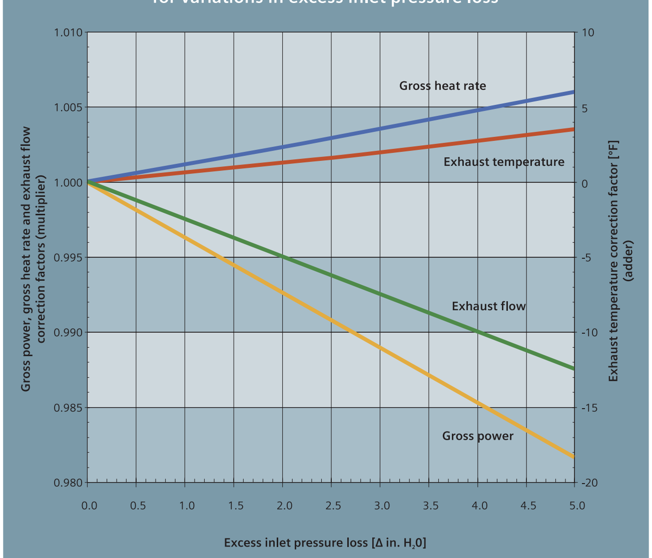
Figure 9 - SGT6-PAC 5000F simple cycle turnkey plant corrections for variations in excess exhaust pressure loss



Conditions:

Gas fuel: 100% CH_4 | Barometric pressure: 14.696 psia | Compressor inlet temperature: 59°F | Inlet total pressure loss: 3.4 in. H_2O | Compressor inlet relative humidity: 60% | Exhaust static pressure loss: 5.0 in. H_2O

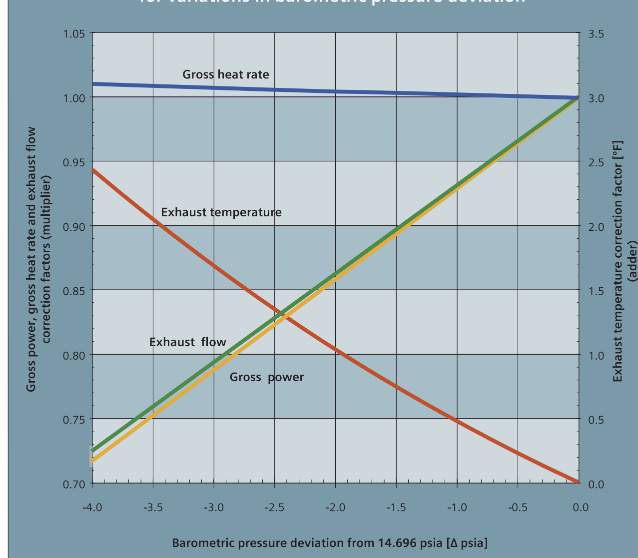
Figure 10 - SGT6-PAC 5000F simple cycle turnkey plant corrections for variations in excess inlet pressure loss



Conditions:

Gas fuel: 100% CH_4 | Barometric pressure: 14.696 psia | Compressor inlet temperature: 59°F | Inlet total pressure loss: 3.4 in. H_2O | Compressor inlet relative humidity: 60% | Exhaust static pressure loss: 5.0 in. H_2O

Figure 11 - SGT6-PAC 5000F simple cycle turnkey plant corrections for variations in barometric pressure deviation



Conditions:

Gas fuel: 100% CH_4 | Barometric pressure: 14.696 psia | Compressor inlet temperature: 59°F | Inlet total pressure loss: 3.4 in. H_2O | Compressor inlet relative humidity: 60% | Exhaust static pressure loss: 5.0 in. H_2O

SGT6-PAC 5000F technical data

SGT6-5000F gas turbine

Compressor

Type	Axial flow
Number of stages	16
Rotor speed	3600 rpm
Pressure ratio	17:1
Inlet guide vanes	Variable

Combustion system

Combustors:	
Type	Dry Low NO_x
Configuration	Can-annular
Fuel	Gas fuel only
	Gas fuel & liquid fuel (option)
Number	16
Fuels:	
Natural gas pressure range	475 to 500 psig - Nominal @ gas turbine filter/separator inlet flange
Liquid fuel (option)	50 to 90 psig @ fuel oil skid interface flange (Demineralized water injection required)

Turbine

Number of stages	4
Number of cooled stages	3

Bearings

Journal bearing:	
Type	Tilting pad
Quantity	2
Thrust bearing:	Drive end
Type	Tilting pad
Number	1

Drive	Cold end, direct coupled

Generator

Standard	ANSI/IEC
Type	
- Base	Open air-cooled (OAC)
- Option	Totally enclosed water-to-air-cooled
- Option	Hydrogen-cooled
Excitation	
- Base	Brushless
- Option	Static
Nameplate rating	
MVA	249 MVA
Power factor	0.90
Voltage	15 KV
Current	8200 A
Frequency	60 Hz
Speed	3600 RPM
Field current	1544 A
Field voltage	270 V
Ambient temperature	59°F / 15°C
Cold gas temperature	32°C
Insulation class	Class F
Operation class	Class F
Short circuit ratio	0.45
Direct axis impedance	Saturated
	X^{d} = 2.13 per unit
	X'^{d} = 0.26 per unit
	X''^{d} = 0.19 per unit

Starting system

Electric motor started	AC Motor
Starting time to base load*	30 min (base)
Turning gear	DC Drive

Recommended inspection intervals

Inspection type - Gas fuel	Hours	Starts
Combustor	8,333	450
Hot gas path	25,000	900
Major overhaul	50,000	1,800

*A fast-start option is available to provide 150 MW in 10 minutes.

SGT6-PAC 5000F

Plant weights and dimensions

Shown below is a typical list of the major pieces of equipment along with their approximate shipping weights and nominal dimensions.

Item	Weight	Length	Width	Height	Remarks
Gas turbine	462,000 lbs	33 ft 0 in	13 ft 0 in	15 ft 0 in	
Electric motor starting package	36,500 lbs	22 ft 6 in	11 ft 6 in	16 ft 9 in	
Electrical package	33,000 lbs	32 ft 0 in	12 ft 6 in	11 ft 3 in	
Lube oil package	60,000 lbs	25 ft 0 in	12 ft 0 in	12 ft 0 in	
Lube oil cooler (fin-fan)	29,000 lbs	25 ft 0 in	12 ft 0 in	13 ft 8 in	with support structure
Lube oil cooler (duplex plate)	16,000 lbs	13 ft 6 in	11 ft 10 in	7 ft 1 in	with support structure
Turbine piping package	35,000 lbs	40 ft 0 in	10 ft 10 in	11 ft 11 in	
Rotor air cooler (fin-fan)	27,000 lbs	22 ft 0 in	13 ft 6 in	12 ft 0 in	
Generator Aeropac II	530,000 lbs	41 ft 0 in	13 ft 0 in	14 ft 0 in	acoustic / weather enclosure; ships separately

Heaviest piece lifted		Weight
During construction	Air-cooled generator	550,000 lbs
After construction	Bladed gas turbine rotor	110,000 lbs

SCC6-5000F combined cycle plants

General description

Combined cycle plants can be made up of various combinations of gas turbines, HRSGs and steam turbines. The scope of supply can be a SGT6-PAC 5000F package, SCC6-PAC 5000F power island or SCC6-5000F turnkey plant.

A typical 2x1 combined cycle power plant consists of two SGT6-5000F gas turbines each with a dedicated HRSG that supplies steam to a shared steam turbine. The gas turbines will primarily burn natural gas with optional provisions to burn liquid fuel as a backup. Each gas turbine will be coupled with a three-pressure reheat HRSG, which will generate steam to operate the steam turbine. Generators attached to the two gas turbines and the steam turbine will supply electrical power to the grid.

Major equipment

A typical 2x1 turnkey combined cycle plant consists of the following major equipment:

- Two SGT6-5000F gas turbines with air-cooled generators
- Two three-pressure level reheat HRSGs with stacks (fired as an option)
- One multi-cylinder reheat condensing steam turbine with air-cooled generator
- One water-cooled condenser using a forced-draft cooling tower
- One integrated plant distribution control system
- Balance of plant (BOP) equipment consisting of pumps, transformers, power electrics, etc.
- HV switchyard.

Major equipment descriptions

Gas turbine

The SGT6-5000F gas turbine as outlined in the general description can be applied in a combined cycle application.

Heat recovery steam generator

The three-pressure, reheat HRSGs produce steam, which drives the steam turbine. The exhaust gas flows horizontally through the HRSGs releasing heat through the finned tubes to the water/steam cycle.

Depending on specific project requirements, the HRSG can be either a drum-type or a once-through design.

The sections of the drum-type HRSG contain economizer tube bundles, evaporator tube bundles with associated steam drums, and a superheater tube bundle. Feedwater is pumped through the economizer sections for optimized performance.

The once-through, BENSON® technology HRSG has an advanced superheater outlet design to enhance fast start capability, making the plant better suited for operating regimes between intermediate and continuous duty. The feedwater is passed through a condensate polishing system and pumped through the sections of the boiler.

Either HRSG design can be supplied with provisions for SCR and/or CO catalyst.

Steam turbine

The steam generated in the HRSG is supplied to a two-cylinder, reheat, condensing steam turbine with high efficiency blading. Depending on the back pressure or the amount of HRSG supplemental firing, the steam turbine is optimized as either a single-flow axial exhaust condensing type, a dual-flow side or a down exhaust condensing type.

The single-flow turbine consists of a single-flow HP turbine element and a combined IP/LP element. The dual-flow turbine consists of a combined HP/IP turbine element and a double flow LP turbine element.

Main steam is supplied directly to the HP turbine inlet valves. Hot reheat and IP induction steam enters through the IP turbine inlet valves. In the dual-flow steam turbine, LP induction steam enters the steam path through a port normally located in the crossover pipe. In the single-flow steam turbine, LP steam enters the steam path through an induction port appropriately located in the turbine blade path. Upon exiting the LP turbine, steam exhausts into a water-cooled or air-cooled condenser.

100% steam turbine bypass system

The condenser is designed to accommodate the exhaust from the steam turbine plus the miscellaneous drains from the steam system. The condenser is also designed to allow 100% steam bypass of the steam turbine.

Condensate pumps

Condensate is pumped from the condenser hotwell by 2x50% condensate pumps (one full capacity pump for each HRSG). The condensate then passes through the low temperature economizer section in the HRSG prior to entering the LP steam drum and boiler feedpump section. For redundancy, an optional 3x50% arrangement is available.

Boiler feedwater pump island

A boiler feedwater pump island concept is employed using 2x50% pumps (one full capacity pump for each HRSG) headered together. These pumps supply feedwater to the HP and LP boiler sections of the HRSGs. The pumps are electric motor-driven and are located adjacent to the HRSG nearest the steam turbine. The pumps take suction from the condensate pump discharge after the low temperature economizer raises the pressure to the appropriate level to supply the feedwater to the boiler section(s).

Cooling system

A typical combined cycle plant incorporates a water-cooled condenser using a forced-draft wet cooling tower. Additional arrangements include a condenser with once-through cooling, air-cooling or a hybrid cooling tower.

Control, protection and monitoring

Control, protection and monitoring functions for the SGT6-5000F gas turbine-based power plant are performed by the Siemens Power Plant Automation (SPPA™) system known as the SPPA-3000. This microprocessor-based distributed control system located within the electrical package has the flexibility to accommodate a wide range of plant configurations and interface options.

Although the SGT6-PAC 5000F power plant control system is provided specifically for the gas turbine-generator unit and its direct auxiliaries, it is expandable to accommodate additional control system automation processors and cabinets of the same manufacturer on the network, in the central control room or other locations.

Balance of Plant (BOP) functions may include thermal equipment, circulating water loops, switchyard monitoring and SCADA interface for a complete combined cycle plant.

Supplemental HRSG firing (option)

Supplemental HRSG firing (duct firing) is available as an option to increase the plant output by introducing additional heat energy into the gas turbine exhaust stream. By adding burners strategically located in the HRSG, plant output can be increased by over 6% with moderate duct firing and over 20% with heavy duct firing.

Site layout and arrangement of equipment

Using a modular approach, the Siemens Reference Power Plant (RPP) can readily be configured to satisfy a number of site or customer specific requirements.

Figure 12 - SCC6-5000F 2x1 combined cycle plant general arrangement drawing (as shown on page 26) illustrates the base design configuration for a single fuel (natural gas only), outdoor arrangement with a cooling tower.

BOP equipment will be provided in accordance with Siemens RPP designs as modified to suit site-specific requirements. Pre-engineered options are available to address customer requirements.

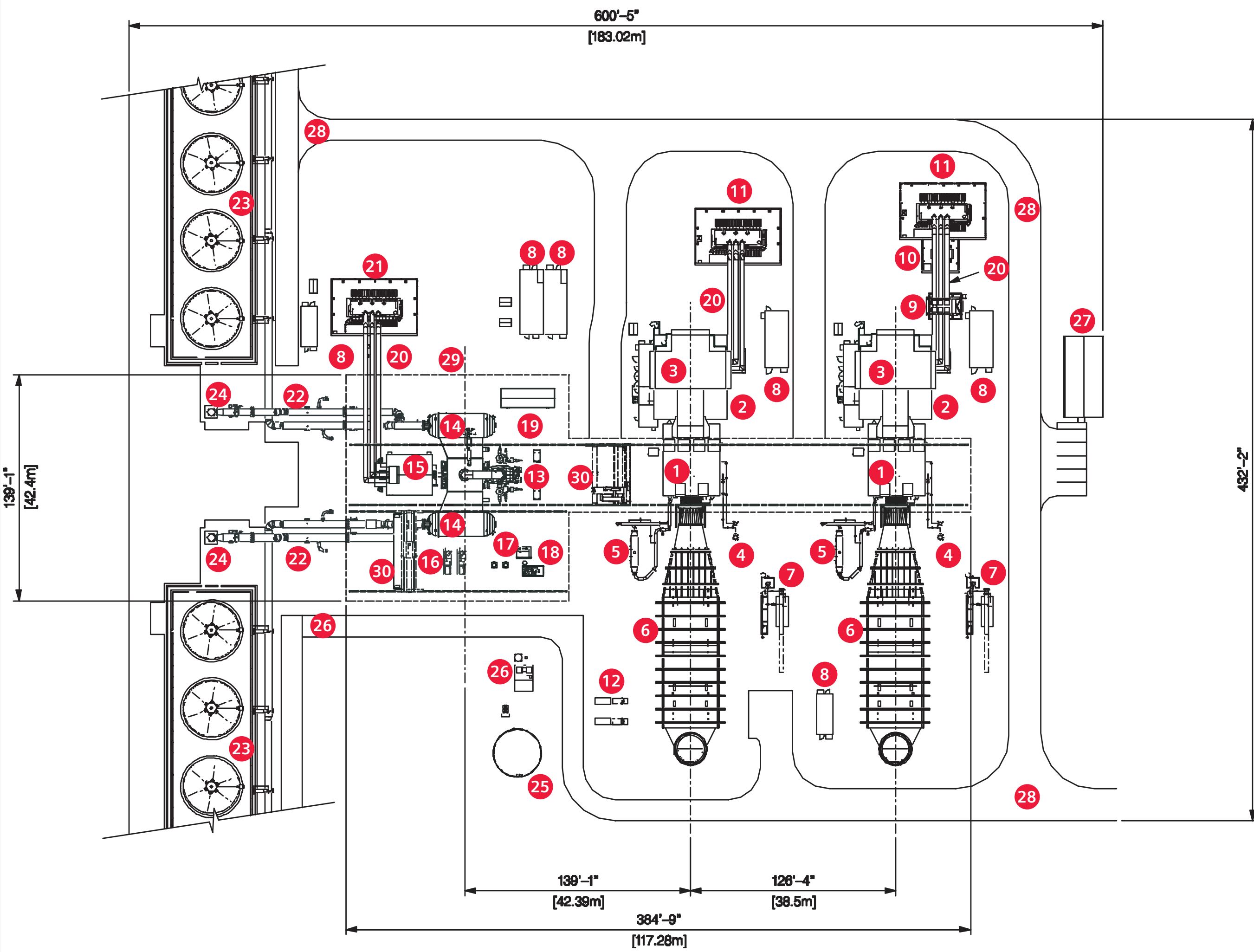
The overall site and building arrangements were developed to optimize space requirements while maintaining ample access for operation and maintenance activities.

The gas turbine-generators, steam turbine-generator, condenser and associated auxiliaries are normally located outdoors but can also be placed in a building as an option. The HRSG and associated auxiliary equipment are located outdoors.

Figure 13 - SCC6-5000F 1x1 combined cycle plant general arrangement drawing (as shown on page 27) illustrates the base design configuration for a single fuel (natural gas only), outdoor arrangement with a cooling tower.

SCC6-5000F plant arrangement diagrams

Figure 12 - SCC6-5000F 2x1 combined cycle plant general arrangement drawing



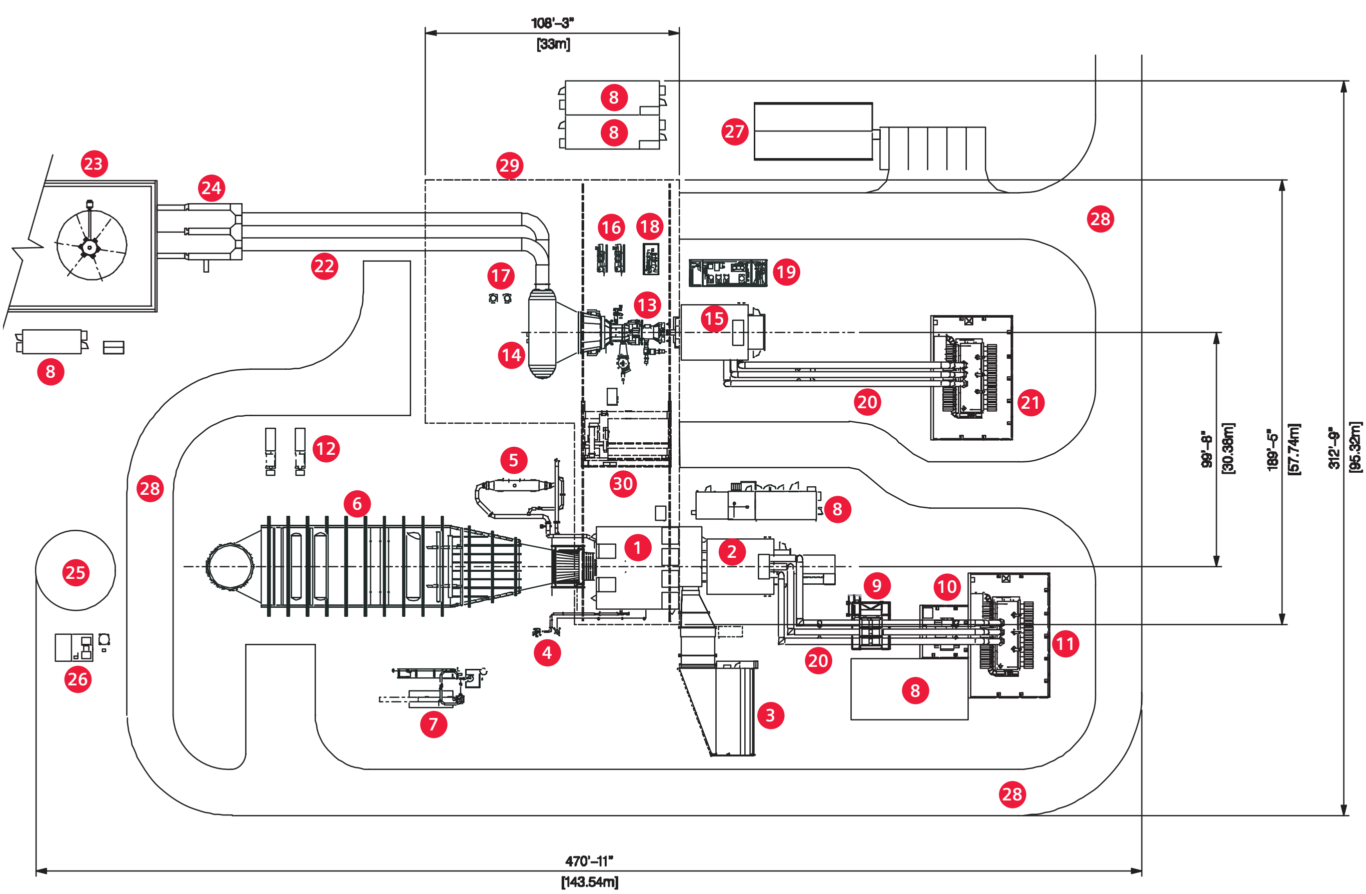
Key:

1. SGT6-5000F Gas Turbine (GT) enclosure
2. GT generator (TEWAC – below inlet filter)
3. GT air inlet filter
4. Fuel gas filter/separator
5. Rotor air cooler (kettle boiler type)
6. Heat Recovery Steam Generator (HRSG)
7. Fuel gas preheater
8. Power control center
9. Generator breaker
10. Auxiliary transformer
11. GT generator transformer
12. Boiler feedwater pumps
13. Steam turbine
14. Surface condenser
15. ST generator (TEWAC)
16. Vacuum pumps
17. Main condensate pumps
18. Gland steam skid
19. Lube oil skid
20. Isolated phase bus duct
21. ST generator transformer
22. Cooling water pipe
23. Cooling tower
24. Cooling tower pump
25. Demineralized water storage tank
26. Compressed air system
27. Control room building
28. Roads
29. Generation building (option)
30. Bridge crane (option with generation building)

Notes: The equipment shown is representative information. This design is subject to change at the discretion of Siemens. All dimensions shown are in feet and inches (metric). Cooling tower location to be determined by prevailing winds.

SCC6-5000F plant arrangement diagrams

Figure 13 - SCC6-5000F 1x1 combined cycle plant general arrangement drawing



Key:

1. SGT6-5000F Gas Turbine (GT) enclosure
2. GT generator (TEWAC)
3. GT air inlet filter
4. Fuel gas filter/separator
5. Rotor air cooler (kettle boiler type)
6. Heat Recovery Steam Generator (HRSG)
7. Fuel gas preheater
8. Power control center
9. Generator breaker
10. Auxiliary transformer
11. GT generator transformer
12. Boiler feedwater pumps
13. Steam turbine
14. Surface condenser
15. ST generator (TEWAC)
16. Vacuum pumps
17. Main condensate pumps
18. Gland steam skid
19. Lube oil skid
20. Isolated phase bus duct
21. ST generator transformer
22. Cooling water pipe
23. Cooling tower
24. Cooling tower pump
25. Demineralized water storage tank
26. Compressed air system
27. Control room building
28. Roads
29. Generation building (option)
30. Bridge crane (option with generation building)

Notes: The equipment shown is representative information. This design is subject to change at the discretion of Siemens. All dimensions shown are in feet and inches (metric). Cooling tower location to be determined by prevailing winds.

SCC6-5000F plant performance

Combined cycle performance

The performance of combined cycle power plants varies with the site conditions, the equipment selected, and the thermal cycle design. For the SGT6-5000F gas turbine based combined cycle turnkey plant, the components and the cycle have been selected to provide increased performance.

With a turnkey plant scope, we control the design and supply of critical components, thus providing the customer with a single point of contact for performance related issues. Turnkey combined cycle performance is shown in the table below.

Figures 14 through 19 provide factors to estimate the performance for different compressor inlet air temperatures and barometric pressures. Figure 20 (as shown on page 30) is a typical cycle diagram for 2x1 combined cycle configuration.

Options are available to increase the plant output on hot days. An inlet air evaporator cooler and/or supplemental HRSG firing can be added to increase the plant output. The combined cycle 2x1 base and output performance (as shown on page 30) shows the typical base plant and typical performance enhanced plant data (including evaporative cooler and supplemental firing options).

Typical SCC6-5000F turnkey combined cycle plant performance

Plant designation	SCC6-5000F 2x1 turnkey			SCC6-5000F 1x1 turnkey		
Cooling configuration	Cooling tower	Once through	Air-cooled	Cooling tower	Once through	Air-cooled
Net power (MW)	593.0	594.8	587.6	294.9	295.9	292.2
Net heat rate Btu/kWh (kJ/kWh)	5983/(6312)	5965/(6293)	6039/(6371)	6013/(6344)	5995/(6325)	6069/(6403)
Steam turbine back pressure in. Hg	1.58	1.00	2.48	1.58	1.00	2.48

Conditions: Elevation: sea level; compressor inlet temp.: 59°F, inlet and exhaust losses and auxiliary loads includes for net power.

Correction curves

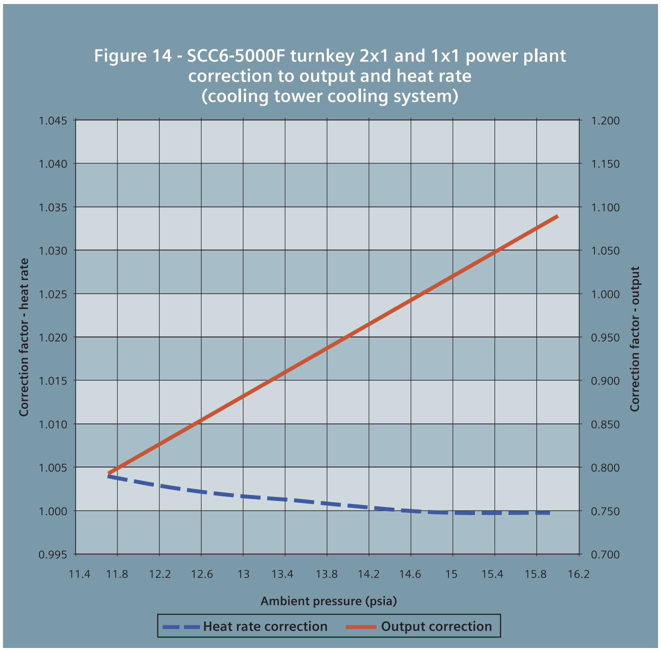


Figure 14 - SCC6-5000F turnkey 2x1 and 1x1 power plant correction to output and heat rate (cooling tower cooling system)

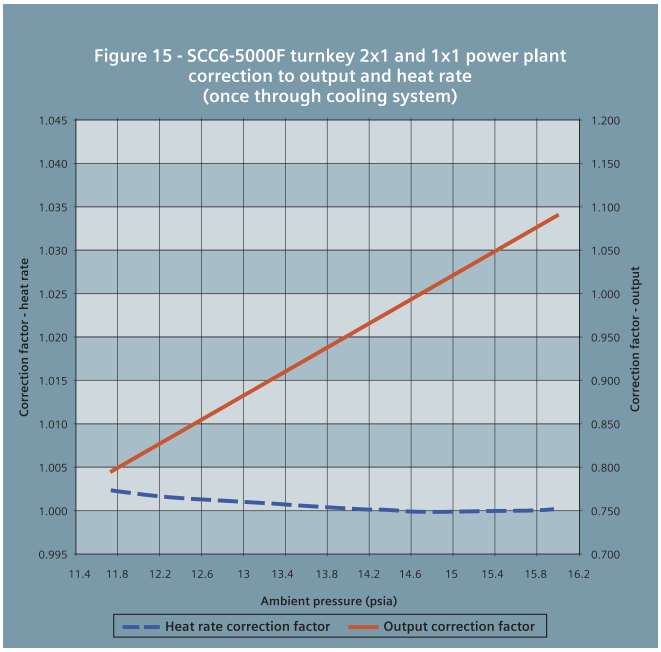
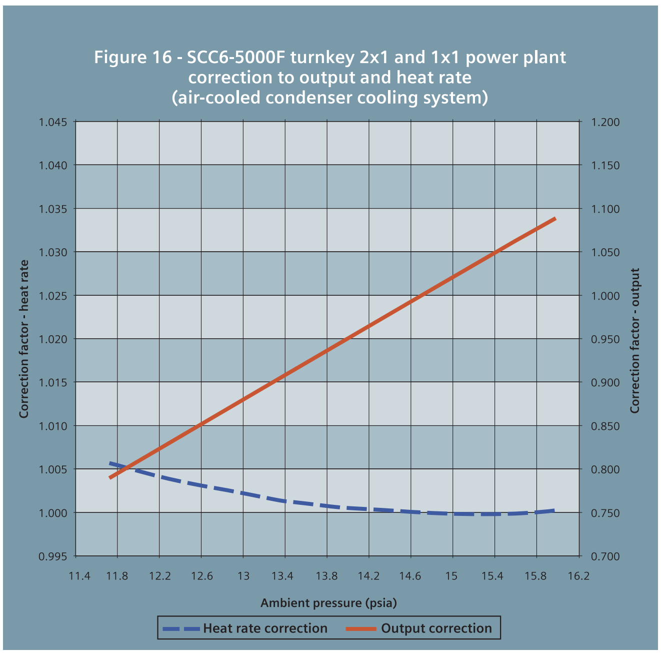
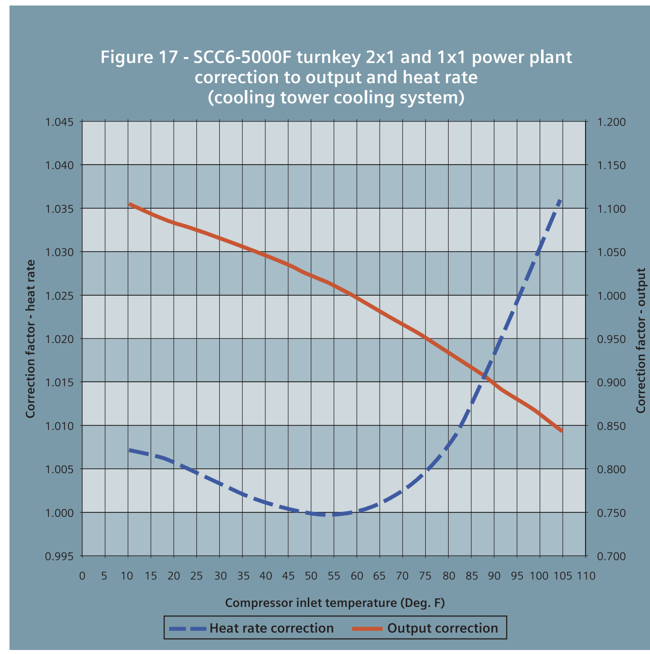
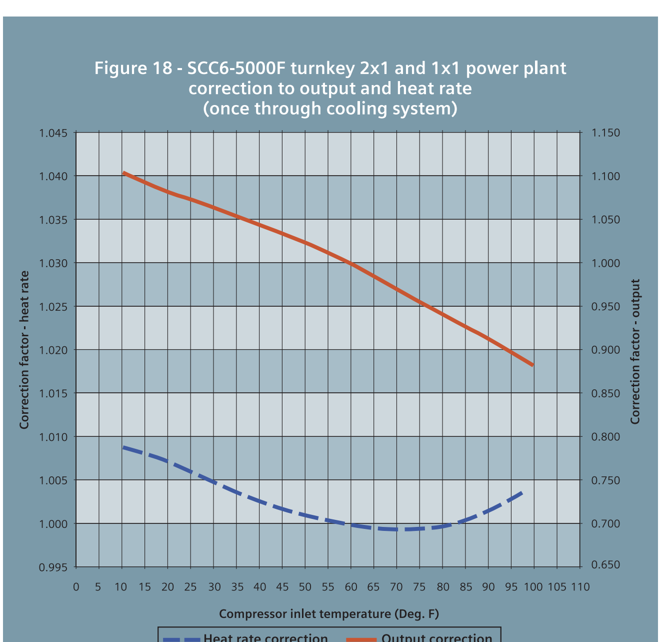


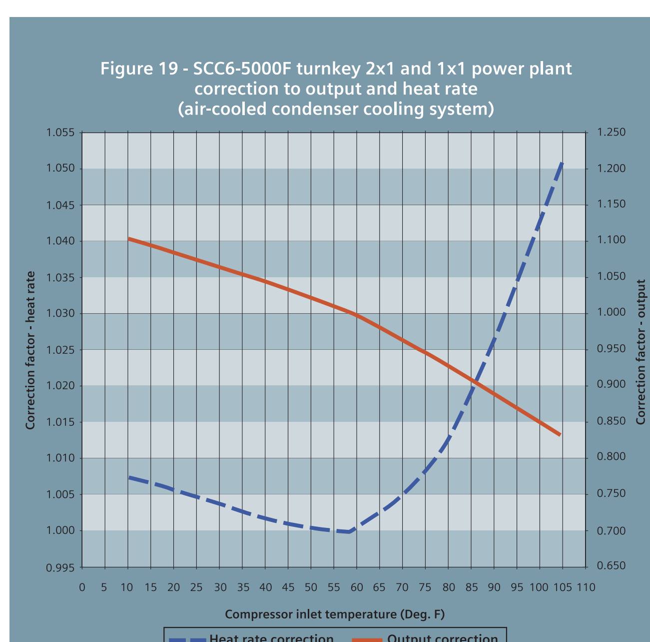
Figure 15 - SCC6-5000F turnkey 2x1 and 1x1 power plant correction to output and heat rate (once through cooling system)

Correction curves









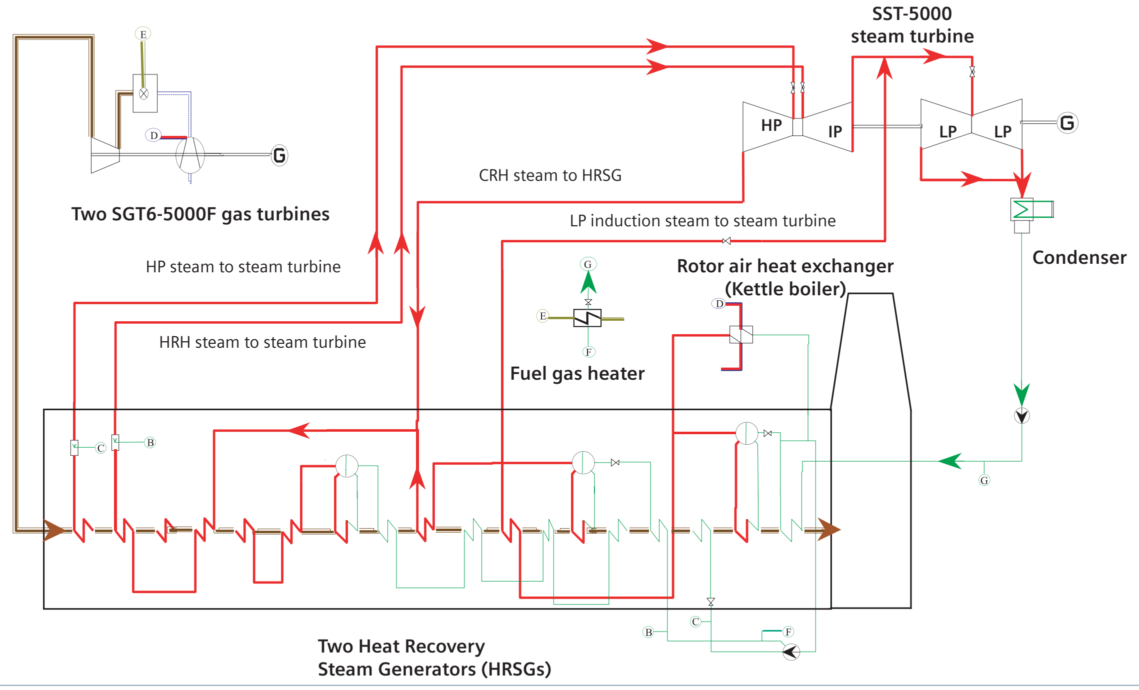
SCC6-5000F plant performance

Combined cycle 2x1 base and output enhanced performance

Operating conditions	Base plant	Plant with performance options
Evaporator cooler	No	Yes
Supplemental firing	No	Yes
Ambient temperature (°F/°C)	59/15	105°F
Relative humidity (%)	60	35
Barometric pressure (psia/bars)	14.69/1.033	14.69/1.033
Fuel	Natural gas	Natural gas
Fuel heating value (LHV)	21511 Btu/lb	20980 Btu/lb
Fuel heating value (LHV)	50034 kJ/kg	48800 kJ/kg
Fuel HHV/LHV ratio	1.1	1.1
Generator power factor	0.9	0.9
ST backpressure (in.-HgA/mbar)	1.5/50	3.19/108
ST throttle pressure (psia/bars)	1817/125	2277/157
ST throttle temperature (°F/°C)	1050/565	1050/565
ST reheat pressure (psia/bars)	351/24	442/30
ST reheat temperature (°F/°C)	1050/565	1050/565
Gross plant output (MW)	598 (1)	592.9 (2)
Net plant output (MW)	590 (1)	580.1 (2)
Net plant heat rate (btu/kWh)	5960 (1)	6227 (2)
Net plant efficiency (%)	57.2 (1)	54.8 (2)

(1) based on once through cooling (2) based on cooling tower

Figure 20 - Cycle diagram with drum-type boiler



Integrated gasification combined cycle plant application

The reliable SGT6-5000F gas turbine technology can be used in low-Btu fuel (syngas) applications, such as Integrated Gasification Combined Cycle (IGCC) and Bitumen upgrader projects where syngas fuel is available.

The SGT6-5000F gas turbine has been analyzed for operation in syngas applications. Few changes are needed when compared to a natural gas fueled gas turbine. The major change is to a dual fuel (syngas and natural gas) combustion system specifically designed for IGCC and other syngas applications. Other changes include the addition of a fuel mixing skid, local N_2 storage for purging the fuel system during start up and shut down, control system changes, and additional monitoring systems needed due to the high H_2 and CO fuel.

The modified combustion system was designed to operate on either syngas or natural gas or both. The syngas capable design is a diffusion combustor derived from the proven DF42 combustion system utilized on natural gas and distillate oil fueled SGT6-5000F engines and on syngas/natural gas in two W501D5 gas turbines at the LGTI IGCC project from 1987 to 1995. The fuel nozzle is designed to accommodate multi-fuel operation, diluent injection, fuel transfers and co-firing. The gas turbine combustor cover plates are modified for syngas operation.

Syngas is the primary fuel for IGCC applications. Natural gas is used for start up and as a backup fuel. During the start up process at 30% load, the gas turbine is transitioned to syngas and taken to base load. The principal components of the syngas system are located outside the turbine enclosure.

After the syngas flows through the syngas saturator and heater in the BOP piping, it is blended with N_2 (as a diluent) at the blending station and supplied to the inlet of the syngas strainer. Exiting the syngas strainer, the syngas is routed through similar components as the natural gas system including the overspeed trip, throttle, and isolation valves and into the syngas manifold.

Based on the proven SCC6-5000F 2x1 combined cycle plant, a nominal 600 MW IGCC power island design has been developed (as shown in Figure 21). This includes a steam bottoming cycle that is fully integrated with the gasification island and a larger steam turbine to maximize plant output.

In addition to the power island Siemens equipment scope of supply may include most of the major compression solutions for today's IGCC plants, including air separation units, main air compressors and O_2, N_2 and CO_2 compression solutions. Depending on the needs of the IGCC project, Siemens can participate in a broader role in the project up to and including supplying the total plant as a member of an EPC Consortium.

The SPPA-T3000 control system normally supplied with a SCC6-5000F 2x1 combined cycle plant can be expanded to control the entire IGCC plant, including the gasification island(s), gas clean-up systems and the air separation unit(s).

Figure 21 - SGT6-PAC 5000F for syngas applications

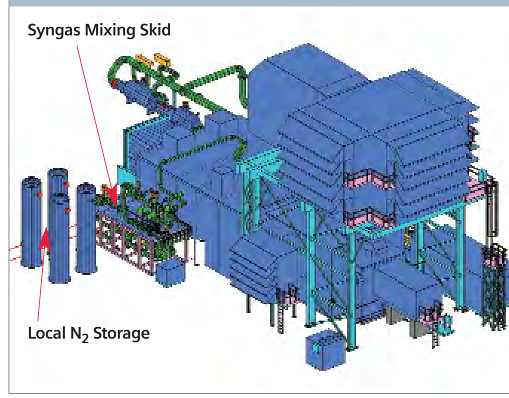


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Exhibit 3

Fast-Cycling Towards Bigger Profits

combined cycle

Fast cycling towards bigger profits

1 June 2007

2

To maximise profits in today's power markets combined cycle plants must be as flexible as possible and capable of fast start-up. With the right package of technologies, very fast start-up times can be achieved and have been demonstrated in the field at operating plants.

Most combined cycle plants were initially designed for baseload operation, with low fuel prices in the 1990s resulting in low electricity costs. Today, however, many already existing combined cycle plants have shifted to intermediate load and new plants are specified for cycling load regimes because of the current high gas prices and the addition of wind capacity dictating a need for flexible back-up power supply. Therefore features providing high operational flexibility, such as short start-up and shut-down times, are highly valued today by power plant owners.

Market drivers

Additional drivers increasing the emphasis on flexibility are the volatile, deregulated, power markets and related risks, such as fluctuating fuel and electricity prices. In addition, a flexible plant opens up new business opportunities including getting involved in hourly and seasonal market arbitrage, participation in ancillary energy markets and peak shaving. Therefore, plants need to have short start-up times and good cycling capabilities, while at the same time achieving the highest possible efficiencies.

In the highly competitive liberalised markets of today many plants do not have a power purchase agreement that guarantees long term and stable revenues. They are more likely to operate as market driven merchant plants in direct competition with other power plants positioned most favourably in the dispatch ranking. Energy traders have various markets offering a variety of different opportunities for placing the power output. Examples are bilateral OTC contracts, power exchanges or markets for ancillary services. Each of these markets itself can be accessed with a variety of products. Within this context a share of the power output can be placed with a long term contract, providing planning security over longer periods, but with lower margins, while another part of the power output can be sold under short term agreements, on the day or even an hour prior, offering higher margins linked to higher risks.

As well as the idea of participating in the market by dividing up the power output, provision of ancillary services provides other ways of achieving higher revenues in liberalised energy markets. For instance, for spinning reserve an allowance is paid simply for the capability to provide power on request. In the event of being dispatched, the power must be provided within minutes and an additional utilisation fee is paid. The plant's capability for participation is the chief criterion to qualify for this market, and a value can be attached in terms of the extra earnings it can bring.

What is required from power plants?

Siemens' reference power plant (RPP) development activities are focused on life-cycle-cost optimisation by identifying and understanding the most important drivers for maximising customer value. The focus of these activities has changed over the years according to the evolving market requirements. In the 1990s, the reference power plants were designed for baseload operation with a small number of starts per year. At that time the start-up time for a 400 MW single shaft plant after an overnight shut-down (of about eight hours) was 90 minutes.

In response to the altered market requirements, we developed several features that were incorporated into the reference power plants. These included a fast start-up concept reducing the start-up time after overnight shutdown for a single-shaft plant by more than 50%.

Looking at the distribution of the dispatch ranking for different power plants in the USA, for example, it can be seen (Figure 1) that the combined cycle plants are relatively close in terms of production costs. In the current market situation, they are in the steep part of the dispatch curve and are mostly in the mid-merit rank. In this area especially a small change in production cost can have a huge impact on the dispatch rate. If a change in plant flexibility reduces the production cost by 6 to 8%, the dispatch rate can increase from 10 to 70%, potentially offering a significant improvement in plant economics, and strengthening the economic case for retrofitting existing units.

Figure 2 shows another view of what is required from the various power plant types. This is for the case of Germany, with its increasing wind load. Starting from the bottom of the curve, the renewables replace other baseload units due to the feed-in obligation.

With the rising share of wind, there is the risk in a low total load situation that, without sufficient flexible back up power from combined cycle and gas turbines, the whole system will be at risk of not sufficiently maintaining reliability of supply in the case of a wind shortage.

How to improve cycling capability

Some of our F-class units already start-up approximately 300 times per year on a daily cycling routine. An improvement in the start-up time and cycling capability will put those plants into the best position to comply with the complex market requirements and to maintain a system reliability.

The cycling capability improvements encompass the entire plant, not just individual components. A selection of measures can be seen in Figure 3.

High performance components play a key role in the plant optimisation, however individually they do not do the trick. Only by incorporating know-how from all the different areas and optimising the interaction between the main components, such as gas turbine/steam turbine/generator and all the major balance of plant equipment (HRSG, pumps, deaeration system etc) and the control system, was it possible to significantly improve the cycling behaviour of the plant.

A faster plant start-up will provide significant benefits whether the start is expected or unexpected (see Figure 4). What do we consider to be an expected or an unexpected start?

An expected start will be the normal start where you know that you have to deliver a certain amount of power at a certain time. The plant is planned to be on-line at times when the revenues are higher than the marginal cost of generation. Generally the revenues are below the marginal cost before that time. With a faster start-up less power will be produced during the unfavourable revenue time than with a slower start-up and will be at full power at the same, favourable, time as with the slower start-up.

In addition that power will be produced at a higher average efficiency as the steeper start-up curve gets you through the low efficiency area faster. The efficiency gain can be translated into saved fuel. Per start this will be around h2700 with an assumed fuel price of h4.9/GJ. For a cycling plant with 200 starts per year this can sum up easily to more than half a million h per year direct savings. Additional savings can come from reduced CO2 emissions of about 30t for each fast start-up.

An unexpected start could be triggered by a call from dispatch that additional power is needed or when an additional short-term market opportunity arises. It is here that the power is needed as fast as possible. Each generated megawatt will have revenues above the marginal cost. With the faster start-up you will generate more power in the same period, again with a significantly higher average efficiency. Here the average efficiency of a fast start is 16 percentage points better than the normal start, with the consequent reduction in CO2 emissions. This increased average efficiency translates into an extra revenue of about h850 000 per year for a cycling plant, taking into account an average electricity revenue of h50/MWh and the additional fuel consumed.

An additional benefit from running up faster are the reduced CO2 emissions due to the higher average efficiency of the start-up and the reduced NOx emissions due to the faster transient through the low power region.

Putting a value on flexibility

Direct modelling of fast start-up benefits can be carried out based on a single plant net present value (NPV) analysis.

The following are the input assumptions for a 400 MW combined cycle power plant:

Load regime: 200 hot, 50 warm starts per year (expected starts 90-95%);

Fuel price: h4.9 per GJ;

Revenues for electricity production: 50%/75% of baseload during warm/hot start, h50 per MWh at baseload;

Costs for balancing energy: h75 per MWh;

Plant lifetime: 20 years;

Other variable costs: no difference between fast and normal start.

The operational duty is considered to be daily cycling, eg with overnight shut-down on weekdays and weekend shut-down. The majority of the starts (>90%) will be in accordance with long-term scheduling. The fuel price of h4.9/GJ is assumed as an average for a European location. As the majority of the starts are expected, a reduction of the electricity revenues to below the average baseload revenues of h50/MWh is assumed. For hot expected starts the revenue during the start is assumed to be 75% of the baseload revenue, for the warm expected start this is reduced to half of the baseload revenues.

The future revenue streams are discounted in the NPV calculation. All other variable costs are considered to be the same for the two different start-up modes.

Reductions in emissions are not considered here. So benefits from, for example, carbon dioxide certificate trading are not taken into account, giving a conservative approach to start-up time reduction evaluation.

The results of the economic evaluation are shown in Figure 5. With the assumptions listed above the evaluated benefit over the plant lifetime is around h100 000 per minute of start-up time reduction.

The evaluation factor (benefit of one minute reduction in start-up time) is strongly dependent on the assumed operational details and the specific market requirements. Figure 5, for example, shows the effect of different proportions of expected and unexpected starts.

The numbers are an indication of the value of flexibility. As they are highly dependent on the boundary conditions projects need to be assessed on a case by case basis.

Even with the conservative assumptions made, a start-up time reduction of 20 minutes, which can be achieved with available Siemens technology for fast cycling plants, will amount to savings of h2 million over the plant lifetime.

This evaluation arises from direct modelling of the benefits against an assumed constant market. For a limited set of input parameters and a manageable set of boundary conditions the direct evaluation gives clear and straightforward evaluation factors. However, considering more advanced market scenarios and operational regimes requires direct modelling against volatile input parameters. Here a dispatch model approach is better suited to accommodate the correlations between different factors or completely different plant behaviours.

As an example of the dispatch modelling approach we can compare two operational strategies for dealing with low electricity revenues at night: shut down vs continuing to operate at minimum load during the night.

In a dispatch model, market assumptions, eg the demand and the revenue curves, are either taken from history or are adapted curves for assumed future market behaviour. The different technical options or operational strategies are then modelled, with their capabilities, constraints and associated costs. The results provide comparisons between the different approaches in the assumed market environment.

In this case we assume: 20 years lifetime; 400 MW combined cycle plant in cycling mode; fuel price of h4.9/GJ; and electricity revenues of h50 /MWh during the day and h25/MWh during the night. The dispatch model shows that shut down at night and restart in the morning has a positive net present value over the plant lifetime of h18.6 million for the operator compared with continuing to operate at minimum load during the night.

The additional start-up cost is far lower than the unfavourable revenue stream at minimum load during the night. This decreases the marginal cost of power production and increases the dispatch rank of the plant.

How fast can start-ups be?

So what start-up times have been achieved in the field with a Siemens combined cycle power plant? Figure 6 shows the results of a plant test on a single shaft site with a conventional drum HRSG. The plant was ramped up fully automatically according to the new fast start procedure.

For the start-up time optimisation, a holistic approach was taken, involving not just the gas turbine and HRSG but all aspects of plant design. With all parties working together further potential was identified with a revised unit start-up procedure for hot starts (about 8 h downtime). The interaction of the gas turbine, steam turbine and BoP was optimised. The result is the so-called parallel start-up procedure where the gas turbine is started and ramped up at the maximum allowable gradient. The exhaust gas is led through the HRSG and the first steam is directly used for steam turbine roll off. There is early closing of the HP/IP bypass valves.

The new concept is not only applicable to new plants but is also available as an upgrade package for plants in operation. After analysing and assessing the existing plant design and equipment, we can define fast start-up features which could be implemented without any disadvantages in terms of plant performance and lifetime.

Some fast-start-up features have already been implemented at plants in Spain and Portugal and have been proven during commissioning and commercial operation.

Adoption of the fast-start procedures outlined here enables these types of combined cycle power units to be the fastest starting plants in their class.

To reduce the lifetime impact of fast cycling on a conventional drum HRSG, we have designed, tested and implemented (at Cottam in the UK) a horizontal-exhaust-flow once-through low-mass-flux vertical-tube Benson HRSG, which is licensed to the major HRSG suppliers. This eliminates drums, but entails additional condensate polishing plant. A number of additional combined cycle plants with this type of Benson HRSG are currently under construction or planned.

How to improve your economics

To summarise:

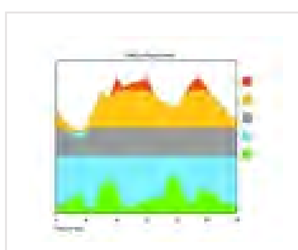
• Changing markets require power plants to be more flexible. Fast start-up and cycling flexibility are essential features to ensure economic success in a liberalised market.

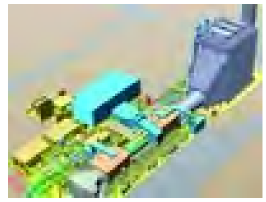
• Fast start-up provides additional benefits to the power plant owner, eg, reductions in fuel costs and emissions, together with increased market compliance advantage.

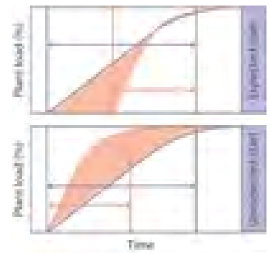
• Combined cycle fast cycling capabilities have been tested and verified in real applications.

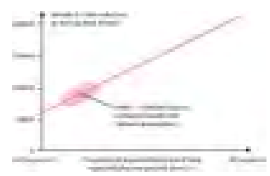
Several owners have now specified the Siemens advanced fast cycling package of features (called Advanced FACY) for new plants and it is being offered as an upgrade for existing plants.

Figure 1. Variable production cost, dispatch rank and projected dispatch rate Figure 2. Typical areas of application for the various power plant types and their requirements (German market) Figure 3. Design features for fast cycling (combined cycle plant with, conventional, drum HRSG) Figure 4. Faster start-up has significant benefits, whether the start is expected or unexpected Figure 5. Calculated benefits of reduction in start-up time, plotted against proportion of expected starts (as percentage of total (expected plus unexpected) starts Figure 6. Comparison, or hot start conditions, of advanced ‘fast cycle’ start-up time with normal start-up time (Siemens SCC5-4000F 1S combined cycle plant). A time of less than 40 minutes was achieved in a fully automated plant test. Fast and reliabl






Plant load (%)
Plant load (%)
Time



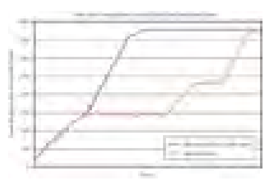


Exhibit 4

Gas Turbine Combined Cycle Fast Start -
The Physics Behind the Concept

Power Engineering

Gas Turbine Combined Cycle Fast Start: The Physics Behind the Concept

06/12/2013

By S. C. Gülen, Bechtel, Principal Engineer

Nowadays all major gas turbine OEMs promote their products with an emphasis on "flexibility" in addition to output and efficiency. The most advertised flexibility feature is the fast start capability of advanced F, G or H class machines in simple and combined cycle modes. Alas, modern gas turbine based combined cycle (GTCC) systems comprise steel behemoths weighing tens of thousands of pounds and operate at extremely high pressures and temperatures while connected to each other via a maze of pipes and valves. This complex architecture presents formidable challenges to designers and operators alike to handle major operational transients with large flow, pressure and temperature (FPT) gradients without adverse impact on reliability, availability and maintainability (RAM). This is primarily achieved by advanced control schemes incorporating model based controls (MBC), design features such as terminal attemperators and cascaded steam bypass as well as material selection. As a result, in terms of dynamic response to transient events, the difference between a modern GTCC and its forerunners is as pronounced as that between cars with carbureted vis-à-vis fuel-injected engines.

The goal of this article is to provide the reader with relevant and easy-to-use technical information (in the form of simple charts, basic equations and representative physical quantities) to form an informed opinion on available technologies and their purported capabilities and benefits along with potential pitfalls and physical limits. The focus is on GTCC startup, which can be considered as a *primus inter pares* among all GTCC transients. Admittedly, an article limited to a few thousand words cannot do justice to the subject matter at hand. The reader is encouraged to consult the listed references for a thorough understanding and guidance for applying the basic principles to his/her own projects.

There are many considerations in a successful GTCC start from standstill, which are discussed in detail elsewhere [1-3]. Correct steam chemistry, establishment of steam seals, vibration, overspeed and thrust controls are all vital for acceptable component life and RAM. When all said and done, however, the single most important issue from a fast start perspective is steam turbine (ST) thermal stress management. Furthermore, if the heat recovery steam generator (HRSG) is drum-type, high pressure (HP) drum thermal stress management becomes an integral part of the problem.

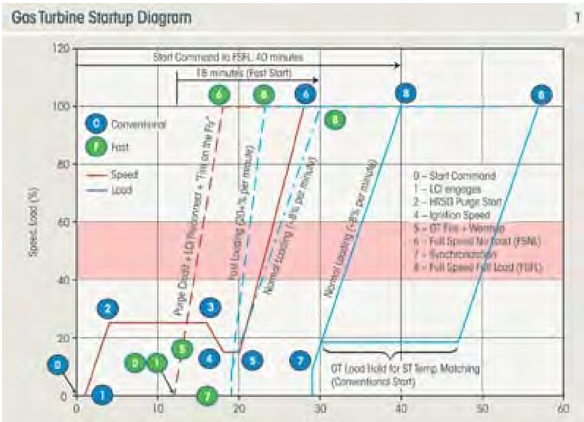
In a nutshell, GTCC startup optimization problem can be formulated as to minimize the time required to reach the dispatch power (e.g., full load or a specific part load) without "breaking anything" in the process - literally. The failure mode to avoid is crack initiation and propagation. Failure to control thermal stresses results in cracks via low/high cycle fatigue (LCF and HCF) and brittle fracture. In fact, LCF is found to account for roughly two thirds of ST rotor life with the remainder attributable mainly to creep. In particular, thick-walled components such as HP drum, ST valves, casings and rotor are exposed to LCF due to thermal cycling (start-stop sequence or load up-down ramps) and associated thermal stress-strain loop.

Definition of key material parameters and their typical values 1

Modulus of Elasticity	E	26,000	ksi
Linear Coefficient of Thermal Expansion	α	6-7 x 10^{-6}	1/R
Poisson's Ratio	ν	0.30	
Thermal Conductivity	k	18.0	Btu/h-ft-F
Density	ρ	490	lb/cuft
Heat Capacity	c	0.125-0.175	Btu/lb-R
Thermal Diffusivity	δ	0.20-0.25	ft²/h

In principle, the solution is simple enough: thermal *decoupling* of GT and ST start processes. Thus, GT is started and rolled to full speed at no load (FSNL) at the maximum rate dictated by the size of static starter (Load Commutating Inverter, LCI), shaft torque limit, particular Dry Low NO_X (DLN) combustion system limits (e.g., availability of heated fuel gas, minimum fuel requirement by the lean blow-out margin, Wobbe index variation, etc.) among others. Following synchronization, GT is loaded as fast as possible first to its minimum emissions-compliant load (MECL) and then to its full load at full speed (FSFL).

GTCC start time definition hinges on when to start the chronometer. Unless specified unambiguously, one can never be sure when time t = 0 is and the difference can be significant. For a conventional start with HRSG purge and normal loading rate (i.e., no holds for HRSG warming) the difference between start command and ignition is 20 minutes (see Figure 1). Thus, the same start time (40 minutes to be exact) can be quoted as 20 minutes by someone who sets t = 0 at ignition. Today's fast start GTs with features like "purge credit", LCI pre-connect and "fire on the fly" can reach FSFL in 18 minutes or less from the start command (depending on the loading rate).

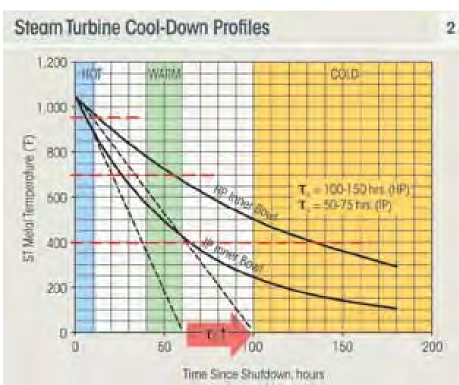


Typical gas turbine startup diagram (conventional and fast versions). Conventional start with GT hold can take up to 50 minutes to reach MECL. Purge credit shaves off 12 minutes of that time. Eliminating GT hold saves another 15+ minutes. With fast start feature MECL point is passed in less than 10 minutes.

The rush to MECL is critical for reduction of startup emissions. The reason for that lies in the basic design philosophy of modern DLN combustors with fuel-air premixing, which are designed to run near the lean limit for low emissions. This is accomplished by piloted, multi-nozzle fuel injectors via sequential activation of fuel flow through individual nozzles (known as staging) to prevent lean blow-out and combustion dynamics while staying within the narrow equivalence ratio band to control NO_X and CO emissions. For older units MECL is 60%; for modern units the low load limit is around 50% (maybe 40% for most advanced systems). The exception to the rule is sequential combustion (reheat) GTs, which can turn off their second combustors to operate at 20% or lower load while emissions-compliant.

Two steps are instrumental in reducing GT start time: elimination of (i) HRSG purge sequence (by performing it right after shutdown in compliance with NFPA® 85) and (ii) hold time at low load with reduced exhaust energy (flow and temperature) to control HRSG steam production rate and steam temperatures (at the HP drum and HP superheater exit). Elimination of direct HRSG steam temperature control via GT load and exhaust energy is the "thermal decoupling", which is the key enabler of fast start. It can be accomplished via a bypass stack and modulated damper controlling the exhaust flow to the HRSG. A recently proposed technique is "air attemperation" of the GT exhaust gas flow via air injection into the transition duct. Ignoring the obvious but wasteful practice of "sky venting", the currently accepted method is a "cascaded" steam bypass system with terminal attemperators (TA). Steam generation and temperature-pressure ramp rates in HP drum are dictated by GT exhaust energy whereas final steam temperature control is accomplished by TAs. Until steam temperatures reach acceptable levels for admission into the ST, steam is bypassed via a route including the reheat superheater so that the latter is pressurized and "wet" (i.e., cooled by steam flow obviating the need for expensive alloys).

Steam FPT acceptable for admission into the ST is dictated by metal temperatures (primarily valves, casings or shells and the rotor). The critical component is the rotor, whose temperature cannot be measured directly and inferred by proxies (e.g., HP and IP inner bowl). ST metal temperature, Tm, is a direct function of unit downtime and ambient temperature as shown in Figure 2 (unless forced cooling is applied to start maintenance as soon as possible to minimize the downtime). The natural cooling time depicted in Figure 2 is represented by the exponential decay law



Typical steam turbine cool down profiles (as measured at HP and IP inner bowls). Shaded regions indicate typical time windows for "hot", "warm" and "cold" start classifications. Red dashed lines indicate average metal HP bowl temperature corresponding to the same.

$$\frac{T_m - T_{amb}}{T_{m,0} - T_{amb}} = e^{-\frac{t}{\tau_c}} \qquad \text{Eq. 1}$$

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- Renewables
- Rotating Machinery
- Steam Generation

with a characteristic cooling time constant, τ_c, as a function of the ambient temperature, Tamb, and the starting value (denoted by subscript 0). This temperature is the main GTCC startup classification gauge instead of widely used but fuzzy terms such as "hot" or "warm", whose definitions vary from one source to another.

Component Tm and, more precisely, its variation in a metal structure across a characteristic dimension, Lc, (e.g., diameter of ST rotor - 20-25 in. for modern GTCC units) along a characteristic dimension, x, is the key determinant of thermal stress via the following formula:

$$\sigma = E' \cdot \alpha \cdot \Delta T_m \qquad \text{Eq. 2}$$

where E' = E / (1-v). For the ST rotor, ΔTm in Eq. 2 is the difference between rotor surface or bore and mean body (bulk) temperatures for surface and bore stresses, respectively. For a given steam temperature, T**stm**, bulk rotor body Tm varies according to the exponential decay law

$$\frac{T_m - T_{m,0}}{T_{stm} - T_{m,0}} = 1 - e^{-\frac{t}{\tau}} \qquad \text{Eq. 3}$$

with a characteristic time constant, τ, which is a function of rotor material (e.g., 1% CrMoV) and size cum geometry represented by Lc,

$$\tau = \frac{\rho \cdot L_c \cdot c}{h} \qquad \text{Eq. 4}$$

where h is the convective heat transfer coefficient (HTC) between steam and metal. Equations 1-4 tell the entire ST thermal stress management story in the concise language of mathematics. Thermal stress is determined by the temperature gradient in the rotor (essentially a cylinder) via Eq. 2; the latter is determined by the initial steam-metal ΔT (denominator of LHS of Eq. 3) with a time lag, which itself is dictated by HTC in Eq. 4. Everything hinges on the initial value of Tm, Tm,0, which is a function of the cooling period (Eq. 1).

In physical terms, this translates into a mechanism to control steam FPT into the steam turbine at initial values sufficient (i) to roll the unit from turning gear (TG) speed to FSNL, (ii) to warm the ST rotor until steam-metal ΔT decreases to an acceptable level and (iii) to ramp them up at acceptable rates to their rated levels while ensuring that thermal stresses do not exceed prescribed limits.

Steam flow enters the picture via HTC in Eq. 4, which controls the rate of heat transfer between steam and the rotor surface as described by the heat flux balance at the steam-metal boundary (x = 0)

$$\dot{q} = h \cdot \left(T_{stm} - T_m\right) = k \cdot \left.\frac{dT_m}{dx}\right|_{x=0} \qquad \text{Eq. 5}$$

This equation introduces the dimensionless Biot number, Bi = h·Lc/k, which is a relative measure of the uniformity of temperature gradients inside a heated or cooled body. Determination of HTC is one of the most uncertainty-prone undertakings in transienTheat transfer problem in a complex geometry such as steam path flow. Its dependence on steam flow is based on the well-known Nusselt number correlation for heat transfer in internal flows, i.e., h ∝ . The heat transferred from steam to the rotor at the surface increases the rotor's bulk temperature according to Fourier's law

$$\frac{dT_m}{dx} = \frac{k}{\rho \cdot c} \cdot \frac{d^2 T_m}{dx^2} \qquad \text{Eq. 6}$$

Equation 6 introduces the thermal diffusivity, δ = k/ρc, which quantifies the speed with which the temperature of a heated or cooled body changes. Typical values for the key parameters governing ST rotor thermal transients are given in Table 2.

Representative values of major parameters characterizing the transient heat transfer during steam turbine warm-up for typical steam flow, pressure and temperatures. 2

m/m_o	P	T	h	Bi	δ	τ
[-]	psia	F	Btu/h-ft²-F	[-]	ft²/h	min
1.0	120	700	116	7	0.26	37
1.0	120	1,050	100	6	0.21	54
1.0	1,200	700	958	56		5
1.0	1,200	1,050	701	41		8
0.2	120	700	32	2		135
0.2	120	1,050	28	2		196
0.2	1,200	700	264	15		16
0.2	1,200	1,050	193	11		28

For ferritic steels used in modern GTCC units, k and ρ do not show significant variation. Thus, δ is primarily a function of temperature and changes by about 25% between 700 and 1,050°F; i.e., rate of change of metal temperature is 25% faster at the higher temperature. The data in Table 2 can be summarized as follows: higher steam flow and/or pressure result in higher rates of heat transfer between steam and metal, which is quantified by higher Biot numbers and shorter time constants (i.e., faster heating or cooling). In conjunction with the data in Table 2, Eqs. 5 and 6 identify the two distinct phases in ST start with thermal stress control:

(i) low flow and high steam-metal ΔT with low HTC until temperature gradients settle down (non-stationary phase or Phase I) and

(ii) increasing steam FPT to load the unit with high HTC and nearly constant, low steam-metal ΔT (quasi-stationary phase or Phase II).

Equation 5 describes Phase I via its simplified solution for a cylindrical geometry given by [4]

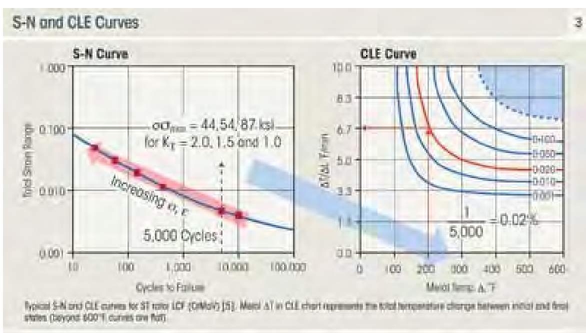
$$\sigma_{max} = E' \cdot \alpha \cdot \left[\frac{Bi}{2.8+Bi+\sqrt{Bi}}\right] \cdot K_T \cdot \Delta T \quad \text{Eq. 7}$$

which gives the maximum thermal stress implied by a given step rise in T**stm** at time t = 0 (with a time lag characterized by the Biot number). Note that the base stress formula of Eq. 2 is amplified by a stress concentration factor KT, which accounts for the presence of geometric discontinuities on the rotor (which is not a perfect cylinder after all). Similarly, Eq. 6 describes Phase II via its simplified form given by

$$\frac{dT_{stm}}{dt} = \frac{\delta}{\phi_F \cdot E' \cdot \alpha \cdot L_c^2} \cdot \sigma_{max} \qquad \text{Eq. 8}$$

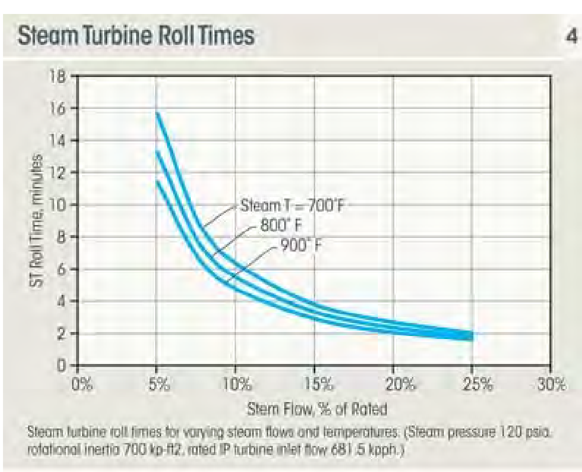
where ØF is the form factor (0.125 for a cylinder [4]). Equation 8 gives the allowable T_{stm} ramp rate for a given maximum allowable stress, σ_{max}, which is dependent on rotor material and typically lies in a range of 50-80 ksi. For the cited range, with the data in Table 2, Eq. 7 suggests that for low HTC (~100 Btu/h-ft^2-F or less) steam-metal ΔT can range from 200-300°F (high KT) to 500°F and higher (low KT). For high HTC (~650 Btu/h-ft^2-F), steam-metal ΔT can range from 100-200°F (high KT) to about 400°F (low KT). Similarly, using Eq. 8 with Table 2, it can be seen that allowable values for dT**stm**/dt range from 3-6°F to 8-10°F.

The allowable stress is not a precisely defined material property. (For ferritic steels used in ST rotor construction, 0.2% tensile yield strength lies between 70-90 ksi for temperatures 600-1,000°F.) It is derived from the S-N curves relating total strain to cycles to failure, which gives the fatigue life of the material in question (for LCF life of CrMoV alloy see Figure 3). Based on the relationship between stress and strain, ε, via the modulus of elasticity, σ = E´ • ε, this curve is used to determine σmax for a defined fatigue life. In practice, the relationship between σ and ΔT allows the translation of the S-N curve into *Cyclic Life Ependiture* (CLE) curves, which determine the allowable T_{stm} ramp rates (Figure 3). Depending on the rotor material, size and geometry and its temperature at start initiation, the range is limited to about 5 to 10°F per minute except for very hot "restarts" after a few hours of downtime.



Typical S-N and CLE curves for ST rotor LCF (CrMoV) [5]. Metal ΔT in CLE chart represents the total temperature change between initial and final states (beyond 600°F curves are flat).

Steam turbines with cascaded steam bypass are typically started by admitting steam from the reheat superheater into the IP section. Admission steam FPT should be sufficient to overcome the rotational inertia (in lb-ft^2) of the entire ST and its generator, Irot, and accelerate it from TG speed (a few rpm) to FSNL (3,000 or 3,600 rpm). Based on available steam FPT and initial IP rotor temperature, using the relationship between ST power generation (expansion from IP inlet to the condenser), rotor torque and rate of change in angular speed, ω, the roll time can be estimated as 2 to 15 minutes (see Figure 4) via

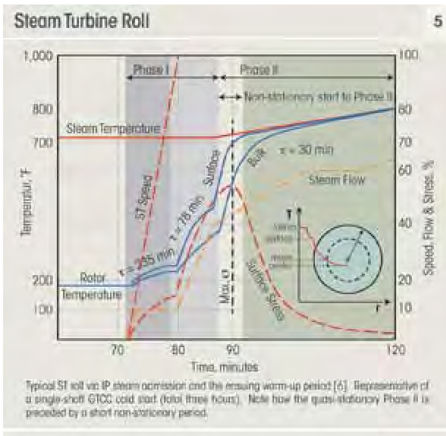


Steam turbine roll times for varying steam flows and temperatures. (Steam pressure 120 psia, rotational inertia 700 kp-ft2, rated IP turbine inlet flow 681.5 kpph.)

$$N(t) \approx \frac{3000}{\pi} \sqrt{\frac{5}{I_{rot}} \cdot \int_0^t \dot{m}_{stm} \cdot \eta \cdot \Delta h_{isen} \cdot dt} \qquad \text{Eq. 9}$$

where N is the rotor speed (rpm) and the argument of the integral on the RHS of Eq. 9 is the power (in Btu/s) generated by steam expanding between IP turbine inlet and condenser [6].

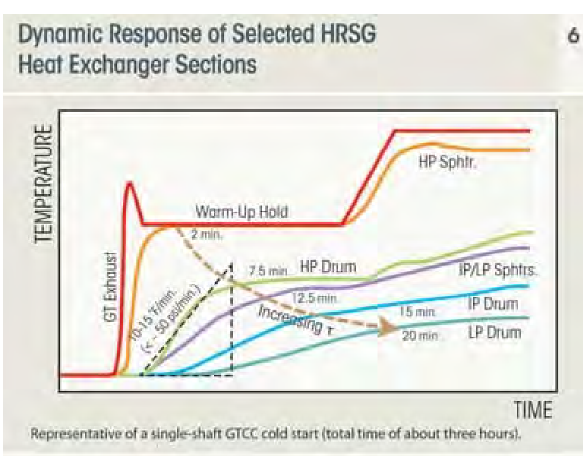
The chart in Figure 5 shows the first two hours of ST roll, warm-up and loading phases for an initial Tm of 180°F (about 5-6 days of downtime per Figure 2). Steam is admitted into the IP turbine at 715°F and 120 psia at a flow rate of 10% of its rated value at full load. This is sufficient for acceleration from TG to synchronization in 8 minutes (see Figure 4). Initial steam-metal ΔT is 500+°F but this is acceptable due to the low HTC (less than 30 Btu/h-ft^2-F per Table 2) and the ensuing low σmax from Eq. 7 (also very high τ > 200 minutes). Following synchronization, IP steam flow is ramped steadily to 40% to accelerate the warm-up process via increased HTC. Once the steam-metal ΔT (based on rotor surface temperature inferred via IP inner bowl thermocouple) reaches about 250°F, T**stm** is ramped (via TA control) at a rate defined by the CLE curve (about 3 to 4°F per minute for an acceptable life of 4 to 5,000 cycles from Figure 3).



Typical ST roll via IP steam admission and the ensuing warm-up period [6]. Representative of a single-shaft GTCC cold start (total three hours). Note how the quasi-stationary Phase II is preceded by a short non-stationary period.

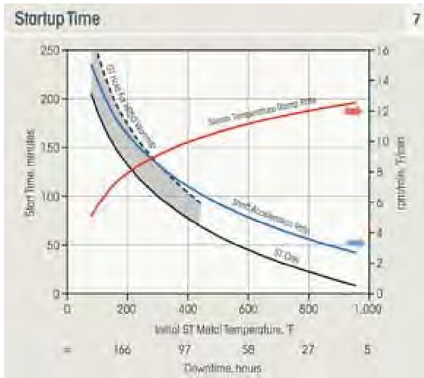
The other component subject to LCF damage due to cycling is the cylindrical HP drum of the HRSG (4-5 inches wall thickness). The limiting thermal stress is at the inner drum wall controlled by saturated steam p-T inside the drum. During startup, mechanical stress due to internal drum pressure and thermal stress due to thermal expansion are in opposite directions, while they are in the same direction during shutdown. Unlike the ST, which is thermally decoupled from the GT via TAs, HRSG sections are directly "under fire". They respond to GT exhaust temperature transients much faster than the ST rotor in direct proportion to their distance from the inlet (see Figure 6). Thermal stress calculations and material properties similar to those described above limit the p-T ramp rate inside the drum to 10-15 °F/min (about 50 psi/min max.) for units designed up to ~1,800 psig at ST throttle (~6-10% higher at the HP drum). Advanced steam cycles with 2,400 psig throttle and drum-type HRSGs (very thick walls) would push down the ramp rate to a few degrees per minute (see Eq. 8 for the relationship between dT_{stm}/dt and Lc). This can be alleviated to a certain degree by using stronger alloy steel (obviously more expensive) and/or designing the HRSG per EN-12952 rather than the ASME code, which results in thinner walls. One obvious solution is once-through design of the HP evaporator, which eliminates the thick-walled drum altogether but has its own drawbacks and caveats. A recent design approach proposes to replace the HP drum by a cylindrical, thin-walled knock-out vessel with external separator bottles and thus avoid the thermal stress problem in cold starts. According to HRSG OEMs, cold starts (T_{drum} < ~400°F) are 20 times more damaging than warm starts (T_{drum} < ~500°F) whereas hot starts (T_{drum} > 500°F) do not impact LCF life. In "hot" starts, HP and reheat superheaters subjected to very steep gas temperature ramps are critical in terms of HRSG life consumption. In this context, one should add that the desirability of purge credit is due to more than startup time reduction. It prevents excessive quenching of superheaters, which act as "supercoolers" during hot starts when subjected to relatively cold GT exhaust with detrimental impact on their fatigue life.

Natural p-T decay of the HP drum can be described by Eq. 1 with τ_c of 60 to 80 hours. It takes about 2-3 days for the pressure to decay to the atmospheric conditions. Bottling up the HRSG via stack dampers with insulation up to the damper, steam sparging (requires auxiliary boiler) or running the SCR ammonia vaporizer heaters help keep the HRSG warm and pressurized over limited duration shutdowns to enable GT starts with no low-load hold. Beyond about three days, however, this is increasingly impractical and even in plants designed for fast starts limited duration GT holds are needed to accomplish HP drum warm-up in two steps (somewhat similar to that shown in Figure 6).



Representative of a single-shaft GTCC cold start (total time of about three hours).

Combining the elements discussed above and illustrated by the ST roll example in Figure 5, a representative ST start curve can be established as a function of the key controlling parameter, namely, ST metal temperature at the startup initiation (Figure 7). Appropriate GT start time per Figure 1 (from start command to the point when ST roll begins) should be added to that for total GTCC start time (e.g., 18 minutes for the fast start). The four-minute mile of fast start capability is roughly 30 minutes from a standstill (to be defined precisely) to combined cycle full load for a "hot" start (e.g., following an overnight shutdown). This is generally compared to a conventional hot start, which takes around one hour (see Figure 1). The underlying physics discussed herein briefly and summarized in Figure 7 hopefully makes it clear that this particular case is only one single point in a continuum of start scenarios driven mainly by the downtime preceding the pushing of the start button.



Startup time of a typical steam turbine in a modern GTCC with drum-type HRSG (from the start of ST roll to the point when all bypass valves are closed and all admission valves are fully open).

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Exhibit 5

October 18, 2013 Letter from Rich Batey to Travis Ritchie

SIEMENS

October 18, 2013

Sierra Club Environmental Law Program
85 Second Street, 2nd Floor
San Francisco, CA 94105

Attention: Mr. Travis Ritchie, Associate Attorney

Subject: Fast Start Combined Cycle

Dear Mr. Ritchie:

A couple of years ago, the Marsh Landing plant (in the San Francisco Bay Area) was commissioned. NRG Marsh Landing features four 200 MW Siemens SGT6 5000F gas turbines in a simple cycle configuration. These gas turbines can ramp up to maximum power in about 12 minutes after the electronic startup command is sent to the gas turbines.

A couple of months ago, NRG commissioned two of the same 5000F model of gas turbines at their El Segundo plant (near Los Angeles). But the El Segundo gas turbines were commissioned in a combined cycle configuration (a Siemens FlexPlant™). Compared to Marsh Landing, the addition of the HRSG and steam turbine dramatically improved the plant efficiency and dramatically reduced the stack emissions per MWH of energy produced. Nevertheless, the El Segundo gas turbines can still startup just as fast as the Marsh Landing gas turbines.

NRG and other companies have permitted (and are permitting) a number of other fast start combined cycle plants. Look for the Marsh Landing, El Segundo, Lodi, Carlsbad and Willow Pass plants on the California Energy Commission web site for details.

With the application of proper HRSG and steam turbine technology, gas turbines can start up and ramp up just as fast in combined cycle configurations as in simple cycle configurations. This capability was demonstrated in aeroderivative gas turbines quite some time ago. In recent years, the advance of HRSG and SCR technology has allowed the fast starting of heavy frame gas turbines.

If you take a look at the listings of combined cycle configurations in the Gas Turbine World 2013 Handbook (GTW), you will see that many heavy frame machines, when configured for combined cycle, have an even greater efficiency (and lower emission rates) than the aeroderivative combined cycle plants. Currently, the following Siemens heavy frame gas turbine models are offered in the US for 60 Hz application: SGT 800 (48 MW), SGT6 2000E (112 MW), SGT6 5000F (232 MW) and ST6 8000H (274 MW). (All MW sizes are nominal, net simple cycle output values when burning natural gas.) Siemens offers all of these models in fast starting combined cycle FlexPlant™ configurations and guarantees the startup times. Combined cycle efficiencies range from 50% to 60% (LHV).

My reading of the EPA's GHG BACT guidelines indicates that combined cycle configuration is required for new gas turbine plants unless there is a unique technical or economic issue with a particular project. As explained above, the technical barriers to combined cycle efficiency and low emission rates have been removed. Therefore, it would seem reasonable for regulators to reject *grid connected* simple cycle plants unless the applicant can demonstrate that its simple cycle plant

Siemens Energy Inc.
A Siemens Company

24411 Ridge Route Drive
Laguna Hills, CA 92653

alternative will have a lower amortized life cycle cost ($/MWH) compared to any reasonable combined cycle alternatives.

[Note: Applicants or regulators may point to existing power plants (yesterday's technology) as alternatives to satisfy BACT guidelines. A better source for up-to-date alternatives would the GTW Handbook or a list of modern alternatives provided by OEM combined cycle suppliers.]

For example, an air emissions permit application for an LM6000PC Sprint (46,200 kw simple cycle per GTW) might be compared to the SGT 800 (47,500 kw simple cycle per GTW). Deploying the SGT 800 in combined cycle will provide 48 MW of fast starting gas turbine capability, plus an additional 19 MW of STG output capability. According to GTW, the efficiencies of the simple cycle LM6000PC Sprint and the SCC 800 1x1 combined cycle are 41.2% and 53.8% respectively. Thus, the efficiency and stack emissions of the plant would be improved by 30% by substituing the combined cycle alternative.

The combined cycle alternative will substantially increase the plant capital cost, but substantially reduce the operating cost, due to the improved fuel economy. The lower operating cost makes the generating unit more competitive on the grid, so the combined cycle alternate produces more energy, driving down the $/MWH cost of electricity. As a result, low emission rate combined cycle alternatives are usually the most economical overall.

Here in California, the more efficient combined cycle example would typically dispatch economically to generate and sell about four times as much energy as the simple cycle example. So, the more efficient and less polluting combined cycle example would probably qualify as GHG BACT on the California grid (and most other grids).

However, it is possible that the cost competitiveness of the existing grid to which the new project is to be connected is so competitive that a new combined cycle alternative cannot compete well enough to justify the added capital cost of combined cycle configuration. Renewable resources, for example, usually dispatch ahead of gas fired resources displacing even the most efficient gas fired resources. In some cases, the transmission connection to the ratepayers may be inadequate. In such cases, project sponsors can hire a reputable consultant to simulate the economic dispatch and competitiveness of the alternatives. The consultant can use that information to calculate and submit the project emissions and cost effectiveness comparisons to air quality regulators as allowed by EPA BACT guidelines.

In summary, combined cycle configuration is the GHG control technology that appears to be required by EPA BACT guidelines – unless the applicant demonstrates that reasonable modern technology combined cycle alternatives are not feasible or economical. Gas turbines can start fast, whether or not they are configured in combined cycle. So combined cycle is feasible even when fast starting is desired. The most economical and appropriately sized combined cycle alternatives are usually, but not always, more economical than simple cycle. However, if an applicant believes that a simple cycle plant is the most economical alternative, then the EPA GHG guidelines apparently allow the applicant to use economic dispatch and life cycle cost calculations to justify the use of simple cycle.

Yours Truly,

Rich Batey

Rich Batey
Region Manager

Exhibit 6

2013 GTW Handbook Price List (Excerpt)

Simple Cycle Plant Prices

Estimated equipment-only budget prices for basic power plant FOB factory in fixed 2013 dollars

Gas Turbine Model	ISO Base Load	Heat Rate Btu/kWh	Efficiency	Budget Plant Price	$ per kW
C200	200 kW	10,300 Btu	33.1%	$220,000	$1,111
VPS1	504 kW	16,378 Btu	20.8%	$460,000	$906
M1A-13D	1,485 kW	14,238 Btu	24.0%	$1,140,000	$765
M7A-17D	1,685 kW	12,841 Btu	26.6%	$1,270,000	$756
OP16-3B (DLE)	1,910 kW	12,732 Btu	26.8%	$1,400,000	$735
OGT2500	2,670 kW	12,780 Btu	26.7%	$1,810,000	$678
M1T-13D	2,930 kW	14,444 Btu	23.6%	$1,920,000	$656
Centaur 40	3,515 kW	12,240 Btu	27.9%	$2,250,000	$640
CX501-KB5	3,897 kW	11,747 Btu	29.0%	$2,440,000	$626
GT10	4,130 kW	11,582 Btu	29.5%	$2,560,000	$620
Centaur 50	4,600 kW	11,630 Btu	29.3%	$2,930,000	$636
501-KB7S	5,245 kW	10,848 Btu	31.5%	$2,940,000	$561
SGT-100	5,400 kW	11,008 Btu	31.0%	$3,170,000	$587
GT13	5,600 kW	10,646 Btu	32.0%	$3,280,000	$585
Taurus 60	5,670 kW	10,860 Btu	31.5%	$3,250,000	$574
MF-61	5,925 kW	11,910 Btu	28.6%	$3,350,000	$566
OGT6000	6,200 kW	11,299 Btu	30.2%	$3,510,000	$565
Taurus 65	6,300 kW	10,375 Btu	32.9%	$3,530,000	$561
501-KH5	6,447 kW	8509 Btu	40.1%	$3,400,000	$533
GT6	6,630 kW	10,450 Btu	32.7%	$3,740,000	$563
SGT-200	6,750 kW	10,824 Btu	31.5%	$3,770,000	$558
CX300	7,900 kW	11,158 Btu	30.6%	$4,220,000	$534
Taurus 70	7,965 kW	9955 Btu	34.0%	$4,270,000	$536
GE10-1	11,250 kW	10,867 Btu	31.4%	$5,540,000	$493
Mars 100	11,430 kW	10,365 Btu	32.9%	$5,580,000	$488
GTU-12PG-2	12,300 kW	10,469 Btu	32.6%	$5,970,000	$485
SGT-400	12,900 kW	9817 Btu	34.8%	$6,260,000	$485
PGT16	13,720 kW	9758 Btu	35.0%	$6,630,000	$484
SGT-400	14,400 kW	9700 Btu	35.2%	$6,900,000	$479
Titan 130	15,000 kW	9695 Btu	35.2%	$7,020,000	$468

Gas Turbine Model	ISO Base Load	Heat Rate Btu/kWh	Efficiency	Budget Plant Price	$ per kW
LM1800E	18,100 kW	9930 Btu	34.4%	$8,210,000	$454
SGT-500	19,100 kW	10,664 Btu	32.0%	$7,800,000	$408
Titan 250	21,745 kW	8775 Btu	40.0%	$8,820,000	$405
PGT25	22,417 kW	9401 Btu	36.3%	$9,010,000	$402
LM2500PE	24,049 kW	9717 Btu	35.1%	$10,130,000	$421
SwiftPac 25	25,455 kW	8960 Btu	38.1%	$10,010,000	$393
UGT 25000	25,680 kW	9590 Btu	35.6%	$9,940,000	$387
MobilePac	26,140 kW	9453 Btu	36.1%	$10,310,000	$394
RB211-G62 DLE	27,216 kW	9387 Btu	36.4%	$10,530,000	$387
LM2500PK	29,316 kW	9287 Btu	36.7%	$10,440,000	$356
RB211-GT62 DLE	29,845 kW	9089 Btu	37.5%	$11,380,000	$381
PGT25+	30,226 kW	8610 Btu	39.6%	$11,890,000	$393
LM2500PR	30,464 kW	8854 Btu	38.5%	$10,850,000	$356
SwiftPac 30	30,850 kW	9260 Btu	36.8%	$11,500,000	$373
MS5002E	31,100 kW	9748 Btu	35.0%	$11,710,000	$377
RB211-GT61 DLE	32,130 kW	8681 Btu	39.3%	$12,190,000	$379
SGT-700	32,214 kW	9255 Btu	36.9%	$11,950,000	$371
PGT25+G4	33,057 kW	8530 Btu	40.0%	$12,330,000	$373
SGT-750	35,930 kW	8787 Btu	38.8%	$13,030,000	$363
LM2500+ RC	36,333 kW	9184 Btu	37.2%	$12,230,000	$337
MS6001B	42,100 kW	10,644 Btu	32.1%	$14,020,000	$333
RB211-H63 WLE	42,473 kW	8679 Btu	39.3%	$14,460,000	$340
LM6000PF	42,732 kW	8173 Btu	41.7%	$15,340,000	$359
LM6000PC Sprint	46,200 kW	8286 Btu	41.2%	$16,070,000	$348
SGT-800	47,500 kW	9058 Btu	37.7%	$16,040,000	$338
LM6000PF Sprint	48,092 kW	8151 Btu	41.9%	$16,280,000	$339
SGT-900	49,500 kW	10,450 Btu	32.7%	$15,970,000	$323
LM6000PC Sprint	50,526 kW	8458 Btu	40.3%	$16,820,000	$333
LM6000PG	51,204 kW	8142 Btu	41.9%	$17,290,000	$338
Trent 60 DLE	54,020 kW	8031 Btu	42.5%	$18,140,000	$336
Trent 60 DLE ISI	61,842 kW	7867 Btu	43.4%	$19,040,000	$308
Trent 60 WLE	62,920 kW	8268 Btu	41.3%	$18,900,000	$300
Trent 60 WLE ISI	65,632 kW	8304 Btu	41.1%	$20,020,000	$305
AE64.3A	75,000 kW	9505 Btu	35.9%	$21,690,000	$289
6F 3-series	77,577 kW	9574 Btu	35.6%	$22,220,000	$286
7E 3-series	88,718 kW	10,192 Btu	33.5%	$24,090,000	$272
LMS100PB	99,400 kW	7695 Btu	44.3%	$38,400,000	$386
LMS100PA	103,500 kW	7815 Btu	43.7%	$39,300,000	$380
SGT6-2000E	112,000 kW	10,066 Btu	33.9%	$31,870,000	$285

Gas Turbine Model	ISO Base Load	Heat Rate Btu/kWh	Efficiency	Budget Plant Price	$ per kW
M501DA	113,950 kW	9780 Btu	34.9%	$32,530,000	$286
~~GT11N2~~	~~115,400 kW~~	10,065 Btu	33.9%	$32,200,000	$279
9E 3-series	128,183 kW	9980 Btu	34.2%	$35,050,000	$273
M701DA	144,090 kW	9810 Btu	34.8%	$38,590,000	$268
V94.2	157,000 kW	9920 Btu	34.4%	$41,170,000	$262
SGT5-2000E	166,000 kW	9834 Btu	34.7%	$43,070,000	$259
AE94.2K	170,000 kW	9348 Btu	36.5%	$44,430,000	$261
7F 3-series	184,906 kW	8953 Btu	38.1%	$45,740,000	$247
M501F3	185,400 kW	9230 Btu	37.0%	$45,350,000	$245
GT13E2	202,700 kW	8980 Btu	38.0%	$52,590,000	$259
SGT6-5000F	232,000 kW	8953 Btu	38.1%	$44,930,000	$216
7F 5-series	215,769 kW	8830 Btu	38.6%	$51,770,000	$240
GT24	230,700 kW	8531 Btu	40.0%	$55,140,000	$239
SGT6-5000F	232,000 kW	8794 Btu	38.8%	$49,420,000	$213
9F 3-series	261,284 kW	9146 Btu	37.3%	$59,290,000	$227
SGT6-8000H	274,000 kW	8530 Btu	40.0%	$64,980,000	$237
M501GAC	276,000 kW	8574 Btu	39.8%	$63,400,000	$230
SGT5-4000F	292,000 kW	8567 Btu	39.8%	$68,160,000	$233
9F 5-series	298,174 kW	8855 Btu	38.5%	$68,490,000	$230
GT26	326,000 kW	8467 Btu	40.3%	$74,890,000	$230
M501J	327,000 kW	8325 Btu	41.0%	$75,120,000	$230
M701G2	334,000 kW	8630 Btu	39.5%	$75,480,000	$226
9F 7-series	339,366 kW	8526 Btu	40.0%	$78,900,000	$233
M701F5	359,000 kW	8530 Btu	40.0%	$79,790,000	$222
SGT5-8000H	375,000 kW	8530 Btu	40.0%	$85,440,000	$228
M701J	470,000 kW	8325 Btu	41.0%	$99,220,000	$211

Combined Cycle Plant Prices

Budget prices for total plant including BOP and construction in fixed 2013 US dollars

Combined Cycle Plant Model	Net Plant Output	Net Plant Efficiency	No. & Type Gas Turbine	Steam Turbine	Budget Plant Price	$ per kW
UGT 15CC1	21.2 MW	44.4%	1 x UGT15000	5.2 MW	$26,300,000	$1,240
LM2500PJ DLE	30.6 MW	49.5%	1 x LM2500PJ	9.4 MW	$36,700,000	$1,200
LM2500PE DLE	32.0 MW	50.4%	1 x LM2500PE	9.4 MW	$38,100,000	$1,192
LM2500PE	32.3 MW	47.1%	1 x LM2500PE	9.0 MW	$38,400,000	$1,188
THM 1304-12N	35.4 MW	47.7%	2 x THM 1304-12N	11.4 MW	$40,200,000	$1,136
SCC-600 1x1	35.9 MW	49.9%	1 x SGT-600	12.6 MW	$40,600,000	$1,132
SwiftPac 30	36.6 MW	50.6%	1 x FT8-3	10.0 MW	$42,200,000	$1,152
RB211-G62 DLE	37.7 MW	50.2%	1 x RB211	12.0 MW	$42,800,000	$1,136
LM2500+ PK	38.5 MW	46.6%	1 x LM2500+ PK	10.1 MW	$43,300,000	$1,124
RB211-GT62 DLE	39.8 MW	51.4%	1 x RB211	12.2 MW	$44,400,000	$1,116
LM2500+ PR	40.6 MW	51.3%	1 x LM2500+ PR	10.9 MW	$44,500,000	$1,096
RB211-GT61 DLE	42.6 MW	52.8%	1 x RB211	12.6 MW	$46,500,000	$1,092
LM2500+ G4 RD	44.3 MW	52.0%	1 x LM2500+ G4 RD	13.4 MW	$47,800,000	$1,080
SCC-700 1x1	45.2 MW	52.3%	1 x SGT-700	14.4 MW	$48,100,000	$1,064
SCC-750 1X1	47.3 MW	51.0%	1 x SGT-750	12.5 MW	$49,600,000	$1,048
LM2500+ G4 RC	48.7 MW	50.2%	1 x LM2500+ G4 RC	13.7 MW	$51,000,000	$1,048
RB211-H63 WLE	54.0 MW	50.8%	1 x RB211	14.2 MW	$55,500,000	$1,028
LM6000PF	55.8 MW	54.1%	1 x LM6000PF	13.8 MW	$56,700,000	$1,016
LM6000PF Sprint	61.6 MW	53.5%	1 x LM6000PF	14.8 MW	$60,100,000	$976
6B 3-series	64.8 MW	50.4%	1 x 6B3	23.3 MW	$63,800,000	$984
Trent 60 DLE	65.4 MW	53.6%	1 x Trent 60	15.8 MW	$63,300,000	$968
SCC-800 1x1	66.6 MW	53.8%	1 x SGT-800	21.0 MW	$64,200,000	$964
UGT 25CC2	67.2 MW	47.0%	2 x UGT25000	17.2 MW	$64,800,000	$964
RB211-H63 WLE	68.4 MW	48.5%	1 x RB211	29.1 MW	$65,400,000	$956
SCC-600 2x1	73.3 MW	50.9%	2 x SGT-600	26.5 MW	$68,000,000	$928
SwiftPac 60	74.2 MW	51.3%	2 x FT8-3	20.6 MW	$70,000,000	$944
Trent 60 DLE ISI	75.5 MW	53.5%	1 x Trent 60	16.1 MW	$70,900,000	$940
Trent 60 WLE	78.0 MW	51.4%	1 x Trent 60	17.7 MW	$72,100,000	$924
Trent 60 WLE ISI	80.3 MW	50.8%	1 x Trent 60	17.8 MW	$73,900,000	$920
SCC-700 2x1	91.6 MW	53.1%	2 x SGT-700	30.0 MW	$80,600,000	$880

Combined Cycle Plant Model	Net Plant Output	Net Plant Efficiency	No. & Type Gas Turbine	Steam Turbine	Budget Plant Price	$ per kW
Trent 60 WLE	102.4 MW	49.1%	1 x Trent 60	43.2 MW	$90,100,000	$880
Trent 60 WLE ISI	109.6 MW	49.0%	1 x Trent 60	46.3 MW	$94,700,000	$864
LM6000PC	111.4 MW	50.9%	2 x LM6000PC	26.0 MW	$95,800,000	$860
1AE643-CC1M	111.7 MW	53.8%	1 x AE64.3A	40.2 MW	$93,800,000	$840
LMS100PB	115.4 MW	51.9%	1 x LMS100PB	19.4 MW	$98,300,000	$852
6F 3-series	118.4 MW	55.0%	1 x 6F3	41.6 MW	$96,600,000	$816
LMS100PA	119.3 MW	50.1%	1 x LMS100PA	19.5 MW	$99,300,000	$832
6B 3-Series	130.9 MW	50.9%	2 x 6B3	47.8 MW	$104,200,000	$796
2 x Trent 60 DLE	131.2 MW	53.8%	2 x Trent 60	31.6 MW	$108,100,000	$824
SCC-800 2x1	135.4 MW	54.7%	2 x SGT-800	44.2 MW	$106,700,000	$788
7E 3-series	135.4 MW	51.1%	1 x 7E3	49.1 MW	$105,300,000	$778
2 x Trent 60 WLE	156.2 MW	51.5%	2 x Trent 60	35.7 MW	$124,300,000	$796
2 x Trent 60 WLE ISI	160.9 MW	50.8%	2 x Trent 60	35.9 MW	$126,100,000	$784
MPCP1(M501)	167.4 MW	51.4%	1 x M501DA	55.3 MW	$125,900,000	$752
SCC6-2000E 1X1	171.0 MW	51.3%	1 x SGT6-2000F	*56.0 MW	$127,900,000	$748
MPCP1(M701)	212.5 MW	51.4%	1 x M701DA	70.4 MW	$156,400,000	$736
2AE643-CC1M	223.7 MW	53.8%	2 x AE64.3A	80.6 MW	$163,700,000	$732
6F 3-Series	239.4 MW	55.6%	2 x 6F3	85.6 MW	$173,300,000	$724
SCC5-2000E 1x1	250.0 MW	52.4%	1 x SGT5-2000E	91.1 MW	$180,000,000	$720
7E 3-Series	270.1 MW	51.0%	2 x 7E3	97.8 MW	$192,300,000	$712
KA13E2-1	281.0 MW	53.5%	1 x GT13E2	*91.0 MW	$201,200,000	$716
MPCP1(M501F)	285.1 MW	57.1%	1 x M501F3	102.4 MW	$200,700,000	$704
SCC6-5000F 1X1	307.0 MW	57.0%	1 x SGT6-5000F	101.0 MW	$214,900,000	$700
7F 5-Series	323.0 MW	58.2%	1 x 7F5	112.0 MW	$224,800,000	$696
KA11N2-2	345.0 MW	51.3%	2 x GT11N2	*115.0 MW	$237,400,000	$688
9F 3-Series	397.1 MW	57.2%	1 x 9F3	142.4 MW	$227,100,000	$572
MPCP1(M501G)	398.9 MW	58.4%	1 x M501G1	134.5 MW	$228,200,000	$572
107H	400.0 MW	60.0%	1 x 7001H	*137.0 MW	$228,800,000	$572
SCC6-8000H 1S	410.0 MW	60.0%	1 x SGT6-8000H	135.0 MW	$232,900,000	$568
MPCP1(M501GAC)	412.4 MW	59.5%	1 x M501GAC	138.8 MW	$234,200,000	$568
9F 5-Series	454.1 MW	59.3%	1 x 9F5	164.9 MW	$256,100,000	$564
KA26-1	467.0 MW	59.5%	1 x GT26	*165.0 MW	$262,600,000	$562
MPCP1(M501J)	470.0 MW	61.5%	1 x M501J	148.0 MW	$264,000,000	$562
MPCP1(M701F4)	477.9 MW	60.0%	1 x M701F4	158.0 MW	$267,600,000	$560
SCC5-2000E 2x1	505.0 MW	52.9%	2 x SGT5-2000E	177.4 MW	$282,400,000	$559
9F 7-Series	512.0 MW	61.0%	1 x 9F7	181.6 MW	$285,100,000	$557
MPCP1(M701F5)	525.0 MW	61.0%	1 x M701F5	171.0 MW	$290,600,000	$554
7F 3-Series	559.7 MW	57.9%	2 x 7FA.04	199.0 MW	$309,000,000	$552
KA13E2-2	565.0 MW	53.8%	2 x GT13E2	*195.0 MW	$314,100,000	$556

Combined Cycle Plant Model	Net Plant Output	Net Plant Efficiency	No. & Type Gas Turbine	Steam Turbine	Budget Plant Price	$ per kW
SCC5-8000H 1S	570.0 MW	60.0%	1 x SGT5-8000H	195.0 MW	$313,700,000	$550
MPCP2(M501F)	572.2 MW	57.3%	2 x M501F3	206.8 MW	$314,500,000	$550
SCC6-5000F 2X1	620.0 MW	57.2%	2 x SGT6-5000F	208.0 MW	$339,800,000	$548
KA24-2	664.0 MW	58.4%	2 x GT24	*202.6 MW	$362,800,000	$546
MPCP1(M701J)	680.0 MW	61.7%	1 x M701J	217.0 MW	$369,900,000	$544
9F 3-Series	798.7 MW	57.5%	2 x 9F3	288.8 MW	$433,200,000	$542
SCC6-8000H 2X1	822.0 MW	60.0%	2 x SGT6-8000H	270.0 MW	$443,900,000	$540
9F 5-Series	913.6 MW	59.7%	2 x 9F5	337.3 MW	$491,900,000	$538
KA26-2	935.0 MW	59.5%	2 x GT26 (2011)	*300.0 MW	$501,900,000	$537
MPCP2(M501J)	942.9 MW	61.7%	2 M501J	298.9 MW	$504,600,000	$535
MPCP2(M701F4)	958.8 MW	60.2%	2 x M701F4	319.0 MW	$511,600,000	$534
9F 7-Series	1025.6 MW	61.1%	2 x 9F7	360.0 MW	$545,600,000	$532
MPCP2(M701F5)	1053.3 MW	61.2%	2 x M701F5	345.3 MW	$558,700,000	$530
SCC5-8000H 2x1	1140.0 MW	60.0%	2 x SGT5-8000F	390.0 MW	$602,800,000	$529

*estimated

Exhibit 7

NRG's California El Segundo Natgas
Power Plant Enters Service

» Print

NRG's California El Segundo natgas power plant enters service

Fri, Aug 2 2013

Aug 2 (Reuters) - U.S. power company NRG Energy Inc said on Friday its 550-megawatt El Segundo natural gas-fired power plant near Los Angeles has entered service.

The combined-cycle plant can generate enough power to supply about 450,000 homes, which is needed in southern California now that local utility Southern California Edison (SCE) has retired its San Onofre nuclear power plant.

NRG Energy said it will sell power from the plant to SCE through a 10-year purchase agreement.

SCE is a unit of Edison International.

The new plant can deliver more than half of its generating capacity in less than 10 minutes and the balance in less than 1 hour, which is needed as California relies more on intermittent renewable technologies like wind and solar that depend on weather conditions.

NRG Energy built the new El Segundo plant at the site of a retired gas-fired steam unit constructed in 1964 that relied on ocean water for cooling.

The new plant relies on reclaimed water for its air-cooled operation, reducing the use of potable water at the site by nearly 90 percent.

During construction, the project created nearly 400 jobs and is expected to increase annual tax revenue in excess of $3 million per year.

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Exhibit 8

Salem Plant Press Release

GE Technology to Repower Footprint Power's Salem Harbor Station, Reducing Emissions and Ensuring Reliable Electric Service for Greater Boston Area

- Replacing the Old Facility in Salem Will Solve Local Reliability Issue and Reduce Regional Greenhouse Gas and Other Emissions
- New Plant to Support Renewable Energy with Area's First "Rapid Response" Combined-Cycle Power Island
- Smaller "Footprint" Plant Opens up Public Access to More than 40 Waterfront Acres

November 01, 2013 11:01 AM Eastern Time

SALEM, Mass.--(EON: Enhanced Online News)--GE (NYSE: GE) steam turbines installed at Salem Harbor Station have provided reliable power to Massachusetts' North Shore for more than 60 years. Today, GE is announcing an agreement with Footprint Power to provide Salem Harbor Station with a new 674-megawatt (MW) natural gas facility to address local reliability needs, reduce regional emissions and facilitate the introduction of the renewable resources Massachusetts requires to meet greenhouse gas emissions reduction goals.

"We selected GE's technology because it provided the best combination of performance and world-class flexibility and efficiency," said Scott Silverstein, president and COO, Footprint Power. "As one of the most flexible and lowest emitting plants on the grid, we can reduce system-wide emissions and system-wide wholesale energy costs while efficiently utilizing natural gas and enabling the integration of additional renewable resources onto the power grid."

"We selected GE's technology because it provided the best combination of performance and world-class flexibility and efficiency"

Footprint Power has built on the city of Salem's efforts to study the potential uses for the power plant site, minimizing the size of the new plant and maximizing the land available for future, non-power uses. Footprint Power's new combined-cycle plant will soon replace the existing Salem Harbor Station while occupying just 20 acres of the 65-acre site.

"GE is working closely with Footprint Power, Salem officials and Massachusetts regulators to turn this 62-year-old facility into a much smaller, much quieter, and much cleaner 21st century plant," said Victor Abate, president and CEO of Power Generation Products—GE Power & Water. "Occupying less than a third of the current site, the new plant will efficiently use the land to allow the community to reclaim and reshape the Salem waterfront."

For the $200 million power equipment contract, GE will supply its FlexEfficiency* 60 technology. Built on this advanced solution, the Salem Harbor Redevelopment Project:

Dramatically Reduces regional CO_2, NO_x, SO_2 and mercury emissions.

The GE units will be among the most environmentally advanced in the country, meeting or exceeding the environmental performance of every other fossil fuel power-generating facility in New England. For example, the new plant will reduce regional carbon emissions by an average of approximately 450,000 tons per year—the equivalent of taking 90,000 cars a year off the road in New England.

The new plant will have the ability to turn down during off-peak hours, eliminating the extra fuel and emissions output associated with a plant startup. With the new plant in operation, it is projected that regional NO_x emissions will be reduced by 10 percent; SO_2 emissions will be reduced by 8 percent; and mercury emissions will be reduced by 6 percent. These reductions result from the efficiency and flexibility of the GE equipment in the new facility. Reductions resulting from retirement of the existing coal and oil facility are not even counted in these totals. The plant will also use air-cooled condensers, completely eliminating the use of hundreds of millions of gallons of water per day from Salem Harbor for once-through cooling.

Supports renewable energy while ensuring reliable energy.

The facility, which will utilize two GE 7F 5-series gas turbines, will include the first "Rapid Response" power island to be deployed in New England. The "Rapid Response" capability will enable the plant to add 300 MW of power to the grid within 10 minutes, supporting the continued deployment of wind and other renewable energy sources, while maintaining an efficiency level that rivals any fossil fuel unit in New England.

Opens up public access to more than 40 acres of prime waterfront property.

Options for this newly available land range from docking for cruise ships to commercial and light industrial marine related uses. The last time this entire stretch of the waterfront was accessible to the public, Harry Truman was president.

According to ISO New England, Inc. (ISO-NE), Footprint's new Salem Harbor facility is needed to maintain the reliability of electricity supply in the greater Boston area beginning on June 1, 2016. In February 2013, Footprint cleared the ISO-NE Forward Capacity Auction to supply electric generating capacity beginning in 2016. The project will receive a five-year capacity payment incentive to construct the facility and fill the power gap in the Northeastern Massachusetts (NEMA)/Boston zone.

Earlier this month, the Energy Facilities Siting Board (EFSB) approved Footprint Power's petition to construct the new power plant, a key step in moving forward with the project that followed unanimous approvals of the Salem's Planning Board, Zoning Board of Appeal and Conservation Commission. Construction of the plant will create an average of 320 construction jobs, peaking at 600 jobs and ending up with 30 to 40 permanent positions.

The existing coal and oil-fired Salem Harbor Station will shut down at the end of May 2014, and GE's equipment will ship in late 2014/early 2015. To reduce the impact on area residents, heavy equipment will be delivered by boat, rather than via streets in local neighborhoods. Commercial operation is planned for June 2016.

To view artist renderings of the new power plant in Salem, please click here and here.

About Footprint Power

A New Jersey-based company, Footprint Power was formed in 2009 by longtime power-industry executives to identify opportunities for the re-powering or re-purposing of older fossil-fuel fired generation facilities. The company was founded on the simple idea that instead of ignoring older, less-efficient coal and oil-fired power plants, it makes more sense to face head on the challenges they pose, while also taking stock of the many opportunities they present. For more information about Footprint Power, visit www.footprintpower.com.

About GE

GE (NYSE: GE) works on things that matter. The best people and the best technologies taking on the toughest challenges. Finding solutions in energy, health and home, transportation and finance. Building, powering, moving and curing the world. Not just imagining. Doing. GE works. For more information, visit the company's website at www.ge.com.

About GE Power & Water

GE Power & Water provides customers with a broad array of power generation, energy delivery and water process technologies to solve their challenges locally. Power & Water works in all areas of the energy industry including renewable resources such as wind and solar; biogas and alternative fuels; and coal, oil, natural gas and nuclear energy. The business also develops advanced technologies to help solve the world's most complex challenges related to water availability and quality. Power & Water's six business units include Distributed Power, Nuclear Energy, Power Generation Products, Power Generation Services, Renewable Energy and Water & Process Technologies. Headquartered in Schenectady, N.Y., Power & Water is GE's largest industrial business.

Follow GE Power & Water on Twitter @GE_PowerWater.

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Hardware
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Metals (Manufacturing)
Natural Resources
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Nuclear
Oil & Gas
Operating Systems
Public Services
Public Utilities
Science
Software
State Government
Urban Planning
Utilities (Computers & Technology)
Websites & Internet (Consumer)
Women (Consumer)

December 4, 2013

Melanie Magee
Air Permits Section (6PD-R)
U.S. EPA, Region 6
1445 Ross Avenue, Suite 1200
Dallas, TX 75202
magee.melanie@epa.gov

RE: Montana Power Station – Permit No. PSD-TX-1290-GHG

Dear Ms. Magee:

These comments are submitted on behalf of Sierra Club and its 600,000 members, including over 21,000 members in Texas. The issues addressed below regarding the proposed *Draft Prevention of Significant Deterioration Permit for Greenhouse Gas Emissions* for the El Paso Electric Company's (EPEC) proposed Montana Power Station are based off of publicly available materials, including the September, 2013 Statement of Basis (SOB) prepared by EPA Region 6 (the Region), the draft permit, the permit application (Application) and the applicant's July 31, 2012 response to information requests (July Revision). These comments are timely pursuant to a series of extensions to submit public comment granted by the Region.

According to the applicant, the Montana Power Station would be a peaking and intermediate load electric generating facility located in El Paso County Texas. The proposed project consists of four new natural gas fired combustion turbines (CT) and associated equipment. The facility would supply approximately 400 MW (nominal) of electric power to El Paso County.[1] The draft permit includes a permitted greenhouse gas (GHG) emission rate for the CTs of 1,194 lb CO_2/MWhr (gross), and an operating limit of 5,000 hours on a 12-month rolling basis per turbine. The total annual project emission limit is 1,004,961 tpy CO2e. (Draft Permit, p.6)

The EPA has a clear mandate to act on climate change. EPA Administrator Gina McCarthy recently reiterated the responsibility of the agency to EPA staff following direction from President Obama: "We have a clear responsibility to act now on climate change." The recently proposed New Source Performance Standard (NSPS) for new electric generating units (EGUs) directly begin to implement this mandate: "Greenhouse gas (GHG) pollution threatens the

[1] EPEC estimates approximately 89.9 MW per unit during summer peak periods. (Application, p.3.)

American public's health and welfare by contributing to long-lasting changes in our climate that can have a range of negative effects on human health and the environment."[2] However, the Region's draft permit completely ignores this mandate to act on climate change, and it ignores the fact that the Montana Power Station would violate the proposed NSPS for EGUs. Sierra Club cannot comprehend how the proposed best available control technology (BACT) limit for the Montana Power Station could be less stringent than the proposed NSPS.

Texas suffered its driest year ever in 2011, and the three years 2011-2013 have been among the driest on record. Cities are struggling to keep reservoirs full, and the Texas coast is experiencing accelerating sea level rise. Places like Galveston Island are spending substantial sums of money to keep the Gulf of Mexico at bay. Texas is very vulnerable to climate changes and the Region must consider climate change impacts from the increased CO2 emissions that would result from the Montana Power Station.

EPEC proposes to construct the 400MW Montana Power Station on a greenfield site northeast of El Paso. The proposed project would consist of four natural gas-fired simple cycle turbines (GE LMS 100) with an electric power output of 100 MW each (de-rated to 89.9 MW during summer). The Montana Power Station is subject to greenhouse gas (GHG) prevention of significant deterioration (PSD) regulations. New construction projects that are expected to emit at least 100,000 tpy of total GHGs on a CO_2e basis, or modifications at existing facilities that are expected to increase total GHG emissions by at least 75,000 tpy CO_2e, are subject to PSD permitting requirements. EPEC estimates that Montana Power Station will result in new GHG emissions of 1,004,961 tons per year (tpy) of CO_2e. Montana Power Station would emit GHGs at a rate far greater than 100,000 tpy CO_2e; therefore, the project is subject to PSD review for all pollutants emitted in a significant amount. The Texas Commission on Environmental Quality (TCEQ) will issue a permit for non-GHG criteria pollutants.

1. The Draft Permit is Less Stringent than the Proposed GHG NSPS for New Electric Generating Units.

On September 20, 2013, EPA issued a signed notice of its Proposed Rule for *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2013-0495 (GHG NSPS). The GHG NSPS will apply to any new electric generating unit that "actually supplies more than one-third of its potential electric output to the grid."[3] For those EGUs that supply more than one-third of their potential electric output to the grid, EPA determined that the "best system of emission reduction" is natural gas combined-cycle (NGCC) technology because it is technically feasible, relatively inexpensive, its emission profile is acceptable low, and it would not adversely affect the structure of the electric power sector.[4] The proposed standard for stationary combustion turbines between 73 MW and 250 MW is 1,100 lb CO_2/MWh (gross).

Section 111(a)(2) of the Clean Air Act defines a "new source" as any stationary source that commences construction or modification after publication of proposed new standards of performance under section 111 that will be applicable to the source. 42 U.S.C. § 7411(a)(2).

[2] Notice of Proposed Rule, *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2013-0495, Sept. 20, 2013, p.17.
[3] *Id.* at p.82.
[4] *Id.* at p.287.

Under this definition, any new fossil fuel-fired EGU greater than 25 MW that commences construction after September 20, 2013, is a "new source" and will be subject to the CO_2 standard that EPA ultimately promulgates when the source begins operating. *United States v. City of Painesville*, 644 F.2d 1186, 1191 (6th Cir. 1981) (CAA §111(a)(2) "plainly provides that new sources are those whose construction is commenced after the publication of the particular standards of performance in question"). The statute uses the date a standard is proposed to define which sources are subject to the standard. The Montana Power Station would therefore be considered a "new sources" subject to the NSPS because it has not commenced construction prior to September 20, 2013.

The Montana Power Station consists of four, 100 MW simple-cycle turbines with a permitted operating limit of 5,000 hours on a 12-month rolling basis per turbine. (Draft Permit § II.) This means that the GHG NSPS, if finalized, would apply to the Montana Power Station. It also means that the Region's proposed BACT limit of 1,194 lb CO_2/MWh (gross) is **higher** than the both the "small unit" limit of 1,100 lb CO_2/MWh and the "large unit" limit of 1,000 lb CO_2/MWh in the proposed GHG NSPS.[5] This difference fundamentally contradicts the purpose of BACT. The Clean Air Act expressly provides: "In no event shall application of "best available control technology" result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section [111 or 112 of the Clean Air Act]."[6] The SOB acknowledged this discrepancy in the SOB, but it dismissed the issue on the grounds that "the proposed NSPS is not a final action and the proposed standard may change." (SOB at p.4.) This logic, however, ignores the reality that EPA headquarters has spent more than a year reviewing available data on turbine efficiencies and concluded that combined-cycle technology is both technically feasible and "relatively inexpensive." In contrast, the Region has simply adopted without question the Applicant's argument that a more efficient natural gas combined-cycle unit is infeasible. The findings in the proposed GHG NSPS undermine the Region's cursory and unsupported finding that "the selection of a combined cycle facility is technically infeasible for the purpose of the proposed project to provide peaking/intermediate load operation as defined by the applicant." (SOB at p.12.) The Region's failure to consider the availability of more efficient combined cycle turbines is improper.

Notably, the proposed NSPS would exempt facilities that supply less than one-third of their potential electric output to the grid. Under normal circumstances, this exception would mean that a typical simple-cycle combustion turbine, such as the LMS 100, operating as a peaking unit would not be required to meet the proposed limits in the NSPS because those units operate at capacity factors much lower than 33 percent. However, the Montana Power Station would still fall under the NSPS if operated as permitted because the Region's permit allows up to 5,000 hours of operation, which is a capacity factor of 57 percent.

[5] It is unclear whether the Montana Power Station would qualify as a "small" or "large" unit under the proposed NSPS. The threshold between small and large is a heat input of 850 MMbtu/hr. The permit and the application do not specify the heat input of the Montana Power Station.

[6] Clean Air Act § 169(3), 42 USC § 7479(3).

2. Combined-Cycle Turbines are More Efficient and Lower Polluting

Clean Air Act § 165(a)(4) requires Montana Power Station to install the Best Available Control Technology (BACT), which is defined as "an emissions limitation … based on the maximum degree of reduction for each pollutant subject to regulation under the Act…" 42 USC 7479(3); 40 CFR 52.21(b)(12). Reducing GHG emissions is directly related to minimizing the quantity of fuel required to make electricity. The PSD provisions do not allow the permitting authority to select a higher emitting technology based on the applicant's preference of different turbine designs. The BACT requirement is defined as "the maximum degree of reduction for each pollutant." 42 USC 7479(3). Therefore, the top-down BACT analysis requires the Region to select the lowest emitting technology as the basis for setting the BACT emission limit. In this case, the simple-cycle turbine designed selected by the Applicant is much less efficient than modern combined-cycle units.

This dismissal of recognizable and achievable energy efficiency gains is contrary to EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases*, which expressly addresses an example of energy efficiency at a coal plant:

> In general, a more energy efficient technology burns less fuel than a less energy efficient technology on a per unit of output basis. For example, coal-fired boilers operating at supercritical steam conditions consume approximately 5 percent less fuel per megawatt hour produced than boilers operating at subcritical steam conditions.[7]

The EPA guidance makes clear that energy efficiency must be considered in the BACT analysis. The NSR Manual further provides: "The reviewing authority…specifies an emissions limitation for the source that reflects the **maximum degree** of reduction achievable…" (NSR Manual, p.B.2 (emphasis added)). Without a showing that the most efficient design is either technically infeasible or that it should be eliminated due to disproportionate site-specific energy, economic or environmental impacts, the Region must set the GHG BACT emission rate limit based on the most efficient turbine design.

The lowest emitting control technology for generation of electricity from fossil fuels is combined cycle natural gas generation with inlet cooling. As demonstrated below, combined cycle gas turbines commonly perform peaking functions in U.S. generating systems.

There are a number of commercially available units from reputable manufacturers that are capable of (1) greater full load efficiency; (2) greater part load efficiency; and (3) ample ramp rates to respond to the daily fluctuations in demand in the EPEC system. These units range in capacity from less than 100 MW to over 900 MW and include the following:

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[7] *PSD and Title V Permitting Guidance for Greenhouse Gases*, March 2011, p.21 (citing: U.S. Department of Energy, Cost and Performance Baseline for Fossil Energy Plants - Volume 1: Bituminous Coal and Natural Gas to Electricity, DOE/NETL-2007/1281, Final Report, Revision 1 (August 2007) at 6 (finding that the absolute efficiency difference between supercritical and subcritical boilers is 2.3 percent (39.1 percent compared to 36.8 percent), which is equivalent to a 5.9 percent reduction in fuel use), available at http://www.netl.doe.gov/energyanalyses/pubs/Bituminous%20Baseline_Final%20Report.pdf).

Unit	MW (net)	CT/HRSG (MW)	Efficiency (net %)	Heat rate (Btu/kWh)	Part Load	Overnight
Alstom KA 24 2x1[8]	664	450/214	59.5	5739	>98% of full load eff. to 80 % load; 95% to 50 % load	450 MW in 10 min.
Mitsubishi M501GAC[9]	404	264/132	59.2	5763		10 min to 264
Mitsubishi 701G	498	334/164	59.3	5755[10]		
Mitsubishi M501J	470	320/140	61.5[11]	5551		10 min to 320/30 min to 460
GE Flex 60	512	339/181	>61	< 5584	>60 percent efficiency to 87% of load	28 min startup
Siemens SCC6-8000-1S	410	274/136	>60	<5687		<30 min.[12]
Siemens SCC6-5000F (Lodi)	305	232/73	>57	<5989		70 MW in 10 min; hot/warm start 200 MW in <30 min.
Proposed 4xLMS 100	392	392/0	45[13]	7580	~ 35.5 percent efficiency (80% of full load eff.) at 50% load[14]	10 min.

The Region must analyze each of the units to determine whether the greater achievable efficiencies constitute BACT for the Montana Power Station. While BACT does not require a specific turbine manufacturer, it does require a limit that is achievable by the best performing units available.

In this case, the Region did not consider any of the available combined-cycle units because it improperly concluded in step 2 that combined-cycle units are technologically infeasible to meet the project purpose as asserted by EPEC. The following section demonstrates that the Region's conclusion regarding the technical feasibility of combined-cycle units is factually incorrect. The Region must therefore revise its BACT analysis to consider the turbines listed above, as well as any other available turbines that can achieve lower GHG emissions.

8 A smaller 1x1 configuration is also available.
9 http://www.doosan.com/doosanheavybiz/attach_files/services/power/power_plant/turbine_gas.pdf
10 http://www.mpshq.com/products/gas_turbines/g_series/performance.html
11 www.mhi.co.jp/technology/review/pdf/e491/e491018.pdf
12 http://www.energy.siemens.com/hq/pool/hq/power-generation/power-plants/gas-fired-power-plants/combined-cycle-powerplants/scc5-8000H/PowerGen_Asia_2012_Bangkok_OneYearCommercialOperation_HClass_Balling_Sfar_Staedtler.pdf
13 Based on 2013 GTW Handbook
14 El Paso Statement of Basis, Figure 3.

3. Combined-Cycle Turbines Are Technically Feasible to Meet the Generation Requirements of El Paso Electric

The Region improperly rejected combined-cycle technology in step 2 of the BACT analysis on the grounds that combined-cycle units are infeasible because allegedly longer startup times are incompatible with the ramping capabilities of the proposed project. (SOB at pp. 11-12.) The Region's rejection of combined-cycle is based on factually inaccurate information. The Region asserted: "Even with faster-start technology, new combined-cycle units may require up to 3.5 hours to achieve full load under some conditions." (SOB at p.12.) There is substantial evidence contradicting this assertion.

Combined-cycle units are fully capable of meeting immediate dispatch needs that are comparable, if not identical, to simple cycle. In fact, vendor documentation in the record – and cited by the Region (SOB at fn. 9) - clearly states that even the LMS 100 turbines proposed for the Montana Power Station are capable of operating as combined-cycle units:

> Even though the LMS100™ system was aimed at the mid-range dispatch segment, it is also attractive in the combined cycle segment. Frame gas turbines tend to have high combined cycle efficiency due to their high exhaust temperatures. In the 80-160MW class, combined cycle efficiencies range from 51–54%. The LMS100™ system produces 120MW at 53.8% efficiency in combined cycle.[15]

The LMS 100 in simple cycle form can reach efficiencies up to 46%, compared to 53.8% in combined cycle. All of the quick start operational flexibility of the LMS 100 is available in a combined-cycle configuration, though at a higher cost. However, the BACT analysis requires the Region to consider technical feasibility in step 2.

Siemens has published documentation that its Fast Start 30 is capable of 10 minute starts after an overnight shutdown. (Exhibit 2, *SGT6-5000F Application Overview*, pp. 4, 15; Exhibit 3, *Fast-Cycling Toward Bigger Profits*; Exhibit 4, June 12, 2013, *Gas Turbine Combined Cycle Fast Start: The Physics Behind the Concept*) Longer times necessary to reach full load are limited to the circumstance where an operator elects to shut the unit down for more than 48 hours. There is no technological limitation that calls for a unit to shut down a unit for that period of time, but an operator may elect to do so if a unit will not be needed for a period of time. However, even in this circumstance, the full output of the combustion turbines that are part of the unit are available within 10 minutes. Therefore, for reliability and renewable integration purposes, combined-cycle units are fully capable of providing fast-response generation. For peaking purposes, combined-cycle units can meet full load simply by warming up the HRSG in anticipation of the demand. This distinction is important because the "peak" is rarely a surprise. Utilities are quite good at estimating peak demand based on weather and usage patterns. Therefore, operators of a combined-cycle unit have sufficient time to warm up a combined cycle unit to meet full load needs, while at the same time having sufficient flexibility to dispatch units quickly at more than half of their full-load capacities within 10 minutes if an urgent need arises.

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[15] Reale, Michael J., LMS100 Platform Manager, General Electric Company, *New High Efficiency Simple Cycle Gas Turbine – GE LMS100*. http://site.ge-energy.com/prod_serv/products/tech_docs/en/downloads/ger4222a.pdf, June 2004. Attached as Exhibit 1, *GE Spec for LMS 100.*

The Region rejected combined cycle technology in step 2 because it incorrectly assumed that combined-cycle units required "up to 3.5 hours to achieve full load under some conditions." (SOB at p.12.) This assertion is both inaccurate and unrepresentative of the actual operation of a utility system. It also fails to assess the modern capabilities of combined-cycle units before even reaching the question of costs. The Region's analysis therefore clearly violates BACT.

a) Examples of Fast-Start Combined Cycle Units That Are Technically Feasible to Meet Short-term Dispatch Requirements

Sierra Club queried turbine vendors on the specific question for whether combined-cycle units can meet fast-ramping capabilities of simple-cycle plants. In response, a representative from Siemens responded as follows: "With the application of proper HRSG and steam turbine technology, gas turbines can start up and ramp up just as fast in combined cycle configurations as in simple cycle configurations. This capability was demonstrated in aeroderivative gas turbines quite some time ago. In recent years, the advance of HRSG and SCR technology has allowed the fast starting of heavy frame gas turbines." (Exhibit 5, *October 18, 2013 Letter from Rich Batey to Travis Ritchie*; *see, also,* Exhibit 6, *2013 GTW Handbook Price List (Excerpt)*.)

The Siemens letter also noted that NRG recently commissioned a plant in El Segundo, California in a combined-cycle configuration that is capable of the same startup times (12 minutes) as the same unit in a simple-cycle configuration. A recent press release noted that the El Segundo plant can achieve even faster startup times: "The new plant can deliver more than half of its [550 MW] generating capacity in less than 10 minutes and the balance in less than 1 hour, which is needed as California relies more on intermittent renewable technologies like wind and solar that depend on weather conditions." (Exhibit 7, Aug. 2, 2013, *NRG's California El Segundo Natgas Power Plant Enters Service*)

There are several other examples of combined-cycle units that can meet fast-start and quick ramping times comparable to simple-cycle units. For example, Footprint Power's Salem Harbor Station will be capable of providing 300 MW of power to the grid "within 10 minutes" using GE's 7F 5-series gas turbine with the "Rapid Response" package. (Exhibit 8, Nov. 1, 2013, *Salem Plant Press Release*.) The plant will reduce greenhouse gases as well as other pollutants including NOx, SO2 and mercury. The plant's operators also touted the "flexibility" of the plant to enable integration of renewables onto the grid. (*See, also,* Exhibit 9, *7F 5-Series Gas Turbine Fact Sheet* (start time of 11 minutes); Exhibit 10, *7F 7-Series Gas Turbine Fact Sheet* (start time of 10 minutes).)

The proposed Oakley Generating Station in California is designed to be able to start up and dispatch quickly with GE's Rapid Response package.[16] The Rapid Response package allows the plant to start up from warm or hot conditions in less than 30 minutes. The Rapid Response package achieves this fast performance by initially bypassing the steam turbine when the gas turbines are started up. In a conventional combined-cycle system, the gas turbine needs to be held at low load for a period of time while the HRSG is warmed up and steam is gradually fed into the steam turbine and the steam turbine is brought up to operating temperature. The steam turbine needs to be brought up to operating temperature slowly in order to minimize thermal stresses on the equipment and to maintain the necessary clearances between the rotating and

[16] Bay Area Air Quality District Final Determination of Compliance for Oakley Generating Station, p.12. (available at: http://www.energy.ca.gov/sitingcases/oakley/documents/others/2011-01-21_BAAQMD_FDOC_TN-59531.pdf)

stationary components of the turbine. In the past, this delay necessitated having to slowly warm up the HRSG and steam turbine and meant that the gas turbine could not increase load as rapidly as a simple-cycle gas turbine to quickly provide power to the grid. It also caused increased emissions, including CO_2, because the combustion turbine needs to be held at low load – where it is not as efficient – while the HRSG and steam turbine are warmed up. Those constraints are avoidable with today's technology. The GE Rapid Response system initially bypasses the steam turbine when the combustion turbines are started, allowing them to ramp up quickly and begin providing power to the grid. The steam turbine can then be warmed up slowly without requiring the combustion turbines to be held at low load (except for a short time for cold startups), through the controlled admission of steam from the HRSGs into the steam turbine. The Rapid Response package therefore allows the facility to start up and begin providing power more quickly than a conventional system, which will enhance operational flexibility and reduce emissions associated with startups.

Another example is the 300 MW Lodi Plant that can deliver 200 MW to the grid in 30 minutes. (Exhibit 11, *Gas Turbine World – Lodi's 300 MW Flex 30*; Exhibit 12, *Lesson from Lodi*) The plant can also ramp up and down at a rate of 13.3 MW/min. This allows the units to respond quickly to intermittent resources or demand while still complying with stringent California emissions requirements. The Siemens fast-start units are specifically designed to reduce the "thermal shock" or "thermal penalty" associated with ramping combined-cycle units up and down.

These units are available today. The El Segundo units came online in September, 2013. The Lodi Energy Center, employing the fast response Siemens system in a 300 MW configuration came on line in 2011.[17] In April of this year Siemens was awarded a contract for a Siemens Flex Plant 30 fast start unit at the Panda Temple II plant in Temple, TX.[18] Financing has been secured and construction of the plant has commenced.[19] Additional fast response units are at the Palmdale Hybrid Energy Plant, where they operate in conjunction with a 50 MW solar facility and are to be located at the proposed Huntington Beach Energy Project.

GE and other manufacturers' units are operating in other countries that, due to higher natural gas prices, have led in the development and adoption of high efficiency, flexible natural gas-fired electric generating technology. GE asserts that it has orders totaling $1.2 billion for Flex Efficiency for 60 plants in the U.S., Japan and Saudi Arabia – countries that use 60 cycle electricity.[20] The Severn Power Plant in Wales is capable of providing full load [834 MWe] within 30-35 minutes with a high degree of flexibility to compensate for intermittent resources such as wind. (Exhibit 14, January 2011, *Fast Cycling and Rapid Start-Up.*) The plant is a result of concerted efforts by turbine manufacturers to meet demand for flexible units with better efficiencies and lower emissions.

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[17] http://www.ccj-online.com/siemens-takes-the-early-lead-in-the-sale-of-packaged-fast-start-plants-for-the-us-market-ge-rounds-out-the-activity-a-distant-second/

[18] http://www.siemens.com/press/en/pressrelease/?press=/en/pressrelease/2013/energy/fossil-power-generation/efp201304026.htm

[19] http://finance.yahoo.com/news/panda-power-funds-secures-financing-123700099.html;

[20] http://www.genewscenter.com/Press-Releases/GE-Launches-Breakthrough-Power-Generation-Portfolio-with-Record-Efficiency-and-Flexibility-with-Natural-Gas-Announces-Nearly-1-2-Billion-in-New-Orders-3b54.aspx. Attached as Exhibit 13, *GE Launches Breakthrough Power Generation Portfolio*.

These examples demonstrate that the feasibility of fast-start and quick ramping combined-cycle turbines has advanced substantially. It is factually inaccurate to claim, as Region 6 does, that combined-cycle units are incapable of meeting the technical capabilities of simple-cycle units. Advancements in HRSG technology allows for faster response times with reduced or even eliminated thermal penalties. There is simply no technological basis to reject combined-cycle units for the Montana Power Station.

b) EPEC's Rationale for Rejecting Combined-Cycle is False

The July Revision asserts several rationales for why a combined cycle unit is less favorable than the LMS 100 units operated as a simple cycle. The Region did not address these rationales, but merely asserted that combined cycle units cannot meet a 10 minute startup. However, the Region did not investigate whether there was any evidence to support a 10 minute startup rate requirement, and even if there was such a need, the evidence provided above clearly shows that more efficient combined-cycle units are capable of meeting a 10 minute startup rate.

EPEC's own data also demonstrates that there is no historic basis for operating an asset with a 10-minute startup rate. A review of El Paso's current generating assets demonstrates that the variability in load in the El Paso system has been and can continue to be met without 400 MW of 10 minute start capacity. (See Exhibit 15, *Analysis of EPEC Load Profile*.)[21] EPEC cannot simply claim, without providing evidence, that its needs can only be met by this specific turbine design. Such as claim is an overly narrow description of the source that would undermine the BACT analysis of other feasible technologies. *See Pio Pico Energy Center*, 16 E.A.D.___, 67 (2013) ("Sierra Club's fear that applicants and permit issuers could so narrowly define the source type they consider in step 2 as to make all other control technologies infeasible is well taken"). Even if there was such a need on EPEC's system, the evidence provided above with respect to modern combined-cycle turbine capabilities shows that more efficient combined-cycle units are capable of meeting a 10-minute startup.

The Applicant's other bases for rejecting combined-cycle are similarly unpersuasive:

Maintenance or "Thermal" Penalty: The July Revision asserts that cycling CCCTs results in a "thermal penalty" because they are not designed to operate with frequent startup and shutdown. (July Revision at p.5.) As noted in the previous section, advances in HRSG technology have reduced or eliminated the thermal penalty associated with multiple startup and shutdowns of combined-cycle units. (*See, e.gs.*, Exhibit 11, *Gas Turbine World – Lodi's 300 MW Flex 30*; Oakley Generating Station[22]) However, even if that problem had not been resolved through modern advancements, this is an economic issue that should be considered in step-4 of the BACT analysis. EPEC asserts: "By cycling a CCCT, you would incur a shorter window between overhauls thereby increasing maintenance costs." (July Revision at p.5.) The costs referred to are not identified, and there is no attempt to analyze whether those costs result in combined-cycle units being economically infeasible. This issue must be addressed in step 4 of the BACT analysis rather than step 2. In fact, the Applicant acknowledges the step-2 technical feasibility of combined-cycle units: "CCCT can be used in this [multiple start-ups and shut-downs during short period of time] operating mode but will incur an increase in maintenance costs due to

[21] Each of the load charts included in Exhibit 15 are available from http://ampd.epa.gov/ampd/QueryToolie.html, visited October, 2013.)

[22] Bay Area Air Quality District Final Determination of Compliance for Oakley Generating Station, p.12. (available at: http://www.energy.ca.gov/sitingcases/oakley/documents/others/2011-01-21_BAAQMD_FDOC_TN-59531.pdf)

thermal gradients." (Id.) The maintenance penalty with increased cycling has largely been overcome with the introduction of Benson designed HRSGs, but even if valid, this issue constitutes an economic cost, not a technical feasibility issue. It therefore does not provide support for the Region's rejection of combined-cycle in step-2 of the BACT analysis.

Reliability: The Applicant asserts that emergency loss of remote generation could cause system blackouts. (July Revision at p.6) Sierra Club acknowledges this risk and the need for emergency dispatch capabilities. However, the Montana Power Station, as described by EPEC, would not meet this need any better than other, more efficient options. As the Applicant notes, "the simple cycle turbines [at the Montana Power Station] will be dispatched ahead of less efficient (and older) local generation units." (Id. at p.5.) This planned operation explains the Applicant's request for 5,000 hours of operation annually, but it undermines the argument that the units are necessary for emergency dispatch. Emergency events are rare; however, EPEC already plant to operate the units up to 5,000 hours per year. This means that for much of the year, perhaps as much as half the hours in the year, Montana Power Station would already be engaged and therefore unavailable (or have limited availability) to meet emergency dispatch needs for reliability.

This rationale for reliability also does not preclude other options such as a more efficient combined-cycle unit or an energy storage unit. If the unit were a combined-cycle turbine, it would already be warm and spinning for several hours during the year. (For example, see the dispatch profile of EPEC's Newman 5 CC, attached as Exhibit 15.) Spinning a combined cycle unit at low loads, which EPEC's system already experiences, would allow for quick ramping to provide emergency reserves. Even if a combined-cycle unit were shut-down, EPEC could simply rely on modern combined-cycle capabilities to quickly ramp up the combustion turbine immediately and bypass the HRSG and steam turbine until the unit was warmed up. In other words, a combined cycle unit is perfectly capable of meeting the emergency reliability needs stated by the Applicant. An energy storage unit is even more flexible and able to provide even faster response in an emergency.

In summary, there is nothing unique about the proposed LMS 100 units that make them better able to meet emergency reliability needs on EPEC's system. Modern combined cycle units or storage units would fulfill the same need at much lower emission rates.

Backing Up Renewables: EPEC states that the LMS 100 units can ramp at 50 MW per minute to meet immediate fluctuations in power associated with intermittent loss of renewable generation. (July Revision, p.6.) However, this assertion ignores the technological capabilities of combined-cycle units. The previous sections cited multiple examples where utilities or merchant owners have built or are in the process of permitting multiple combined cycle units to meet renewable flexibility needs. (Exhibit 7, Aug. 2, 2013, *NRG's California El Segundo Natgas Power Plant Enters Service;* Exhibit 8, Nov. 1, 2013, *Salem Plant Press Release*; Exhibit 11, *Gas Turbine World – Lodi's 300 MW Flex 30;* Exhibit 14, January 2011, *Fast Cycling and Rapid Start-Up.*) The Lodi plant in particular can meet a ramp rate of 13.3 MW/min, which is much faster than the stated need for EPEC. Similarly, the GE 7F-5 Series and the GE 7F-7 series combined-cycle units can meet ramp rates of 40 MW/min and 50 MW/min, respectively. (Exhibit 9, *7F 5-Series Gas Turbine Fact Sheet*; Exhibit 10, *7F 7-Series Gas Turbine Fact Sheet*.)

The quick ramping and quick start capabilities of combined cycle units can meet the needs of a variable electric grid. Moreover, the Montana Power Station will not be the only flexible supply unit on the grid. The Applicant's own load profile (July Revision, Appendix E, p.4) shows a relatively smooth daily load. Combined cycle natural gas units with reliability reserve capacity can ramp up or down to meet load and supply fluctuations. This is a characteristic of grids throughout the country, and in particular in California where penetration of renewables is particularly high. There is no basis for EPEC's inability to meet intermittent grid needs with a more efficient combined-cycle unit.

c) Other Utility Operators of Peaking Units Recognize the Ability of Combined-Cycle Units to Serve as Peaking Units.

While neither EPA nor EPEC evaluated the potential natural gas fired alternatives to the GE LMS 100, it turns out that another permit applicant has done so. The following is an excerpt from the GHG BACT analysis prepared by CH2MHill for the Huntington Beach Energy Plant (HBEP) peaking project which utilizes[23] a fast response Mitsubishi 3 x 1 501 D CCGT unit:

> The HBEP's design objectives are to be able to operate over a wide MW production range with an overall high thermal efficiency, in order to respond to the fast changing load demands and changes necessitated by renewable energy generation swings. This rapid response is accomplished by utilizing fast start/stop and ramping capability and the use of the duct burners to bridge the MW production when additional combustion turbines are started (as opposed to the duct burner's traditional roll of providing peaking power during periods of high electrical demand). At maximum firing rate, the maximum power island ramp rate is 110 MW/minute for increasing in load and 250 MW/minute for decreasing load. At other load points, the load ramp rate is 30 percent. The HBEP start time to 67 percent load of the power island is 10 minutes, and it is projected that the project will operate at an approximate 40 percent annual capacity factor. The HBEP offers the flexibility of fast start and ramping capability of a simple-cycle configuration, as well as the high efficiency associated with a combined cycle.
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>
> The HBEP will be dispatched remotely by a centralized control center over an anticipated load range of approximately 160 to 528 MW for each 3-by-1 power island. Over this load range, the HBEP anticipated heat rate is estimated at approximately 7,400 to 8,000 Btu/kWh lower heating value (LHV) (~ 8,140 to 8,800 Btu/kWh HHV). The HBEP will be able to start and provide 67 percent of

[23] The permit applications for the project demonstrate its commercial availability. The project is undergoing California environmental review and commencement of onsite construction is anticipated in 2015.

the power island load in 10 minutes and provide 110 MW/min of upward ramp and 250 MW/min of downward ramp capability.[24]

In the course of its analysis CH2MHill produced an analysis of the heat rate for the 501 DA fast response CCGT proposed compared to the LMS100 units across the anticipated range of outputs. In this analysis it can be seen that as each LMS unit comes on line the system suffers a substantial penalty for part load performance compared to the 501 DA and that across the entire anticipated load range the 501 DA demonstrates a lower (more efficient) heat rate.

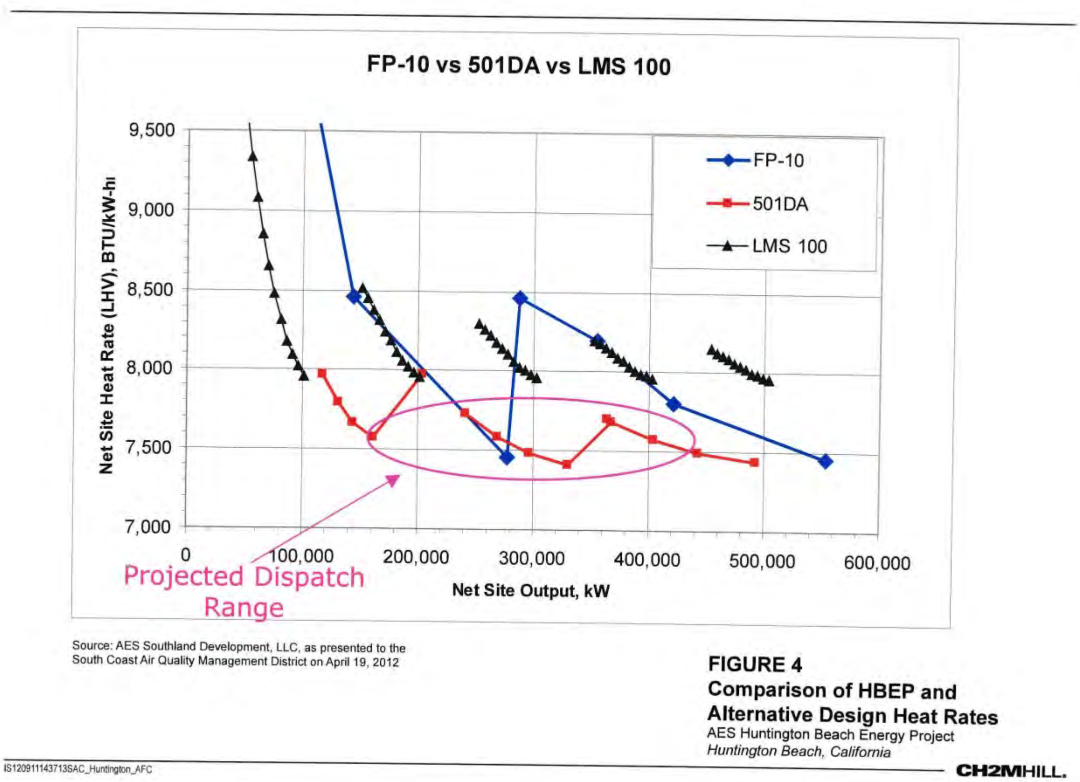

FIGURE 4
Comparison of HBEP and Alternative Design Heat Rates
AES Huntington Beach Energy Project
Huntington Beach, California

CH2MHill also provided a graphic illustration of the startup and ramp rate of the proposed Mitsubishi fast response unit.

[24] Exhibit 16, *BACT Determination for the Huntington Beach Energy Project* http://www.energy.ca.gov/sitingcases/huntington_beach_energy/documents/applicant/AFC/Volume%202%20Appendices/HBEP_Appendix%205.1D_BACT%20Determination.pdf (page 3.24).

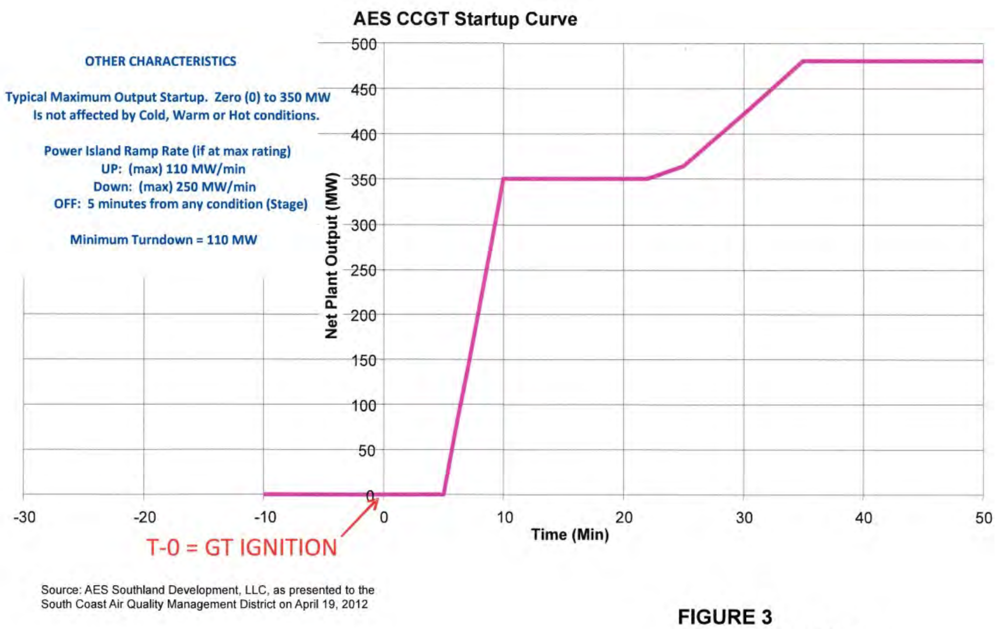

FIGURE 3
HBEP Startup Curve
AES Huntington Beach Energy Project
Huntington Beach, California

IS120911143713SAC_Huntington_AFC CH2MHILL.

This analysis of the HBEP plant demonstrates that more efficient, lower polluting technology is available. The Region must consider these data in determining the appropriate BACT limit for the Montana Power Station. The Region cannot simply rely on the Applicant's own assertions and data that its preferred turbine technology constitutes BACT.

4. <u>The Region Failed to Consider Penalties Experienced by the LMS 100 at Part Load Operation</u>

Aeroderivative units, such as the LMS 100, suffer a greater reduction in power and efficiency at high temperature and part load operation than frame-based units.[25] Neither EPEC nor EPA evaluated the performance of the chosen LMS 100 unit under the actual operating conditions anticipated for the plant. It is instructive to compare the part load performance of the LMS 100 units with combined-cycle generating units.

The load response curves for the LMS 100 provided by GE show a sharp decline in efficiency from 43 percent to 35.7 percent at 50 percent load, with a corresponding rise in heat rate from 7,935 Btu/kWh to 9557 Btu/kWh. In contrast, the Alstom KA 24 has a full load efficiency of approximately 59 percent and its heat rate is 5783 Btu/kWh. It maintains that heat

[25] *See, generally*, 2013 GTW Handbook.

rate to below 80 percent load and at 50 percent load its heat rate is less than 6130 Btu/kWh.[26] At full load, the Alstom enjoys a heat rate advantage of 1,250 Btu/kWh compared to the LMS 100, at part load the Alstom advantage rises to over 3,400 Btu/kWh.[27]

The Region must consider this data as part of its analysis of combined-cycle units in lieu of less efficient simple-cycle units.

5. The Operating Scenarios that the Region Used to Derive BACT Limits Are Unrealistic and Inconsistent With the Stated purpose of the Plant as a Peaking and Intermediate Unit.

The Region based the annual CO_2 tonnage cap for each of the units on the assumption that each of those units would operate at full load for the full 5000 hours of operation requested by EPEC. That is, EPA assumed a capacity factor (100 percent) that even baseload units cannot and do not achieve. This assumption is entirely unrealistic and inconsistent with the stated purpose of the plant as a peaking and intermediate service generator. A plant that is running at 100 percent capacity cannot respond to the fluctuations in load that are associated with summertime peak demand. Copper Station, EPEC's current peaking unit, does not demonstrate anything close to the "full on/full off" performance that EPA assumes.

At the same time EPA bases its hourly average CO_2 limit on an assumed operating scenario in which each of the four turbines operates at 50 percent load and that ambient temperatures are 105°F. Sierra Club recognizes that there may be some times when an individual unit may operate at 50 percent load and 105°F and so an hourly limit (i.e. a "never to exceed in any single hour" limit) based on this assumption for an individual unit might be appropriate. However, if the ambient temperature reaches 105°F all units in the system will be operating at or near full capacity and the newest and most efficient units will be operating at full capacity. EPEC offers no argument or data to support the unrealistic assumption that all four units at the Montana Power Station will operate at 50 percent load during such high demand days. The hourly operating limit for the facility should be based on the assumption that no more than one unit at a time is operating at suboptimal efficiency. This permit modification can be accomplished by establishing emission limits that are to be met at various load ranges of the unit, based on part load operation of one unit and full load operation of any other unit that is online at the time. Compliance would be based on the net hourly generation during each hour and the limit applicable to that level of generation.

The Region also increases the proposed BACT limit by 3 percent to accommodate the asserted probability that the unit that is delivered will not have the rated efficiency. Once again, there is no support for this adjustment. A 3 percent increase in heat rate at each unit will have an operating (fuel) cost penalty of several million dollars per year and more than $100 million over the useful life of the plant – for which the vendor would presumably be liable. Accordingly, there is no reason to believe that the unsupported assertion relied on by the Region has any merit. The unbiased literature in the field supports a must lower adjustment factor.

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[26] http://www.energiaadebate.com/alstom/Turbina%20de%20Gas%20GT24/GT24%20-%20Technical%20Paper.pdf See also, Alstom's discussion of its low load operation and fast response options and its ability to support the spinning reserve market.

[27] GHG emissions are proportional to the heat rate. The Alstom 24/26 series of turbines have been installed in a number of facilities worldwide, including at the Lake Road, CT generating station (2002). http://www.alstom.com/Global/Power/Resources/Documents/Brochures/gt24-and-gt26-gas-turbines.pdf

> Conservative OEMs tend to bid some margin, i.e. with slightly higher heat rate and lower power output to allow for normal variations in manufacturing tolerances and test uncertainties. Typically with performance guarantees, there is **a margin of 0.5 to 1%** points on efficiency and power ratings which is why slightly better performance may initially be realized in actual service.

2013 Gas Turbine World Handbook, Pequot Publications (2013), p. 40 (emphasis added).

EPA also proposes a 6 percent increase in the allowable limit to account for degradation in performance over time, as well as for temperature and humidity effects. There is no documentation in the record to support this figure for unrecoverable[28] degradation in performance. Further, the adjustment from ISO conditions for humidity should be to decrease the heat rate, not increase it, since El Paso typically has lower humidity than the ISO assumed conditions. Finally, Sierra Club questions the appropriateness of any further increase in the allowable heat rate based on temperature, since the "unadjusted" heat rate already includes an assumption that each operating hour will be at 105°F, and each turbine is equipped with an inlet cooling device that reduces the temperature of the air entering the turbine to 60°F.

The Region significantly compounds the error in its assumption by establishing the resulting 1,194 lb/MWh limit on a rolling 5,000 hour basis. For this limit, the underlying assumption is that all four units always operate at 50 percent load and that the temperature is always 105°F when they operate. Clearly, these assumptions are unrealistic. The assumption concerning ambient temperatures during 5,000 hours of operation can be shown to be incorrect by reference to hourly, monthly and annual temperature data for El Paso.[29] The assumption concerning regular operation at 50 percent load can be shown to be incorrect by examination of the load patterns for EPEC's existing peaking and non-peaking assets reported to EPA's Air Markets Program Database. Sierra Club has reviewed operating records for each of the gas-fired units in EPECs system for several months and has observed no instance in which any unit has ever operated at full load for a month. The proposed part load assumption is also inconsistent with the annual CO_2 emission limit, which assumes that each unit operates at full load, including periods when it is starting up and shutting down, for 5,000 hours per year. Since "startup" is defined to occur at 50 percent load, this assumption is physically impossible.

EPEC relies on a promotional piece of literature provided by GE to show that its units are capable of cycling more than once per day to support its claim that it "needs" an emission allowance for 832 startup and shutdown ("SUSD") events per year. Sierra Club does not doubt that simple-cycle units can cycle several times per day. However, we have no way of knowing the circumstances under which the GE literature was developed. More importantly, there is nothing in the record to support the unrealistic assumption that each new unit in the EPEC system will experience 832 SUSDs each year, and substantial evidence in EPA's data bases indicates that the Montana Power Station will not experience this extraordinary number of SUSD events. The stated purpose of the project and the system would support, at most, 365 SUSD events, and it is highly unlikely that each unit could amass 5,000 operating hours per year while shutting down four times each day.

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[28] That is, degradation in performance that cannot be restored or minimized by proper routine maintenance.
[29] For example, the annual mean temperature for El Paso is 63.1°F; the mean temperature for July in El Paso is 82.2°F. http://www.el-paso.climatemps.com/temperatures.php.

Further, the EPEC system load data included in the application does not show multiple daily peaks and valleys that would support such an assumption. (Application, p.61.) Rather, that data shows a smooth increase to a peak and then a smooth decline to overnight lows. Sierra Club has reviewed several months' operating data for each of EPEC's units and has yet to identify an instance where any unit had more than one SUSD in a day.[30] Given the infrequent operation of EPEC's simple-cycle unit (Copper Station) and the relatively few SUSD's of EPEC's load following and base load units, we believe that a complete review of the EPEC system operating record will establish that fewer than 100 SUSDs should be anticipated for any new units. Any decision by the Region on the number of anticipated SUSDs must be based on the demonstrated operating record of the EPEC system and not on a product capability literature that is unrelated to the anticipated usage of the equipment in the EPEC system.

6. EPA's Rolling 5,000 Operating Hours Limit Is Unenforceable and Unnecessary

EPA has proposed to average the operating hour emission recordings for each day over a 5,000 hour operating period to determine compliance with the BACT limit of 1,194 lb. CO_2/MWh. (Draft Permit, § III.A.2.a.) However, this limit could conceivable allow EPEC to operate the units for many years before a baseline is established. If EPEC operates the Montana Power Station as a peaking unit, which EPEC has said is an option, then the proposed units would be expected to operate only 700-1,000 hours per year. Thus, at reasonably expected annual operating levels, the first 5,000 hours would not be expected to occur for five to seven years or more. During this time, compliance could not be determined, and the units would essentially be allowed to operate for years without any applicable GHG rate limit. This provision would therefore allow for many years of non-compliance with no opportunity to enjoin the ongoing violation or collect penalties in the interim; it is therefore unenforceable as a practical matter.

This provision is also arbitrary in that there has been no showing in the record of any need to extend the averaging period beyond one year. The limit is based on assumptions that are well beyond "worst case" and there is no need to accommodate year-over-year differences in weather condition or load.

A CO_2 CEMS normally takes 4 measurements per hour.[31] The standard error of the mean – the probability that the calculated mean of a series of 2,800 measurements will be substantially different from the "actual" mean is quite small (0.02 times the standard deviation of the sample) and not significantly different from the standard error of a series of 20,000 measurements with the same standard deviation. The additional 17,200 measurements provide no discernible improvement to the accuracy of the determination of the mean of the sample – and so provide no benefit to the operator other than the five to seven year grace period described above. The Region must revise this permit condition to ensure that the BACT permit limit is enforceable on an annual basis. The Region should base the 1,194 lb CO_2/MWh rate on a 365-day rolling average limit, as measured by CEMS.

[30] These operating data are obtained from http://ampd.epa.gov/ampd/QueryToolie.html, visited October, 2013.
[31] The statistical result is also insignificant if one assumes that there are 700 measurements per year rather than 2,800.

7. EPEC and The Region Have Employed Out Of Date ISO Ratings For The LMS 100

The development of a proposed emission limit starts with the new and clean heat rate at standard conditions. EPEC reported that the LMS 100 ISO heat rate was 7,937 Btu/kWh (LHV).[32] However, the 2013 GTW Handbook reports several different versions of the LMS 100, the most efficient version identified has a listed heat rate of 7,580 Btu/kWh. The Region and EPEC should clarify whether the proposal is to use the most efficient LMS 100 currently available and the ISO heat rate of that unit. The Region should then follow the lead of other agencies and require an acceptance test, corrected to ISO conditions, for any unit that is determined to be BACT. It is our understanding that increasing altitude impacts the available capacity of the unit, but does not affect the heat rate in any meaningful way. This is consistent with the data provided by GE in Figure 3 of the SOB.[33] Temperature and humidity also can adversely impact the heat rate of a unit. El Paso can be hot in the summer months, but it is dry. Hot, humid conditions have a greater impact on the anticipated efficiency of a turbine. The load/efficiency/temperature curves provided by GE do not contain information relating to the humidity that is assumed to determine the impact on temperature. Further, the SOB notes that "[a]n evaporative cooling system will be used to cool the incoming combustion turbine air (to approximately 60°F) in order to increase the combustion air mass flow." (SOB p.16) Given the presence of inlet air chilling, the use of a temperature correction to 105°F would seem to be unwarranted. The temperature correction curves provided by EPEC's consultant do not specify whether they include the use of inlet air chilling and there is nothing in the record that addresses this issue. We assume that there is some energy cost associated with the inlet air chilling employed, but it does lead to better than ISO "ambient" air temperatures that the unit experiences. The Region must revise emission limit to reflect the expected operating conditions for the Montana Power Station.

8. The Region Must Consider Energy Storage in Lieu of Natural Gas Peakers

In addition to more efficient combined-cycle natural gas unit, the Region must consider modern energy storage units in step 1 of the BACT analysis. Energy storage is a zero-carbon alternative that can meet most, if not all, peaking capacity needs. If, as the Applicant states, the purpose of the project is to provide peaking capacity, then zero-emission energy storage units may provide that service with far lower emissions. Energy storage is particularly attractive for a system such as EPEC's where there is a high summer peak for a short duration, followed by longer off-peak periods where there is significant excess generating capacity. For example, EPEC relies on the Palo Verde nuclear plant as well as older combined-cycle natural gas units, which EPEC claims cannot be cycle off quickly or frequently. Any excess generation from Palo Verde, other existing natural gas units, or from future low-variable cost renewable generation units could be used to charge energy storage facilities during off-peak hours. Those units can then be quickly reversed to provide peak capacity during periods of high demand.

The California Energy Storage Alliance (CESA) has issued an analysis showing the numerous capabilities and advantages that energy storage offers compared to simple-cycle units

[32] SOB, p 14
[33] Brooks, F.J. *GE Gas Turbine Performance Characteristics,* visited at http://www.muellerenvironmental.com/documents/GER3567H.pdf, p. 8.

such as the LMS 100.[34] The technology could feasibly meet the business purpose of the Applicant to provide peaking capacity, reliability, and integration of renewable resources. It is also commercially available, as demonstrated in part by a recent California Public Utilities Commission decision directing public utilities to acquire 1,325 MW of energy storage by 2020.[35] The Region must include energy storage as an identified technology for providing energy services for purposes of its BACT analysis.

9. The Applicant Cannot Narrowly Define the Source In Order to Avoid BACT.

EPEC asserts that its plan to construct each of the four units of the Montana Power Station constitutes a single project that should be the subject of a single permit.[36] EPEC then asserts that four simple-cycle 100 MW units, rather than a single 400 MW CCGT, are essential to the purpose of the plant to meet the annual growth in demand that is predicted for 2014 -2017. This assertion is without support. Instead, this assertion represents the "overly narrow" definition of the project purpose that the Environmental Appeals Board ("EAB") was rightly concerned about in its recent Pio Pico decision. *Pio Pico Energy Center,* 16 E.A.D.___, 67 (2013) ("Sierra Club's fear that applicants and permit issuers could so narrowly define the source type they consider in step 2 as to make all other control technologies infeasible is well taken"). EPEC makes no attempt to demonstrate that other alternatives, such as a gas unit combined with energy storage, or different configurations of combined-cycle units, could not also meet its needs for peaking and cycling demand during the period. Companies routinely phase in capacity in anticipation of future needs. This is possible both with simple-cycle units as well as combined cycle units or a combination of renewable, storage and fossil generation. At times, the lumpy nature of generation build-out could lead to surplus generation capacity that is greater than current needs. However, particularly in a high-growth system such as EPEC's, the system will eventually grow to require the excess capacity. An examination of EPECs IRP shows that there are several years in the future where EPEC will have more generation capacity than needed in a given year.[37] EPEC has not made any showing that its staggered development of the Montana Power Station is necessary for its business purpose, nor has it demonstrated that construction of the full amount of capacity at the outset is infeasible or that additional generation could not be purchased if EPEC decided to delay construction of the new unit for a year. The IRP also shows that there are a number of units in EPECs system that can be retired or mothballed – including some very old and very inefficient units if the additional new generation capacity were available. This would accelerate the environmental benefits of bringing on a newer and more efficient combined-cycle unit.

EPEC's simple assertion that it must construct four separate simple-cycle units is insufficient to demonstrate that more efficient generation cannot be phased in to more closely match its needs. It is not uncommon for utilities to phase construction of combined cycle units so that the simple cycle turbines are installed first and the HRSG and steam turbines are installed in a

[34] http://www.storagealliance.org/sites/default/files/Presentations/Energy%20Storage%20Cost%20Effectiveness%202013-09-23%20FINAL.pdf

[35] http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M079/K171/79171502.PDF

[36] As discussed below, the Montana Power Station requires a separate BACT determination for units that are not scheduled to commence construction within 18 months.

[37] IRP, Long Range Forecast, 20-Year Loads and Resources Document. Attachment F

separate phase. EPEC's IRP includes installation of several new CCGTs in this fashion. For example, if EPEC purchased a CCGT configuration in a 2x1 configuration, the additional generation capacity could be completed in three phases; if it elected a 2x2 configuration the project could be completed in four phases.

10. Phased Construction

EPEC's plan to construct units 3 and 4 of the Montana Power Station in 2016 and 2017 would violate the requirement that a BACT review be completed no sooner than 18 months before the commencement of construction. "For phased construction projects, the determination of best available control technology shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of the project. At such time, the owner or operator of the applicable stationary source may be required to demonstrate the adequacy of any previous determination of best available control technology for the source." 40 CFR 52.21(j)(4). EPEC cannot assume that the applicable BACT limit will be the same in two or three years from now. The entire purpose of BACT is to require facilities to keep up with modern pollution control technologies. The Region must therefore require that EPEC begin construction (i.e. break ground) on all four units with 18 months of a final PSD permit or re-apply for a new PSD permit for the later units.

11. The Cost Analysis for Carbon Capture and Sequestration In The Region's Statement of Basis is Invalid

Carbon capture and sequestration (CCS) is a process that uses adsorption or absorption to remove CO_2 from flue gas, with subsequent desorption to produce a concentrated CO_2 stream. The CO_2 is then transported to an appropriate storage location, most likely underground in a geological storage reservoir such as a deep saline aquifer or a depleted oil well or coal seam. The Region identified CCS as a feasible technology for purposes of step 2 of the BACT analysis. (SOB at p.11) However, the Region rejected CCS in step 4 on the grounds "the addition of CCS would increase the total capital project costs by more than 50%, which is excessive in relation to the overall cost of the proposed project." (SOB at p.13.) The Region's basis for rejecting CCS in step 4 is improper. As the EPA has regularly asserted, rejection on the basis of a percentage of total costs is not valid in a BACT analysis.

a) The Region Incorrectly Applied the Standard for Eliminating a Technically Feasible Alternative for Adverse Economic Impacts

The Region's determination that CCS is too expensive in relation to the total costs of the entire project is not a valid basis for rejection in step 4 of the BACT analysis. The Region's analysis concluded that the annualized cost of CCS is more than 50% the total project costs (SOB at p. 13) The NSR Manual expressly rejects this type of conclusion without more analysis. "[T]he capital cost of a control option may appear excessive when presented by itself or as a percentage of the total project cost. However, this type of information can be misleading."[38] Cost considerations in determining BACT should be expressed in terms of average cost effectiveness. *NSR Manual* at B.36; *see, also, Inter-Power of New York, Inc.,* 5 E.A.D. 130 at 136 (1994). On its face, the Region's conclusion that costs of CCS would be 50% more than the

[38] *NSR Manual*, p. B.45.

estimated total project costs is an invalid basis for rejecting CCS as BACT in step 4 of the top-down BACT analysis.

In past permits, the Region relied on the EAB's decision in *In re: City of Palmdale (Palmdale Hybrid Power Project)*, PSD Appeal No. 11-07, 15 E.A.D. __ (Sep. 17, 2012) to support its decision to rely on a comparison of total project costs rather than a cost effectiveness calculation. That decision is distinguishable from the present case. The available data in *City of Palmdale* indicated that CCS would be more than twice the value of the total facility costs. (*Id.* at 54.) In this case, even if the Applicant's inflated cost numbers are accepted, the cost of CCS is a fraction of the total cost of the facility. If the cost analysis is corrected using site-specific data, that fractional cost would be even lower. Furthermore, the EAB clearly stated in *City of Palmdale* that "permit issuers typically consider two economic criteria: average and incremental cost effectiveness" and "[c]ost effectiveness is typically calculated as the dollars per ton of pollutant emissions reduced." (*Id.* (internal quotations omitted)) The EAB allowed an exception to that general rule because with respect to GHG control technology "it may be appropriate in **some cases** to assess the cost effectiveness of a control option in a less detailed quantitative (or even qualitative) manner." (*Id.* (emphasis added)) However, the Region has interpreted this narrow exception so broadly that it has eliminated any meaningful cost effectiveness analysis.

Rather than applying a total cost comparison in some extreme cases, as suggested by *City of Palmdale*, the Region has applied total cost comparison in **every** GHG BACT analysis for at least the past year. (*See, e.gs.*, PSD-TX-1296-GHG, Celanese SOB, p.12 ("[t]he estimated CCS capital needed only for capture and a new pipeline for the current project results in an increase of more than 25% in the capital costs for Celanese's project"); PSD-TX-102982-GHG, Baytown Olefins Plant SOB, p.10 ("[t]he addition of CCS would increase the total capital project costs by more than 25%"); PSD-TX-1288-GHG, La Paloma Energy Center SOB, p. 12 ("the cost of CCS would more than double the cost of the current project"); PSD-TX-612-GHG, Air Liquide SOB, p.13 ("the annualized cost of CCS…is more than four times the estimated annualized capital cost for the proposed project").) The Region has applied the narrow exception to the consideration of cost effectiveness cited in *City of Palmdale* to cases where CCS costs range from only 25 percent of total project costs up to 400 percent of total project costs. Clearly, the Region's application of cost analysis in step 4 is arbitrary and capricious. The Region has not provided any boundaries or rationale for when a GHG control technology is appropriately compared to total project costs instead of the NSR Manual's preferred method of relying on cost effectiveness.

The Region must consider the average cost effectiveness of CCS compared to the costs borne by other similar facilities. The Region cannot in every single BACT analysis rely on the total annualized capital costs of CCS compared to the total facility costs. The NSR Manual expressly rejects this approach:

> BACT is required by law. Its costs are integral to the overall cost of doing business and are not to be considered an afterthought. Consequently, for control alternatives that have been effectively employed in the same source category, the economic impact of such alternatives on the particular source under review should be not nearly as pertinent to the BACT decision making process as the

> average and, where appropriate, incremental cost effectiveness of the control alternative.[39]

The Region must base its BACT decision on the average cost effectiveness of CCS, which should be expressed in terms of $/ton of CO_2 removed with CCS **<u>that are specific to the facility at issue</u>**. The SOB includes a generic citation to the cost of storage at $256 per ton for a new natural gas facility (SOB at p.13.), and relied on other generic cost data to conclude that CCS would result in $112.93 per ton of CO2 removed. (Application at p.50, Table 10.3.) However, nothing about these estimates is specific to the Montana Power Station; they are simply generic price estimates that have been extrapolated based on the expected output of the Montana Power Station.[40]

The first step in calculating the average cost effectiveness of alternative control options (such as CCS), is for the Region to correctly define the baseline emission rate. Baseline emission rates are "essentially uncontrolled emissions, calculated using realistic upper boundary operating assumptions," for the applicant's proposed operation.[41] Once the baseline is calculated, the cost-per-ton of pollutant controlled is calculated for each control option by dividing the control option's annualized cost by the tons of pollution avoided ("Baseline emissions rate – Control option emission rate"). *In re Steel Dynamics*, 9 E.A.D. 165, 202 n.43 (EAB 1999); *In re Masonite Corp.*, 5 E.A.D. 551, 564 (EAB 1994); *NSR Manual* at B.36-.37; *cf. In re: City of Palmdale* (Palmdale Hybrid Power Project), PSD Appeal No. 11-07 at 54 (E.A.B. Sept. 17, 2012)("[cost effectiveness] is typically calculated as the dollars per ton of pollutant emissions reduced").

When determining if the most effective pollution control option has sufficiently adverse economic impacts to justify rejecting that option and establishing BACT as a less effective option, a permitting agency must determine that the cost-per-ton of emissions reduced is beyond "the cost borne by other sources of the same type in applying that control alternative." *NSR Manual* at B.44; *see also Steel Dynamics, Inc.*, 9 E.A.D. 165 at 202 (2000)*; Inter-Power*, 5 E.A.D. at 135 ("In essence, *if the cost of reducing emissions with the top control alternative, expressed in dollars per ton, is on the same order as the cost previously borne by other sources of the same type in applying that control alternative, the alternative should initially be considered economically achievable, and, therefore, acceptable as BACT*." (quoting *NSR Manual* at B.44) (emphasis original)). This high standard for eliminating a feasible BACT technology exists because the collateral impacts analysis in BACT step 4 is intended only as a safety valve for when impacts unique to the facility make application of a technology inapplicable to that specific facility. The Region inappropriately compared the total cost of CCS to the total cost of the facility. To reject CCS, BACT requires a demonstration that the costs of pollutant removal are disproportionately high for the specific facility <u>compared to the cost of control at other facilities</u>. No such CCS comparison was made here.

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[39] *NSR Manual*, p. B.31.

[40] The Region also relied on a substantially inflated estimate for natural gas prices. The Cost Manual does not permit EPA to escalate the cost of natural gas. 2014 prices for Henry Hub natural gas has fluctuated between $3.11-$4.04 per MMbtu. http://www.eia.gov/dnav/ng/hist/rngwhhdm.htm The Region must base its CCS analysis on current natural gas prices without escalating those prices.

[41] See *NSR Manual* at B.37.

b) The Cost Effectiveness Methodology is Incorrect

EPEC did not provide any site-specific cost analysis for the Montana Power Station. Instead, the Applicant relied on generic data from a 2010 DOE study. (Application at p.49.) Importantly, EPEC did not look at generic data for the cost of construction; EPEC started with the estimated cost per ton to remove CO2, and simply extrapolated the number based on the Montana Power Station's anticipated emissions. In other words, without making any calculations specific to the size of the plant or the cost of any particular line-item expense, EPEC assumed that removing, transporting and storing carbon would cost $112.93 per ton of CO2 removed. (Application at p.50, Table 10.3.) Under this analysis, every single facility contemplated for construction would have the same $/ton cost effectiveness estimate. The Region similarly did not include an average cost effectiveness calculation of CCS expressed in terms of cost-per-ton of GHG removed in either the SOB or the Draft Permit. The Region merely extrapolated the generic costs per ton of removal put forth by the applicant and determined that total capital cost for CCS compared to the estimated total project costs were too high. This rationale does not meet BACT requirements to reject a technology for adverse economic impacts.

EPEC's reliance on the DOE/NETL 2010 Report is also inappropriate because the DOE/NETL 2010 Report did not use the BACT cost effectiveness "overnight" method. Instead, the report used the LCOE method or Levelized Cost of Electricity.[42] The LCOE method analyzes the cost of generating electricity for a particular system. It is an economic assessment of the cost of the energy-generating system including all of the costs over its lifetime: initial investment, O&M, cost of fuel, cost of capital. It is the antithesis of the BACT overnight method and therefore does not provide a valid foundation for EPEC's cost effectiveness analysis.

The DOE/NETL analysis also included costs not allowed in BACT cost effectiveness analyses, including financing costs, owner's costs, royalties, and AFUDC. The DOE/NETL cost analysis also used a 30-year, current-dollar levelized cost estimating method inconsistent with BACT methodology. These costing approaches overestimate costs compared to those calculated using the BACT "overnight method." Cost effectiveness is a relative determination that relies on comparison to costs borne by other similar facilities, calculated using the same method for all facilities in the range considered. The Region's failure to adhere to this methodology invalidates the BACT analysis.

Although the BACT requirement to control GHG emissions in a PSD permit is relatively new, there are other analyses that took a hard look at the cost of CCS controls. Recently, the Region considered a permit application from Air Liquide to replace several combustion turbines at its Bayou Cogeneration Facility. The Applicant included a detailed cost analysis that broke down the base capital costs for post-combustion CO2, a breakdown of pipeline capital and O&M costs, and an estimate of geological storage costs. (*See*, Permit No. PSD-TX-612-GHG) In a supplemental filing submitted the Region on October 14, 2013, Air Liquide revised its estimates further to include the availability of offsets to the cost of CCS offsets tax credits or revenue from enhanced oil recovery (EOR). Air Liquide then compared the estimated total annualized cost of CCS to the total tons of CO2 per year that would be removed and concluded that project-specific CCS installation at the facility would cost $57/ton of CO2 avoided. Similarly, the Celanese Clear Lake facility recently submitted supplemental information to the Region with respect to its

[42] *See, Report of the Interagency Task Force on Carbon Capture and Storage,* August 2010, Appendices p. A-14. Available at: http://www.epa.gov/climatechange/Downloads/ccs/CCS-Task-Force-Report-2010.pdf

application for permit PSD-TX-1296-GHG that include a line-item analysis of specific costs necessary to construct and operate CCS controls at that specific facility.[43] The Region must undertake a similar analysis with the EPEC application that considers line-item, site-specific costs to construct CCS at the Montana Power Station.

Other facilities that are actually implementing CCS could also provide estimated cost effectiveness data. CCS is a transferable technology between industries that has been successfully deployed within the power generation industry. A project in Texas, the NRG WA Parish project, is being constructed to capture CO_2 from flue gas carbon at a 200 MW coal plant.[44] Shell is completing a CCS project at the Peterhead natural gas power plant in Scotland.[45] The Region must consider the cost of CCS at these and other facilities when making a determination about whether CCS at the Montana Power Station creates an adverse economic impact unique to the facility at issue.

Even if EPEC's generic CCS cost estimate of $112.93 per ton of CO_2 removed for CCS at the Montana Power Station were valid, that average cost effectiveness does not necessarily constitute an adverse economic impact unless it is disproportionate to the cost-per-ton of CCS at other facilities. Based on the data available, EPEC cannot possibly make a determination that it is more costly to install CCS at its facility compared to other typical facilities because EPEC used generic cost assumptions that reflected the expected cost at typical facilities. In other words, EPEC admits that its costs are the same as a similarly situated facility. Taken a step further, EPEC's estimate of $112.93 per ton of CO2 removed is much less than the Region's cited estimate of $256 per ton of CO2 removed. (SOB at p.13.) To reject CCS at the EPEC plant when other facilities will be using the same technology, the applicant must demonstrate—with actual data—that the cost per ton at the Montana Power Station is disproportionate to other facilities. The SOB, on its face, precludes such a determination because it indicates that the generic estimate used by EPEC is less than half of the "low-side published estimates" for CO2 capture and storage. (SOB at p.13.) Based on the current record, the Region cannot reconcile this issue. The Region must reopen the record to require a site-specific analysis of CCS costs at the Montana Power Station.

c) The CCS Analysis Lacks Basic Design Elements

The EPEC analysis fails to include a description of even the most basic design parameters for CCS. The design basis is fundamental to the BACT analysis. The NSR Manual provides:

> Before costs can be estimated, the control system design parameters must be specified. The most important item here is to ensure that the design parameters used in costing are consistent with emissions estimates used in other portions of the PSD application. In general, the BACT analysis should present vendor-supplied design parameters.

NSR Manual, p. B.33. The NSR Manual goes on to explain that the first step in preparing a BACT cost effectiveness analysis is to determine "the limits of the area or process segment to be costed... This well-defined area or process segment is referred to as the battery limits. The

[43] http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/celanese-submittal-info11082013.pdf
[44] http://www.nrgenergy.com/petranova/waparish.html

[45] http://www.shell.co.uk/gbr/environment-society/environment-tpkg/peterhead-ccs-project.html

second step is to list and cost each major piece of equipment within the battery limits. The top-down BACT analysis should provide this list of costed equipment. The basis for equipment cost estimates also should be documented, either with data supplied by an equipment vendor…or by a referenced source…" *NSR Manual,* p. B.33; *Steel Dynamics,* 9 E.A.D. at 200 ("where the top pollution control candidate…is found to be inappropriate due to economic impacts, the rationale for the finding should be fully documented for the public record)(internal quotations omitted").

The EPEC cost analysis is missing all of these critical elements. It does not contain the design basis, the battery limits, a list of each piece of equipment and its cost, or the source of the proffered lump-sum cost data for the capture and compression plants, which are the major cost items. The cost estimate, for example, is missing any basis at all, such as process flow diagrams and design drawings; heat, energy and material balances; type and amount of amine; and temperatures, pressures, flows rates, and specific chemical species in the gas streams to be treated.[46] Instead, everything in the cost analysis is based on the generic data provided in the 2010 DOE/NETL report.

To thoroughly evaluate the feasibility and the cost of carbon capture on specific emission sources, the applicant must provide the Region and the public with the composition, pressure, and volumetric flow rates of the facility. The cost of capture (normalized to $/ton) is typically driven by the partial pressure of CO_2 in the exhaust stream and the total volumetric flow of gas to determine size of equipment and potential economies of scale. This information can be used to determine the feasibility of capturing a portion of the GHG emissions from the plant. The analysis must also include specific design and bid estimates for pipeline and storage costs. The Region must require a supplemental filing with this information and extend the public comment period to respond to that additional information. Based on the limited and generic information provided by EPEC, it is not possible to evaluate the reasonableness of the CCS cost estimates.

d) The Region Must Provide Substantial Evidence to Support its Conclusion that CCS is Economically Infeasible

The Region cannot simply reject a technologically feasible alternative to control GHGs because there are no other BACT determinations requiring add-on technology to control GHG. For every pollutant newly subject to a BACT limit and for every new technology developed to control that pollutant, there has to be a first instance where the control is determined to be BACT. The legislative history is clear that Congress intended BACT to perform a technology-forcing function.[47] The Region has made no showing why the Montana Power Station PSD permit should not require CCS, especially when other similar facilities employ CCS, even if not pursuant to a BACT determination. The BACT analysis of CCS must at a minimum consider costs at facilities that have deployed CCS to determine whether any unusual or unique circumstances at the Montana Power Station warrant rejection of CCS.[48]

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[46] See, e.g., typical design basis at http://webarchive.nationalarchives.gov.uk/20121217150422/http://decc.gov.uk/assets/decc/11/ccs/chapter5/5.4-design-basis-for-co2-recovery-plant.pdf

[47] *See* S. Rep. No. 95-252, 95th Cong., 1st Sess. 31 (1977), reprinted in 3 A Legislative History of the CAA Amendments of 1977 at 1405; 123 Cong. Rec. S9171, 3 Legislative History at 729 (remarks of Sen. Edmund G. Muskie, principal author of 1977 Amendments).

[48] *See, e.g., Cost and Performance of Carbon Dioxide Capture from Power Generation, International Energy Agency. Available at: http://www.iea.org/publications/freepublications/publication/costperf_ccs_powergen-1.pdf*

12. The Region Failed to Consider Offsets to the Cost of CCS

EPEC's estimate the cost for CCS does not include offsets to those costs from source such as the income generated from selling the CO_2 for use in enhanced oil recovery or the various tax credits that may be available. At the low end, the market value for CO_2 is at least $6 per ton. This income stream from the sale of CO_2 for enhanced oil recovery (EOR) would reduce the cost of CO_2 CCS. Selling the captured CO_2 would also eliminate the capital and O&M costs associated with geological storage.

Neither EPEC nor the Region considered the potential for offsetting the cost of CO_2 using enhanced oil recovery. This rejection of the potential for a revenue stream from CO_2 ignores market realities. CO_2 has a market value for use in enhanced oil recovery or other industrial uses. The costs of carbon storage can be offset by enhanced oil recovery revenues where available.[49] Estimates of the market price of CO_2 for enhanced oil recovery are around $33 per ton.[50] Even without enhanced oil recovery, CO_2 has a market value of between $5-$20 per ton.[51]

Denbury Resources in Texas uses CO_2 in enhanced oil recovery and has entered into long-term contracts to purchase CO_2 from six proposed plants or sources in the Gulf Coast region. Two of these six projects are currently under construction with estimated completion dates in 2013 and 2014. These two sources will supply about 165 MMcf/day of CO_2[52] or about 3.4 million tons per year, which is twice the amount of CO_2 that would be produced by the EPEC project. It follows, therefore, that EPEC would reasonably find a willing buyer in Denbury for its captured CO_2. Any potential sale value of CO_2 would offset the cost of CCS for the Montana Power Station and should be reflected in the cost effectiveness analysis.

The amount that Denbury might pay for this CO_2 is unknown, but according to its operations report, Denbury's cost to produce CO_2 in 2011 was $0.31 per Mcf,[53] which equals about $6/ton.[54] In addition, according to the 2008 Congressional testimony of Denbury Resources Vice President Ronald Evans, it costs about $20/ton to obtain CO_2 from natural sources and transport

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[49] Massachusetts Institute of Technology, *Future of Coal in a Carbon Constrained* World 2007 at 58-59. Available at: http://web.mit.edu/coal/.

[50] *Carbon Dioxide Enhanced Oil Recovery: A Critical Domestic Energy, Economic, And Environmental Opportunity*, National Enhanced Oil Recovery Initiative, Appendix D, Figure D1. Available at: http://www.neori.org/NEORI_Report.pdf

[51] *See*, Rushing, Sam, *Carbon Dioxide Apps Are Key In Ethanol Project Developments*, Ethanol Producer Magazine, April 15, 2011. Available at: www.ethanolproducer.com/articles/7674/carbon-dioxide-apps-are-key-in-ethanol-project-developments

[52] Operations - Gulf Coast Region CO2 Sources. Available at: http://www.denbury.com/operations/co2-sources/gulf-coast-region/default.aspx.

[53] Ibid.

[54] 1 tonne of CO2 occupies 556.2 m^3 x 35.3147 ft^3/m^3 = 19,642 ft^3 = 19.642 Mcf. As there are 1.1023 short tons in a metric tonne, 1 ton of CO2 occupies 17.819 Mcf. Therefore, ($0.31/Mcf)(19.643 Mcf/ton) = $6.1/ton.

it moderate distances.[55] Moreover, a recent US DOE report placed $45 per ton as the market price for CO_2 and indicated that the CO_2 market is stable, and CO_2 demand is high at that price.[56]

CCS costs can be further offset by tax credits of $10-$20 per ton of CO_2 in accordance with Internal Revenue Code Section 45Q (26 USC § 45 Q). Neither the application nor the SOB attempted to offset the cost of CCS with these potential revenue streams or tax credits. The ability of EPEC to reduce its net cost of installing and operating CCS is a critical component of the cost effectiveness calculations. The Region must consider these issues in its BACT analysis to appropriately consider the cost of CCS as a control technology. The consideration of offsetting the cost of CCS is especially critical because the Region based its rejection of CCS on the cost impact of the technology in step 4 of the top-down BACT analysis.

13. <u>EPEC Did Not Consider Specific CCS Opportunities in the Region</u>

The CCS cost analysis provided by EPEC looked only at a 110 mile pipeline without explaining how or why that length of pipeline was necessary. EPEC did not consider other potential storage options in the El Paso region. Texas has a substantial network of pipelines and storage capabilities, including depleted oil fields that could provide additional opportunities, at potentially lower costs, for the storage of CO_2. The coastal plains region in Texas along the Gulf Coast contains 65% of the country's estimated accessible carbon storage resources, with an estimated 2,000 gigatons of accessible storage resources.[57] The Region's BACT analysis did not even attempt to identify or provide any cost estimates for CCS at any of the region's deplted oil fields or other geologic formations. The Region must require EPEC to analyze other CCS options in the area.

14. <u>The Region Improperly Considered Adverse Energy and Environmental Impacts</u>

The Region implies that, aside from adverse economic impacts, CCS should be eliminated as BACT based on environmental impacts due to additional energy demands. (SOB at p.13-14.) The extent to which the Region relied the energy and environmental impacts to reject CCS as BACT is unclear. However, the NSR Manual makes clear that energy and environmental impacts from the Montana Power Station are not a valid basis to reject CCS as BACT.

The NSR Manual provides that energy impacts that are "significant or unusual" should be examined in a BACT analysis.[58] In most cases, extra fuel or electricity required to power a control device should simply be factored in to the economic impacts analysis.[59] In this case, there are no significant or unusual energy impacts to install CCS. The energy requirements to power a

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[55] *Spinning Straw Into Black Gold: Enhanced Oil Recovery Using Carbon Dioxide*, Subcommittee On Energy And Mineral Resources , Committee On Natural Resources U.S. House Of Representatives, Thursday, June 12, 2008. Available at: http://www.gpo.gov/fdsys/pkg/CHRG-110hhrg42879/html/CHRG-110hhrg42879.htm

[56] See DOE/NETL-2010-1417, "Storing CO_2 and Producing Domestic Crude Oil with Next Generation CO_2-EOR Technology," (April 30, 2010) Table 13 footnote.

[57] U.S. Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013, National assessment of geologic carbon dioxide storage resources—Results: U.S. Geological Survey Circular 1386, p. 41. Available at: http://pubs.usgs.gov/circ/1386/

[58] *NSR Manual*, p. B.29.

[59] *NSR Manual*, p. B.30.

CCS system at the Montana Power Station are the same as any other site. To the extent they are considered, energy costs should be included in the economic analysis related to the costs of additional fuel or electricity to power the CCS. There are no site-specific or other unique energy issues at the Montana Power Station such as fuel scarcity or supply constraints that would render CCS infeasible. Therefore, there is no basis to reject CCS for energy impacts.

Similarly, there are no identified adverse environmental impacts from the Montana Power Station's installation of CCS. The SOB asserts that several criteria pollutants would be emitted at increased levels due to the combustion of an additional 5.1 billion cubic feet of natural gas to account for the energy penalty. (SOB at p.13) This assessment of a potential increase in criteria pollutants is not a valid basis for rejecting a feasible control technology due to adverse environmental impacts. As the NSR Manual expressly states, the "environmental impacts analysis is not to be confused with the air quality impacts (i.e. ambient concentrations)…"[60] In this case, whether CCS at the Montana Power Station would increase some criteria pollutants does not constitute an adverse environmental impact because the only impacts the Region points to are ambient air concentrations. There are no other identified significant or unusual impacts from the addition of CCS other than the additional energy requirements to operate CCS. Therefore, there is no basis to reject CCS due to adverse environmental impacts

Sierra Club appreciates the opportunity to provide these comments.

Sincerely,

__*/s/_Travis Ritchie*_______________

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[60] *NSR Manual*, p. B.46.

Exhibit 9

7F 5-Series Gas Turbine Fact Sheet

7F 5-Series Gas Turbine

Product of GE's FlexEfficiency* Portfolio

Right-sized, reliable for lifecycle cost advantage

fact sheet

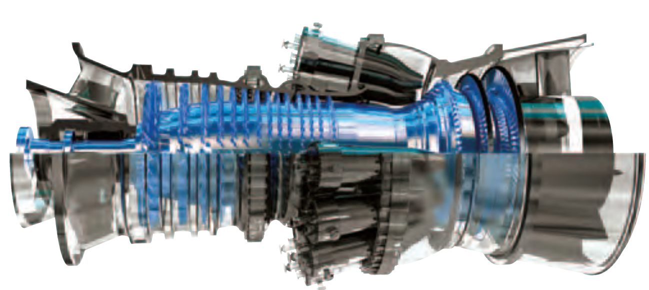
To meet the increasingly dynamic operating demands of today's global energy industry, power producers are looking for flexible, efficient and reliable technology to partner with renewables. As the world's largest manufacturer of gas turbines, GE is uniquely positioned to bring this evolution of its F-class platform to meet customer demands for flexible cyclic operation by delivering power with advanced start-up and extended turndown capability, fast ramp rate, and low lifecycle costs in peaking, cyclic, and continuous operation.

Advanced Proven Technology

GE's pioneering F-class technology comprises over 1,110 gas turbines in operation globally, accumulating over 45 million hours of reliable operation. With more than 20 years of proven field experience, GE's 7F family of gas turbines is meeting the needs of power producers around the world. The 7F 5-series gas turbine, part of GE's FlexEfficiency 60 Portfolio, is built on proven advancements to its inlet, compressor, combustion, and power turbine systems. Flexibility is enhanced by a proven 14-stage compressor with removable blades and three-dimensional aerodynamic airfoils for increased efficiency. The hybrid radial diffuser recovers static pressure for the proven Dry Low NO_x (DLN) 2.6 combustion system for enhanced steady state and transient performance. Torque from the three-stage power turbine, based on GE's proven 60 hertz advanced hot gas path technology, is transmitted through its proven rotor architecture. Technologies from GE's vast power generation and aviation experience include aerodynamics, heat transfer, cooling and sealing, and materials technologies that are fully integrated with an advanced, model-based control system.

Features and Benefits

- Advanced 3D aerodynamic 14-stage compressor with super-finish airfoils delivers improved fuel efficiency with less long-term degradation
- DLN 2.6 combustion system provides proven operating flexibility with turndown to 36% of gas turbine baseload, accommodating fuel composition variation while maintaining emissions guarantees
- 3-stage advanced hot gas path using proven technology of the 7F 3-series gas turbine with advanced cooling and sealing technologies to improve efficiency and lifecycle costs
- GE's proprietary Mark* VIe model-based control system enhances performance and increases operational flexibility
- The 7F 5-series gas turbine fuel flexibility offers operation on a wide range of natural gas or distillate fuel, allowing operators higher availability during gas supply disruptions
- Simplified air-cooled architecture combined with proven materials provide the lowest lifecycle cost in its class



The 7F 5-Series Gas Turbine Demonstrates Flexibility in the Following Key Areas:

- **Efficiency:** Greater than 59% in combined cycle
- **Start Capability:** 11 minutes to baseload
- **Ramp Rate:** 40 MW/minute per gas turbine within emissions guarantees
- **Minimum Load:** Turndown to 36% of gas turbine baseload
- **Emissions:** 2 ppm NO_x and CO in combined cycle with Selective Catalytic Reduction (SCR) and CO catalyst

Field Proven and Full-Speed, Full-Load Factory Tested

With more than 800 7F gas turbines operating in the field providing over 29 million fired hours and 700 thousand fired starts, 60 hertz customers around the world have come to rely on the proven reliability and availability of GE's 7F gas turbines.

The 7F 5-series gas turbine has been validated at GE's full-speed, full-load gas turbine validation test facility in Greenville, South Carolina, USA. This dual fuel, non-grid connected facility has the capability to test part loads, peak loads, variable frequency operation, and transient capability. The 7F 5-series gas turbine has met or exceeded GE's validation requirements through extensive testing and operation.

Net gas turbine simple cycle output	216 MW
Net gas turbine simple cycle efficiency	Greater than 38.7%
Gas turbine exhaust energy	Greater than 1150 MMBtu/hour
Net combined cycle efficiency	Greater than 59%
NO_X emissions (at 15% O_2)	2 ppm in combined cycle 9 ppm gas turbine only
CO emissions	2 ppm in combined cycle 9 ppm gas turbine only
Gas turbine start time	11 minutes to baseload
Gas turbine ramp rate	40 MW/minute per gas turbine within emissions guarantees
Gas turbine minimum load	Turndown to 36% of gas turbine baseload

Normalized to *Gas Turbine World* conditions
Based on 2x1 multi-shaft FlexEfficiency 60 Combined Cycle Power Plant with selective catalytic reduction and CO catalyst.

Applicability

The 7F 5-series gas turbine has been developed for both 60 hertz cyclic and continuous operation in simple and combined cycle applications.

the power of FlexEfficiency

To learn more about this offering, contact your GE Sales Representative or visit www.ge-flexibility.com

GEA20305 (09/2012)

Exhibit 10

7F 7-Series Gas Turbine Fact Sheet

7F 7-Series Gas Turbine

Efficient, flexible, and reliable advanced technology

fact sheet

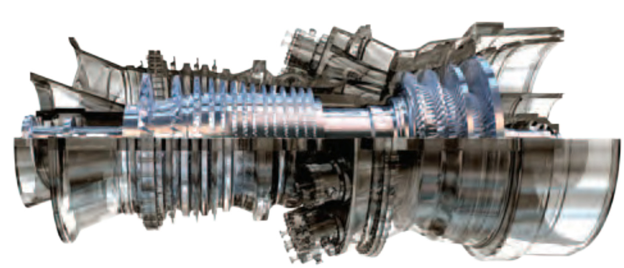
To meet the increasingly dynamic operating demands of today's global energy industry, power producers are looking for technology capable of providing industry leading baseload efficiency, as well as unparalleled flexibility to partner with intermittent renewable energy sources. As the world's largest manufacturer of gas turbines, GE is uniquely positioned to bring the latest evolution of its F-class platform to meet customer demands for flexible cyclic operation by delivering power with advanced start-up capability, improved turndown capability, faster ramp rate, and higher efficiency in both cyclic and baseload operation.

Advanced Proven Technology

GE's pioneering F-class technology comprises over 1,110 gas turbines in operation globally, accumulating over 44 million hours of reliable operation. With more than 20 years of development, GE's 7F 7-series gas turbine as part of the FlexEfficiency* 60 Portfolio is built on proven advancements from its inlet system to its exhaust to the heat recovery steam generator. Its low loss filtration system feeds a 14-stage three-dimensional aerodynamic compressor. The hybrid radial diffuser recovers static pressure for the evolved Dry Low NO_x (DLN) 2.6 combustion system with advanced fuel staging for enhanced steady state and transient performance. Torque from the new four-stage hot gas path, with an inner shell for better managed clearances, is transmitted through a simplified rotor arrangement. Technologies from GE's vast power generation and aviation experience include aerodynamics, heat transfer, cooling and sealing, and materials technologies that are fully integrated with an advanced, model-based control system.

Features and Benefits

- Advanced 3D aerodynamic 14-stage compressor delivers improved operating and fuel efficiencies
- DLN 2.6+AFS (Axial Fuel Staged) combustion system enhances fuel staging capability, enabling turndown to 20% of gas turbine baseload while accommodating fuel composition variance with emissions guarantees
- 4-stage hot gas path using advanced cooling and sealing technologies and F-class materials improves efficiency and allows more starts per inspection interval
- GE's proprietary Mark* VIe model-based control system enhances performance and increases operational flexibility
- The 7F 7-series gas turbine fuel flexible feature offers operation on a wide range of natural gas or distillate fuel, allowing operators higher availability during gas disruptions
- Simplified air-cooled architecture combined with proven materials provides the lowest life-cycle cost per produced MW in its class



fact sheet

The 7F 7-series gas turbine is exceeding its predecessors in the following key areas:

- **Efficiency:** Greater than 61% in combined cycle
- **Start Capability:** 10 minutes to gas turbine baseload
- **Ramp Rate:** 50 MW/minute per gas turbine within emissions guarantees
- **Minimum Load:** Turndown to 20% of gas turbine baseload
- **Emissions:** 2 ppm NO_x and CO in combined cycle with Selective Catalytic Reduction (SCR) and catalyst

Field Proven and Full-Speed, Full-Load Factory Tested

With more than 800 7F gas turbines operating in the field with more than 29 million fired hours and 700 thousand fired starts, 60 hertz customers around the world have come to rely on the 7F gas turbine's proven reliability and availability.

Prior to first fire in the field, the gas turbine will be validated at full-speed, full-load in GE's Greenville, South Carolina gas turbine validation test facility. This dual fuel, non-grid connected facility also provides part-load, variable frequency, and transient capability testing.

Net gas turbine simple cycle output	250 MW
Net gas turbine simple cycle efficiency	Greater than 40%
Gas turbine exhaust energy	Greater than 1250 MMBtu/hour
Net combined cycle efficiency	Greater than 61%
NO_x emissions (at 15% O_2)	2 ppm in combined cycle 20 ppm gas turbine only
CO emissions	2 ppm in combined cycle 9 ppm gas turbine only
Gas turbine start time	10 minutes to baseload
Gas turbine ramp rate	50 MW/minute per gas turbine within emissions guarantees
Gas turbine minimum load	Turndown to 20% of baseload

Normalized to *Gas Turbine World* conditions

Based on 2x1 multi-shaft FlexEfficiency 60 Combined Cycle Power Plant with selective catalytic reduction and CO catalyst. Minimum turndown values assume one gas turbine operating.

Applicability

The 7F 7-series gas turbine has been developed for both 60 hertz cyclic and continuous operation in simple cycle and combined cycle applications.

the power of FlexEfficiency

To learn more about this offering, contact your GE Sales Representative or visit www.ge-flexibility.com

GEA20194 (09/2012)

Exhibit 11

Gas Turbine World – Lodi’s 300 MW Flex 30

Featured in Gas Turbine World Magazine (Sept/Oct 2012)

Lodi's 300MW Flex 30 plant ushers in a new era for the US

The Siemens Flex Plant 30 at Lodi designed to deliver 200MW of power to the grid within 30 minutes of startup is capable of daily cycling at over 57 percent combined cycle efficiency.

By Junior Isles

The Lodi Energy Center, owned and operated by the Northern California Power Agency, is the first operating Siemens Flex Plant 30 combined cycle gas turbine power plant in the US. Key operational features:

• Output. Lodi has nominally rated the plant at 300MW base load which is a bit lower than its design rating.

• Duty cycle. Designed for intermediate to continuous duty and capable of daily cycling.

• Ramp rate. Can ramp up or down at 13.4 MW/min and turndown in standard emissions compliance to less than 50 per cent load.

California has set very ambitious carbon reduction targets and renewable energy goals under the 2006 climate change act and 33 per cent renewable portfolio standard requirement of 2011 with its associated need for fast start backup power.

Lodi plant expected to have over 95 percent annual availability

Lodi Energy Center's design to combine operating flexibility with the ability to quickly start up and provide efficient part-load and base load power calls for a high degree of redundancy.

Lodi is expected to operate with an annual availability factor of more than 95 percent, calculated as the percentage of time that the plant is able to generate power – determined in large part by the reliability of critical operating equipment and maintenance shutdown requirements.

To ensure operational reliability and availability, Lodi has installed a number of back-up ancillary systems including:

- two 100 percent fuel gas compressors;
- two 100 percent capacity feed water pumps;
- two 100 percent capacity condensate pumps;
- two 100 percent capacity circulating water pumps;
- two 100 percent capacity air compressors; and
- extra capacity 7-cell evaporative cooling tower.

The plant also incorporates an evaporative cooling tower to cool the steam turbine's condenser. Recycled water for process and cooling water uses will be delivered from an adjacent City of Lodi's water pollution control facility and an onsite well will provide potable water.

As intermittent sources such as wind and solar PV grow, so does the need for back-up power plants that are able to provide power quickly when the wind does not blow and the sun does not shine. Gas-fired plants are widely regarded as the best option for providing this back-up.

In August, the Northern California Power Agency inaugurated the Lodi Energy Center (LEC) – the first operating Siemens Flex-Plant 30 combined cycle gas turbine power plant in the USA is designed for intermediate to continuous duty and is capable of daily cycling.

Lodi Flex 30 combined cycle project

Lodi has nominally rated its Flex 30 plant at 300MW net output at an expected 57.8% net plant efficiency, including all BOP equipment.

SCC6-5000F 1x1 Plant	
Net plant output*	307,000 kW
Net heat rate LHV	5990 Btu/kWh
Net plant efficiency	57.0%

Lodi Flex 30 Plant	
Net plant output**	300,000 kW
Net heat rate (LHV)	=6000 Btu/kWh
Expected efficiency	57.8%

Plant configuration

The LEC plant is designed around a 208MW natural gas-fired SGT6-5000F gas turbine with evaporative air inlet cooling and dry low NOx combustors to control air emissions, 3-pressure Nooter Eriksen heat recovery steam generator, selective catalytic reduction (SCR) and carbon monoxide (CO) catalyst to further reduce emissions, and a 100MW SST-900RH condensing steam turbine generator.

Installed plant cost**	1300 $/kW
Operating cost (est)	$90 million/yr
Rated power capacity**	2,400,000 MWh/yr
Expected operation	1,600,000 MWh/yr

Sources: 2012 GTW Handbook* and Lodi Energy Center**

According to Siemens, overall plant start-up times are reduced by up to 50 per cent due to the integration of fast start-features, including the three-pressure HRSG with Benson once-through technology, high capacity steam attemperation (desuperheating), full capacity steam bypass systems, innovative piping warm-up strategies, and Siemens' steam turbine stress controller (STC).

The latest version of the SGT6-5000F gas turbine at the heart of the plant is capable of reaching full output in 30 minutes. It also can ramp up or down at a rate of 13.3 MW/min and remain compliant with emissions regulations below 50 percent part-load turndown conditions.

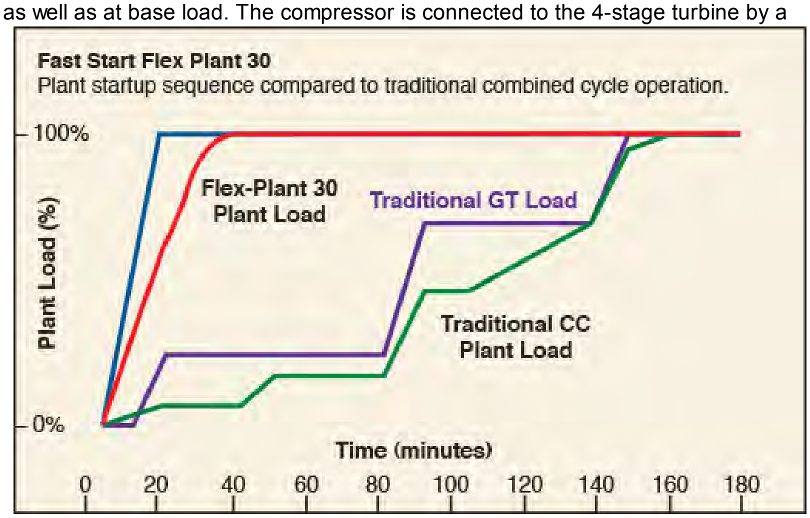
Fast-start design

According to Siemens, its fast start capability to deliver 200 MW in 30 minutes or less can result in a 30 per cent reduction in greenhouse gas emissions when compared to traditional F-class combined cycle plants i.e. more than 200 t/year of carbon monoxide.

Lodi Flex 30 project. First operating Siemens Flex 30 combined cycle gas turbine pow er plant in the United States is nominally rated at 300MW net plant output and 57.8% net efficiency.

Since its first introduction in 1993, the engine has evolved over time with improvements made to increase efficiency and power output, extend maintenance intervals and enhance operating flexibility. According to Siemens, the engine is now designed for high reliability and frequent ramping and has no service penalty for fast starting or fast ramping.

It features a 13-stage compressor with four rows of variable compressor guide vanes enabling high efficiency at part load as well as at base load. The compressor is connected to the 4-stage turbine by a single tie-bolt.



No nickel-based alloys are used in the rotor construction. Instead the rotor uses upgraded steel discs in the turbine section with a rotor air cooler to allow for greater flexibility in turbine blade cooling air temperature.

Ultra low NOx

The engine is offered with an option of two combustion systems. The latest version of the turbine uses an ultra low NOx (ULN) combustion system that employs 16 can-annular combustors to reduce NOx levels to less than 9 ppm.

The ULN system uses five fuel stages to mix the natural gas with combustion air. The pilot and the main pre-mixers on the combustor support housing employ swirler fuel injection, where the fuel is injected off the swirler vanes. This provides more injection points and better mixing than the previous dry low NOx combustor.

In addition to reducing NOx, the ULN combustion system controls CO, volatile organic compounds and particulate emissions. The reduction in low-load CO emissions is achieved by operational modifications and bypassing supplemental cooling air around the combustor.

The result of bypassing air around the combustor is increased combustor flame temperature, which leads to reduced CO production. In this version, CO emissions are kept below 10 ppm down to at least 40% load, without alteration to the internal architecture of the combustion system. This allows greater flexibility during cyclic operation.

Lodi opted for standard DLN

Lodi passed up the ULN option in favor of a standard 25 ppm DLN combustion system and rely on catalytic reduction to reduce plant emissions to less than 2 ppm NOx –in line with California environmental regulations.

Likewise, Lodi chose to equip its gas turbine with a standard motor and torque converter starter, with a turning gear speed of 3 rpm.

To achieve improved gas turbine start capability, the gas turbine could have been supplied with a static frequency converter (SFC) starter instead of a mechanical starter (with SFC design, the generator operates as a motor).

The SFC unit allows more efficient and faster rotor acceleration than an equivalent size mechanical starting motor. It can increase the turning gear speed from 3 rpm, for earlier models, to 120 rpm.

Higher turning gear speed enables the generator rotor wedges to lock up, prevents compressor blade locking mechanism wear, and locks turbine blades into running position.
The higher speed also helps the engine to cool down faster, because the turbine parts are cooled faster and blade tip clearances are similar to the cold tip clearance.

Combined cycle integration

Although flexible gas turbines can start fast, once deployed into combined cycle mode, steam cycle constraints need to be considered. The gas turbine is exhausting a high volume of high temperature air and the heat sink needs to be able to absorb and dissipate that energy without damaging any equipment.

In a traditional combined cycle power plant, the ramp rate of the gas turbine is constrained by limitations imposed by equipment in the bottoming cycle. To protect that equipment, the gas turbine is ramped to a low-load hold point – letting the rest of the cycle warm up and allowing time to achieve appropriate steam chemistry – then ramped a bit more.

At this hold point, the gas turbine produces much higher CO emissions than at base load, so the result is “low power” and “high emissions” during the hold. Typically the gas turbine in a three-pressure, reheat combined cycle arrangement experiences two such holds prior to allowing the steam turbine to go to a valves wide open condition.

Several changes were made to remove these constraints, the first of which was a change in boiler design. Initial Siemens fast-plant operation, for example, was enabled by the use of a Benson once-through HRSG design.

This eliminated the thick walled drum and allows for unrestricted gas turbine ramping. It is still the benchmark of fast start HRSG technologies and is incorporated in Siemens Flex Plant designs, including the design used at Lodi.

HRSG designs improved

More recently, HRSGs with thinner walled drums have become available as an alternative choice for Siemens Flex Plants. They offer much faster ramp rates than a traditional cycle, but somewhat slower ramp rates than the Benson design.

In a traditional combined cycle, the bottoming cycle piping system is susceptible to stresses due to high thermal transients. In a Siemens fast start Flex Plant, the systems are fitted with high capacity attemperation to maintain temperature and avoid thermal shocks.

In addition, the steam turbines are supplied with stress controllers. And the cycle includes an auxiliary boiler to provide steam that keeps the steam turbine seal system warm and ready to start.

To benefit from all of these features, optimized control logic in a fully integrated control system is applied. This system monitors and adjusts to optimize combined cycle operation, protecting each part while enabling fast flexible gas turbine start.

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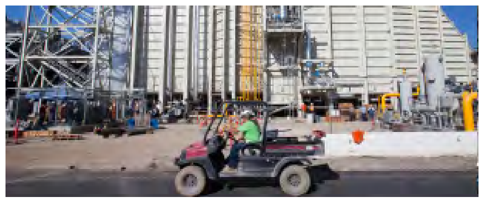

Once-through HRSG. Nooter Eriksen three–pressure heat recovery steam generator with Benson once-through technogy equipped with SCR and CO catalyst to minimize emissions.

Startup and ramping

The sequence of operation used to manage the Flex Plant 30 begins with accelerating the gas turbine to synchronization speed.

The exhaust gas is directed through the fast cycling Benson HRSG and the steam is initially dumped to the condenser, bypassing the steam turbine. The steam turbine and associated piping are warmed, and the steam turbine is then loaded to a valves wide-open condition.

This was never possible in a conventional bottoming cycle due to the high thermal transients that would result. This new start sequencing capability enables fast power to the grid from the early gas turbine ramp, and significantly lowers start-up emissions.

Starting the bottoming cycle quickly enables the entire plant to deliver power to the grid faster. According to Siemens, current versions of its Flex Plant enable 150MW in 10 minutes per gas turbine, and can move the bottoming cycle to valves wide open in well under 45 minutes for an overnight shut down.

Integrating renewables

The fast start and cycling characteristics of the technology was one of the key reasons for the use of Flex Plant 30 at Lodi.

Siemens also recently announced two new Flex-Plant projects in Temple and Sherman Texas along with the two California plants, one at LEC and the other at El Segundo.

Siemens reports that these four state-of-the-art plants will meet the US market's need for clean fossil power solutions with 'fast ramping' capability to balance intermittent renewables on the power grid.

According to the California Energy Commission, the operating flexibility of the new LEC will facilitate greater use of renewable sources such as wind and solar for electricity generation, which have been more difficult to integrate into the grid because of their intermittency.

"The Lodi Energy Center will provide grid reliability to the Central Valley, while integrating renewable resources," said Energy Commission Chair Robert. B. Weisenmiller. "This is the future for fast-start gas fired combined cycle power plants in the country." ■

Participants in the LEC project

The new Lodi plant will serve the needs of 13 different project participants actively involved in development of the Lodi Energy Center.

Agencies include the Modesto Irrigation District, Power and Water Resources Pooling Authority, Plumas-Sierra Rural Electric, State of California Dept. of Water Resources and the Bay Area Rapid Transit.

The project also involved the City of Ukiah; City of Lodi; City of Biggs; City of Azusa; City of Lompoc; City of Santa Clara; City of Healdsburg and the City of Gridley.

Total construction cost of the project is estimated at around $388 million which will be paid for through bond financing; the cost of operating the plant is estimated at $90 million per year.

Energy produced will be used in a variety of ways. The California Dept. of Water Resources, with rights to roughly one third of the plant's energy output, will use the electricity to move water down the state's aqueduct for millions of residents.

Importantly, for environmental goals, the new Lodi plant also will help the California Resource's Agency discontinue buying coal energy from outside the state. The last contract is due to expire next year.

Reclaimed water from the City of Lodi's White Slough wastewater treatment facility will be supplied to the power plant for cooling and steam generation.

The tertiary-treated water is further processed by LEC's advanced water quality facilities before use in the steam generation process and in the power plant cooling system.

The City of Lodi is expected to receive approximately $1 million for the sale of 1800 acre-feet of reclaimed water annually, turning a water disposal liability into a financial asset for the host city.

Other Feature Articles

H-80 dual shaft gas turbine rated over 110MW and 37% efficiency
Combined cycle heat rates at simple cycle $/kW plant costs
Prospects for lower cost and more efficient IGCC power
Lodi's 300MW Flex 30 plant ushers in a new era for the US
CLN uprates 501 to 6 MW with under 18 ppm NOx and zero CO

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Exhibit 12

Lesson from Lodi

FORTNIGHTLY'S Power Profit

Published on *PowerProfit* (http://powerprofit.fortnightly.com)

If there's an electric power project under development that best reflects the current state of the U.S. gas turbine market, it might be the Northern California Power Agency's (NCPA) 280-MW, natural gas-fired combined-cycle plant in Lodi, Calif.

Scheduled for startup in 2012, the plant will serve some 14 different entities, including eight area municipalities. More important, it's the first application of a new combined-cycle plant specifically designed to operate at a wide range of loads at 57-percent-plus efficiency and deliver up to 200 MW of power to the grid in just 30 minutes.

In addition to reducing the carbon footprint of the NCPA's membership, the system—which the manufacturer, Siemens Energy, calls the Flex Plant 30 power island—will allow the agency to react quickly to the uncertain market conditions many expect will result when state-mandated renewable energy plants begin pouring power into California's wholesale electricity pool.

In other words, the plant will provide financial cover, a hedge if you will, against whatever California's energy future brings.

"California's renewable energy program will certainly bring change, but at this point we're not sure how much," says Ken Speer, the NCPA's assistant general manager of generation services. "So we based our decision on the belief that a more flexible generating resource, one with a fast start capability, will be a valuable asset."

Following the Market

Most U.S. electric utilities and independent power producers looking to add new generation share concerns similar to those at NCPA. With cap-and-trade legislation still pending, gas-fired turbines provide the lowest possible carbon footprint, next to renewable sources.

"For some participants, the Lodi plant will replace coal-based (power purchase agreements) that expire in 2012 and 2013," Speer says. "Those contracts represent a carbon footprint of 2,100 to 2,200 lbs of CO_2 per MWh, while this plant will be less than 800 lbs per MWh. So, these participants are cutting their carbon footprint by nearly two-thirds."

And with new renewable portfolio standards now in effect in 33 states, combined-cycle plants increasingly will be called upon to serve as a back-up power source. A new plant must be able to cycle up and down efficiently, while staying within its emissions limits, even at low load operation.

It's not surprising then, that when it comes to the latest original equipment manufacturer (OEM) gas turbine offerings, the new catchphrase is “operational flexibility.” Such suppliers as Siemens, General Electric (GE) and Alstom are rolling out an assortment of upgrades to existing machines that will boost output and efficiency and enhance the ability to react quickly to changing load requirements.

“In the U.S. roughly 45 percent of the generating capacity is more than 30 years old and a number of those plants will need to be replaced near term, even if economic growth remains sluggish,” says Patrik A. Meier, Alstom Power’s gas turbine product manager. “With the delays in permitting coal and nuclear plants, a natural gas-fired turbine plant represents a comparatively quick solution.”

GE, which also was in the running for the Lodi project, has introduced a new Frame 7FA gas turbine that will generate 211 MW, a 36-MW increase over the current 7FA in simple cycle operation. When configured in a rapid response two-unit combined-cycle arrangement, the company says the system will be able to deliver 150 MW to the grid in just 10 minutes.

The combined-cycle configuration, GE adds, will be able to achieve a fuel cost savings of more than $2 million a year with natural gas at $6 per MMBtu when compared to a similar plant with an earlier version of the 7FA, and avoid the annual emission of more than 19,000 metric tons of CO_2 compared to previous performance.

Key to the new turbine design, the company says, is: 1) a more efficient compressor that increases airflow; 2) enhanced fuel efficiency via three-dimensional aerodynamic airfoils; and 3) a hybrid radial compressor diffuser. Three variable stator vane stages support unit flexibility by allowing the control system to adjust compressor airflow to meet varying fuel and ambient conditions, or in response to changing operating conditions.

“Though we’re seeing slower sales overall due to the economy, the gas-fired power plant is going to be a strong segment going forward,” says Jim Donohue, gas turbine marketing manager at GE. “With the new 7FA, we’ve given customers a tool to respond to potential emissions legislation. Plus, it has a fast start capability, so it can deliver power quickly to the grid while striking a balance between efficient operations and emissions compliance.”

Alstom Power has introduced upgrades to its 193-MW, 60-Hz GT24 turbine as well. It too has focused on optimizing the unit’s compressor, increasing the airflows through it and facilitating an increase in combined- cycle performance of nearly 9 MW, by increasing the unit’s turbine inlet temperatures.

The turbine also is part of Alstom’s latest 60-Hz KA24 combined-cycle power plant offering, which is comprised of a three casing, double flow low-pressure steam turbine, air-cooled generator, and water-cooled condenser, and a three-stage reheat, horizontal type heat recovery steam generator (HRSG). The integrated system, Alstom says, will produce power with efficiencies exceeding 57 percent, with a turndown capability to near 20 percent and full start-up in less than 50 minutes.

“When we introduced the GT24 in the 1990s, the machine was ideally suited to serve the combined-cycle market,” says Mark Stevens, KA24 product manager. “The sequential combustion system provided the high exhaust temperatures needed to support combined-cycle operation at a variety of loads, which combined with three rows of inlet guide vanes supports high partial-load efficiency. When we first introduced it we were looking for good all-around performance, not just high baseload operation. From that viewpoint, it was a little ahead of its time."

Flexible Tech

Today's big issue, of course, is cycling. Due to changing market fundamentals, fewer gas turbine combined-cycle plants are running at full base load operation anymore. In many cases, cycling duty has become the new normal.

As a result, combined-cycle plants need to operate efficiently at low load and, when necessary, ramp up quickly without negatively impacting emissions, fuel or O&M costs. That needn't be a problem, according to the OEMs, because of these new integrated offerings.

With a traditional gas turbine-powered combined-cycle plant, the startup always, by necessity, has been gradual in order to protect the downstream steam cycle piping and components within the HRSG and the gas turbine. Start up too quickly and the components will be thermally stressed, which degrades and weakens the metals and drives up O&M costs.

Under its combined-cycle configuration, GE's Donohue says the gas turbine is decoupled from the HRSG and steam turbine to enable a rapid response to changing load demand. Instead of bringing the entire system up slowly to avoid over-stressing metal piping and other components, the bottoming cycle hardware associated with the HRSG and steam turbine is warmed up separately.

A twin gas turbine set is brought up to full output quickly, delivering some 150 MW of electricity to the grid in about 10 minutes, compared to nearly an hour under previous combined-cycle configurations. Equally important, Donohue says, is that bringing a turbine to full output quickly cuts startup emissions by half. Therefore, he says, the configuration is ideally suited to backup duty for RPS-mandated intermittent renewable sources.

"With the HRSG and steam turbine cycle, you've got a lot of steel," Donohue says. "With the system's rapid response capability, you let the HRSG and steam turbine warm up to about 30 percent, while the GT goes right to full load. It's done through a combination of new controls, piping and valves. The overall system efficiency remains the same."

GE will demonstrate the new combined-cycle plant at the 586-MW Oakley Generating Station in Oakley, Calif., being developed by Radback Energy Inc. When the plant is finished, Radback will transfer ownership to PG&E.

The Siemens plant at Lodi also integrates a number of features to facilitate fast startups, including a three pressure reheat HRSG with Benson once-through technology, high capacity steam attemperation and full capacity steam bypass systems. Simply put, steam initially produced in the HRSG is bypassed to the condenser until the steam turbine is ready to accept it, and then the steam turbine is monitored for faster ramp rates. Full combined-cycle plant load, Siemens says, could be reached in as little as 45 minutes.

"It's not that the turbine design is radically different. The difference is in the steam cycle." says John M. Wilson, vice president of new unit sales at Siemens North America. "If you cut the gas turbine startup time, you can cut the startup emissions by well over 50 percent of a non Flex-plant, plus you have the associated fuel savings. But the real design changes are to the steam cycle in the HRSG components, like the steam valving and our T-3000 integrated control system."

The generator is motored to bring the gas turbine up to speed (*i.e.*, less firing of the gas turbine than is required when using a starting motor) and the unit can generate power with a low NOx combustor to deliver NOx emissions of 9 ppm. With the installation of SCR and CO_2 catalysts, stack emissions compliance can be reached in about 30 minutes.

"You can get 10 to 30 MW a minute from a large industrial gas turbine," Wilson says. "With the more traditional combined-cycle plants, the HRSG/steam turbine cycle limits the gas turbine to a much slower rate. So with the Lodi project, we've designed the steam cycle with enough flexibility to accommodate the gas turbine."

Though the GT24 has been around for more than a decade, Alstom's Meier says its dual combustor design always has been ideally suited to cycling duty. For example, he says, the turbine can maintain low load operations on only one of the two combustor stages. The turbine still delivers enough heat to keep the water-steam cycle, including the HRSG and steam turbine operating, allowing the combined cycle to be turned down as low as 20 percent, while still meeting emissions requirements.

"In today's energy markets customers need a plant that can react quickly to take advantage of the most profitable hours in the market," he says. "With our integrated combined-cycle concept, we can reach full system output in less than 50 minutes, compared to the traditional 60 to 90 minutes."

If necessary, he adds, the system's HRSG can be fitted with additional gas burners to quickly provide additional output, if and when it's necessary. "If you need more power, you ignite the supplementary burners. In that case, the overall system efficiency declines, but you can boost the output," he says.

O&M Squeeze

OEMs are adding such flexibility to their plant designs because they expect natural gas to play an increasing role across various load profiles, from peaking to base load operations. This reliance on gas is driven, in part, by the expansion of unconventional gas sources (*See "Gas Market Outlook"*). According to a report released last year by the Colorado School of Mines, the country's natural gas reserves estimates rose to 2,074 trillion cubic feet in 2008, up from 1,532 trillion cubic feet in 2006. With this supply increase due in particular to new domestic shale gas opportunities, the availability of natural gas appears stable.

At the same time, however, OEMs understand uncertainties affecting gas sources—including imported liquefied natural gas (LNG)—and they've taken steps also to address potential fuel composition issues, should they arise. Each company says its machines will adjust automatically to changes in chemical composition—as opposed to shutting the unit down to address burner components and settings—if a large amount of regasified LNG enters the system, for example.

OEMs also have applied newer, more protective coatings to extend the operating life of key internals, particularly those exposed to the higher operating temperatures in the hot gas path; such high temperatures are needed to increase unit output and efficiency. Further, they have established remote, 24-7 diagnostics phone centers with trained technicians using Web-enabled technology to help resolve operations issues if or when they arise.

In a somewhat novel approach, Alstom has begun offering a GT24 MXL upgrade package that allows plant operators to switch online between two turbine operating modes. The “M” mode increases power output, while the “XL” backs it off, thereby extending component life. An operating data counter tracks operations in both modes to give the customer a running tally of the unit’s start-stop operations, which helps in scheduling the unit’s next maintenance outage.

“When market demand is high you can instantly switch to M mode for maximum power and efficiency,” Meier explains. “When demand is lower, you can switch to XL mode with a temperature drop that reduces the operating stress on components. Regularly operating in this mode can extend a unit’s inspection interval by up to 4,000 equivalent operating hours.”

Of course all these developments come at a price.

Though OEMs acknowledge added performance measures will boost the cost of their machines and combined-cycle systems, they demur when asked by how much. Whether U.S. power producers will be willing to pay the extra premium hinges on some of the very uncertainties that are driving the need for flexibility in the first place. In other words, depending on how market conditions and regulatory factors evolve, the value of these new systems might increase substantially.

“The investment is prudent in high-priced emissions markets for NOx, CO_2 and VOCs,” Siemens’s Wilson concludes. “CO_2 mitigation will make it worth the added investment everywhere.”

Assuming Control: Today’s I&C Technology

Many generators are hoping to get more flexibility out of existing power plants by swapping out their instrumentation and controls systems. Others are being forced in this direction as their old systems reach the end of their useful lives. Fortunately, indications are it’s a buyer’s market, with fierce competition among suppliers to expand functionality, accelerate installation and contain costs.

“It’s pretty competitive right now. Due to the economy, there are fewer retrofits,” says Kevin Kochirka of ABB’s power generation division. “We’re a DCS (distributed control system) supplier, and we’re seeing PLC (programmable logic controller) suppliers bidding on our jobs. You never used to see that.”

Citing obsolescence issues, OEMs who supplied the first wave of digital hardware and software controls in the 1980s and 1990s are eliminating parts and service support to introduce replacement systems. Customers who keep using their old systems must buy replacement parts from third-party suppliers, often at higher prices, and handle maintenance in-house.

Further, with a growing number of gas turbine combined-cycle plants now being cycled to meet changing market conditions, experts say older control systems could present reliability issues as operators push them beyond their intended design limitations.

“Older control systems weren’t really designed for cycling duty,” says Andy Dieball, I&C product manager with Siemens Energy. Specifically, older systems employ a simplex-type controls arrangement, which have a single connection between, for example, the control panel and a valve. By contrast, new systems have redundancy measures built-in, essentially providing multiple connections to the valve so if one fails, another takes over.

“There are many other technical improvements available, like turbine vibration monitoring and predictive maintenance,” says Bill Lauer, business development manager with Emerson Controls. “For example, the customer can simulate operational changes to measure the impact on turbine performance.”

Additionally, new systems offer greater longevity and serviceability than black-box systems did in the past. Instead of proprietary logic that only the vendor can service, I&C manufacturers today are rolling out simpler controls featuring open architecture designs that will make it relatively easy to expand or migrate to newer technologies. This should help avoid the obsolescence issues that plagued older designs.

And the demands of competition have driven vendors to optimize their installation processes, to perform complete system replacements in even the narrowest of outage windows. Such was the case when Siemens Energy replaced an early-1990s DCS at a 285-MW Cogentrix cogeneration facility in Carneys Point, N.J.

The plant, which consists of two coal-fired boilers and a steam turbine, delivers 20 MW to an adjacent industrial host, E.I. DuPont De Nemours and Co. Since DuPont operates 24-7, 365 days a year, it couldn’t live with a prolonged outage for the DCS upgrade. As a result, it gave Cogentrix just 36 hours to complete the change-out.

Siemens assembled the new system at its Alpharetta, Ga., facility and had technicians simulate the replacement, step by step, right down to the new cabinets.

“It was truly remarkable. When it was time to go everybody did their tasks in parallel,” says Steve DiCarlo, Cogentrix plant manager. “They ripped the old DCS out, put the new one in and we brought one of the units up to produce steam, all within 36 hours. I have to give them a well-deserved ‘touché.’”

Exhibit 13

GE Launches Breakthrough Power Generation Portfolio

GE Launches Breakthrough Power Generation Portfolio with Record Efficiency and Flexibility with Natural Gas; Announces Nearly $1.2 Billion in New Orders

Downloads

September 26, 2012

- New FlexEfficiency* 60 Technology to Power New Projects in the U.S., Saudi Arabia and Japan
- Unprecedented Combination of Efficiency and Flexibility Will Reduce Emissions and Allow Greater Integration of Renewable Energy onto the Grid
- Expanded Portfolio to Include Larger Gas Turbines
- New Gas Turbines to be Built and Tested in Greenville, S.C., and Shipped around the Globe

SAN FRANCISCO—September 26, 2012—GE (NYSE: GE) unveiled today its new FlexEfficiency 60 power generation portfolio engineered to harness natural gas and enable greater use of renewable energy. The FlexEfficiency 60 portfolio combines record-breaking efficiency, which will reduce emissions and save money (compared to prior GE configurations), along with unprecedented flexibility, which will enable utilities to deliver power quickly when it is needed and to ramp down when it is not, balancing the grid cost-effectively.

GE also announced that the company has secured nearly $1.2 billion in new orders for FlexEfficiency 60 technology for projects in the United States, Saudi Arabia and Japan, demonstrating strong international demand for technology that can provide highly efficient baseload power and pair natural gas with renewables.

At the heart of the new portfolio is the ecomagination*-qualified FlexEfficiency 60 Combined-Cycle Power Plant, the most flexible and most efficient power plant of its kind with the capability to reach greater than 61 percent thermal efficiency. This record-breaking efficiency will save fuel, reduce emissions and save money for power companies. Like its 50-hertz counterpart, the FlexEfficiency 50 Plant introduced in 2011, the FlexEfficiency 60 Plant is able to rapidly increase or decrease its power output in response to fluctuations in wind and solar power, enabling the integration of more renewable resources onto the power grid.

Natural Gas Power Generation for a Changing Energy Landscape

"This is a great milestone for our natural gas portfolio. We stated a year ago that we would bring our FlexEfficiency technology to our customers in places such as the U.S., Middle East, Japan and Brazil, and today we delivered," said Steve Bolze, president and CEO of GE Power & Water. "We continue to invest in and build the broadest gas-fueled power generation portfolio in the industry. From 1-megawatt distributed power to 300-megawatt baseload power, GE technology helps meet the power needs of people everywhere in the world."

FlexEfficiency 60 technology will be manufactured and tested at the world's largest gas turbine manufacturing facility in Greenville, S.C., where GE's engineers and technologists are at work engineering and building advanced technologies that deliver cleaner, more-efficient energy to the world.

The newest member of GE's ecomagination portfolio, the FlexEfficiency 60 Plant is configured to take on the world's toughest environmental challenges, avoiding up to 56,000 metric tons of carbon emissions per year relative to existing technology. If just one equivalent-size coal plant was replaced with the FlexEfficiency 60 Plant, the offset carbon emissions would be 2.6 million metric tons per year, the equivalent of 500,000 U.S. cars coming off the road.

The FlexEfficiency 60 Portfolio will include four gas turbines covering a range of customer needs. The newest is the 7F 7-series with record-breaking flexibility and efficiency in combined cycle. GE also is announcing the enhanced, highly flexible 7F 5-series. These technologies are available to customers today. A new 7F 9-series, configured to be the largest and most efficient in the portfolio, and an enhanced 7F 3-series will be available in the future. Combined, the portfolio offers the broadest power range of advanced gas turbines in the industry, from 185 megawatts to more than 300 megawatts. The FlexEfficiency 60 Portfolio also includes an enhanced D-17 steam turbine, H26 hydrogen-cooled generator and Mark* VIe Integrated Control System that can be configured into the FlexEfficiency 60 Combined-Cycle Power Plant.

Flexible and Efficient Technology for the Globe

Power grids around the world are split into two frequencies—50 hertz (Europe, much of Asia and Africa) and 60 hertz (North America, much of South America, Saudi Arabia, southern Japan, Korea, Taiwan). GE first developed FlexEfficiency technology for customers in the 50-hertz world. The FlexEfficiency 60 portfolio marks the expansion of this groundbreaking technology to the rest of the world, allowing efficient partnering of natural gas and renewable energy.

The $1.2 billion in new sales is comprised of orders for 19 gas turbines—13 for the 7F 5-series gas turbine and six for the new, larger 7F 7-series gas turbine introduced today. The 7F 7-series builds on the success of the 7F 5-series and GE's F-class technology and is based on years of experience in GE's Aviation and power generation businesses.

Paul Browning, president and CEO, GE Thermal Products business, said, "Today's announcement positions GE with the broadest, most comprehensive gas turbine portfolio, delivering a combination of record-setting efficiency and flexibility. Our expanded portfolio of large block gas turbines enables us to meet the complex and diverse energy and resource needs of our global customers today and in the future."

Below is a breakdown of the FlexEfficiency 60 Portfolio projects announced today:

- Chubu Electric Power, Japan—GE will ship six 7F 7-series gas turbines to Chubu Electric Power Co., Inc.'s Nishi-Nagoya thermal power plant in Nagoya city, Japan. The plant will support the government's initiative for cleaner, more-efficient energy production. It will produce more than 2,300 megawatts in combined-cycle operation. GE will supply the six 7F 7-series gas turbines to Toshiba, the engineering, procurement and construction contractor for the project. The first unit will be shipped in February 2016 with all six turbines expected to be in service by March 2018. In addition to the equipment, GE will supply parts for the project.

- Riyadh Power Plant 12, Saudi Arabia—GE will supply eight 7F 5-series gas turbine-generators for the expansion of Saudi Electricity Company's (SEC) PP12 project, which will add more than 1,990 megawatts of power to help SEC meet its future electricity demands when it enters commercial operation in 2015. PP12 will be the largest air-cooled combined-cycle project in Saudi Arabia using GE's F-class gas turbines and will be the first application of 7F 5-series gas turbines in the region. The gas turbines will burn natural gas provided by the Saudi national oil and gas company Saudi Aramco. The machines will be equipped with GE's latest dry low NO_x combustion technology to reduce emissions, extend maintenance intervals and enable the plant to operate more flexibly.
- Cherokee Clean Air Clean Jobs Project, Colorado—Two GE 7F 5-series gas turbines will power the Cherokee project in Denver, which will convert an existing coal plant into a cleaner burning, natural gas combined-cycle facility. The Cherokee repowering project is part of Colorado's Clean Air Clean Jobs Act passed in 2010, which helps retire or retrofit the state's coal plants. The new plant will be owned and operated by the Public Service Company of Colorado, a wholly owned subsidiary of Xcel Energy, a major U.S. electric and natural gas company. GE expects to ship the gas turbines in the fourth quarter of 2013, with commercial operation beginning in the fourth quarter of 2015. GE also will supply technical direction, training and spare parts.
- Hess Corporation—GE will provide two 7F 5-series gas turbines and a GE D11 steam turbine to Hess Corporation for an upcoming project in the United States.
- Customer in Western U.S.—GE will provide one 7F 5-series gas turbine for an industrial application in the Western United States. This new combined-cycle power plant will repower coal fired steam turbines with cleaner, flexible natural gas.

Learn more at www.ge-flexibility.com.

About GE

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Exhibit 14

Fast Cycling and Rapid Start-Up

Fast cycling and rapid start-up: new generation of plants achieves impressive results

Reprint from:
Modern Power Systems, January 2011

Author:
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Answers for energy.

SIEMENS

Fast cycling and rapid start-up: new generation of plants achieves impressive results

In last month's issue an analysis of the operational characteristics of various power generation technologies (pp 61-65) concluded that modern combined cycle power plants, with cycling and fast start capabilities, have a number of advantages in a grid where a large percentage of renewables is envisaged, as in Germany, for example. In this second article the theme of combined cycle plant operational flexibility is explored further. Recent innovations in combined cycle technology are described, as well as newly commissioned power plants that demonstrate what can be achieved.

Lothar Balling, *Siemens, Erlangen, Germany*

Figure 1. Recent combined cycle projects with enhanced flexibility and fast start capabilities

Pont sur Sambre, France

Sloe Centrale, Netherlands

Marchwood, England

Pego, Portugal

Enecogen, Netherlands

Hemweg and Diemen, Netherlands

The increased use of combined cycle plants for power generation over the past decade can be attributed to their high efficiencies, short execution times and relatively low investment costs. But now their potential for cycling and fast start-up is becoming an increasingly important selling point.

This need for increased flexibility first emerged at the end of the 1990s in the United States and the United Kingdom. The price of fuel continued to rise due to the large number of plants being built during the boom. Plants initially planned to have a base-load role were shifted to the load regime of an intermediate-load plant.

The challenge presented to projects by this changed requirement gave birth to the idea of trying to improve plant flexibility without compromising plant service life or plant efficiency.

As the market continued to develop, a demand for quicker start-ups soon followed the demand for more frequent start-ups. This market demand finally resulted in the launch by Siemens of a development project called FACY (FAst CYcling), which combined all the initial engineering ideas into a single integrated plant concept. The aim of the resulting R&D programme was to design a plant for an increased number of starts and to reduce start-up times. If possible, no limits were to be placed on the gas turbine by other power plant components, such as the heat recovery steam generator or steam turbine, during hot and warm starts.

In the course of the project, potential areas came to light where further optimisation could be achieved, although these had to wait for a second development generation to be implemented.

The major improvement offered by this second generation involved the start-up procedure. Hold points at which a plant waits until certain steam parameters have been reached were eliminated as part of the shortened "Start on the Fly" start-up procedure. In this procedure, the steam turbine is started up in parallel to the gas turbine using the first steam which becomes available after a hot start.

While the first generation FACY reduced start-up times for a hot start from 100 to 55 minutes, the second generation succeeded in pushing start-up times down below the 40 minute mark.

The first plants incorporating the features of both the first and second generations of the

Figure 2. The rise of renewables (EU-27)

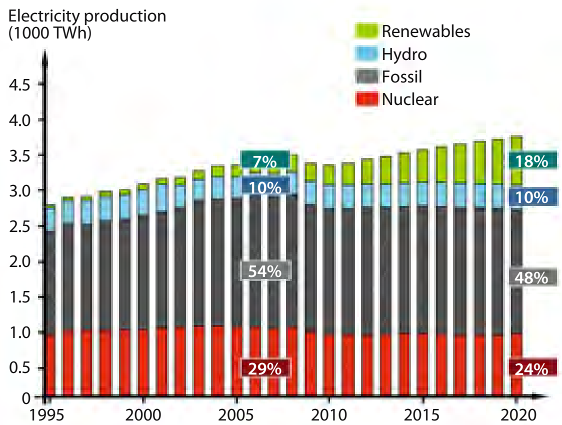
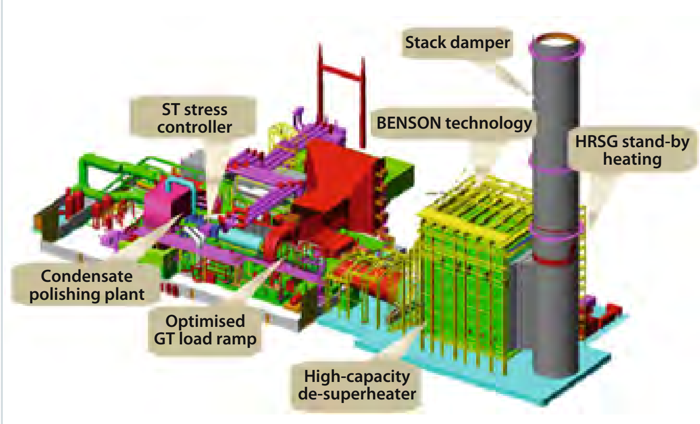


Figure 3. Main features of the Fast Cycling (FACY) concept



FACY concept have now entered commercial operation (Figure 1).

A good example is Sloe Centrale, a 2 x 430 MW F-class single shaft plant in the Netherlands, where 30-minute start-up times were recorded during acceptance tests, while achieving over 59% net efficiency. Equally good results have been exhibited by other newly commissioned plants. This means that the second generation of FACY has far surpassed expectations in a number of cases.

Shortening start-up times and improving starting reliability while increasing the number of starts was only one of many new requirements with respect to plant flexibility.

An increasingly important driver (as discussed in last month's article) is the growing percentage of renewables envisaged on the grid (see Figure 2). Wind and solar energy are not continuously available and difficult to predict precisely. Reserve power generating capabilities must therefore be provided which can be activated quickly. Gas turbine based plants are an obvious choice here as they can be started up at relatively short notice. The inherent inertia of other types of power generating facilities is usually much greater, making them largely unsuitable for use as a rapidly available reserve source of power. There are, of course, other fast-responding sources of power such as pumped storage. But they do not provide enough capacity to cover the renewable generating capacity in the European grid system, with the prospect of 30% renewables by 2030.

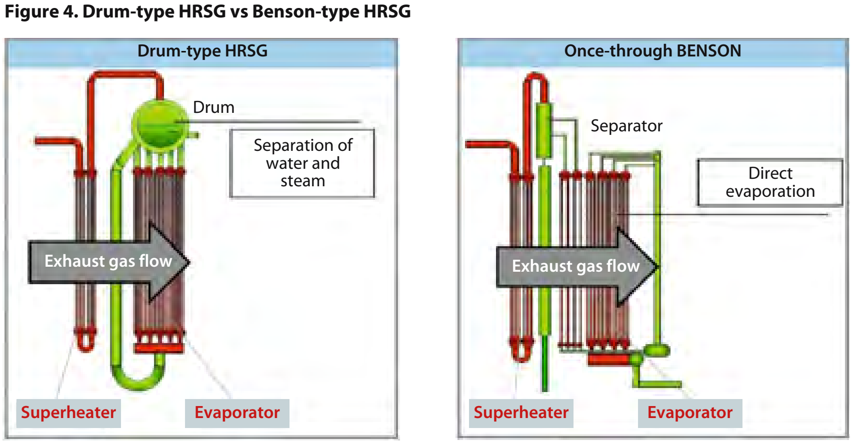
High availability and reliability power plants, such as combined cycle units, are required in order to compensate for fluctuating renewables. The requirements with respect to grid support, which are usually defined in a country-specific grid code, have recently become more rigorous for this reason.

Some of the most stringent requirements are to be found in the UK grid code. Requirements in the areas of load stabilisation at low frequencies, primary and secondary frequency response, and island operation capability have presented a particular challenge to UK operators for quite some time. However, the recently handed over 840 MW multi-shaft F-class Marchwood plant has finally demonstrated that the problem can be solved without compromising efficiency (over 58%) by introducing additional technical features and optimising the plant concept.

A decisive factor in the success of Marchwood was the integrated approach, which combined the potentials of several systems and components in a single solution, including use of gas turbine compressor optimisation, firing reserves, fast wet compression and other measures, combined with an optimised I&C/closed-loop control concept.

The new demand for extremely fast power generating availability is also becoming apparent in CCGT developers' economic assessments. Only a few years ago there were projects in which start-up times did not figure at all in the assessment, whereas now we are seeing over 100 000 €/min for some projects.

Figure 4. Drum-type HRSG vs Benson-type HRSG



FAst CYcling concept (FACY)

The idea of focusing plant design on an increased number of fast starts originated from market conditions and from specific projects. A multidisciplinary team of component and plant experts (for the steam turbine, gas turbine, balance of plant and auxiliary systems, I&C and steam generator) was formed by Siemens around 2002 to identify improvement potential in the existing plant concepts.

The team identified the following priorities:

- Maintaining pressure and temperature in the main components during shutdowns, by using stack dampers, auxiliary steam, etc.
- "Ready-for-operation" water/steam cycle using a fully automated start-up concept without manual operation or intervention during hot start.
- Optimised component design (eg, high capacity and fast acting de-superheaters) and plant operation to reduce material fatigue caused by load cycling.
- Flexible operation concept to allow the operator to predetermine component fatigue and to choose start-up time and ramp rate.
- Optimisation of the automation and control concept.
- New start-up sequence, "Start on the Fly", to allow a nearly unrestrained ramp-up.

Figure 3 summarises the main features of the FACY concept. These measures help reduce start-up time significantly. They are modular and are offered, configured and implemented on a project-specific basis.

Preserving warm start conditions

Major heat loss from the HRSG occurs through the stack and therefore a stack damper is deployed to limit heat loss during shut-down. Cooling down of the HRSG is considerably reduced and delayed.

Furthermore, auxiliary steam can be used to heat the HRSG. These measures increase the shut-down periods for which the criteria for hot and warm starts remain applicable.

Ready-for-operation mode of water/steam cycle

Auxiliary steam is also used to maintain the water/steam cycle in a ready-for-operation mode. This means auxiliary steam is fed into the gland steam system of the steam turbine. Keeping the gland steam system in operation prevents air from being drawn into the steam turbine and the condenser. Since the steam

Figure 5. "Start on the Fly" – an improved start-up sequence

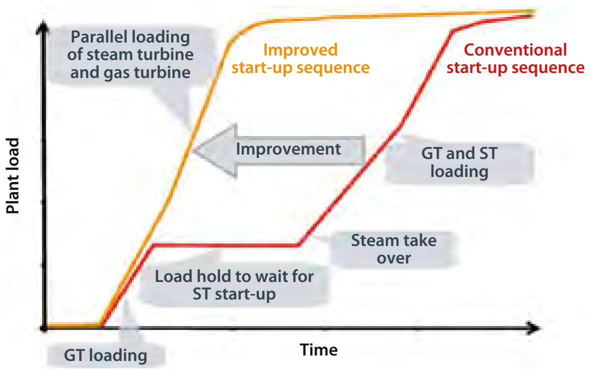
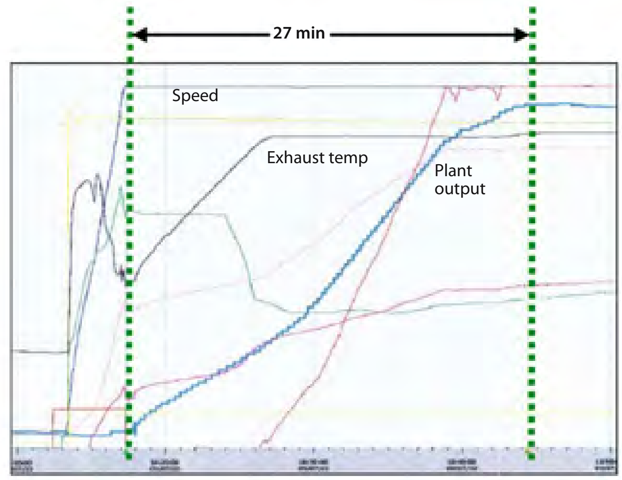


Figure 6. The 430 MW Pont sur Sambre combined cycle plant (SCC5-4000F 1S)



turbine and the condenser are sealed off from the ambient air, the condenser vacuum pumps can maintain the vacuum.

To enhance the start-up procedure, the condensate polishing plant can be used to bring the water/steam cycle within specified chemistry limits faster.

Optimised component design and plant operation to reduce material fatigue

In a conventional HRSG the high pressure drum is one of the most critical components in the start-up and ramping procedure. As a thick-walled component it is exposed to large temperature gradients and high operating pressures. Thermal stress in the high-pressure drum walls limits the load-, start up- and shut down- gradients of the HRSG.

However there is no high pressure drum in a Benson-type boiler, so these limits do not apply. The Benson boiler technology employs once-through steam generation, which means that conventional separation of steam and boiling water inside a drum is not necessary. Instead, steam is generated directly within the evaporator tubes, as shown in Figure 4.

Use of Benson technology allows the number of permissible starts and cycling events during the plant lifetime to be significantly increased, by reducing stress induced fatigue in the high pressure section of the HRSG.

Also, a temperature-controlled start-up process, using an optimised high-capacity de-superheater to limit steam temperatures during the start-up, has been developed for warm and cold starts. This reduces thermal stress in critical components of the steam turbine.

Optimising the automation

There are essentially two ways in which automation system is optimised to support improved start-up:

- Design limits are fully exploited through the use of closed-loop control instead of earlier empirically based approaches. A turbine stress controller is used to determine thermal stress based on temperature differences measured within the steam turbine and ensures that stress limits are not exceeded. The turbine stress controller makes it possible to shorten the start-up time without reducing the lifetime of heat-critical turbine components.
- Two additional start-up modes – "FAST" and "COST-EFFECTIVE" – in addition to the "NORMAL" mode have been introduced. The operator has the option of choosing the appropriate start-up mode depending on such factors as current electricity market prices. Maintenance intervals can be extended using the "COST EFFECTIVE" setting, while the "FAST" mode permits controlled fast start-up, but entails increased maintenance requirements.

The start-up procedure is automated to a level that enables hot starts with only a few operator actions, the aim being to minimise inefficient and unproductive periods during start-up preparations. Draining and venting are largely automated, for example.

Second-generation FACY – "Start on the Fly"

In addition to the features included in the original FACY concept, a procedure for parallel start-up of gas and steam turbines has been developed. It is based on monitoring and

Figure 7. The 860 MW Irsching 5 combined cycle plant (SCC5-4000F 2+1)

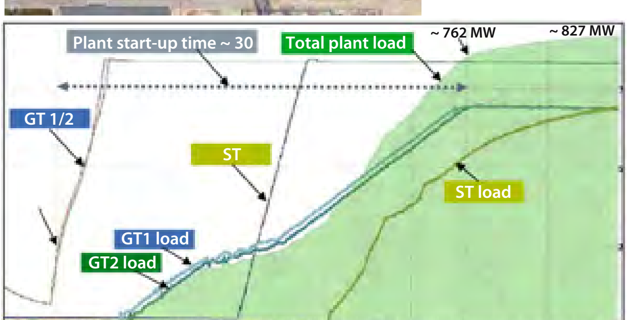
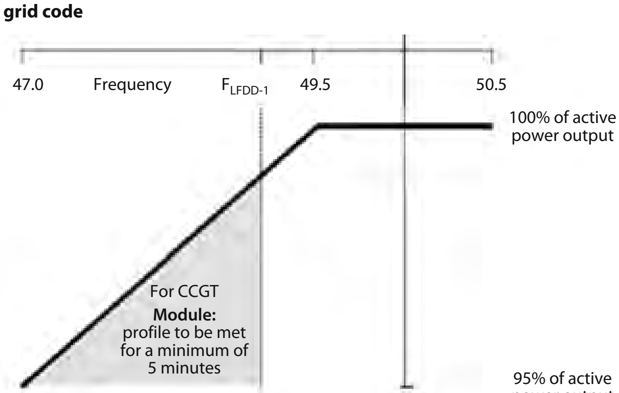


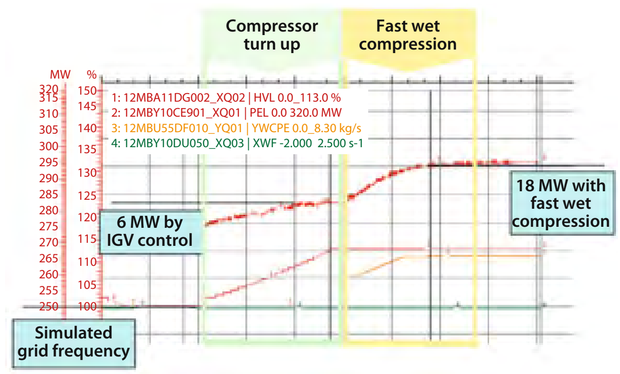
Figure 8. Load stabilisation at low frequency in accordance with the UK grid code



Note: Frequency F_{LFDD-1} is the relay trip setting of the first stage of the Automatic Low Frequency Demand Disconnection Scheme

Figure 9. The 840 MW Marchwood combined cycle plant (SCC5-4000F MS)

Figure 10. Load stabilisation at low frequency, Marchwood test results



controlling the temperature gradients within limits acceptable for all critical plant components and on long term turbine operating experience over a range of steam conditions. The new concept enables the plant to be started-up without any gas turbine load hold points, enabling a new start-up sequence to be implemented – see Figure 5. The main innovation is the early steam turbine starting point with earlier acceleration and loading of the turbine.

Recent operating results

The features described above have been implemented in plants across Europe and excellent results have been achieved in single shaft as well as in multi shaft configurations. Two notable examples are the Pont sur Sambre F-class single shaft plant in France and the F-class multi shaft configuration at Irsching 5 in Germany, Figures 6 and 7, respectively.

Both units have demonstrated the capability to start-up and reach full load in about 30 minutes folowing an overnight shut down, without compromising efficiency, achieving levels of over 58% and over 59%, respectively.

It is noteworthy, that the single shaft operating concept allows parallel start up of several units at a site, resulting in multiples of, eg, 430 MW, being available in around 30 minutes, as has been demonstrated at Sloe Centrale, with its two units.

Grid support

In liberalised electricity markets, the minimum requirements for power plant dynamics are set out in grid codes. Some of the most stringent requirements imposed on plant dynamics are to be found in the grid code of the UK, reflecting its island geography. Three of the most critical considerations are: load stabilisation at low frequencies; primary and secondary frequency response; and island operation capability.

Load stabilisation at low frequencies

Normal fluctuations in the balance between generation and consumption are reflected in fluctuations in grid frequency which can be compensated for by means of routine frequency control measures. The frequency can, however, also decrease or even increase significantly in the event of unusually large disturbances.

Unfortunately a decrease in grid frequency also means a reduction in turbine speed and subsequently a decrease of power output. This decrease in speed causes the compressor in a gas turbine to produce a reduced volumetric flow, thus decreasing gas turbine output if appropriate compensatory measures are not implemented.

The United Kingdom grid code stipulates that power output must be maintained for a minimum of 5 minutes in the event of a frequency drop, down to 49.5 Hz – so as to avoid further taxing of the grid due to under-frequency. If a greater decrease in frequency occurs, the grid code permits a maximum decrease in output of 5%, down to 47 Hz, as illustrated in Figure 8.

To counteract this decrease in power output, several measures for increased output can be implemented at short notice. The decrease in output can be compensated for by rapidly opening the guide vanes on the compressor. The fuel flow is increased at the same time. This can compensate for a drop in power of around 6 MW.

In unfavourable operating conditions, however, this increase in output will not be sufficient on its own. In this case Fast Wet Compression (a patented Siemens concept) can be used to mobilise a further power reserve of around 12 MW.

Fast Wet Compression consists of spraying demineralised water into the compressor inlet. The mass of the injected water increases the mass flow through the compressor. The evaporating water also cools the air flow at the compressor inlet. The air density and consequently the mass flow through the compressor increase due to this cooling process. Rapid activation of the system constitutes a challenge to control systems, as the fast increase in power output requires perfect co-ordination between the gas turbine control system and the water injection.

These grid support features have been validated and demonstrated in the Marchwood F-class multi shaft plant in the UK, at a power output of about 840 MW and over 58% efficiency (Figure 9).

Plots from the Marchwood tests are shown in Figure 10. It can be seen that an 18 MW increase was achieved (for each gas turbine) by opening the compressor IGVs and then initiating fast wet compression, thus meeting the requirement of the United Kingdom grid code.

Figure 11. Frequency response at low and high frequencies in accordance with UK grid code

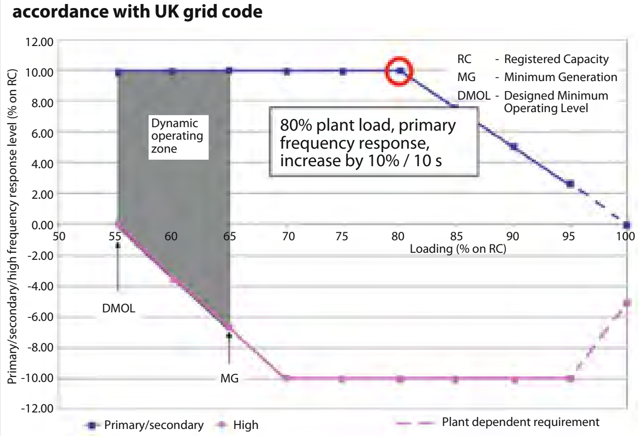


Figure 12. Frequency response test at low frequency, Marchwood, July 2009 (data for one GT)

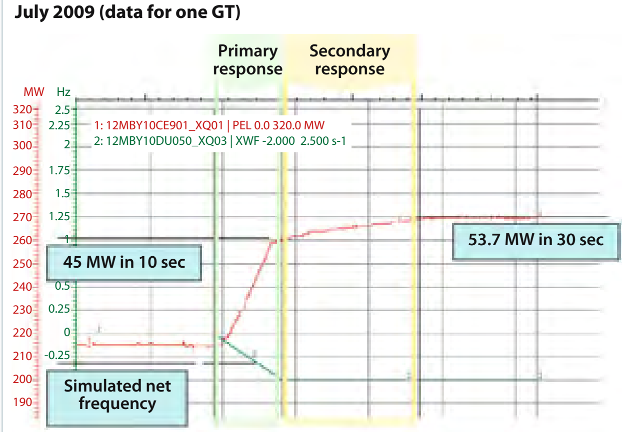


Figure 13. Island operation test at Marchwood (data for one GT)

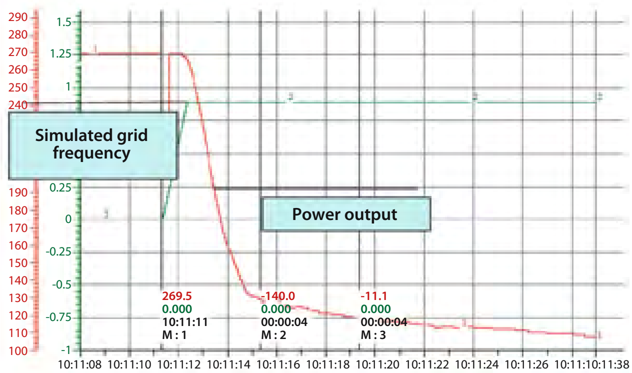
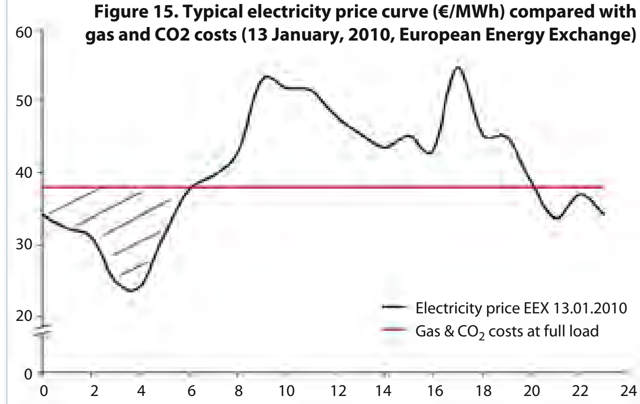


Figure 15. Typical electricity price curve (€/MWh) compared with gas and CO2 costs (13 January, 2010, European Energy Exchange)



Primary and secondary frequency response

The purpose of load stabilisation at low frequencies is to prevent further destabilisation of the grid when the frequency decreases due to major disturbances. Primary and secondary frequency responses are now required for grid support during normal operation. For this purpose the UK grid code stipulates that a power plant operating at part load must be capable of making additional power available. Figure 11 illustrates the relevant part of the UK grid code. We can see that a power plant operating at under 80% load must be able to make available at least 10% of its rated power within 10 seconds in the event of a decrease in frequency. For secondary frequency response 10% of its rated power must be made available within 30 seconds. Figure 11 shows that the requirements are reduced when the plant is operating at loads over 80%.

Unlike load stabilisation at low frequency, there is no need to look for a further power reserve in this case. The challenge lies more in the speed at which the power must be made available.

To meet the requirements of the grid code, we rely on fast repositioning of the compressor IGVs coupled with fuel control optimised to such an extent that load ramps are possible without destabilising combustion.

Figure 12 illustrates the results of tests done on the Marchwood plant and clearly shows that the required additional power is achieved both after 10 seconds and after 30 seconds. In fact, performance is significantly better than that required by the grid code in both instances.

Another aspect of the grid code, also shown in Figure 11, is high frequency response, namely that load must be reduced by 10% of rated power within 10 seconds in the event of over-frequencies of up to 500 mHz. However, when it comes to load reduction the island operation requirement (see next section) is even more stringent.

Island operation capability

The primary objective of island operation capability is to stabilise the grid, in the event of excess power and an abrupt drop in consumption within an islanded portion of the grid, resulting in a very rapid frequency increase. The power plant must react to this frequency increase by throttling back to stabilise the frequency, thus avoiding a forced shut-down due to over-frequency.

Uncontrolled shut-down of power plants can result in a grid collapse, which is why the UK grid code stipulates that power plants must be capable of rapidly decreasing from rated power to the design minimum operating level (DMOL). The DMOL must not be smaller than 55% of rated power in this case. This load reduction must be effected sufficiently quickly that the island frequency remains below 52 Hz. Grid studies based on the UK National Grid requirements show that the load reduction must take place within around 8 seconds.

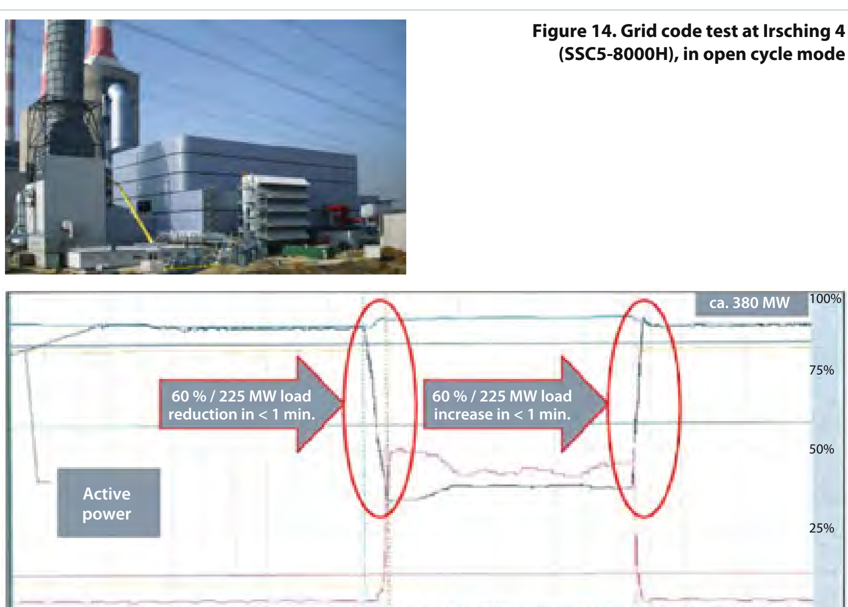
The power plant must detect island formation automatically and take immediate action. As soon as island operating mode is activated, permitted load change ramps are set to the maximum value. The inlet guide vanes in the gas turbine compressor are closed without delay. At the same time the various closed-loop controls ensure that the power is decreased at the maximum rate of change for load. Maintaining flame stability and avoiding potential flash backs in the combustion system are the main objectives of closed-loop control optimisation, so as to avoid emergency shutdown of the gas turbine.

Figure 13 illustrates an island operation test at Marchwood. The gas turbine output was decreased by 52% within 4 seconds as the result of a simulated fast frequency increase of 0.9 Hz, without initiating a plant trip. A further decrease of 4% was achieved in the following 4 seconds. Thus performance again exceeded grid code requirements.

Transfer to the H

Meanwhile, these basic plant features demonstrated in F-class plants are being transferred also to H-class technology and have already been validated in open cycle operation at Irsching 4 (Figure 14), demonstrating that even this latest and highest efficiency technology is capable of supporting the same stringent grid code requirements.

Figure 14. Grid code test at Irsching 4 (SSC5-8000H), in open cycle mode



The bottom line: benefits to the operator

The previous sections clearly demonstrate that FACY and Start on the Fly permit a reduction in start-up times as well as an increased number of start-ups, enabling nightly power plant shut-downs. The latter offers two additional benefits:

- Carbon dioxide emissions are minimised by shortening inefficient plant start-ups. Maximum electrical efficiency is reached faster and total emissions are reduced.
- Since nightly shutdowns and reliable start-ups become economically feasible, overall carbon dioxide emissions are further reduced as inefficient overnight parking at

load is avoided. Other power plants within the grid can then be operated at full load and maximum efficiency.

Operators benefit from this, primarily through fuel savings and a reduction in carbon dioxide emissions during the start-up phase. Shortening the start-up time by using Start on the Fly for a hot start offers an estimated added value of more than 3 million euros alone, assuming that the savings described above are realised over the service life of a 430 MW power plant.

The option of disconnecting the plant from the grid overnight offers enormous potential in the form of savings in operating costs.

Night-time electricity prices have been at such a low level in the European system that a combined cycle power plant could no longer be operated at a profit during the night due to high gas and carbon dioxide costs (see Figure 15). To minimise these losses, power plants are operated at part load or are shut down altogether at night.

Reducing the load already brings about a significant reduction in losses. However when the load decreases, so does overall efficiency, meaning that gas and carbon dioxide costs can only be reduced disproportionately.

In addition to the positive effect of load reduction, shutting a power plant down at night can achieve other significant benefits. Only shut-down and start-up costs are incurred, for example. Restrictions relating to the permitted number of start-ups for the plant have been significantly reduced, thanks to the FACY programme. FACY and Start on the Fly have also significantly reduced start-up times. The result is lower gas consumption and lower carbon dioxide emissions, providing the power plant operator with an additional economic benefit for every start.

Figure 16. Savings in gas consumption and avoided CO_2 emissions resulting from night-time shutdown. This is based on a gas price of 20.2 €/MWh, CO_2 costs of 2.88 €/MWh and a night-time electricity price of 29.4 €/MWh. The performance data are based on an SCC5-4000F single-shaft plant with a cooling tower

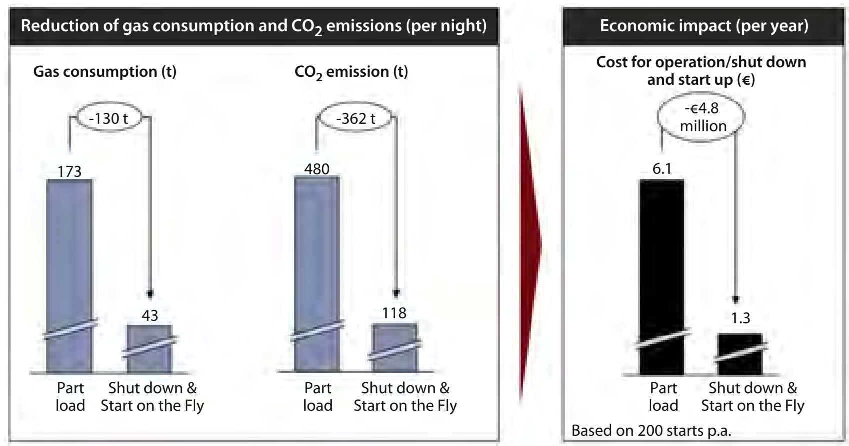


Figure 16 shows the carbon dioxide and fuel savings which can be achieved by night-time shutdown using FACY compared with night-time part-load operation at about 25%. We can see that the power plant in this example can avoid up to 130 tons of gas consumption and 362 tons of carbon dioxide emissions per night through night-time shutdown. This increases the annual power plant profit by 4.8 million euros as compared with night-time part-load operation.

Today grid support features arise primarily from the grid access requirements of the individual countries. No monetary valuation of the additional plant flexibility is included in tender specifications as yet. For this reason today's plants are designed purely based on grid code specifications. Depending on the level of electricity market liberalisation, however, the various flexibility features enable additional earnings to be generated, in particular by participating in the frequency reserve market.

Another potential benefit is that plants with high reliability and operational flexibility, able to cope well under disturbed grid conditions, can expect to be prioritised for dispatch. MPS

Severn Power handed over

One of the latest additions to the fleet of flexible Siemens combined cycle plants in commercial operation is Severn Power, Uskmouth, near Newport in Wales, UK. This was handed over to Dong Energy on 26 November 2010, one week ahead of schedule. The 834 MWe F-class single-shaft plant is equipped with many of the cycling and fast start-up features described in the main article, and, like other plants mentioned there, is able to achieve full output in only 30-35 minutes following an overnight shut down.

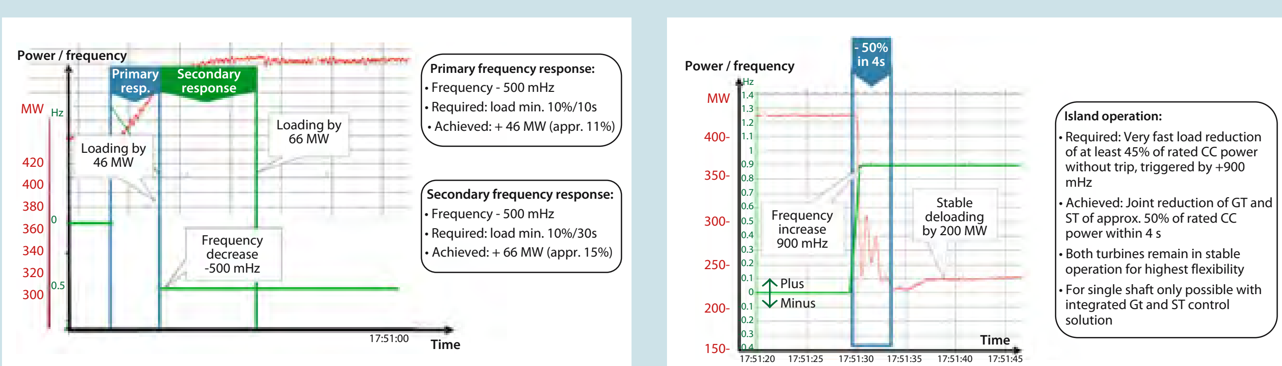
With Fast Wet Compression and other features, tests at Severn have indicated that its performance in terms of UK grid code support is at least as good as that of Marchwood (see pp 39-40).

The plant's high degree of operating flexibility also means that it is capable of very quickly compensating for the fluctuating feed-in from wind turbines.

Use of an air-cooled condenser instead of a cooling tower and application of an innovative waste water concept also minimises water consumption.

Efficiency is about 58% and, thanks to advanced burner technology, the plant's nitrogen oxide emission levels are very low, around 15 ppm.

In terms of health & safety during construction, the project has also been exemplary, clocking up more than three million working hours without a lost time accident, with over 1200 workers on the site at peak times.



Results of grid code support tests at the new Severn Power combined cycle plant

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Exhibit 15

Analysis of EPEC Load Profile

<u>Exhibit 15</u>

<u>Analysis of EPEC Load Profile</u>

The “ramp rate is the rate at which one can add load to a unit per unit of time. The ramp rate that is available in a system is the sum of the ramp rates of the units in the system that are operating at less than full capacity at any given point in time. The only information in the record for this permit concerning the ramp rates that might be needed in the EPEC system at any given point in time is Figure 1 in EPEC’s application, which EPEC styles “Typical Load Profile for Summer Day.” This profile demonstrates a fairly constant increase from a baseload level of 800 MW to slightly over 1,400 MW over a period of 10 hours. This represents a system-wide ramp rate of approximately 60 MW/hr or 1 MW/min. The actual system load in the EPEC service area likely varies more than what is portrayed in EPEC’s submission. However, this is the only information in the record on this issue. The combined ramp rates for the several units that will be in operation at any point in time will be two hundred MW/min or more.

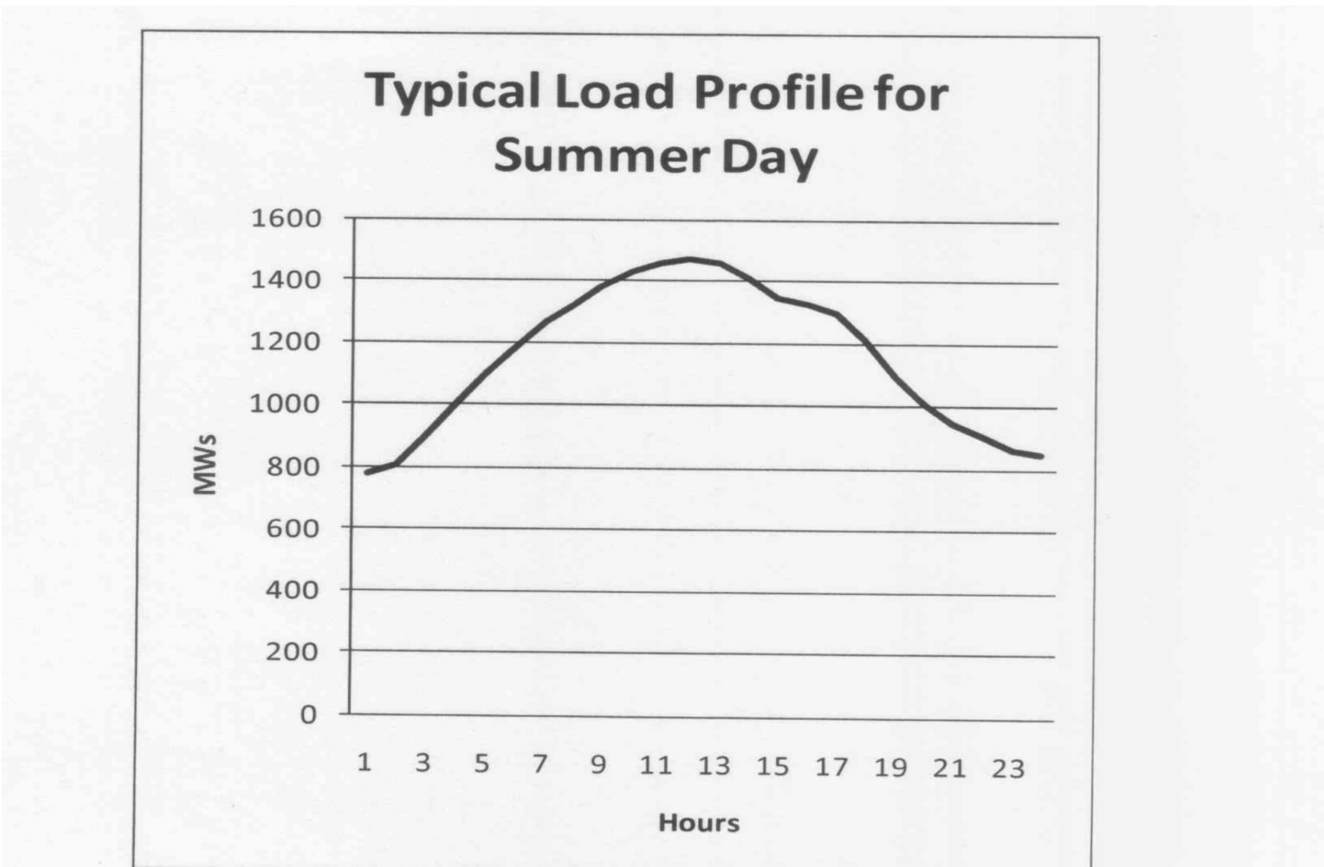
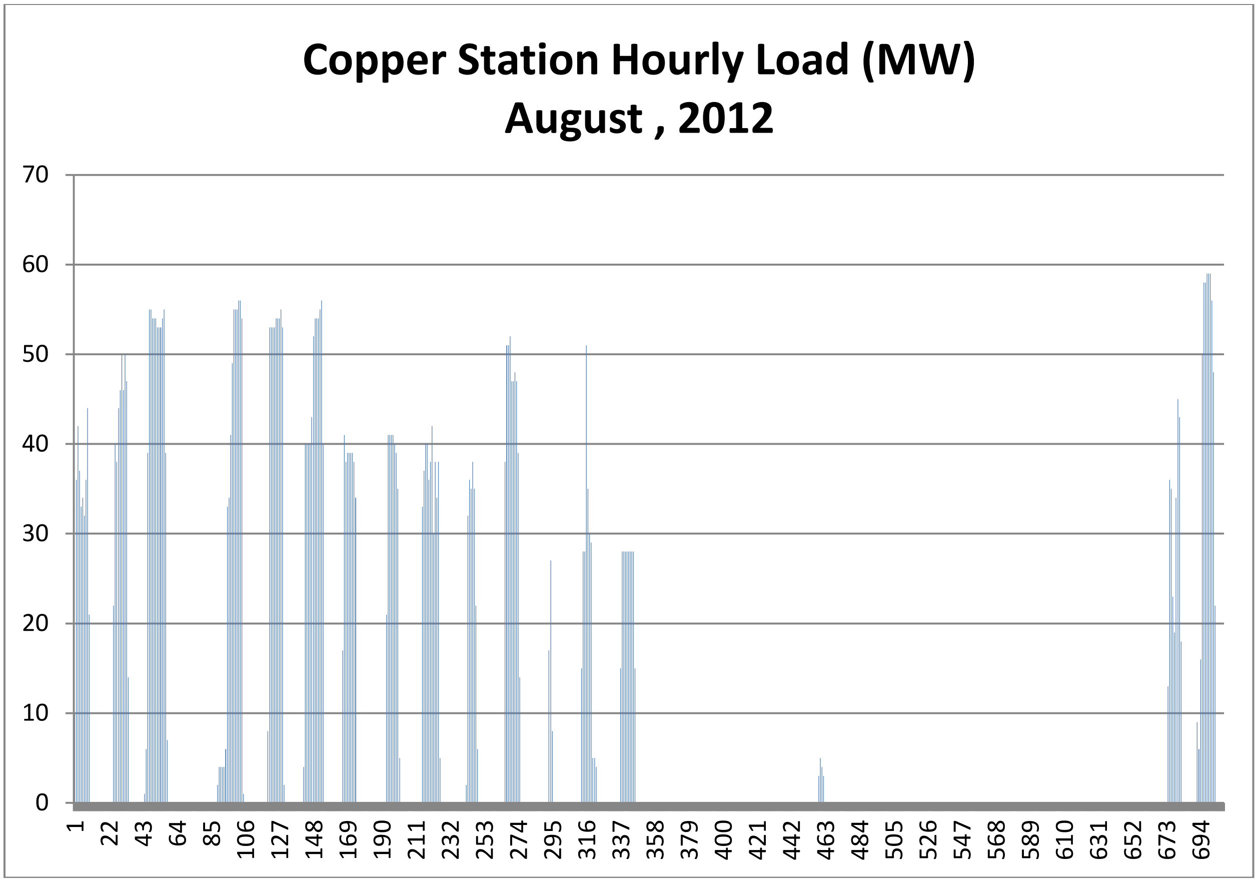


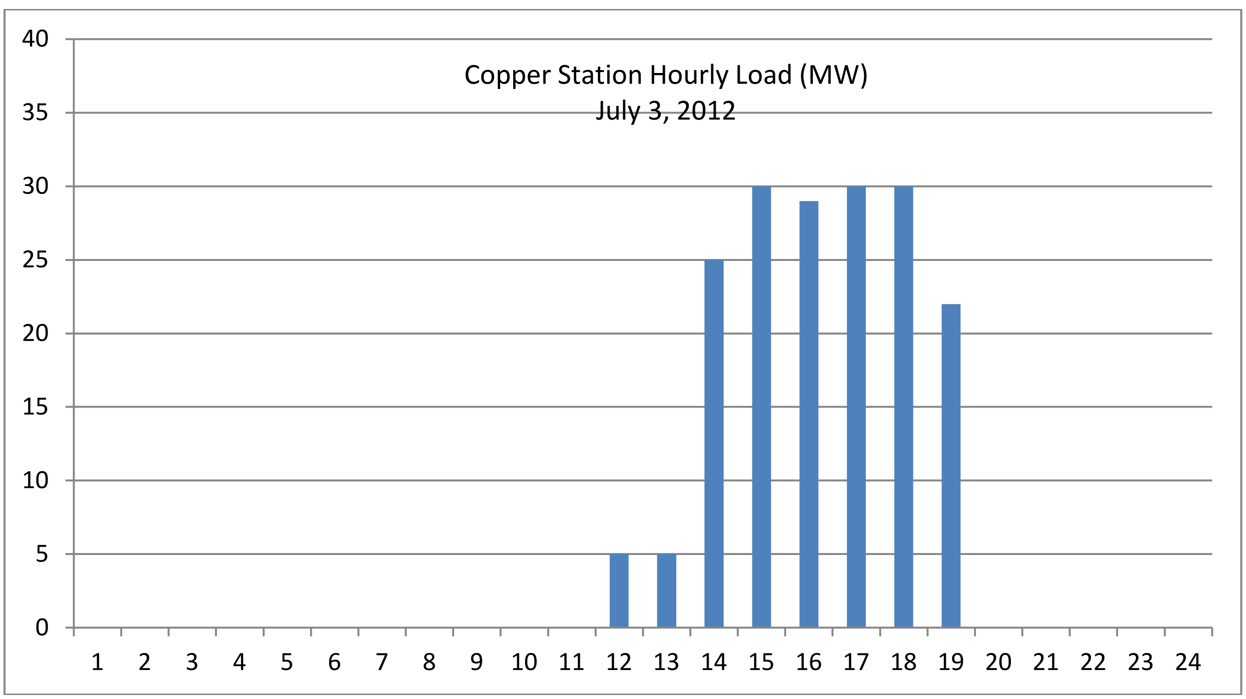
Figure 1 – EPEC’s Daily Load Profile

With only 43 MW of peaking capacity in its current system, EPEC manages the fluctuations in demand in its system. The peaking unit (Copper) is infrequently used, even in the summer[1]

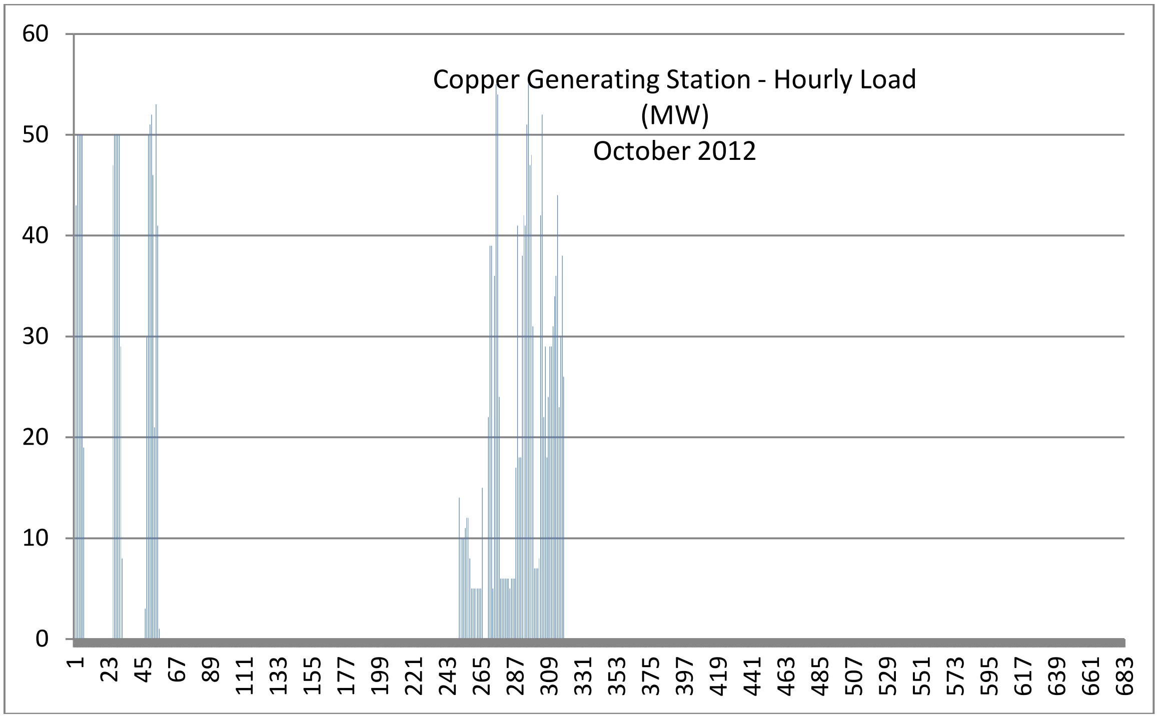
[1] Each of the load charts that follow are obtained from http://ampd.epa.gov/ampd/QueryToolie.html, visited October, 2013



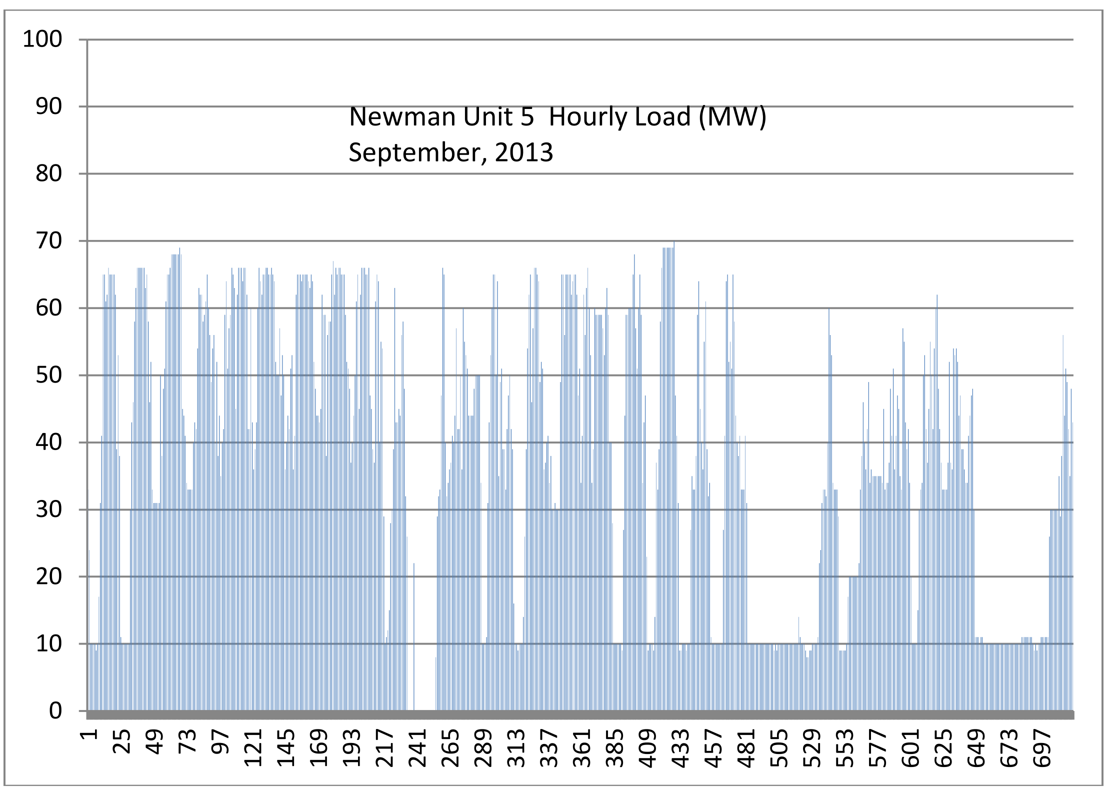
And even when used, it may only operate for a few hours at part load

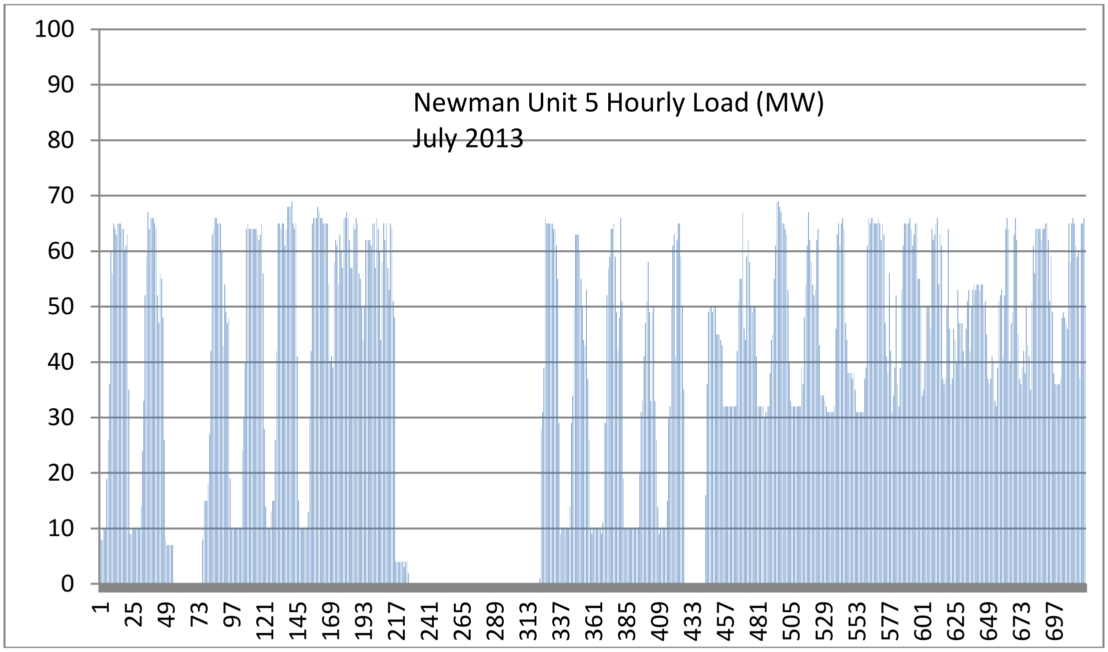


In shoulder seasons, Copper Station contributes even less to managing the peak load.

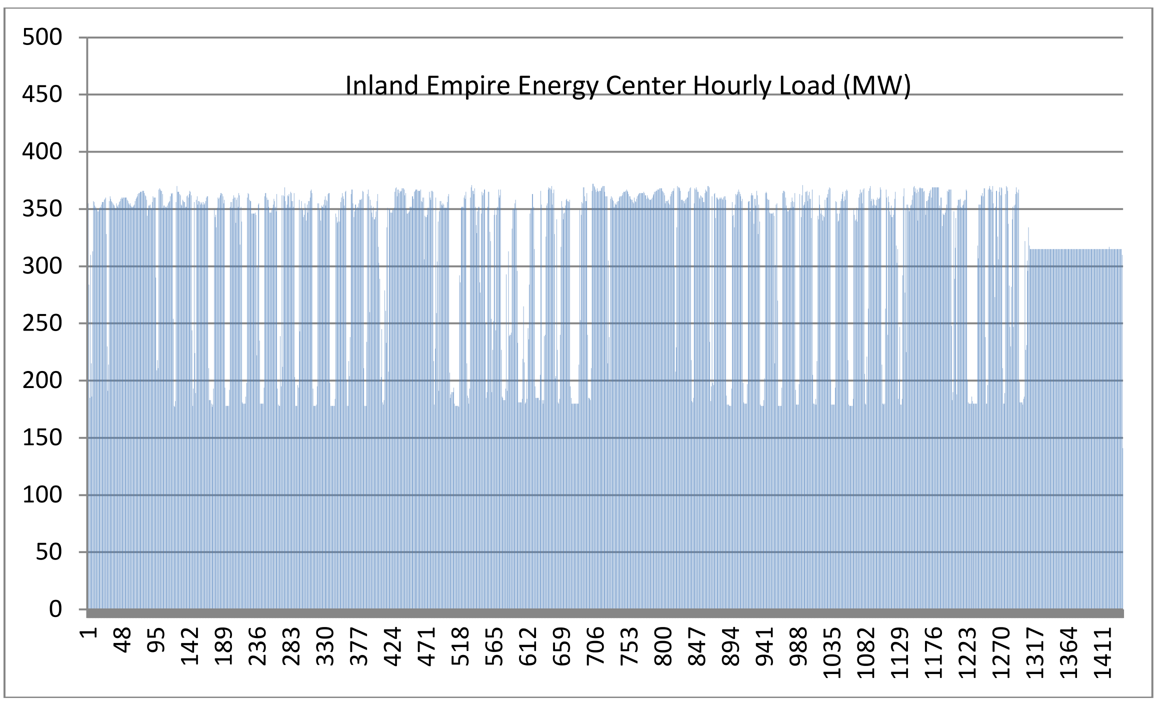


Instead most of the "peaking function" is accomplished by utilizing the ramping ability of existing units, including the CCGTs Newman 5.





This capability is not limited to EPEC units, but is, in fact, quite common.



The Inland Empire Energy Center achieves an in-use annual GHG emission rate of 780 lb/MWh (gross) and 803 lb/MWh (net) while providing this degree of peaking load support.[2]

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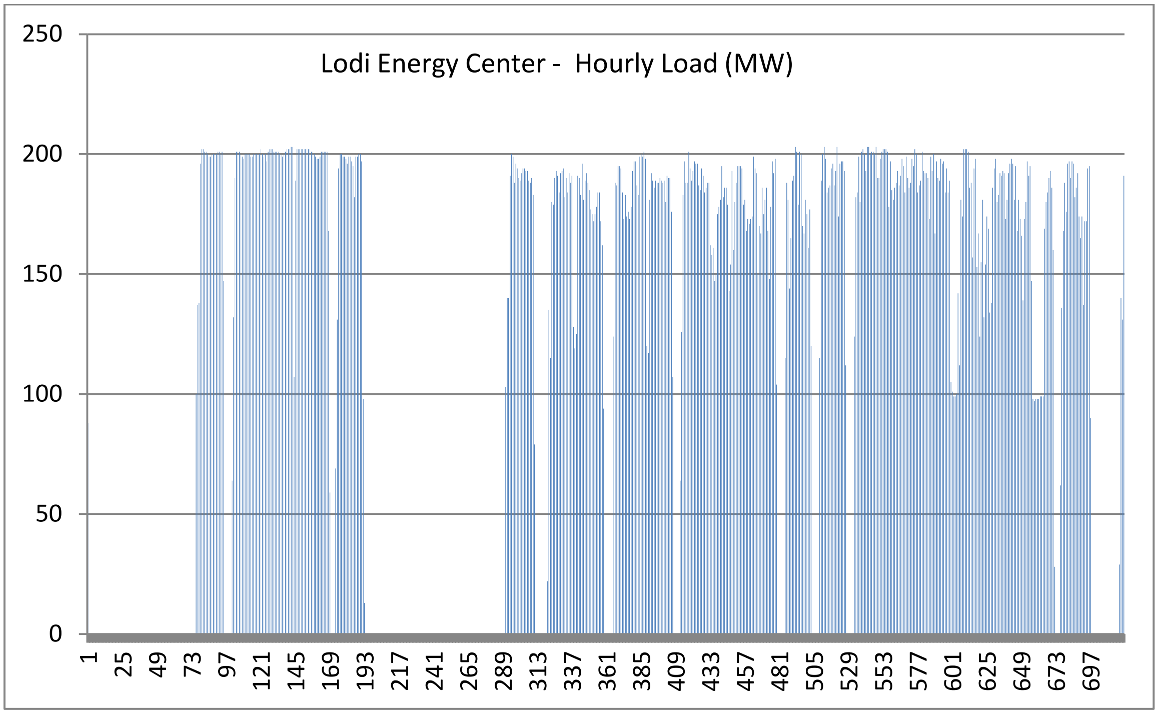
[2] *See* "New Combined Cycle Units," EPA-HQ-OAR-2011-0660-0029, *available at* http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2011-0660-0029 (last visited June 1, 2012).

Demonstrating the ability of a fast response CCGT to supply daily cycling and load following needs.



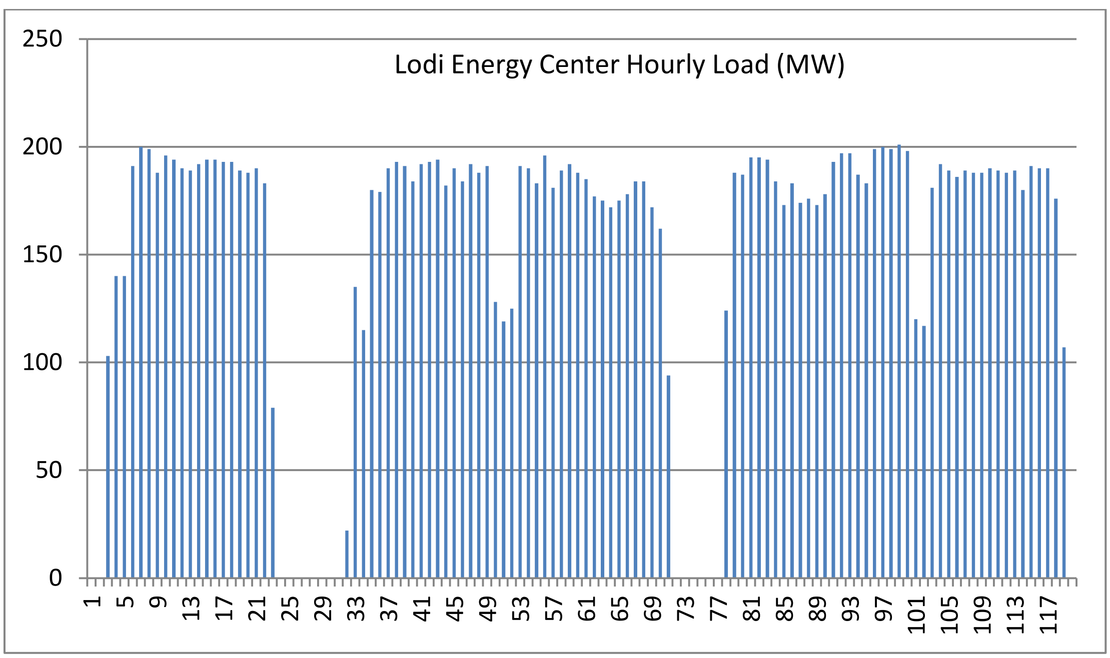


Exhibit 16

BACT Determination for the
Huntington Beach Energy Project

Appendix 5.1D
Criteria Pollutant and Greenhouse BACT Analysis

BACT Determination for the Huntington Beach Energy Project

Prepared for

AES Southland Development, LLC

Submitted to

South Coast Air Quality Management District
EPA Region IX

June 2012

CH2MHILL®

Contents

Acronyms and Abbreviations

°F	degree(s) Fahrenheit
AES-SLD	AES Southland Development, LLC
AFC	Application for Certification
BAAQMD	Bay Area Air Quality Management District
BACT	best available control technology
Btu/kWh	British thermal units per kilowatt-hour
CAISO	California Independent System Operator
CARB	California Air Resources Board
CCS	carbon capture and storage
CEC	California Energy Commission
CFR	Code of Federal Regulations
CH_4	methane
CO	carbon monoxide
CO_2	carbon dioxide
CPUC	California Public Utilities Commission
CPV	Competitive Power Ventures
CTG	combustion turbine generator
DLN	dry low NO_x
DOE	U.S. Department of Energy
EOR	enhanced oil recovery
EPA	U.S. Environmental Protection Agency
GHG Tailoring Rule	Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule
GHG	greenhouse gases
GWh	gigawatt-hour(s)
H_2	hydrogen
HBEP	Huntington Beach Energy Project
HFC	hydrofluorocarbon
HHV	higher heating value
HRSG	heat recovery steam generator
IPCC	Intergovernmental Panel on Climate Change
LAER	Lowest Achievable Emission Rate
lb/hr	pound(s) per hour
lb/MMBtu	pound(s) per million British thermal unit
LHV	lower heating value
Mandatory Reporting Rule	EPA Final Mandatory Reporting of Greenhouse Gases Rule
MMBtu	million British thermal units
MMBtu/hr	million British thermal units per hour
MPSA	Mitsubishi Power Systems Americas
$MTCO_2$/MWh	metric ton(s) of carbon dioxide per megawatt-hour
MW	megawatt(s)
MWh	megawatt-hour(s)
N_2	nitrogen

N_2O	nitrous oxide
NATCARB	National Carbon Sequestration Database and Geographic Information System
NETL	National Energy Technology Laboratory
NGCC	natural gas combined-cycle
NO	nitric oxide
NO_2	nitrogen dioxide
NO_x	oxides of nitrogen
NSR	New Source Review
O_2	oxygen
OTC	once-through cooling
PFC	perfluorocarbons
PM_{10}	and particulate matter less than 10 microns in diameter
$PM_{2.5}$	particulate matter less than 2.5 microns in diameter
ppm	part(s) per million
ppmv	part(s) per million by volume
ppmvd	part(s) per million dry volume
PSA	pressure swing adsorption
PSD	Prevention of Significant Deterioration
psig	pound(s) of force per square inch gauge
PTE	Potential to Emit
RACT	Retrofit Available Control Technology
RCEC	Russell City Energy Center
RPS	Renewable Portfolio Standard
SCAQMD	South Coast Air Quality Management District
scf	standard cubic feet
SCR	selective catalytic reduction
SF_6	sulfur hexafluoride
SJVAPCD	San Joaquin Valley Air Pollution Control District
SNCR	selective non-catalytic reduction
SO_2	sulfur dioxide
SoCalCarb	Southern California Carbon Sequestration Research Consortium
SoCalGas	Southern California Gas
SO_x	sulfur oxides
STG	steam turbine generator
SWRCB	State Water Resources Control Board
tpy	ton(s) per year
VOC	volatile organic compound
WestCarb	West Coast Regional Carbon Sequestration Partnership

SECTION 1

Project Description

1.1 Project Overview

AES Southland Development, LLC (AES-SLD) proposes to construct the Huntington Beach Energy Project (HBEP) at the existing AES Huntington Beach Generating Station site at 21730 Newland Street, Huntington Beach, California 92646. HBEP will consist of two, three-on-one combined-cycle power blocks with a net capacity of 939 megawatts (MW). Each power block will consist of three Mitsubishi Power Systems Americas (MPSA) 501DA combustion turbines (CTG), one steam turbine generator (STG), and an air-cooled condenser. Each combustion turbine will be equipped with a heat recovery steam generator (HRSG) and will employ supplemental natural gas firing (duct burning). The turbines will use dry low NO_x (DLN) burners and selective catalytic reduction (SCR) to limit NO_x (oxides of nitrogen) emissions to 2 parts per million by volume (ppmv). Emissions of carbon monoxide (CO) will be limited to 2 ppmv and volatile organic compounds (VOC) to 1 ppmv through the use of best combustion practices and an oxidation catalyst. Best combustion practices and burning pipeline-quality natural gas will minimize emissions of the remaining pollutants.

HBEP will retain the use of the two existing 275-horsepower diesel-fired emergency fire water pumps installed during the Huntington Beach Generating Station Units 3 and 4 retooling project in 2001. Because the existing fire water pumps are permitted sources by the South Coast Air Quality Management District (SCAQMD) and are not being modified nor will change their operating profile, the project owner has not included the fire pumps in the best available control technology (BACT) analysis for HBEP.

Authorization for the construction and operation of HBEP will be through the California Energy Commission (CEC) Application for Certification (AFC) licensing process and the SCAQMD New Source Review/Prevention of Significant Deterioration (NSR/PSD) permitting process. Because HBEP includes the use of steam to generate electricity, the project is also categorized as one of the 28 major PSD source categories (40 Code of Federal Regulations [CFR] 52.21(b)(1)(i)). Therefore, the project is subject to PSD permitting requirements if the Potential to Emit (PTE) from the project exceeds 100 tons per year (tpy) for any regulated pollutant, with the exception of greenhouse gases (GHG). The threshold for GHGs is a PTE of 100,000 tpy. Because the existing Huntington Beach Generating Station Units 1 and 2 will be retired and removed as part of the project, the maximum 2-year historical past actual emissions from these two units between calendar years 2007 and 2011 will be subtracted from the PTE for HBEP.

Despite the netting analysis, the resulting PTE is still expected to exceed the 100-tpy or 100,000-tpy threshold for at least one of the PSD-regulated pollutants. Therefore, the project will be considered a major stationary source in accordance with PSD regulations. The SCAQMD has also been delegated partial PSD permitting authority.[1] Therefore, the PSD BACT analysis is being submitted to the SCAQMD as part of the permitting process.

1.2 Project Objectives

HBEP's key design objective is to provide up to 939 MW of environmentally responsible, cost-effective, operationally flexible, and efficient generating capacity to the western Los Angeles Basin Local Reliability Area in general, and specifically to the coastal area of Orange County. The project would serve local area reliability needs, southern California energy demand and provide controllable generation to allow the integration of the ever increasing contribution of intermittent renewable energy into the electrical grid. The project will displace older and less efficient generation in Southern California, and has been designed to start and stop very quickly and be able to quickly ramp up and down through a wide range of generating capacity. As more renewable electrical resources are brought on line as a result of electric utilities meeting California's Renewable Portfolio Standard,

[1] http://www.epa.gov/region09/air/permit/pdf/full-scagmd-psd-delegation.pdf

projects strategically located within load centers and designed for fast starts and ramp-up and down capability, such as HBEP, will be critical in supporting both local electrical reliability and grid stability.

HBEP will provide needed electric generation capacity with improved efficiency and operational flexibility to help meet southern California's long-term electricity needs. The California Independent System Operator (CAISO) has identified a need for new power generation facilities in the western Los Angeles Basin Local Reliability Area to replace the ocean water once-through-cooling (OTC) plants that are expected to retire as a result of the California State Water Resources Control Board's (SWRCB) *Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling* (OTC Policy) (CAISO, 2012a; SWRCB, 2010). The base case study results from CAISO's year 2021 long-term Local Capacity Requirement proceeding estimates that between 2,424 and 3,834 MW of new generation is required in the Los Angeles Basin due to planned OTC retirements consistent with SWRCB OTC Policy. The requirement for new generation in light of OTC retirements in the Los Angeles Basin is also confirmed in CAISO's Once-Through Cooling and AB-1318 Study Results presented on December 8, 2011 (CAISO, 2011). CAISO also notes that many of the OTC facilities have characteristics that support renewable integration and that repower or replacement generating capacity must retain or improve upon such capabilities (CAISO, 2012b).

The project objectives are also contingent on the use of the offset exemption contained within the SCAQMD's Rule 1304(a)(2) that allows for the replacement of older, less-efficient electric utility steam boilers with specific new generation technologies on a megawatt-to-megawatt basis (that is, the replacement megawatts are equal to or less than the megawatts from the electric utility steam boilers). The offset exemption in Rule 1304(a)(2) requires the electric utility steam boiler be replaced with one of several specific technologies, including the combined-cycle configuration used by HBEP.

HBEP was designed to address the local capacity requirements within the Los Angeles Basin with the following objectives:

- Provide the most efficient, reliable, and predictable power supply available by using combined-cycle, natural-gas-fired combustion turbine technology to replace the OTC generation, support the local capacity requirements of Southern California's Western Los Angeles Basin and be consistent with SCAQMD Rule 1304(a)(2).
- Develop a 939-MW project that provides efficient operational flexibility with rapid-start and steep ramping capability (30 percent per minute) to allow for the efficient integration of renewable energy sources into the California electrical grid with competitive electrical generation pricing.
- Reuse existing electrical, water, wastewater, and natural gas infrastructure and land to the extent possible to minimize terrestrial resource and environmental justice impacts by developing on a brownfield site.
- Secure a sufficient-sized site to maintain existing generating capacity to meet regional grid reliability requirements during the development of HBEP.
- Site the project to serve the Western Los Angeles Basin load center without constructing new transmission facilities.
- Assist the State of California in developing increased local generation projects, thus reducing dependence on imported power.
- Site the project on property that has industrial land use designation with consistent zoning.
- Ensure potential environmental impacts can be avoided, eliminated, or mitigated to a less-than-significant level.

Locating the project on an existing power plant site avoids the need to construct new linear facilities, including gas and water supply lines, discharge lines, and transmission interconnections. This reduces potential offsite environmental impacts, and the cost of construction. The proposed HBEP site meets all project siting objectives.

The HBEP will provide power to the grid to help meet the need for electricity and to help replace dirtier, less efficient fossil fuel generation resources retired because of the use of OTC. HBEP will enhance the reliability of the state's electrical system by providing power generation near the centers of electrical demand and providing fast response generating capacity to enable increased renewable energy development. Additionally, as demonstrated by the analyses contained in this AFC, the project would not result in any significant environmental impacts.

SECTION 2

Criteria Pollutant BACT Analysis

Based on the SCAQMD's BACT definition and major source thresholds (SCAQMD Rule 1302 and 1303), a BACT analysis is required for the uncontrolled emissions of NO_x, VOCs, CO, sulfur oxides (SO_x), and particulate matter less than 10 microns in diameter (PM_{10}) and particulate matter less than 2.5 microns in diameter ($PM_{2.5}$). Also, the U.S. Environmental Protection Agency (EPA) requires a BACT analysis for the emissions of GHGs as part of the PSD permit application required under the EPA Tailoring Rule. The GHG BACT analysis is included in the following section.

The project owner plans to rely on the response characteristics of the MPSA 501DA combustion turbines and duct burners to provide a wide range of efficient, operationally flexible, fast-start, fast-ramping capacity to allow for the efficient integration of renewable energy sources into the California electrical grid. The project owner has proposed two separate permit levels to allow the flexibility of operating the turbines with and without duct burners. The HBEP emission limits are presented in Table 2-1.

TABLE 2-1
Proposed Emission Limits for the Huntington Beach Energy Project

	Emission Limit (at 15 percent O_2)	
Pollutant	**Without Duct Burners**	**With Duct Burners**
NO_x	2.0 ppm (averaged over 1 hour)	2.0 ppm (averaged over 1 hour)
CO	2.0 ppm (averaged over 1 hour)	2.0 ppm (averaged over 1 hour)
VOC	1.0 ppm (averaged over 1 hour)	1.0 ppm (averaged over 3 hours)
PM_{10}	4.5 lb/hr	9.5 lb/hr
$PM_{2.5}$	4.5 lb/hr	9.5 lb/hr
SO_x	<0.75 grain of sulfur/100 scf of natural gas	<0.75 grain of sulfur/100 scf of natural gas

Notes:

lb/hr = pound(s) per hour
O_2 = oxygen
ppm = part(s) per million
scf = standard cubic feet

The following discussion presents an assessment of the BACT for HBEP (with and without duct burners) and includes the following components:

- Outline of the methodology used to conduct the criteria pollutant BACT analyses
- Discussion of the available technology options for controlling NO_x, CO, VOCs, PM_{10}, $PM_{2.5}$, and SO_x emissions
- Presentation of the proposed BACT emission levels identified for the HBEP

2.1 Methodology for Evaluating the Criteria Pollutant BACT Emission Levels

The NO_x, CO, VOC, PM_{10}, $PM_{2.5}$, and SO_x BACT analysis for the HBEP is based on the EPA's top-down analysis method. The following top-down analysis steps are listed in the EPA's *New Source Review Workshop Manual* (EPA, 1990):

- Step 1: Identify all control technologies
- Step 2: Eliminate technically infeasible options
- Step 3: Rank remaining control technologies by control effectiveness
- Step 4: Evaluate the most-effective controls, and document the results
- Step 5: Select the BACT

As part of the control technology ranking step (Step 3), emission limits for other recently permitted natural-gas-fired combustion turbines (with and without DUCT BURNERS) were compiled based on a search of the various federal, state, and local BACT, Retrofit Available Control Technology (RACT), and Lowest Achievable Emission Rate (LAER) databases. The following databases were included in the search:

- **EPA RACT/BACT/LAER Clearinghouse (EPA, 2012)**
  - Search included the NO_x, CO, VOC, PM, and sulfur dioxide (SO_2) BACT/LAER determinations for combined-cycle and cogeneration, large combustion turbines (greater than 25 MW) with permit dates between 2001 and April 2012.
- **California Air Pollution Control Officers Association / California Air Resources Board (CARB) BACT Clearinghouse (CARB, 2012)**
  - Search included the BACT determinations listed in CARB's BACT clearinghouse for combined-cycle turbines from all California air districts.
- **Local Air Pollution Control Districts BACT Guidelines/Clearinghouses:**
  - **SCAQMD BACT Guidelines (SCAQMD, 2012)**
    - Search included the BACT determinations for combined-cycle gas turbines listed in SCAQMD BACT Guidelines for major sources.
  - **Bay Area Air Quality Management District (BAAQMD) BACT/Toxics BACT Guidelines (BAAQMD, 2012)**
    - Search included the BACT determinations for combined-cycle turbines equal to or greater than 40 MW in Section 2, Combustion Sources, in the BAAQMD BACT Guidelines.
  - **San Joaquin Valley Air Pollution Control District (SJVAPCD) BACT Clearinghouse (SJVAPCD, 2012)**
    - Search included the BACT determinations listed under the SJVAPCD BACT Guideline Section 3.4.2 (combined-cycle, uniform-load gas turbines greater than 50 MW)
- **BACT Analyses for Recently Permitted Combustion Turbine CEC Projects (CEC, 2012)**
  - Review included the BACT analysis for the Pio Pico, GWF Tracy, Hanford, and Henrietta projects, the Oakley Generating Station Project, the Mariposa Energy Project, the Russell City Energy Center, the Los Esteros Critical Energy Facility – Phase 1 and Phase 2, the Palmdale Hybrid Power Project, and the Watson Cogeneration and Electric Reliability Project.

The natural-gas-fired combustion turbine permit emission limits for each of the BACT pollutants at other recently permitted facilities were then compared to the proposed emission limits for the HBEP, as set forth in Table 2-1. If the emission limits at other facilities were less than the values in Table 2-1, additional research was conducted to find which turbine technology had been selected and whether the facilities had been constructed (Step 3). If it could be demonstrated that other units with lower emission rates either had not yet been built or used a different turbine technology than that selected for the HBEP, the proposed emission limits for the HBEP were determined to be BACT (Step 5).

2.2 Criteria Pollutant BACT Analysis

2.2.1 Oxides of Nitrogen

NO_x is a byproduct of the combustion of an air-and-fuel mixture in a high-temperature environment. NO_x is formed when the heat of combustion causes the nitrogen (N_2) molecules in the combustion air to dissociate into individual N_2 atoms, which then combine with O_2 atoms to form nitric oxide (NO) and nitrogen dioxide (NO_2). The principal form of nitrogen oxide produced during turbine combustion is NO, but NO reacts quickly to form NO_2, creating a mixture of NO and NO_2 commonly called NO_x.

2.2.1.1 Identification of Combustion Turbine NO_x Emissions Control Technologies – Step 1

Several combustion and post-combustion technologies are available for controlling turbine NO_x emissions. Combustion controls minimize the amount of NO_x created during the combustion process, and post-combustion controls remove NO_x from the exhaust stream after the combustion has occurred. Following are the three basic strategies for reducing NO_x during the combustion process:

1. Reduction of the peak combustion temperature
2. Reduction in the amount of time the air and fuel mixture is exposed to the high combustion temperature
3. Reduction in the O_2 level in the primary combustion zone

Following is a discussion of the potential control technologies for combined-cycle and cogeneration combustion turbines:

NO_x Combustion Control Technologies. The two combustion controls for combustion turbines are (1) the use of water or steam injection, and (2) DLN combustors, which include lean premix and catalytic combustors.

Water or Steam Injection. The injection of water or steam into the combustor of a gas turbine quenches the flame and absorbs heat, reducing the combustion temperature. This temperature reduction reduces the formation of thermal NO_x. Water or steam injection also allows more fuel to be burned without overheating critical turbine parts, increasing the combustion turbine maximum power output. Combined with a post-combustion control technology, water or injection can achieve a NO_x emission of 25 part(s) per million dry volume (ppmvd) at 15 percent O_2, but with the added economic, energy, and environmental expense of using water.

DLN Combustors. Conventional combustors are diffusion-controlled. The fuel and air are injected separately, with combustion occurring at the stoichiometric interfaces. This method of combustion results in combustion “hot spots,” which produce higher levels of NO_x. The lean premix and catalytic technologies are two types of DLN combustors that are available alternatives to the conventional combustors to reduce NO_x combustion “hot spots.”

In the lean premix combustor, which is the most popular DLN combustor available, the combustors reduce the formation of thermal NO_x through the following: (1) using excess air to reduce the flame temperature (i.e., lean combustion); (2) reducing combustor residence time to limit exposure in a high-temperature environment; (3) mixing fuel and air in an initial “pre-combustion” stage to produce a lean and uniform fuel/air mixture that is delivered to a secondary stage where combustion takes place; and/or (4) achieving two-stage rich/lean combustion using a primary fuel-rich combustion stage to limit the amount of O_2 available to combine with N_2 and then a secondary lean burn-stage to complete combustion in a cooler environment. Lean premix combustors have only been developed for gas-fired turbines. The more-advanced designs are capable of achieving a 70- to 90 percent NO_x reduction with a vendor-guaranteed NO_x concentration of 9 to 25 ppmvd.

Catalytic combustors use a catalyst to allow the combustion reaction to take place with a lower peak flame temperature to reduce thermal NO_x formation. The catalytic combustor uses a flameless catalytic combustion module, followed by completion of combustion (at lower temperatures) downstream of the catalyst.

Neither water injection nor DLN combustors can control NO_x formed from the use of duct burners to supplementally fire the HRSGs in a combined cycle configuration. NO_x from duct burners is controlled by limiting the amount of duct firing required and with post-combustion pollution control technologies.

Post-combustion NO_x Control Technologies. Three post-combustion controls are available for combustion turbines: (1) SCR, (2) SCONOx™ (that is, EMx), and (3) selective non-catalytic reduction (SNCR). Both SCR and EMx control technologies use a catalyst bed to control the NO_x emissions and, combined with DLN or water injection, are capable of achieving NO_x emissions levels of 2.0 ppmvd for combined-cycle gas turbines. EMx uses a hydrogen regeneration gas to convert the NO_x to elemental N_2 and water. SNCR also uses ammonia to control NO_x emissions but without a catalyst.

Selective Catalytic Reduction. SCR is a post-combustion control technology designed to control NO_x emissions from gas turbines. The SCR system is placed inside the exhaust ductwork and consists of a catalyst bed with an ammonia injection grid located upstream of the catalyst. The ammonia reacts with the NO_x and O_2 in the presence of a catalyst to form N_2 and water. The catalyst consists of a support system with a catalyst coating typically of titanium dioxide, vanadium pentoxide, or zeolite. A small amount of ammonia is not consumed in the reaction and is emitted in the exhaust stream; this is referred to as "ammonia slip."

EMx System. The EMx system uses a single catalyst to remove NO_x emissions in the turbine exhaust gas by oxidizing NO to NO_2 and then absorbing NO_2 onto the catalytic surface using a potassium carbonate absorber coating. The potassium carbonate coating reacts with NO_2 to form potassium nitrites and nitrates, which are deposited onto the catalyst surface. The optimal temperature window for operation of the EMx catalyst is from 300 to 700 degrees Fahrenheit (°F). EMx does not use ammonia, so there are no ammonia emissions from this catalyst system (CARB, 2004).

When all of the potassium carbonate absorber coating has been converted to N_2 compounds, NO_x can no longer be absorbed and the catalyst must be regenerated. Regeneration is accomplished by passing a dilute hydrogen-reducing gas across the surface of the catalyst in the absence of O_2. Hydrogen in the gas reacts with the nitrites and nitrates to form water and N_2. Carbon dioxide (CO_2) in the gas reacts with the potassium nitrite and nitrates to form potassium carbonate, which is the absorbing surface coating on the catalyst. The regeneration gas is produced by reacting natural gas with a carrier gas (such as steam) over a steam-reforming catalyst (CARB, 2004).

Selective Non-catalytic Reduction. SNCR involves injection of ammonia or urea with proprietary conditioners into the exhaust gas stream without a catalyst. SNCR technology requires gas temperatures in the range of 1,600 to 2,100 °F[2]. This technology is not available for combustion turbines because gas turbine exhaust temperatures are below the minimum temperature required of 1,600°F.

2.2.1.2 Eliminate Technically Infeasible Options – Step 2

Pre-combustion NO_x Control Technologies

Water or Steam Injection. The use of water or steam injection is considered a feasible technology for reducing NO_x emissions to 25 ppmvd when firing natural gas under most ambient conditions. Combined with SCR, water or steam injection can achieve 2 ppmvd NO_x levels but at a slightly lower thermal efficiency as compared to DLN combustors.

DLN Combustors. The use of DLN combustors is a feasible technology for reducing NO_x emissions from the HBEP. DLN combustors are capable of achieving 9 to 25 ppmvd NO_x emission over a relatively large operating range (70 to 100 percent load), and when combined with SCR can achieve controlled NO_x emissions of 2 ppmvd.

The XONON™ technology has been demonstrated successfully in a 1.5-MW simple-cycle pilot facility, and it is commercially available for turbines rated up to 10 MW, but catalytic combustors such as XONON™ have not been demonstrated on an industrial E Class gas turbine. Therefore, the technology is not considered feasible for the proposed HBEP.

Post-combustion NO_x Control Technologies

Selective Catalytic Reduction. The use of SCR, with an ammonia slip of less than 5 ppm, is considered a feasible technology for reducing NO_x emissions to 2 ppmvd at 15 percent O_2 when firing natural gas.

EMx System. In the Palmdale Hybrid Power Project PSD permit, EPA noted that it appears EMx has only been demonstrated to achieve 2.5 ppm NO_x (EPA, 2011). In addition, the BAAQMD concluded in a recent permitting case that "it is clear that EMx is not as developed as SCR at this time and cannot achieve the same level of emissions performance that SCR is capable of" (BAAQMD, 2011). Therefore, EMx technology is not considered feasible for achieving the proposed HBEP NO_x limit of 2.0 ppm NO_x.

[2] http://www.icac.com/i4a/pages/index.cfm?pageid=3399

Selective Non-catalytic Reduction. SNCR requires a temperature window that is higher than the exhaust temperatures from natural-gas-fired combustion turbine installations. Therefore, SNCR is not considered technically feasible for the proposed HBEP.

2.2.1.3 Combustion Turbine NO_x Control Technology Ranking – Step 3

Based on the preceding discussion, the use of water injection, DLN combustors, and SCR are the effective and technically feasible NO_x control technologies available for the HBEP. DLN combustors were selected because these allow for lower NO_x emission rate (9 ppmvd) from the combustion turbine over either water or steam (wet) injection (25 ppmvd). Furthermore, DLN combustors result in a very slight improvement in thermal efficiency over the wet injection NO_x control alternative and reduce the HBEP's water consumption. When used in combination with SCR, these technologies will control NO_x emissions to 2.0 ppm (1-hour) with and without duct burners.

Applicable BACT clearinghouse determinations and the BAAQMD, CARB, SCAQMD, and SJVAPCD BACT determinations were reviewed to identify which NO_x emission rates have been achieved in practice for other natural-gas-fired combustion turbine projects. The results of this review are presented in Table 2-2.

TABLE 2-2
Summary of NO_x Emission Limits for Combustion Turbines
Technology Ranking for Turbines With and Without Duct Burning

Facility	Facility ID Number	NO_x Emission Limit at 15 percent O_2
Middleton Facility	ID-0010	3.0 ppm (24-hour) without duct burners; 3.5 ppm (24-hour) with duct burners
Mirant Gastonia Power Facility	NC-0095	2.5 ppm (24-hour) for first 500 hour, 3.5 ppm (24-hour) after
Berrien Energy, LLC	MI-0366	2.5 ppm (24-hour)
Black Hills Corp./Neil Simpson	WY-0061	2.5 ppm (24-hour)
COB Energy Facility, LLC	OR-0039	2.5 ppm (4-hour)
Kelson Ridge	MD-0033	2.5 ppm (3-hour)
Kyrene Generating Station, Salt River Project	AZ-0041	2.5 ppm (3-hour)
Duke Energy Wythe, LLC	VA-0289	2.5 ppm
Port Westward Plant	OR-0035	2.5 ppm
FPL Martin Plant	FL-0244	2.5 ppm
Empire Power Plant	NY-0100	2.0 ppm (3-hour) without duct burners; 3.0 ppm (3-hour) with duct burners
Tracy Substation Expansion Project	NV-0035	2.0 ppm (3-hour)
Langley Gulch Power Plant	ID-0018	2.0 ppm (3-hour)
Palomar Escondido – SDG&E	2001-AFC-24	2.0 ppm (1-hour); 2.0 ppm (3-hour) with duct burners or transient hour of +25 MW
Warren County Facility	VA-0308	2.0 ppm with or without duct burners
Ivanpah Energy Center, L.P.	NV-0038	2.0 ppm (1-hour) without duct burners; 13.96 lb/hr with duct burners
Gila Bend Power Generating Station	AZ-0038	2.0 ppm (1-hour)
Duke Energy Arlington Valley	AZ-0043	2.0 ppm (1-hour)
Colusa II Generation Station	2006-AFC-9	2.0 ppm (1-hour)
Avenal Energy – Avenal Power Center, LLC	2008-AFC-1	2.0 ppm (1-hour)
Russell City Energy Center	2001-AFC-7	2.0 ppm (1-hour)

TABLE 2-2
Summary of NO_x Emission Limits for Combustion Turbines
Technology Ranking for Turbines With and Without Duct Burning

Facility	Facility ID Number	NO_x Emission Limit at 15 percent O_2
CPV Warren	VA-0291	2.0 ppm (1-hour)
IDC Bellingham	CA-1050	2.0 ppm/1.5 ppm (1-hour)
Oakley Generating Station	2009-AFC-4	2.0 ppm (1-hour)
GWF Tracy Combined-cycle Project	2008-AFC-7	2.0 ppm (1-hour)
Watson Cogeneration Project	2009-AFC-1	2.0 ppm (1-hour)

Note: This table does not include all projects listed in the BACT databases. The purpose of this table is to present a summary of the most-stringent emission limits and to highlight any projects with an emission limit less than 2.0 ppm NO_x identified during the database search.

Source: EPA RACT/BACT/LAER Clearinghouse and the California Energy Commission (EPA, 2012 and CEC, 2012)

The review of these recent determinations identified only the IDC Bellingham Project as having emission limits less than the proposed BACT emission limit for the HBEP of 2.0 ppm NO_x. Based on the Final Determination of Compliance for the Oakley Generating Station Project, BAAQMD noted that the IDC Bellingham facility in Massachusetts was permitted with a two-tiered NO_x emission limit that imposed an absolute not-to-exceed limit of 2.0 ppm but also required the facility to maintain emissions below 1.5 ppm during normal operations (BAAQMD, 2011). However, BAAQMD also noted that the IDC Bellingham facility was never built, and that the emission limit was therefore never achieved in practice (BAAQMD, 2011). As a result, the proposed emission rate of 2.0 ppm (1-hour) with and without duct burners for HBEP is the lowest NO_x emission rate achieved in practice for similar sources and, therefore, is the BACT emission limit for NO_x control.

2.2.1.4 Evaluate Most-effective Controls and Document Results – Step 4

Based on the information presented in this BACT analysis, the proposed NO_x emission rates of 2.0 ppm (1-hour) with and without duct burners are the lowest NO_x emission rates achieved in practice at similar sources. Therefore, an assessment of the economic and environmental impacts is not necessary.

2.2.1.5 NO_x BACT Selection – Step 5

The proposed BACT for NO_x emissions from the HBEP is the use of DLN combustors with SCR to control NO_x emissions to 2.0 ppmvd (1-hour average) with and without duct burners.

2.2.2 CO

CO is discharged into the atmosphere when some of the fuel remains unburned or is only partially burned (incomplete combustion) during the combustion process. CO emissions are also affected by the gas turbine operating load conditions. CO emissions can be higher for gas turbines operating at low loads than for similar gas turbines operating at higher loads (EPA, 2006).

2.2.2.1 Identification of Combustion Turbine CO Emissions Control Technologies – Step 1

Effective combustor design and post-combustion control using an oxidation catalyst are two technologies (discussed below) for controlling CO emissions from a combustion turbine. As noted in the NO_x BACT analysis, the EMx and XONON technologies were determined to not be feasible for HBEP.

Best Combustion Control. CO is formed during the combustion process as a result of incomplete combustion of the carbon present in the fuel. The formation of CO is limited by designing the combustion system to completely oxidize the fuel carbon to CO_2. This is achieved by ensuring that the combustor is designed to allow complete mixing of the combustion air and fuel at combustion temperatures (in excess of 1,800°F) with an excess of combustion air. Higher combustion temperatures tend to reduce the formation of CO but increase the formation of NO_x. The application of water injection or staged combustion (DLN combustors) tends to lower combustion temperatures (in order to reduce NO_x formation), potentially increasing CO formation. However, using good combustor design and following best operating practices will minimize the formation of CO while reducing the combustion temperature and NO_x emissions.

Oxidation Catalyst. An oxidation catalyst is typically a precious metal catalyst bed located in the HRSG. The catalyst enhances oxidation of CO to CO_2, without the addition of any reactant. Oxidation catalysts have been successfully installed on numerous simple- and combined-cycle combustion turbines.

2.2.2.2 Eliminate Technically Infeasible Options – Step 2

Using good combustor design, following best operating practices, and using an oxidation catalyst are technically feasible options for controlling CO emissions from the proposed HBEP.

2.2.2.3 Combustion Turbine CO Control Technology Ranking – Step 3

Based on the preceding discussion, using best combustor control and an oxidation catalyst are technically feasible combustion turbine control technologies available to control CO emissions. Accordingly, the project owner proposes to control CO emissions using both methods to meet a CO emission limit of 2.0 ppmvd (1-hour) with and without duct burners.

Applicable BACT clearinghouse determinations and the SCAQMD, EPA, BAAQMD, CARB, and SJVAPCD BACT determinations were reviewed to determine whether CO emission rates less than the proposed HBEP levels have been achieved in practice for other natural-gas-fired combustion turbine projects. A summary of the emission limits for projects identified in the database is presented in Table 2-3. As this table demonstrates, most projects have CO emission rates that are the same as or higher than the CO emission rate proposed for the HBEP. However, three projects have CO emission rates that are lower than the CO emission rate proposed for the HBEP. These projects are discussed below.

TABLE 2-3
Summary of CO Emission Limits for Combined-cycle Turbines
Emission Control Ranking for Turbines With and Without Duct Burner Firing

Facility	Facility ID Number	CO Emission Limit at 15 percent O_2
La Paz Generating Facility	AZ-0049	3.0 ppm (3-hour)
Rocky Mountain Energy Center	CO-0056	3.0 ppm
Welton Mohawk Generating Station	AZ-0047	3.0 ppm with duct burners (3-hour)
Copper Mountain Power	NV-0037	3.0 ppm with duct burners (3-hour)
Currant Creek	UT-0066	3.0 ppm (3-hour)
Lawrence Energy	OH-0248	2.0 ppm without duct burners; 10.0 ppm with duct burners
Berrien Energy, LLC	MI-0366	2.0 ppm without duct burners (3-hour); 4.0 ppm with duct burners (3-hour)
COB Energy Facility	OR-0039	2.0 ppm (4-hour)
Avenal Energy – Avenal Power Center, LLC	2008-AFC-1	2.0 ppm (3-hour)
Wallula Power Plant	WA-0291	2.0 ppm (3-hour)
Duke Energy Arlington Valley (AVEFII)	AZ-0043	2.0 ppm (3-hour)
Wanapa Energy Center	OR-0041	2.0 ppm (3-hour)
Vernon City Light and Power	CA-1096	2.0 ppm (3-hour)
Mariposa Energy Project	2009-AFC-3	2.0 ppm (3-hour)
Palmdale Hybrid Power Plant Project	08-AFC-9	2.0 ppm without duct burners (1-hour); 3.0 ppm with duct burners (1-hour)

TABLE 2-3
Summary of CO Emission Limits for Combined-cycle Turbines
Emission Control Ranking for Turbines With and Without Duct Burner Firing

Facility	Facility ID Number	CO Emission Limit at 15 percent O_2
Wansley Combined-cycle Energy Facility	GA-0102	2.0 ppm with duct burners
McIntosh Combined-cycle Facility	GA-0105	2.0 ppm with duct burners
Sumas Energy 2 Generation Facility	WA-0315	2.0 ppm (1-hour)
Oakley Generating Station	2009-AFC-4	2.0 ppm (1-hour)
Goldendale Energy	WA-302	2.0 ppm (1-hour)
IDC Bellingham	CA-1050	2.0 ppm (1-hour)
Russell City Energy Center	2001-AFC-7	2.0 ppm with duct burners (1-hour)
Watson Cogeneration Project	2009-AFC-1	2.0 ppm with duct burners (1-hour)
Magnolia Power Project	CA-1097	2.0 ppm with duct burners (1-hour)
CPV Warren	VA-0291	1.3 ppm without duct burners; 1.2 ppm with duct burners
Warren County Facility	VA-0308	1.3 ppm without duct burners
Kleen Energy Systems	CT-0151	0.9 ppm (1-hour)

Note: This table does not include all projects listed in the BACT databases. The purpose of this table is to present a summary of the most-stringent emission limits and to highlight any projects with an emission limit less than 2.0 ppm CO identified during the database search.

Source: EPA RACT/BACT/LAER Clearinghouse and the California Energy Commission (EPA, 2012 and CEC, 2012).

Competitive Power Ventures (CPV) Warren and Warren County Facilities. A new PSD permit application was submitted in April 2010 to the Virginia Department of Environmental Quality by Virginia Electric Power and Power Company (Dominion), and the final PSD permit was issued on December 21, 2010. The final PSD permit includes CO emission limits of 1.5 ppm and 2.4 ppm, on a 1-hour averaging basis for operating conditions without and with duct burner, respectively. Based on publically available information, Dominion expects commercial operation of the Warren facility to occur in late 2014 or early 2015. Therefore, this level of control has not been demonstrated in practice on a long-term basis with a short (1-hour) averaging period.

Kleen Energy Systems. The Kleen Energy Systems facility conducted the initial source tests in June 2011. Based on a November 2011 letter from the Connecticut Department of Energy & Environmental Protection, the facility was able to successfully demonstrate compliance with the CO emission limits of 0.9 and 1.5 ppmvd for unfired and fired operation, respectively. However, given the lack of long-term compliance with these lower emission limits, these CO emission levels are not considered achieved in practice at this time.

Conclusion. As shown in Table 2-3, the proposed CO emission rate of 2.0 ppmvd (1-hour) with and without duct burners for the HBEP is the lowest CO emission rate achieved in practice for other facilities using good combustion practices and an oxidation catalyst.

2.2.2.4 Evaluate Most Effective Controls and Document Results – Step 4

The proposed CO emission rate of 2.0 ppmvd (1-hour) with and without duct burners for the HBEP is the lowest CO emission rate achieved or verified with long-term compliance records for other similar facilities. Therefore, an assessment of the economic and environmental impacts is not necessary.

2.2.2.5 CO BACT Selection – Step 5

The BACT for CO emissions from the HBEP is good combustion design and the installation of an oxidation catalyst system to control CO emissions to 2.0 ppmvd (1-hour) with and without duct burners.

2.2.3 VOCs

The pollutants commonly classified as VOCs are discharged into the atmosphere when some of the fuel remains unburned or is only partially burned (incomplete combustion) during the combustion process

2.2.3.1 Identification of Combustion Turbine VOC Emissions Control Technologies – Step 1

Effective combustor design and post-combustion control using an oxidation catalyst are two technologies for controlling VOC emissions from a combustion turbine. The industrial combustion turbine proposed for HBEP is able to achieve relatively low, uncontrolled VOC emissions of approximately 3 ppmvd because the combustors have a firing temperature of approximately 2,500°F with an exhaust temperature of approximately 1,000°F. A DLN-equipped combustion turbine that incorporates an oxidation catalyst system can achieve VOC emissions in the 2 ppmvd range. As noted in the NOx BACT analysis, the EMx and XONON technologies were determined to not be feasible for HBEP.

Best Combustion Control. As previously discussed, VOCs are formed during the combustion process as a result of incomplete combustion of the carbon present in the fuel. The formation of VOC is limited by designing the combustion system to completely oxidize the fuel carbon to CO_2. This is achieved by ensuring that the combustor is designed to allow complete mixing of the combustion air and fuel at combustion temperatures with an excess of combustion air. Higher combustion temperatures tend to reduce the formation of VOC but increase the formation of NO_x. The application of water injection or staged combustion (DLN combustors) tends to lower combustion temperatures (to reduce NO_x formation), potentially increasing VOC formation. However, good combustor design and best operating practices will minimize the formation of VOC while reducing the combustion temperature and NO_x emissions.

Oxidation Catalyst. An oxidation catalyst is typically a precious metal catalyst bed located in the exhaust duct. The catalyst enhances oxidation of VOC to CO_2 without the addition of any reactant. Oxidation catalysts have been successfully installed on numerous simple- and combined-cycle combustion turbines.

2.2.3.2 Eliminate Technically Infeasible Options – Step 2

Good combustor design and the use of an oxidation catalyst are both technically feasible options for controlling VOC emissions from the proposed HBEP.

2.2.3.3 Combustion Turbine VOC Control Technology Ranking – Step 3

Based on the preceding discussion, using good combustor control and an oxidation catalyst are technically feasible combustion turbine control technologies available to control VOC emissions. Accordingly, the project owner proposes to control VOC emissions using both methods to meet a VOC emission limit of 1.0 ppmvd (1-hour) without duct burners and 1.0 ppmvd (3-hour) with duct burners.

Applicable BACT clearinghouse determinations and the SCAQMD, EPA, BAAQMD, CARB, and SJVAPCD BACT determinations were reviewed to determine whether VOC emission rates less than the proposed HBEP levels have been achieved in practice for other natural-gas-fired combustion turbine projects. A summary of the emission limits for projects identified in the database is presented in Table 2-4.

TABLE 2-4
Summary of VOC Emission Limits for Combined-cycle Turbines
Emission Control Ranking for Turbines With and Without Duct Burner Firing

Facility	Facility ID Number	VOC Emission Limit at 15 percent O_2
Florida Power and Light Martin Plant	FL-0244	1.3 ppm without duct burners; 4 ppm with duct burners
Duke Energy Arlington Valley (AVEFII)	AZ-0043	1 ppm without duct burners (3-hour); 4 ppm with duct burners (3-hour)
Fairbault Energy Park	MN-0071	1.5 ppm without duct burners; 3.0 ppm with duct burners
VA Power – Possum Point	VA-0255	1.2 ppm without duct burners; 2.3 ppm with duct burners

TABLE 2-4
Summary of VOC Emission Limits for Combined-cycle Turbines
Emission Control Ranking for Turbines With and Without Duct Burner Firing

Facility	Facility ID Number	VOC Emission Limit at 15 percent O_2
Los Esteros Critical Energy Facility – Phase 2c	2003-AFC-2	2.0 ppm with duct burners (3-hour)
GWF Tracy Combined-cycle Project	2008-AFC-7	1.5 ppm without duct burners (3-hour); 2.0 ppm with duct burners (3-hour)
Avenal Energy – Avenal Power Center, LLC	2008-AFC-1	1.4 ppm without duct burners; 2.0 ppm with duct burners (3-hour)
Watson Cogeneration Project	2009-AFC-1	2.0 ppm without duct burners (1-hour); 2.0 ppm with duct burners (1-hour)
Palmdale Hybrid Power Plant Project	SE 09-01	1.4 without duct burners (1-hour); 2.0 ppm with duct burners (1-hour)
Victorville Hybrid Gas-Solar	2007-AFC-1	1.4 ppm without duct burners; 2.0 ppm with duct burners
Colusa II Generation Station	2006-AFC-9	1.38 ppm without duct burners; 2.0 ppm with duct burners
FPL Turkey Point Power Plant	FL-0263	1.6 ppm without duct burners; 1.9 with duct burners
Plant McDonough Combined-cycle	GA-0127	1.0 ppm (1-hour) without; 1.8 ppm with duct burners (3-hour)
FPL West County Energy Center Unit 3	FL-0303	1.2 ppm with duct burners; 1.5 with duct burners
Gila Bend Power Generating Station	AZ-0038	1.4 ppm with duct burners
Liberty Generating Station	NJ-0043	1.0 ppm (no duct burners)
Empire Power Plant	NY-0100	1.0 ppm (no duct burners)
Fairbault Energy Park	MN-0053	1.0 ppm (3-hour) (no duct burners)
Oakley Generating Station	2009-AFC-4	1.0 ppm (1-hour) (no duct burners)
Sutter – Calpine	1997-AFC-02	1.0 ppm with duct burners (calendar day average)
Russell City Energy Center	2001-AFC-7	1.0 ppm with duct burners (1-hour)
CPV Warren	VA-0291	0.7 without duct burners; 1.6 with duct burners; (3-hour)
Warren County Facility	VA-0308	0.7 without duct burners; 1.0 with duct burners
Chouteau Power Plant	OK-0129	0.3 ppm (3-hour) with duct burners

Note: This table does not include all projects listed in the BACT databases. The purpose of this table is to present a summary of the most-stringent emission limits and to highlight any projects with an emission limit less than 1.0 ppm VOC identified during the database search.

Source: EPA RACT/BACT/LAER Clearinghouse and the CEC (EPA, 2012 and CEC, 2012).

As this table demonstrates, most projects have VOC emission rates that are the same as or higher than the VOC emission rate proposed for the HBEP. However, the following projects have VOC emission rates that are lower than the VOC emission rate proposed for the HBEP:

- Russell City Energy Center
- CPV Warren and Warren County facilities
- Chouteau Power Plant

Russell City Energy Center. The Russell City Energy Center (RCEC) has a VOC permit limit of 1.0 ppmvd at 15 percent O_2 with and without duct burners averaged over 1 hour. Although the 1.0 ppmvd limit averaged over a 1-hour period for the duct burners scenario is more restrictive than the proposed HBEP limit of 1.0 ppmvd at 15 percent O_2 averaged over a 3-hour period, construction of the RCEC has not been completed. Therefore, long-term demonstration of compliance with the proposed emission rate and averaging period has not been demonstrated in practice.

CPV Warren and Warren County Facilities. The Warren County Facility and CPV Warren are the same facility (Permit Number 81391). A new application submitted in April 2010 to the Virginia Department of Environmental Quality by Virginia Electric Power and Power Company (Dominion) will replace the listed determinations, and the final PSD permit was issued on December 21, 2010. The final PSD permit includes VOC emission limits of 0.7 ppm and 1.6 ppm on a 3-hour averaging basis for operating conditions without and with duct burner, respectively. Based on publically available information, Dominion expects commercial operation of the Warren facility to occur in late 2014 or early 2015. Therefore, this level of control has not been demonstrated in practice on a long-term basis.

Chouteau Power Plant. The Oklahoma Air Quality Division issued the Chouteau Power Plant a construction permit on January 20, 2009. The facility was built and is currently operational. The BACT analysis for the Chouteau Power Plant concluded that good combustion practices with an emission limit of 0.3 ppmvd at 15 percent O_2 for the Siemens-Westinghouse V84.3A model industrial frame combustion turbines was BACT (Fielder, 2009). However, the construction permit for the Chouteau Power Plant does not include a VOC concentration limit consistent with the BACT determination, but rather includes a mass emission limit of 5.27 pounds per hour with duct burners operating. The permit also includes the heat input for each turbine/HRSG of 1,882 million British thermal units per hour (MMBtu/hr). Using these values, the VOC emission rate in pound(s) per million British thermal unit (lb/MMBtu) is 0.028, whereas the HBEP maximum VOC emission rate is 0.0012 lb/MMBtu. Therefore, HBEP's VOC emission rate is lower than the Chouteau Power Plant permit value defined in units of lb/MMBtu.

Conclusion. As shown in Table 2-4, the proposed VOC emission rate of 1.0 ppmvd (1-hour) without duct burners and 1.0 ppmvd with duct burners (3-hour) for the HBEP is the lowest VOC emission rate demonstrated in practice or permitted for other facilities using good combustion practices and an oxidation catalyst.

2.2.3.4 Evaluate Most Effective Controls and Document Results – Step 4

The proposed VOC emission rate of 1.0 ppmvd (1-hour) without duct burners and 1.0 ppmvd with duct burners (3-hour) for the HBEP is the lowest VOC emission rate achieved or permitted for other similar facilities. Therefore, an assessment of the economic and environmental impacts is not necessary.

2.2.3.5 VOC BACT Selection – Step 5

The BACT for VOC emissions from the HBEP is good combustion design and the installation of an oxidation catalyst system to control VOC emissions to 1.0 ppmvd (1-hour) without duct burners and 1.0 ppmvd (3-hour) with duct burners.

2.2.4 PM_{10} and $PM_{2.5}$

PM from natural gas combustion has been estimated to be less than 1 micron in equivalent aerodynamic diameter, has filterable and condensable fractions, and is usually hydrocarbons of larger molecular weight that are not fully combusted (EPA, 2006). Because the particulate matter is less than 2.5 microns in diameter, the BACT control technology discussion assumes the control technologies for PM_{10} and $PM_{2.5}$ are the same.

2.2.4.1 Identification of Combustion Turbine PM_{10} and $PM_{2.5}$ Emissions Control Technologies – Step 1

Pre-combustion Particulate Control Technologies. The major sources of PM_{10} and $PM_{2.5}$ emissions from a natural-gas-fired gas turbine equipped with SCR for post-combustion control of NOx are: (1) the conversion of fuel sulfur to sulfates and ammonium sulfates; (2) unburned hydrocarbons that can lead to the formation of PM in the exhaust stack; and (3) PM in the ambient air entering the gas turbine through the inlet air filtration system, and the aqueous ammonia dilution air. Therefore, the use of clean-burning, low-sulfur fuels such as natural gas will result in minimal formation of PM_{10} and $PM_{2.5}$ during combustion. Best combustion practices will ensure proper air/fuel mixing ratios to achieve complete combustion, minimizing emissions of unburned hydrocarbons that can lead to formation of PM at the stack. In addition to good combustion, use of high-efficiency filtration on the inlet air and SCR dilution air system will minimize the entrainment of PM into the exhaust stream.

Post-combustion Particulate Control Technologies. Two post-combustion control technologies designed to reduce PM emissions from industrial sources are electrostatic precipitators and baghouses. However, neither of these control technologies is appropriate for use on natural-gas-fired turbines because of the very low levels and small aerodynamic diameter of PM from natural gas combustion.

2.2.4.2 Eliminate Technically Infeasible Options – Step 2

Electrostatic precipitators and baghouses are typically used on solid/liquid-fuel fired or other types of sources with high PM emission concentrations, and are not used in natural-gas-fired applications, which have inherently low PM emission concentrations. Therefore, electrostatic precipitators and baghouses are not considered technically feasible control technologies. However, best combustion practices, clean-burning fuels, and inlet air filtration are considered technically feasible for control of PM_{10} and $PM_{2.5}$ emissions from the HBEP.

2.2.4.3 Combustion Turbine PM_{10} and $PM_{2.5}$ Control Technology Ranking – Step 3

The use of best combustion practices, clean-burning fuels, and inlet air filtration are the technically feasible natural-gas-fired turbine control technologies proposed by the project owner to control PM_{10} and $PM_{2.5}$ emissions to 4.5 lb/hr without duct burners and 9.5 lb/hr with duct burners. Furthermore, because no add-on control devices are technically feasible to control PM emissions from natural-gas-fired turbines, there would be little an applicant could do beyond using best combustion practice and using clean-burning fuels and inlet air filtration to control particulate emissions (BAAQMD, 2011).

2.2.4.4 Evaluate Most Effective Controls and Document Results – Step 4

Based on the information presented in this BACT analysis, using proposed good combustion practice, pipeline-quality natural gas, and inlet air filtration to control $PM_{10}/PM_{2.5}$ emissions to 4.5 lb/hr without duct burners and 9.5 lb/hr with duct burners is consistent with BACT at other similar sources. Therefore, an assessment of the economic and environmental impacts is not necessary.

2.2.4.5 PM_{10} and $PM_{2.5}$ BACT Selection – Step 5

The BACT for $PM_{10}/PM_{2.5}$ emissions from the HBEP is using good combustion practice, pipeline-quality natural gas, and inlet air filtration to control $PM_{10}/PM_{2.5}$ emissions to 4.5 lb/hr without duct burners and 9.5 lb/hr with duct burners.

2.2.5 SO_2

Emissions of SO_x are entirely a function of the sulfur content in the fuel rather than any combustion variables. During the combustion process, essentially all the sulfur in the fuel is oxidized to SO_2.

2.2.5.1 Identification of Combustion Turbine SO_2 Emissions Control Technologies – Step 1

Two primary mechanisms are used to reduce SO_2 emissions from combustion sources: (1) reduce the amount of sulfur in the fuel, and (2) remove the sulfur from the combustion exhaust gases.

Limiting the amount of sulfur in the fuel is a common practice for natural-gas-fired turbines. For instance, natural-gas-fired turbines in California are typically required to combust only California Public Utilities Commission (CPUC) pipeline-quality natural gas with a sulfur content of less than 1 grain of sulfur per 100 scf. The HBEP would be supplied with natural gas from the Southern California Gas (SoCalGas) pipeline, which is limited by tariff Rule 30 to a maximum total fuel sulfur content of less than 0.75 grain of sulfur per 100 scf. Therefore, the use of pipeline-quality natural gas with low sulfur content is a BACT control technique for SO_2.

There are two principal types of post-combustion control technologies for SO_2—wet scrubbing and dry scrubbing. Wet scrubbers use an alkaline solution to remove the SO_2 from the exhaust gases. Dry scrubbers use an SO_2 sorbent injected as powder or slurry to remove the SO_2 from the exhaust stream. However, the SO_2

concentrations in the natural gas exhaust gases are too low for the scrubbing technologies to work effectively or to be technically feasible.

2.2.5.2 Eliminate Technically Infeasible Options – Step 2

Use of pipeline-quality natural gas with very low sulfur content is technically feasible for the HBEP. However, because sulfur emissions from natural-gas-fired turbines are extremely low when using pipeline-quality natural gas, the two post-combustion SO_2 controls for natural-gas fired turbines (wet and dry scrubbers) are not technically feasible.

2.2.5.3 Combustion Turbine SO_2 Control Technology Ranking – Step 3

Use of pipeline-quality natural gas with very low sulfur content is the only technically feasible SO_2 control technology for natural-gas-fired turbines, and it is the most effective SO_2 control technology used by all other natural-gas-fired turbines in California. Therefore, using pipeline-quality natural gas with a regulatory limit of 0.75 grain of sulfur per 100 scf of natural gas for the HBEP is BACT for SO_2.

2.2.5.4 Evaluate Most Effective Controls and Document Results – Step 4

Based on the information presented in this BACT analysis, the use of pipeline-quality natural gas with a maximum of 0.75 grain of sulfur per 100 scf of natural gas as a BACT control technique for SO_2 will achieve the lowest SO_2 emission rates achieved in practice at other similar sources. Therefore, an assessment of the economic and environmental impacts is not necessary.

2.2.5.5 SO_2 BACT Selection – Step 5

The BACT for SO_2 from the HBEP is use of pipeline-quality natural gas with a sulfur content of less than 0.75 grain of sulfur per 100 scf of natural gas.

2.2.6 BACT for Startups and Shutdowns

Startup and shutdown events are a normal part of the power plant operation, but they involve NO_x, CO, and VOC emissions rates that are highly variable and greater than emissions than during steady-state operation[3]. This is because emission control systems are not fully functional during these events. In the case of the DLN combustors, the turbines must achieve a minimum operating rate before these systems are functional. Likewise, the SCR and oxidation catalyst systems must be heated to a specific minimum temperature before the catalyst systems become effective. Furthermore, startup and shutdown emissions are dependent on a number of project specific factors; therefore, permitted startup and shutdown emission limits are highly variable. For these reasons, BACT for startup and shutdown will consider only the duration of these events.

2.2.6.1 Control Devices and Techniques to Limit Startup and Shutdown Emissions

The available approach to reducing startup and shutdown emissions from combustion turbines is to use best work practices. By following the plant equipment manufacturers' recommendations, power plant operators can limit the duration of each startup and shutdown event to the minimum duration achievable. Plant operators also use their own operational experience with their particular turbines and ancillary equipment to optimize startup and shutdown emissions. The proposed numerical emission limits for the startup and shutdowns are outlined below.

2.2.6.2 Determination of BACT Emissions Limit for Startups and Shutdowns

Startups. The combustion turbine vendor (MPSA) has determined a turbine startup period of 10 minutes from first fire to full load operation. This startup period does not include the warm-up time required by the SCR and oxidation catalyst systems, which is affected by the length of time the system has been inactive. The length of time is related to the temperature and pressure of the steam cycle. Three startup cases (hot, warm, and cold) were provided based on engineering estimates to reflect the different length of time between combustion turbine activity. A hot startup is defined as the turbine being inactive for up to 9 hours. A warm startup is defined as the

[3] Because $PM_{10/2.5}$ and SO_2 emissions are dependent on the amount of fuel combusted, $PM_{10/2.5}$ and SO_2 emissions during startup and shutdown would be less than full load operations since less fuel is consumed as compared to full load operations.

turbine being inactive for between 9 and 49 hours, and a cold startup is defined as the turbine being inactive for more than 49 hours. Table 2-5 presents the proposed startup emissions and durations proposed as BACT.

TABLE 2-5
Facility Startup Emission Rates Per Turbine

Startup	NO_x (lb/event)	CO (lb/event)	VOC (lb/event)	NO_x (lb/hr)	CO (lb/hr)	VOC (lb/hr)	Duration (minutes/event)
Cold	28.7	116	27.9	25.5	115.3	25.9	90
Warm	16.6	46.0	21.0	23.2	50.0	21.6	32.5
Hot	16.6	33.6	20.4	23.2	37.6	21.0	32.5

Shutdowns. The turbine vendor also supplied the emission estimates for a typical shutdown event occurring over 10 minutes, which was combined with engineering estimates to determine shutdown emissions. The shutdown process begins with the combustion turbine reducing load until the DLN system is no longer functional but the SCR and oxidation remain functional. Table 2-6 presents the shutdown emissions and duration proposed as BACT.

TABLE 2-6
Facility Shutdown Emission Rates Per Turbine

	NO_x (lb/event)	CO (lb/event)	VOC (lb/event)	NO_x (lb/hr)	CO (lb/hr)	VOC (lb/hr)	Duration (minutes/event)
Shutdown	9.0	45.3	31.0	17.8	50.7	31.8	10

2.2.6.3 Summary of the Proposed BACT for Startups and Shutdowns

The project owner proposes to limit individual startups and shutdown durations to an enforceable BACT permit limit of 32.5 minutes for a hot and warm startup, 90 minutes for a cold startup, and 10 minutes for a shutdown event.

GHG BACT

3.1 Introduction

This BACT evaluation was prepared to address GHG emissions from HBEP, and the evaluation follows EPA regulations and guidance for BACT analyses as well as the EPA's PSD and Title V Permitting Guidance for Greenhouse Gases (EPA, 2011b). GHG pollutants are emitted during the combustion process when fossil fuels are burned. One of the possible ways to reduce GHG emissions from fossil fuel combustion is to use inherently lower GHG-emitting fuels and to minimize the use of fuel, which in this case is achieved by using thermally efficient CTGs, well-designed HRSGs, and STGs to generate additional power from the heat of the CTG exhaust. In the HBEP process, the fossil fuel burned will be pipeline quality natural gas, which is the lowest GHG-emitting fossil fuel available. The HBEP gas turbines selected to meet the project's objectives have a high operating turndown rate while maintaining a high thermal efficiency.

3.1.1 Regulatory Overview

Based on a series of actions, including the 2007 Supreme Court decision, the 2009 EPA Endangerment Finding and Cause and Contribute Finding, and the 2010 Light-Duty Vehicle Rule, GHGs became subject to permitting under the Clean Air Act. In May 2010, EPA issued the GHG permitting rule officially known as the "Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule" (GHG Tailoring Rule), in which EPA defined six GHG pollutants (collectively combined and measured as CO_2e) as NSR-regulated pollutants and therefore subject to PSD permitting when new projects emitted those pollutants above certain threshold levels. Under the GHG Tailoring Rule, beginning July 1, 2011, new sources with a GHG PTE equal to or greater than 100,000 tpy of CO_2e will be considered a major source and will be required to undergo PSD permitting, including preparation of a BACT analysis for GHG emissions. Modifications to existing major sources (CO_2e PTE of 100,000 tpy or greater) that result in an increase of CO_2e greater than 75,000 tpy are similarly required to obtain a PSD permit, which includes a GHG BACT analysis. The project results in an emissions increase above the new source PSD thresholds for CO_2e. Therefore, the project is subject to the GHG Tailoring Rule, and is required to obtain a PSD permit for GHGs.

3.1.2 BACT Evaluation Overview

BACT requirements are intended to ensure that a proposed project will incorporate control systems that reflect the latest control technologies that have been demonstrated in practice for the type of facility under review. BACT is defined under the Clean Air Act (42 U.S.C. Section 7479[3]) as follows:

> *The term "best available control technology" means an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this chapter emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant. BACT is defined as the emission control means an emission limitation (including opacity limits) based on the maximum degree of reduction which is achievable for each pollutant, taking into account energy, environmental, and economic impacts, and other costs. ….*

EPA guidance specifies that a BACT analysis should be performed using a top-down approach in which all applicable control technologies are evaluated based on their effectiveness and are then ranked by decreasing level of control. If the most-effective control technology is not being selected for the project, the control technologies on the list are evaluated as to whether they are infeasible because of energy, environmental, and/or economic impacts. The most effective control technology in the ranked list that cannot be so eliminated is then defined as BACT for that pollutant and process. A further analysis must be conducted to establish the emission limit that is BACT, based on determining the lowest emission limit that is expected to be consistently achievable over the life of the plant, taking into account site-specific and project-specific requirements.

The steps required for a “top-down” BACT review are the following:

1. Identify available control technologies.
2. Eliminate technically infeasible options.
3. Rank remaining technologies.
4. Evaluate remaining technologies (in terms of economic, energy, and environmental impacts).
5. Select BACT (the most-effective control technology and lowest consistently achievable emission limit) that has not been eliminated for economic, energy, or environmental impact reasons.

For a facility subject to the GHG Tailoring Rule, the six covered GHG pollutants are:

- CO_2
- Nitrous oxide (N_2O)
- Methane (CH_4)
- Hydrofluorocarbons (HFC)
- Perfluorocarbons (PFC)
- Sulfur hexafluoride (SF_6)

Although the top-down BACT analysis is applied to GHGs, there are “unique” issues in the analysis for GHG that do not arise in BACT for criteria pollutants (EPA, 2011b). For example, EPA recognizes that the range of potentially available control options for BACT Step 1 is currently limited and emphasizes the importance of energy efficiency in BACT reviews. Specifically, EPA states that (EPA, 2011b):

> *The application of methods, systems, or techniques to increase energy efficiency is a key GHG-reducing opportunity that falls under the category of “lower-polluting processes/practices.” Use of inherently lower-emitting technologies, including energy efficiency measures, represents an opportunity for GHG reductions in these BACT reviews. In some cases, a more energy efficient process or project design maybe used effectively alone; whereas in other cases, an energy efficient measure may be used effectively in tandem with end-of-stack controls to achieve additional control of criteria pollutants.* (EPA, 2011b)

Based on this reasoning, EPA provides permitting authorities with the discretion to use energy-efficient measures as “the foundation for a BACT analysis for GHGs . . .” (EPA, 2011b).

3.2 GHG BACT Analysis

3.2.1 Assumptions

During the completion of the GHG BACT analysis, the following assumptions were made:

- The HBEP BACT analysis for criteria pollutants will result in the installation of a SCR system for NO_x emissions reduction and an oxidation catalyst for control of CO and VOCs for each turbine.
- During actual combustion turbine operation, the oxidation catalyst may result in minimal increases in CO_2 from the oxidation of any CO and CH_4 in the flue gas. However, the EPA Final Mandatory Reporting of Greenhouse Gases Rule (Mandatory Reporting Rule) (40 CFR 98) factors for estimating CO_2e emissions from natural gas combustion assume complete combustion of the fuel. While the oxidation catalyst has the potential of incrementally increasing CO_2 emissions, these emissions are already accounted for in the Mandatory Reporting Rule factors and included in the CO_2e totals.
- Similarly, the SCR catalyst may result in an increase in N_2O emissions. Although quantifying the increase is difficult, it is generally estimated to be very small or negligible. From the HBEP GHG emissions inventory, the estimated N_2O emissions only total 45.8 metric tons per year. Therefore, even if there were an

order-of-magnitude increase in N_2O as a result of the SCR, the impact to CO_2e emissions would be insignificant as compared to total estimated HBEP CO_2e emissions.

Use of the SCR and oxidation catalyst slightly decreases the project thermal efficiency due to backpressure on the turbines (these impacts are already included in the emission inventory) and, as noted above, may create a marginal but unquantifiable increase to N_2O emissions. Although elimination of the NO_x and CO/VOC controls could conceivably be considered as an option within the GHG BACT, the environmental benefits of the NO_x, CO, and VOC control are assumed to outweigh the marginal increase to GHG emissions. Therefore, even if carried forward through the GHG BACT analysis, they would be eliminated in Step 4 because of other environmental impacts. Therefore, omission of these controls within the BACT analysis was not considered.

3.2.2 BACT Determination

The top-down GHG BACT determination for the combustion turbines and HRSGs with duct burners is presented below. This BACT analysis is based on one power block consisting of three combustion turbines, three HRSGs, one steam turbine, and ancillary facilities.

The primary GHG of concern for HBEP is CO_2. This analysis primarily presents the GHG BACT analysis for CO_2 emissions because CH_4 and N_2O emissions are insignificant, at less than one percent of facility GHG CO_2e emissions. HBEP will emit insignificant quantities of SF_6, HFCs or PFCs pollutants, used in electrical switch gear and comfort cooling systems. Therefore, the primary sources of GHG emissions would be the natural-gas-fired combustion turbines with duct burners.

This determination follows EPA's top-down analysis method, as specified in EPA's GHG Permitting Guidance (EPA, 2011b). The following top-down analysis steps are listed in the EPA's *New Source Review Workshop Manual* (EPA, 1990):

- Step 1: Identify all control technologies
- Step 2: Eliminate technically infeasible options
- Step 3: Rank remaining control technologies by control effectiveness
- Step 4: Evaluate most effective controls and document results
- Step 5: Select BACT

Each of these steps, described in the following sections, was conducted for GHG emissions from the CTGs and HRSGs with duct burners. The following top-down BACT analysis has been prepared in accordance with the EPA's *New Source Review Workshop Manual* (EPA, 1990) and takes into account energy, environmental, economic, and other costs associated with each alternative technology.

The previous and current emission limits reported for combined-cycle and cogeneration turbines were based on a search of the various federal, state, and local BACT, RACT, and LAER databases. The search included the following databases:

- EPA BACT/LAER Clearinghouse (EPA, 2012)
  - Search included the CO_2 BACT/LAER determinations for combined-cycle and cogeneration, large combustion turbines (greater than 25 MW) with permit dates for the years 2001 through 2011.
- BACT Analyses for Recently Permitted Combined-cycle CEC Projects (CEC, 2012)
  - Review included the GHG BACT analysis for the RCEC, the Palmdale Hybrid Power Project, and the Watson Cogeneration Project.

3.2.2.1 Identification of Available GHG Emissions Control Technologies – Step 1

There are two basic alternatives for limiting the GHG emissions from the HBEP combined-cycle equipment:

- Carbon capture and storage (CCS)
- Thermal efficiency

The proposed HBEP design and operation will consist of two “3-by-1” combined-cycle generating power blocks, both including three natural-gas-fired Mitsubishi 501DA CTGs with fired HRSGs, and one STG. The project owner has determined that this configuration is the only alternative that meets all of the project objectives as further detailed in Section 1.2. Several of the primary objectives of the HBEP are to backstop variable renewable resources with a multiple stage generator project that incorporates fast start capability, a high degree of turndown, fast ramping capability, and a high thermal efficiency. Therefore, other potentially lower emitting renewable generation technologies were not evaluated in this BACT analysis because this would change the fundamental business purpose of the HBEP.

This is consistent with EPA’s March 2011 *PSD and Title V Permitting Guidance for Greenhouse Gases,* which states:

> *EPA has recognized that a Step 1 list of options need not necessarily include inherently lower polluting processes that would fundamentally redefine the nature of the source proposed by the permit applicant…”, and “…the permitting authority should keep in mind that BACT, in most cases, should not regulate the applicant’s purpose or objective for the proposed facility… (p. 26).*

The only identified GHG emission “control” options are post-combustion CCS and thermal efficiency of the proposed generation facility.

Carbon Capture and Storage. CCS technology is composed of three main components: (1) CO_2 capture and/or compression, (2) transport, and (3) storage.

CO_2 Capture and Compression. CCS systems involve use of adsorption or absorption processes to separate and capture CO_2 from the flue gas, with subsequent desorption to produce a concentrated CO_2 stream. The concentrated CO_2 is then compressed to “supercritical” temperature and pressure, a state in which CO_2 exists neither as a liquid nor a gas, but instead has physical properties of both liquids and gases. The supercritical CO_2 would then be transported to an appropriate location for underground injection into a suitable geological storage reservoir, such as a deep saline aquifer, or depleted coal seam, ocean storage site, or used in crude oil production for enhanced oil recovery.

The capture of CO_2 from gas streams can be accomplished using either physical or chemical solvents or solid sorbents. Applicability of different processes to particular applications will depend on temperature, pressure, CO_2 concentration, and contaminants in the gas or exhaust stream. Although CO_2 separation processes have been used for years in the oil and gas industries, the characteristics of the gas steams are markedly different than power plant exhaust. CO_2 separation from power plant exhaust has been demonstrated in large pilot-scale tests, but it has not been commercially implemented in full-scale power plant applications.

After separation, the CO_2 must be compressed to supercritical temperature and pressure for suitable pipeline transport and geologic storage properties. Although compressor systems for such applications are proven, commercially available technologies, specialized equipment is required, and operating energy requirements are very high.

CO_2 Transport. The supercritical CO_2 would then be transported to an appropriate location for injection into a suitable storage reservoir. The transport options may include pipeline or truck transport, or in the case of ocean storage, transport by ocean-going vessels.

Because of the extremely high pressures, as well as the unique thermodynamic and dense-phase fluid properties of supercritical CO_2, specialized designs are required for CO_2 pipelines. Control of potential propagation fractures and corrosion also require careful attention to contaminants such as oxygen, nitrogen, methane, water, and hydrogen sulfide.

While transport of CO_2 via pipeline is proven technology, doing so in urban areas will present additional concerns. Development of new rights–of-way in congested areas would require significant resources for planning and execution, and public concern about potential for leakage may present additional barriers.

CO_2 Storage. CO_2 storage methods include geologic sequestration, oceanic storage, and mineral carbonation. Oceanic storage has not been demonstrated in practice, as discussed below. Geologic sequestration is the process of injecting captured CO_2 into deep subsurface rock formations for long-term storage, which includes the use of a deep saline aquifer or depleted coal seams, as well as the use of compressed CO_2 to enhance oil recovery in crude oil production operations.

Under geologic sequestration, a suitable geological formation is identified close to the proposed project, and the captured CO_2 from the process is compressed and transported to the sequestration location. CO_2 is injected into that formation at a high pressure and to depths generally greater than 2,625 feet (800 meters). Below this depth, the pressurized CO_2 remains “supercritical” and behaves like a liquid. Supercritical CO_2 is denser and takes up less space than gaseous CO_2. Once injected, the CO_2 occupies pore spaces in the surrounding rock, like water in a sponge. Saline water that already resides in the pore space would be displaced by the denser CO_2. Over time, the CO_2 can dissolve in residual water, and chemical reactions between the dissolved CO_2 and rock can create solid carbonate minerals, more permanently trapping the CO_2.

The U.S. Department of Energy (DOE) National Energy Technology Laboratory (NETL), via the West Coast Regional Carbon Sequestration Partnership (WestCarb) has researched potential geologic storage locations including those in Southern California. This information has been presented in NETL’s 2010 *Carbon Sequestration Atlas of the United States and Canada* (http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlasIII/index.html), NETL’s National Carbon Sequestration Database and Geographic Information System (NATCARB) database (http://www.netl.doe.gov/technologies/carbon_seq/natcarb/storage.html) and Southern California Carbon Sequestration Research Consortium’s (SoCalCarb) Carbon Atlas (http://socalcarb.org/atlas.html). As shown in Figures 1 and 2, a number of deep saline aquifers and oil and gas reservoirs have been found to be potentially suitable for CO_2 storage. No potential for storage in depleted coal seams or basalt formations was identified.

The *Carbon Sequestration Atlas* lists the deep saline formations in Ventura and Los Angeles Basins as the “most promising” locations in Southern California, and it states that “California may also be a candidate for CO_2 storage in offshore basins, although the lack of available data has limited the assessment of their CO_2 storage potential to areas where oil and gas exploration has occurred.” The atlas also notes the potential for use of oil and gas reservoirs in the Los Angeles and Ventura Basins, although it states that “Reservoirs in highly fractured shales within the Santa Maria and Ventura Basins are not good candidates for CO_2 storage.”

Funded via the American Recovery and Reinvestment Act, the Wilmington Graben project is an ongoing, comprehensive research program for characterization of the potential for CO_2 storage in the Pliocene and Miocene sediments offshore from Los Angeles and Long Beach. The study includes analysis of existing and new well cores, seismic studies, engineering analysis of potential pipeline systems, and risk analyses. However, no pilot studies of CO_2 injection into onshore or offshore geologic formations in the vicinity of the project site have been conducted to date.

Thermal Efficiency. Because CO_2 emissions are directly related to the quantity of fuel burned, the less fuel burned per amount of energy produced (greater energy efficiency), the lower the GHG emissions per unit of energy produced. As a means of quantifying feasible energy efficiency levels, the State of California established an emissions performance standard for California power plants. California Senate Bill 1368 limits long-term investments in baseload generation by the state’s utilities to power plants that meet an emissions performance standard jointly established by the CEC and the CPUC. CEC regulations establish a standard for baseload generation (that is, with capacity factors in excess of 60 percent) of 1,100 pounds (or 0.55 ton) CO_2 per megawatt-hour (MWh). This emission standard corresponds to a heat rate of approximately 9,400 British thermal units per kilowatt-hour (Btu/kWh) (CEC, 2010).

The HBEP is a highly efficient multiple-staged generator project that incorporates a high degree of turndown, fast start, and ramping capability that will support grid reliability as renewable generating sources comprise a larger share of California’s energy production. This allows an increased use of wind power and other renewable energy sources, with backup power available from the HBEP. A natural-gas-fired plant such as the HBEP uses a relatively small amount of electricity to operate the facility compared to the energy in the fossil fuel combusted. Therefore, minimal benefit occurs in terms of energy efficiency and GHG emission reductions of the facility associated with lowering electricity usage at the facility compared to increasing the thermal efficiency of the process.

The addition of the high thermal efficiency of the HBEP's generation to the state's electricity system will facilitate the integration of renewable resources in California's generation supply and will displace other less-efficient, higher GHG-emitting generation.

California's Renewable Portfolio Standard (RPS) requirement was increased from 20 percent by 2010 to 33 percent by 2020, with the adoption of Senate Bill 2 on April 12, 2011. To meet the new RPS requirements, the amount of dispatchable, high-efficiency, natural gas generation used as regulation resources, fast-ramping resources, or load-following or supplemental energy dispatches will have to be significantly increased. The HBEP will aid in the effort to meet California's RPS standard, because a significant attribute of the HBEP is that the combined-cycle facility can operate similarly to a peaking plant but at higher thermal efficiency.

Based on proprietary design and operational adjustments, the HBEP will allow a rapid startup of the combustion turbines. As presented in Figure 3, all combustion turbines in a power block can be started and taken from ignition to full load (~350 MW) in a 10-minute period. The HBEP HRSG operation will be integrated into the startup sequence, and full steam turbine generator output can be expected in approximately 40 minutes after fuel ignition for a hot or warm startup scenario. At maximum firing rate, the maximum power island ramp rate is 110 MW/minute for increasing in load and 250 MW/minute for decreasing load. At other load points, the load ramp rate is 30 percent.

The HBEP Mitsubishi 501DA combustion turbines allow for a unique operating configuration when integrated with the HRSG and duct burner operation. Over the anticipated projected load dispatch range presented in Figure 4, the HBEP 3-by-1 configuration maintains an efficient heat rate over almost the entire load range. Operation within this high efficiency band is maintained through operational changes by the combustion turbine, HRSG/steam turbine, and duct burners. These operational adjustments allow efficient operation over most of the project operating range. In traditional combined-cycle facilities, the duct burners are used in a peaking or power augmentation capacity. However, the HBEP closes the MW production gap between starting the second and third combustion turbines of a power block through the use of the duct burners, which tend to decrease thermal efficiency of the system but make available more MW in less time and at a lower heat rate as compared to a peaking facility.

In summary, using the Mitsubishi 501DA turbines with the flexible operational integration scheme allows the project goals to be met, while maintaining a higher efficiency than comparable peaking combustion turbine applications. The ability to produce fast-ramping power to augment renewable power sources to the grid make the HBEP a highly energy-efficient system.

3.2.2.2 Eliminate Technically Infeasible Options – Step 2

The second step for the BACT analysis is to eliminate technically infeasible options from the control technologies identified in Step 1. For each option that was identified, a technology evaluation was conducted to assess its technical feasibility. The technology is feasible only when it is available and applicable. A technology that is not commercially available for the scale of the project was considered infeasible. An available technology is considered applicable only if it can be reasonably installed and operated on the proposed project.

Carbon Capture and Storage. Although many believe that CCS will allow the future use of fossil fuels while minimizing GHG emissions, there are a number of technical barriers concerning the use of this technology for the HBEP, as follows:

- No full-scale systems for solvent-based carbon capture are currently in operation to capture CO_2 from dilute exhaust steams such as those from natural-gas-fired electrical generation systems at the scale proposed for the HEBP.
- Use of captured CO_2 for enhanced oil recovery (EOR) is widely believed to represent the practical first opportunity for CCS deployment; however, identification of suitable oil reservoirs with the necessary willing and able owners and operators is not feasible for HBEP to undertake. Oil and gas production in the vicinity of HBEP is available for EOR; however, only pilot-scale projects are known in the region and only estimates are available on the capacity of these miscible oil fields.

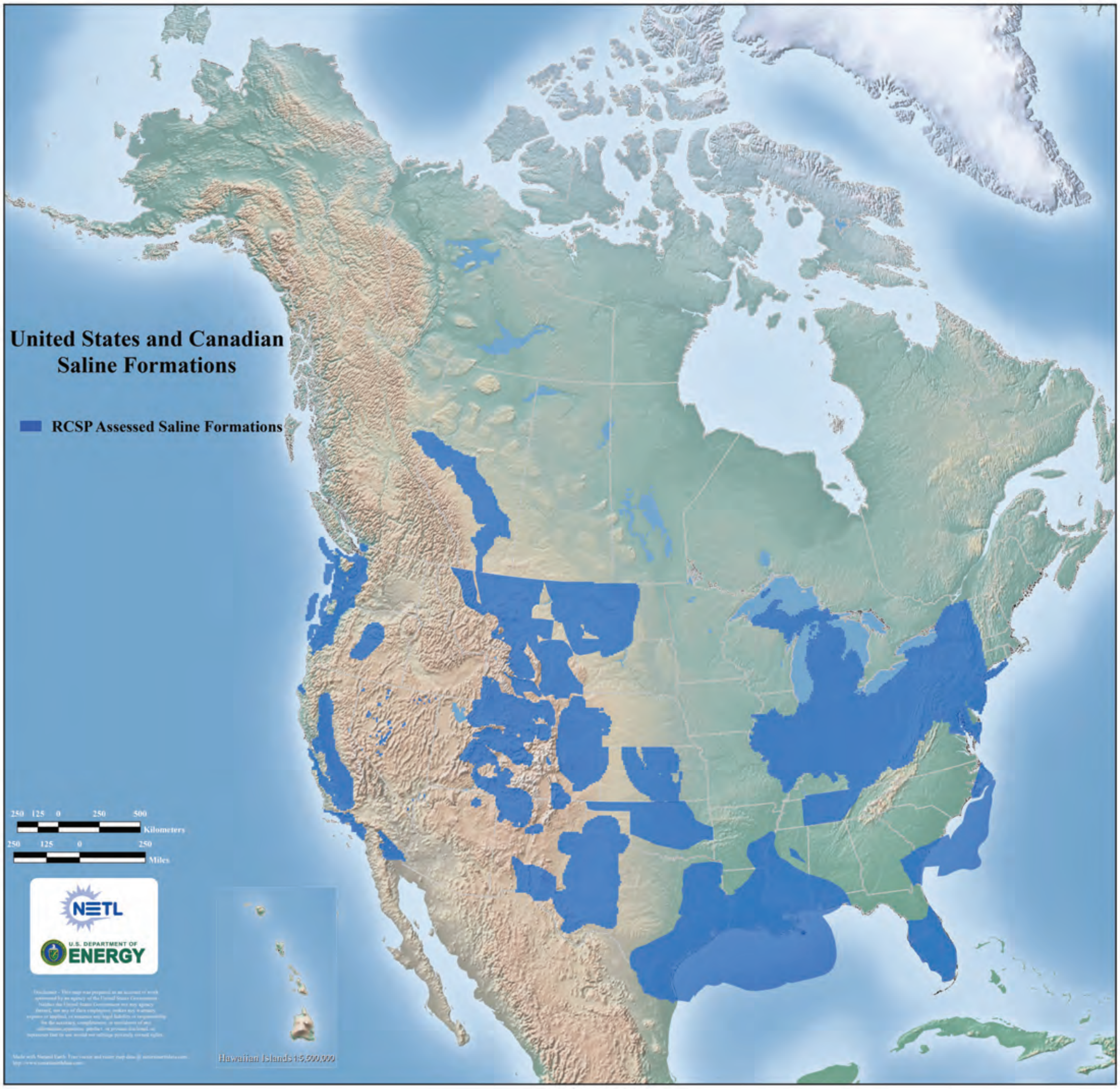


FIGURE 1
United States and Canadian Saline Formations
AES Huntington Beach Energy Project
Huntington Beach, California

CH2MHILL.

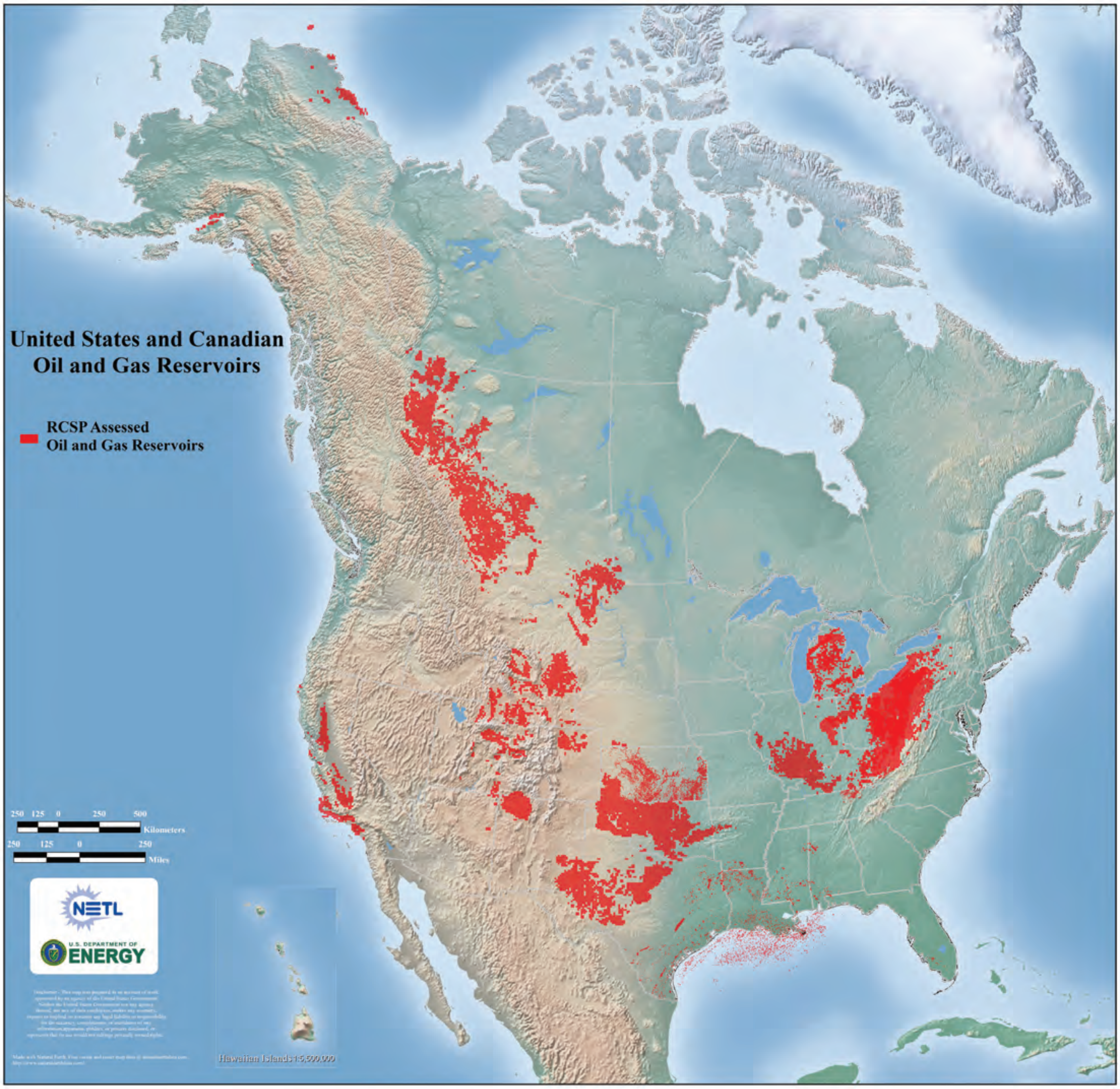
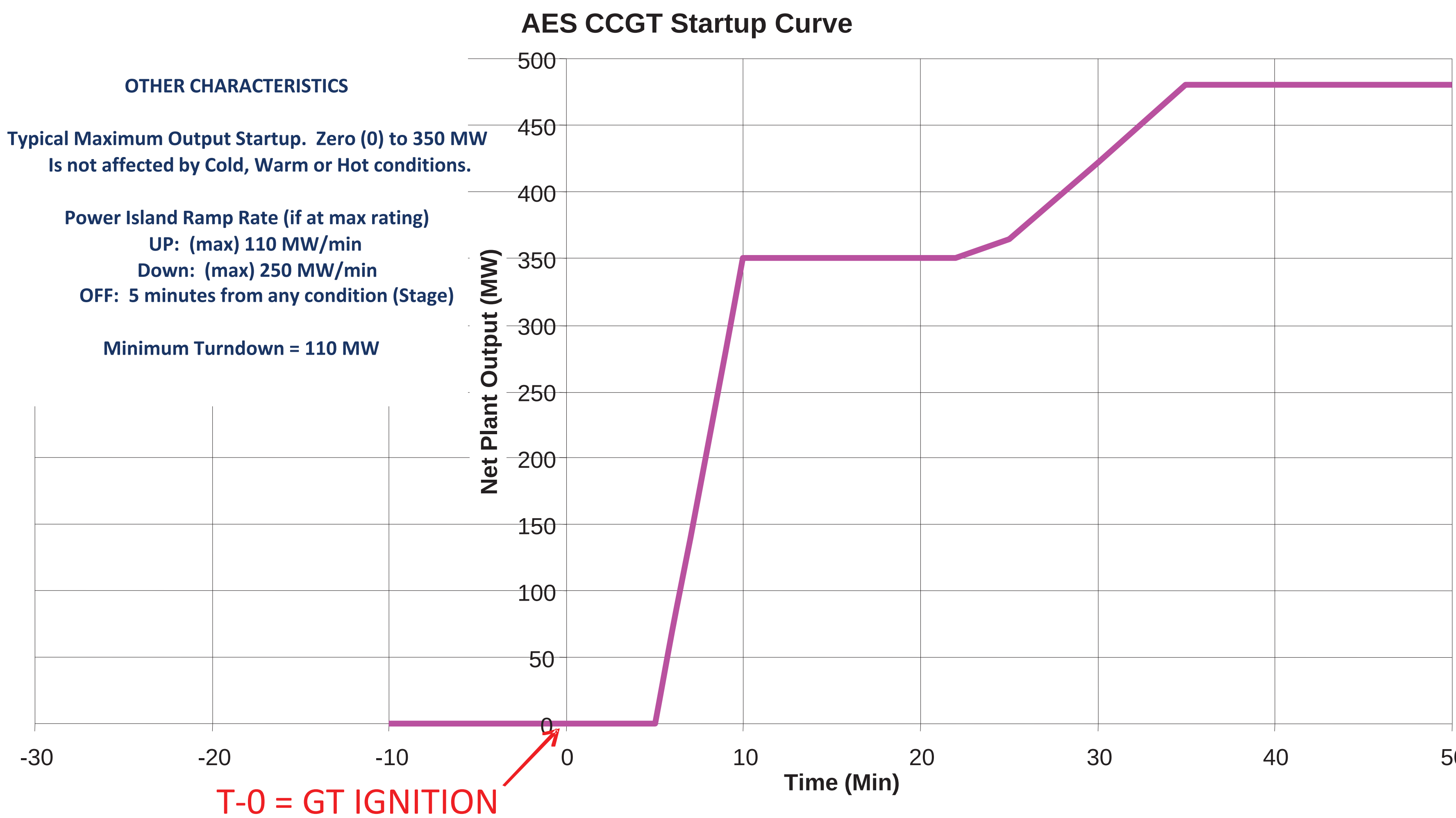


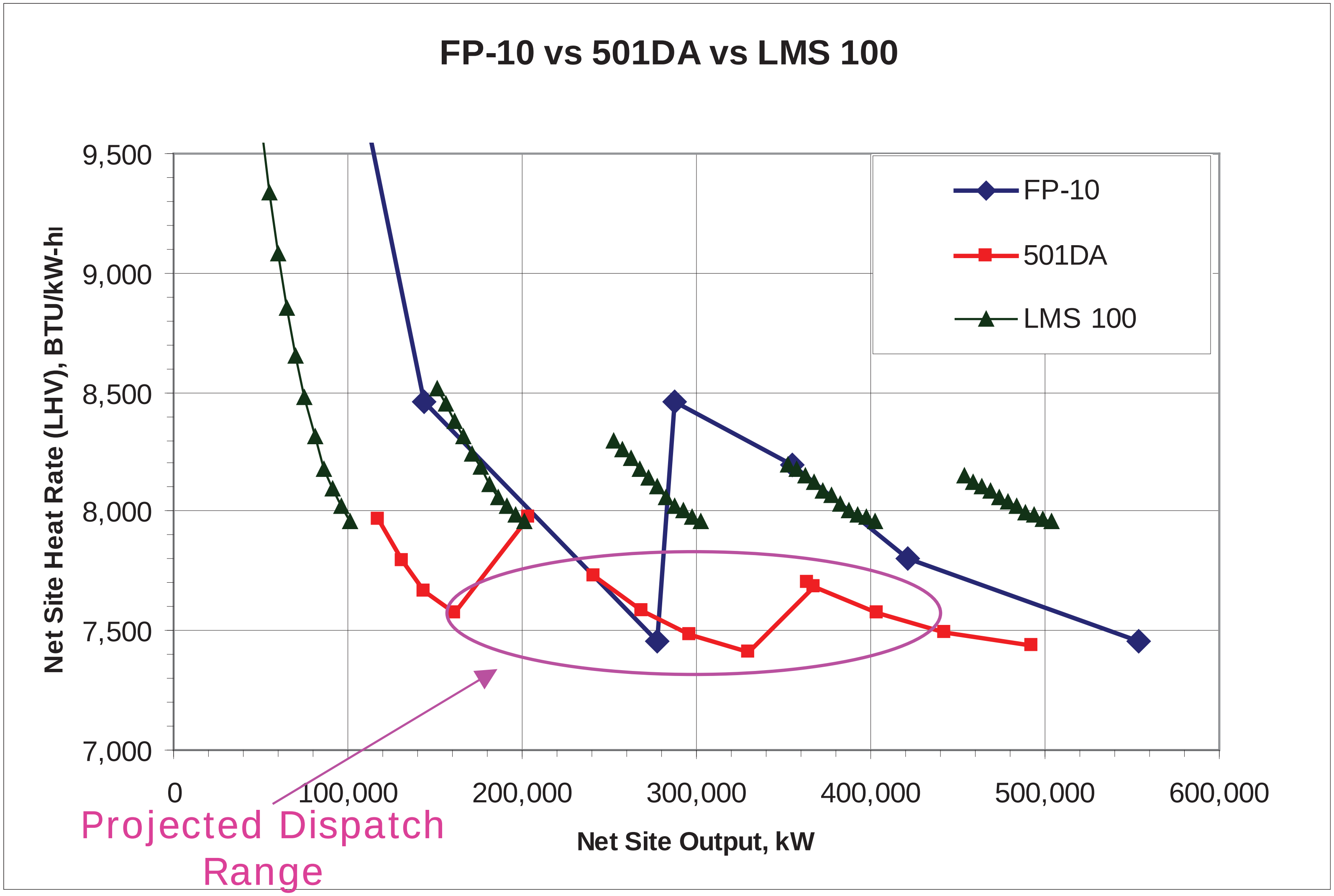
FIGURE 2
United States and Canadian Oil and Gas Reservoirs
AES Huntington Beach Energy Project
Huntington Beach, California

CH2MHILL.



Source: AES Southland Development, LLC, as presented to the South Coast Air Quality Management District on April 19, 2012

FIGURE 3
HBEP Startup Curve
AES Huntington Beach Energy Project
Huntington Beach, California



Source: AES Southland Development, LLC, as presented to the South Coast Air Quality Management District on April 19, 2012

FIGURE 4
Comparison of HBEP and Alternative Design Heat Rates
AES Huntington Beach Energy Project
Huntington Beach, California

- Little experience exists with other types of storage systems, such as deep saline aquifers (geological sequestration) or ocean systems (ocean sequestration). These storage systems are not commercially available technology.
- Because of the developmental nature of CCS technology, vendors and contractors do not provide turnkey offerings; separate contracting would be required for capture system design and construction; compression and pipeline system routing, siting and licensing, engineering and construction; and geologic storage system design, deployment, operations, and monitoring. Because no individual facility could be expected to take on all of these requirements to implement a control technology, this demonstrates that the technology as a whole is not yet commercially available.
- Significant legal uncertainties continue to exist regarding relationship between land surface ownership rights and subsurface (pore space) ownership, and potential conflicts with other uses of land such as exploitation of mineral rights, management of risks and liabilities, and so on.
- The potential for frequent startup and shutdown, as well as intended rapid load fluctuations, of generation units at the HBEP facility makes CCS impractical for two reasons – inability of capture systems to start up in the same short time frame as combustion turbines, and infeasibility for potential users of the CO_2 such as EOR systems to use uncertain and intermittent flows. As described above, the units at the HBEP facility are designed to accommodate rapidly fluctuating power and steam demands from renewable electrical generation sources.

These issues are discussed in more detail below.

As suggested in the *EPA New Source Review Workshop Manual*, control technologies should be demonstrated in practice on full-scale operations to be considered available within a BACT analysis: "Technologies which have not yet been applied to (or permitted for) full scale operations need not be considered available; an applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice" (EPA, 1990). As discussed in more detail below, carbon capture technology has not been demonstrated in practice in power plant applications. Other process industries do have carbon capture systems that are demonstrated in practice; however, the technology used for these processes cannot be applied to power plants at the scale of HBEP.

Three fundamental types of carbon capture systems are employed throughout various process and energy industries: sorbent adsorption, physical absorption, and chemical absorption. Use of carbon capture systems on power plant exhaust is inherently different from other commercial-scale systems currently in operation, mainly because of the concentration of CO_2 and other constituents in the gas streams.

For example, CO_2 is separated from petroleum in refinery hydrogen plants in a number of locations, but this is typically accomplished on the product gas from a steam CH_4reforming process that contains primarily hydrogen (H_2), unreacted CH_4, and CO_2. Based on the stoichiometry of the reforming process, the CO_2 concentration is approximately 80 percent by weight, and the gas pressure is approximately 350 pounds of force per square inch gauge (psig). Because of the high concentration and high pressure, a pressure swing adsorption (PSA) process is used for the separation. In the PSA process, all non-hydrogen components, including CO_2 and CH_4, are adsorbed onto the solid media under high pressure; after the sorbent becomes saturated, the pressure is reduced to near atmospheric conditions to desorb these components. The CO_2/CH_4 mixture in the PSA tail gas is then typically recycled to the reformer process boilers to recover the heating value; however, where the CO_2 is to be sold, an additional amine absorption process would be required to separate the CO_2 from CH_4. In its May 2011 *Department of Energy's (DOE)/NETL Advanced Carbon Dioxide Capture R&D Program: Technology Update*, NETL notes the different applications for chemical solvent absorption, physical solvent absorption, and sorbent adsorption processes. As noted in Section 4.B, "When the fluid component has a high concentration in the feed stream (for example, 10 percent or more), a PSA mechanism is more appropriate" (NETL, 2011).

In another example, at the Dakota Gasification Company's Great Plains Synfuels Plant in North Dakota, CO_2 is separated from intermediate fuel streams produced from gasification of coal. The gas from which the CO_2 is separated is a mixture of primarily H_2, CH_4, and 30 to 35 percent CO_2; a physical absorption process (Rectisol) is used. In contrast, as noted on page 29 of the *Report of the Interagency Task Force on Carbon Capture and Storage* (DOE and EPA, 2010), CO_2 concentrations for natural-gas-fired systems are in the range of 3 to 5 percent. This adds significant technical challenges to separation of CO_2 from natural-gas-fired power plant exhaust as compared to other systems.

In Section 4.A of the above-referenced technology update, NETL notes this difference between pre-combustion CO_2 capture such as that from the North Dakota plant versus the post-combustion capture such as that required from a natural-gas-fired power plant: “Physical solvents are well suited for pre-combustion capture of CO_2 from syngas at elevated pressures; whereas, chemical solvents are more attractive for CO_2 capture from dilute low-pressure post-combustion flue gas” (NETL, 2011).

In the 2010 report noted above, the task force discusses four currently operating post-combustion CO_2 capture systems associated with power production. All four are on coal-based power plants where CO_2 concentrations are higher (typically 12 to 15 percent), with none noted for natural gas-based power plants (typically 3 to 5 percent).

The DOE/NETL is a key player in the nation’s efforts to realize commercial deployment of CCS technology. A downloadable database of worldwide CCS projects is available on the NETL website (http://www.netl.doe.gov/technologies/carbon_seq/global/database/index.html). Filtering this database for projects that involve both capture and storage, which are based on post-combustion capture technology (the only technology applicable to natural gas turbine systems) and are shown as “active” with “injection ongoing” or “plant in operation,” yields four projects. Three projects, one of which is a pilot-scale process noted in the interagency task force report as described above, are listed at a capacity of 274 tons per day (100,000 tpy), and the fourth has a capacity of only 50 tons per day. Post-combustion CCS has not been accomplished on a scale of the HEBP facility, which could produce up to approximately 3.2 million tpy or 8,662 tons per day CO_2e. Furthermore, scale-up involving a substantial increase in size from pilot scale to commercial scale is unusual in chemical processes and would represent significant technical risk.

A chemical solvent CCS approach would be required to capture the approximate 3 to 5 percent CO_2 emitted from the flue gas generated from the natural-gas-fired systems (combined-cycle) used at the HEPB facility. To date, a chemical solvent technology has not been demonstrated at the operating scale proposed.

As detailed in the August 2010 report, one goal of the task force is to bring 5 to 10 commercial demonstration projects online by 2016. With demonstration projects still years away, clearly the technology is not currently commercially available at the scale necessary to operate the HEBP facility. It is notable that several projects, including those with DOE funding or loan guarantees, were cancelled in 2011, making it further unlikely that technical information required to scale up these processes can be accomplished in the near future. For example, the AEP Mountaineer site (AEP; a former DOE demonstration commercial-scale project) was to expand capture capacity to 100,000 tpy; however, to date only the “Project Validation Facility” was completed and only accomplished capture of a total of 50,000 metric tons and storage of 37,000 metric tons of CO_2. AEP recently announced that the larger project will be cancelled after completion of the front-end engineering design because of uncertain economic and policy conditions.

EPA’s Fact Sheet and Ambient Air Quality Impact Report for the Palmdale project states that “commercial CO_2 recovery plants have been in existence since the late 1970s, with at least one plant capturing CO_2 from gas turbines”. However, on review of the fact sheet referenced for the gas turbine project (http://www.powermag.com/coal/2064.html), it is notable that the referenced project is not a commercial-scale operation; rather, it is a pilot study at a commercial power plant. The pilot system captured 365 tons per day of CO_2 from the power plant, in the range of the power pilot tests noted above. Full-scale capture of power plant CO_2 has not yet been accomplished anywhere in the world.

The interagency task force report notes the lack of demonstration in practice:

> *Current technologies could be used to capture CO_2 from new and existing fossil energy power plants; however, they are not ready for widespread implementation primarily because they have not been demonstrated at the scale necessary to establish confidence for power plant application.*

Since the CO_2 capture capacities used in current industrial processes are generally much smaller than the capacity required for the purposes of GHG emissions mitigation at a typical power plant, there is considerable uncertainty associated with capacities at volumes necessary for commercial deployment. (DOE and EPA, 2010)

The ability to inject into deep saline aquifers as an alternative to EOR reservoirs is a major focus of the NETL research program. Although it is believed that saline aquifers are a viable opportunity, there are many uncertainties. Risk of mobilization of natural elements such as manganese, cobalt, nickel, iron, uranium, and barium into potable aquifers is of concern. Technical considerations for site selection include geologic siting, monitoring and verification programs, post-injection site care, long-term stewardship, property rights, and other issues.

At least one planned saline aquifer pilot project is underway in the Lower San Joaquin Valley near Bakersfield, California (the Kimberlina Saline Formation), that may act as a possible candidate location for geologic sequestration and storage. According to WestCarb, a pilot project plant operated by Clean Energy Systems is targeting the Vedder Sandstone formation at a depth of approximately 8,000 feet, where there is a beaded stream unit of saline formation that may be favorable for CO_2 storage. It is unclear when the project is planned for full scale testing, and no plans are currently available to build a pipeline within the area to transport CO_2 to the test site. As noted above, the Wilmington Graben project is a large-scale study of the potential for geologic storage in offshore formations near Los Angeles; however, no indications of near-term plans for pilot testing were noted in NETL or SoCalCarb's websites.

As noted above, presumably the CO_2 could be used for EOR applications within the Los Angeles and Ventura Basins, but the exact location, time frame, and needed flow rates for those existing or future EORs are unclear because this information is typically treated as being a trade secret. During a study to evaluate the "future oil recovery potential in the major oil basins and large oil fields in California," the DOE concluded that a number of oil fields in the Los Angeles Basin are "amendable to miscible CO_2-EOR." Two of those oil fields, the Santa Fe Springs and Dominquez fields, are located approximately 30 miles from the HEBP facility. However, the feasibility of obtaining the necessary permits to build infrastructure and a pipeline to transport CO_2 to these fields through a densely urbanized area is uncertain.

Figure 5 from the Interagency Task Force report shows that no existing CO_2 pipelines are shown in California. The report does note that nationally there are "many smaller pipelines connecting sources with specific customers"; however, based on lack of natural or captured CO_2 sources in Southern California, it is assumed that no pipelines exist. The SoCalCarb carbon atlas shows a number of existing pipelines in the region; however, these are petroleum product pipelines. As noted above, because of high pressures, potential for propagation facture, and other issues, CO_2 pipeline design is highly specialized, and product pipelines would not be suitable for re-use of CO_2 transport.

Regarding CO_2 storage security, the CCS task force report (DOE and EPA, 2010) notes such uncertainties:

"The technical community believes that many aspects of the science related to geologic storage security are relatively well understood. For example, the Intergovernmental Panel on Climate Change (IPCC) concluded that "it is considered likely that 99 percent or more of the injected CO_2 will be retained for 1,000 years" (IPCC, 2005). However, additional information (including data from large-scale field projects, such as the Kimberlina project, with comprehensive monitoring) is needed to confirm predictions of the behavior of natural systems in response to introduced CO_2 and to quantify rates for long-term processes that contribute to trapping and, therefore, risk profiles (IPCC, 2005). "

Field data from the Kimberlina CCS pilot project will provide additional information regarding storage security for that and other locations. Meanwhile, some uncertainties will remain regarding safety and permanence aspects of storage in these types of formations.

The effectiveness of ocean sequestration as a full-scale method for CO_2 capture and storage is unclear given the limited availability of injection pilot tests and the ecological impacts to shallow and deep ocean ecosystems. Ocean sequestration is conducted by injecting supercritical liquid CO_2 from either a stationary or towed pipeline at targeted depth interval, typically below 3,000 feet. CO_2 is injected below the thermocline, creating either a rising droplet or a dense phase plume and sinking bottom gravity current. Through NETL, extensive research is being conducted by the Monterey Bay Aquarium Research Institute on the behavior of CO_2 hydrates and dispersion of these hydrates within the various depth horizons of the marine environment; however, the experiments are small in scale and the results may not be applicable to larger-scale injection projects in the near future. Long-term effects on the marine environment, including pH excursions, are ongoing, making the use of ocean sequestration technically infeasible at the current time. The feasibility of implementing a commercially available sequestration approach is further brought into question, with the IPCC stating:

> *Ocean storage, however, is in the research phase and will not retain CO_2 permanently as the CO_2 will re-equilibrate with the atmosphere over the course of several centuries…Before the option of ocean injection can be deployed, significant research is needed into its potential biological impacts to clarify the nature and scope of environmental consequences, especially in the longer term…Clarification of the nature and scope of long-term environmental consequences of ocean storage requires further research.* (IPCC, 2005).

Questions may also arise regarding the international legal implications of injecting industrial generated CO_2 into the ocean, which may eventually migrate to other international waters.

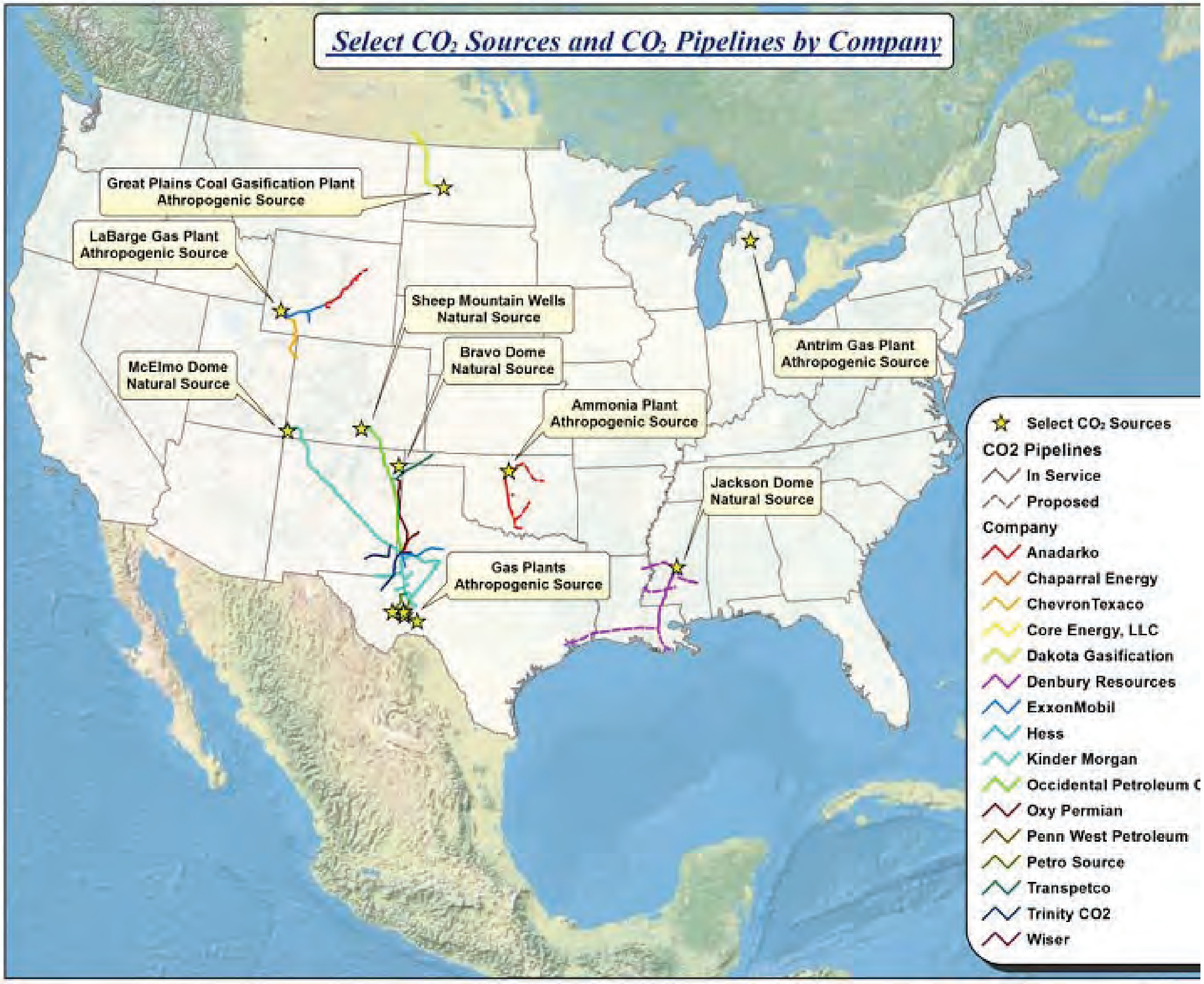
CCS technology development is dominated by vendors that are attempting to commercialize carbon capture technologies and by academia-led teams (largely funded by DOE) that are leading research into the geologic systems. The ability for electric utilities to contract for turn-key CCS systems simply does not exist at this time.

Most current carbon capture systems are based on amine or chilled ammonia technology, which are chemical absorption processes. Although capture system startup and shutdown time of vendor processes could not be confirmed within this BACT analysis, clearly both types of processes would require durations that exceed the time required for HBEP turbine startup or load response. As described above, HEBP may start or stop turbines and duct burners, and it may adjust the load on the operating turbines rapidly to meet grid reliability demands. In contrast, both amine and chilled ammonia systems require startup of countercurrent liquid-gas absorption towers and either chilling of the ammonia solution or heating of regeneration columns for the amine systems. It is technically infeasible for the carbon capture systems to start up and shut down or to make large adjustments in gas volume in the time frames required to serve this type of operation effectively; this means that portions of the HBEP operation would run without CO_2 capture even with implementation of a CCS system. Alternatively, the CCS system could be operated at a minimum load during periods of expected operation. However, this approach would consume energy, offsetting some of the benefit.

Finally, the potential to sell CO_2 to industrial or oil and gas operations is infeasible for an operation such as this, where daily operation of HBEP depends on grid dispatch needs, particularly to offset reductions from renewable energy sources. Even if a potential EOR opportunity could be identified, such an operation would typically need a steady supply of CO_2. Intermittent CO_2 supply from potentially short duration with uncertain daily operation would be virtually impossible to sell on the market, making the EOR option unviable. Therefore, CCS technology would be better suited for applications with low variability in operating conditions.

In the EPA PSD and Title V GHG permitting guidance, the issues noted above are summarized: "A number of ongoing research, development, and demonstration projects may make CCS technologies more widely applicable *in the future*" (EPA, 2011b; italics added). From page 36 of this guidance, it is noted:

> *While CCS is a promising technology, EPA does not believe that at this time CCS will be a technically feasible BACT option in certain cases. As noted above, to establish that an option is technically infeasible, the permitting record should show that an available control option has neither been demonstrated in practice nor is available and applicable to the source type under review. EPA recognizes the significant logistical hurdles that the installation and operation of a CCS system presents and that sets it apart from other add-on controls that are typically used to reduce emissions of other regulated pollutants and already have an existing reasonably accessible infrastructure in place to address waste disposal and other offsite needs. Logistical hurdles for CCS may include obtaining contracts for offsite land acquisition (including the availability of land), the*



Source: Figure B-1 from the "Report of the Interagency Task Force on Carbon Capture and Storage", August 2010.

FIGURE 5
Existing and Planned CO2 Pipelines in the United States with Sources
AES Huntington Beach Energy Project
Huntington Beach, California

> *need for funding (including, for example, government subsidies), timing of available transportation infrastructure, and developing a site for secure long-term storage. Not every source has the resources to overcome the offsite logistical barriers necessary to apply CCS technology to its operations, and smaller sources will likely be more constrained in this regard.* (EPA, 2011b)

The CCS alternative is not considered technically feasible for the HEBP, and it should therefore be eliminated from further consideration in Step 2. However, at the suggestion of EPA team members on other recent projects, economic feasibility issues will be discussed in Step 4.

Thermal Efficiency. Thermal efficiency is a standard measurement metric for combined-cycle facilities; therefore, it is technically feasible as a control technology for BACT consideration.

3.2.2.3 Combustion Turbine GHG Control Technology Ranking – Step 3

Because CCS is not technically feasible, the only remaining technically feasible GHG control technology for the HEBP is thermal efficiency. While CCS will be discussed further in Step 4, and if it were technically feasible would rank higher than thermal efficiency for GHG control, thermal efficiency is the only technically feasible control technology that is commercially available and applicable for the HEBP.

3.2.2.4 Evaluate Most Effective Controls – Step 4

Step 4 of the BACT analysis is to evaluate the remaining technically feasible controls and consider whether energy, environmental, and/or economic impacts associated with the remaining control technologies would justify selection of a less-effective control technology. The top-down approach specifies that the evaluation begin with the most-effective technology.

Carbon Capture and Sequestration. As demonstrated in Step 2, CCS is not a technically feasible alternative for the HEBP. Nonetheless, at the suggestion of the EPA team members on other recent projects, economic feasibility of CCS technology is reviewed in this step. Control options considered in this step therefore include application of CCS technology and plant energy thermal efficiency. As demonstrated below, CCS is clearly not economically feasible for the HEBP.

On page 42 of the EPA PSD and Title V Permitting Guidance, it is suggested that detailed cost estimates and vendor quotes should not be required where it can be determined from a qualitative standpoint that a control strategy would not be cost effective:

> *With respect to the valuation of the economic impacts of [AES] control strategies, it may be appropriate in some cases to assess the cost effectiveness of a control option in a less detailed quantitative (or even qualitative) manner. For instance, when evaluating the cost effectiveness of CCS as a GHG control option, if the cost of building a new pipeline to transport the CO_2 is extraordinarily high and by itself would be considered cost prohibitive, it would not be necessary for the applicant to obtain a vendor quote and evaluate the cost effectiveness of a CO_2 capture system.* (EPA, 2011b)

The guidance document also acknowledges the current high costs of CCS technology:

> *EPA recognizes that at present CCS is an expensive technology, largely because of the costs associated with CO_2 capture and compression, and these costs will generally make the price of electricity from power plants with CCS uncompetitive compared to electricity from plants with other GHG controls. Even if not eliminated in Step 2 of the technical feasibility of the BACT analysis, on the basis of the current costs of CCS, we expect that CCS will often be eliminated from consideration in Step 4 of the economical feasibility of the BACT analysis, even in some cases where underground storage of the captured CO_2 near the power plant is feasible.*(EPA, 2011b)

The costs of constructing and operating CCS technology are indeed extraordinarily high, based on current technology. Even with the optimistic assumption that appropriate EOR opportunities could be identified in order to lower costs, compared to “pure” sequestration in deep saline aquifers, or through deep ocean storage, additional costs to HBEP would include the following:

- Licensing of scrubber technology and construction of carbon capture systems
- Significant reduction to plant output due to the high energy consumption of capture and compression systems
- Identification of oil and gas companies holding depleted oil reservoirs with appropriate characteristics for effective use of CO_2 for tertiary oil recovery, and negotiation with those parties for long-term contracts for CO_2 purchases
- Construction of compression systems and pipelines to deliver CO_2 to EOR or storage locations
- Hiring of labor to operate, maintain, and monitor the capture, compression, and transport systems
- Resolving issues regarding project risk that would jeopardize the ability to finance construction

The interagency task force report provides an estimate of capital and operating costs for carbon capture from natural gas systems: “For a [550-MWe net output] NGCC plant, the capital cost would increase by $340 million and an energy penalty of 15 percent would result from the inclusion of CO_2 capture” (DOE and EPA, 2010). Using the ”Capacity Factor Method” for prorating capital costs for similar systems of different sizes as suggested by the Association for the Advancement of Cost Engineering and other organizations, the CO_2 capture system capital cost for the HEBP is estimated as at least $467 million. Based on an estimated HBEP capital cost of $500 million to $550 million for the plant and equipment, the capture system alone would nearly double the cost of the overall plant equipment capital cost.

As noted above, the effort required to identify and negotiate with oil and gas companies that may be able to utilize the CO_2 would be substantial. Prospective EOR oil fields are located within the area, but no active commercial facilities exist within the Los Angeles Basin, making predictions for CO_2 demand generated by CCS difficult. And, because of the patchwork of oil well ownership, many parties could potentially be involved in negotiations over CO_2 value.

Because of the extremely high pressures required to transport and inject CO_2 under supercritical conditions, the compressors required are highly specialized. For example, the compressors for the Dakota Gasification Company system are of a unique eight-stage design. It is unclear whether the Task Force natural gas combined-cycle (NGCC) cost estimate noted above includes the required compression systems; if not, then this represents another substantial capital cost.

Pipelines must be designed to withstand the very high pressures (over 2,000 psig) and the potential for corrosion if any water is introduced into the system. As noted above, if CCS were otherwise technically and economically feasible for the HEBP, the most realistic scenario could be to construct a pipeline from the Huntington Beach area to either the Santa Fe Springs or Dominquez oil fields near Los Angeles for EOR, assuming that permits and right-of-way agreements are obtained and there is an active EOR operation in this location. As noted above, the approximate distance of the pipeline to either of these two fields is approximately 30 miles. Based on engineering analysis by the designers of the Denbury CO_2 pipeline in Wyoming, costs for an 8-inch CO_2 pipeline are estimated at $600,000 per mile, for a total cost of $18 million. Therefore, the pipeline alone would represent an additional 3 percent increase to the capital cost assuming that the EOR opportunities could be realized; however, costs could be substantially higher to transport CO_2 to deep saline aquifer or ocean storage locations.

It is unlikely that financing could be approved for a project that combines CCS with generation, given the technical and financial risks. Also, as evidenced with utilities’ inability to obtain CPUC approval for integrated gasification / combined-cycle projects because of their unacceptable cost and risk to ratepayers (such as Wisconsin’s disapproval of the Wisconsin Electric Energy project), it is reasonable to assume that the same issues would apply in this case before the CEC.

In summary, capital costs for capture system and pipeline construction alone would almost double the project capital cost, and lost power sales resulting from the CCS system energy penalty would represent another major impact to the project financials and a multi-fold increase to project capital costs. Other costs, such as identification, negotiation, permitting studies, and engineering of EOR opportunities; operating labor and maintenance costs for capture, compression, and pipeline systems; uncertain financing terms or inability to finance; and difficulty in obtaining CEC approval would also impact the project also, it is unclear whether compression systems are included in the task force estimate of capture system costs. Not only is CCS not technically feasible at this project scale, as the above discussion demonstrates, but CCS is clearly not economically feasible for natural-gas-fired turbines at this time.

Thermal Efficiency. A search of the EPA's RACT/BACT/LAER Clearinghouse was performed for NGCC projects. GHG permit information was found for one source—Westlake Vinyls Company LP Cogeneration Plant (LA-0256)—which was issued a permit in December 2011. The record for this source includes only hourly and annual CO_2e emission limitations and no information of costs estimated performed for the GHG BACT determination. Recent GHG determinations were completed for the Russell City Energy Center and the Palmdale Hybrid Power Project in California. Both projects proposed the use of combined-cycle configurations to produce commercial power, and the BACT analyses for both projects concluded that plant efficiency was the only feasible combustion control technology. However, the Palmdale project includes a 251-acre solar thermal field that generates up to 50 MWs during sunny days, which reduces the project's overall heat rate.

Because CCS is not technically or economically feasible, thermal efficiency remains the most effective, technically feasible, and economically feasible GHG control technology for the HBEP. The operationally flexible turbine class and steam cycle designs selected for the HBEP are the most thermally efficient for the project design objectives, operating at the projected annual capacity factor of approximately 40 percent. Table 3-1 compares the HBEP heat rate with that of other recent projects.

TABLE 3-1
Comparison of Heat Rates and GHG Performance Values of Recently Permitted Projects

Plant Performance Variable	Heat Rate (Btu/kWh)	GHG Performance ($MTCO_2$/MWh)
Huntington Beach Energy Project	8,236[a]	0.479[b]
Watson Cogeneration Project[c]	5,027 to 6,327	0.219 to 0.318
Palmdale Hybrid Power Project	6,970[d]	0.370[d]
Russell City Energy Project	6,852[e]	0.371[f]

[a] Calculated higher heating value (HHV) net heat rate at 65.8°F at site elevation, relative humidity of 58.32 percent, no inlet air cooling, without duct burners. Heat rate varies over the anticipated load dispatch range.

[b] Calculated CO_2 emissions at conditions in footnote a above are 163,658 lb/hr with 166.3 combined MW (both combustion turbine and steam turbine generation)

[c] From Watson Cogeneration Project Commission Final Decision

[d] From Tables 3 and 4 of the Palmdale Hybrid Power Project Greenhouse Gas BACT Analysis (AECOM, 2011)

[e] Net design heat rate with no duct burners, from "GHG BACT Analysis Case Study, Russell City Energy Center; November 2009, updated February 3, 2010.

[f] From Russell City total heat input of 4,477 MMBtu/hr (from PSD Permit), generation of 653 MW was calculated utilizing design heat rate of 6,852 Btu/kwh. From reference document in footnote d above, 1-hour CO_2 limit is 242 $MTCO_2$/hr, which yields 0.371 $MTCO_2$/MWh.

Note:

$MTCO_2$/MWh = metric tons of carbon dioxide per megawatt-hour

As shown in Table 3-1, when comparing the HBEP heat rate and GHG performance values for other recently permitted facilities, the HBEP heat rate is greater than that of other recent projects. However, the HBEP operating configuration and project goals are different than those of other recently permitted projects. The Watson Cogeneration project is a combined heating and power project, and it is designed for base load operation and not for flexible, dispatchable, or fast ramping capability. While the Palmdale project was designed for fast ramping operation (15 MW/minute), the project is described as being designed as a base load project. The HBEP's design objectives are to be able to operate over a wide MW production range with an overall high thermal efficiency, in order to respond to the fast changing load demands and changes necessitated by renewable energy generation swings. This rapid response is accomplished by utilizing fast start/stop and ramping capability and the use of the duct burners to bridge the MW production when additional combustion turbines are started (as opposed to the duct burner's traditional roll of providing peaking power during periods of high electrical demand). At maximum firing rate, the maximum power island ramp rate is 110 MW/minute for increasing in load and 250 MW/minute for decreasing load. At other load points, the load ramp rate is 30 percent. The HBEP start time to 67 percent load of the power island is 10 minutes, and it is projected that the project will operate at an approximate 40 percent annual capacity factor.

The HBEP offers the flexibility of fast start and ramping capability of a simple-cycle configuration, as well as the high efficiency associated with a combined cycle. Therefore, comparison of operating efficiency and heat rate of the HBEP should be made with simple cycle or peaking units instead of combined-cycle or more base-loaded units. Table 3-2 shows that the HBEP compares very favorably to the peaker units listed.

TABLE 3-2
Generation Heat Rates and 2008 Energy Outputs[a]

Plant Name	Heat Rate (Btu/kWh)[b]	2008 Energy Output (GWh)	GHG Performance ($MTCO_2$/MWh)
La Paloma Generating	7,172	6,185	0.392
Pastoria Energy Facility L.L.C.	7,025	4,905	0.384
Sunrise Power	7,266	3,605	0.397
Elk Hills Power, LLC	7,048	3,552	0.374
Sycamore Cogeneration Co	12,398	2,096	0.677
Midway-Sunset Cogeneration	11,805	1,941	0.645
Kern River Cogeneration Co	13,934	1,258	0.761
Ormond Beach Generating Station	10,656	783	0.582
Mandalay Generating Station	10,082	597	0.551
McKittrick Cogeneration Plant	7,732	592	0.422
Mt Poso Cogeneration (coal/pet. coke)	9,934	410	0.930
South Belridge Cogeneration Facility	11,452	409	0.625
McKittrick Cogeneration	9,037	378	0.494
KRCD Malaga Peaking Plant[c]	9,957	151	0.528
Henrietta Peaker[c]	10,351	48	0.549
CalPeak Power – Panoche	10,376	7	0.550
Wellhead Power Gates, LLC[c]	12,305	5	0.652
Wellhead Power Panoche, LLC[c]	13,716	3	0.727
MMC Mid-Sun, LLC[c]	12,738	1.4	0.675
Fresno Cogeneration Partners, LP PKR[c]	16,898	0.8	0.896
Palmdale Hybrid Power Project (PHPP)	6,970	4,993 [d]	0.370

[a] Reference: From the Palmdale Hybrid Power Project AFC Final Decision, Page 6.1-14, Table 4 (CEC, 2011)
[b] Based on the HHV of the fuel.
[c] Peaker facilities.
[d] Based on continuous operation at peak capacity.

GWh = gigawatt-hour(s)

The HBEP will be dispatched remotely by a centralized control center over an anticipated load range of approximately 160 to 528 MW for each 3-by-1 power island. Over this load range, the HBEP anticipated heat rate is estimated at approximately 7,400 to 8,000 Btu/kWh lower heating value (LHV) (~ 8,140 to 8,800 Btu/kWh HHV). The HBEP will be able to start and provide 67 percent of the power island load in 10 minutes and provide 110 MW/min of upward ramp and 250 MW/min of downward ramp capability. Comparing the thermal efficiency of the HBEP to other recently permitted California projects demonstrates that the HBEP is more thermally efficient than other similar projects that are designed to operate as a peaker unit. Based both on its flexible operating characteristics and favorable energy and thermal efficiencies as compared with other comparable peaking gas turbine projects, the HBEP thermal efficiency is BACT for GHGs.

3.2.2.5 GHG BACT Selection – Step 5

Based on the above analysis, the only remaining feasible and cost-effective option is the "Thermal Efficiency" option, which therefore is selected as the BACT.

As shown above, the Mitsubishi 501DA combustion turbines operating in a multistage generator combined-cycle operating configuration compare favorably with other comparable turbines operating in a peaking capacity. The HBEP turbines and duct burners will combust natural gas to generate electricity from both the CTG and STG units. Therefore, the thermal efficiency for the project is best measured in terms of pounds of CO_2 per MWh.

The performance of all CTGs degrades over time. Typically, turbine degradation at the time of recommended routine maintenance is up to 10 percent. Additionally, thermal efficiency can vary significantly with combustion turbine turndown and steam turbine/duct burning combinations. Finally, annual metrics for output-based limits on GHG emissions are affected by startup and shutdown periods because fuel is combusted before useful output of energy or steam. Therefore, the annual average thermal efficiency performance of any turbine will be greater than the optimal efficiency of a new turbine operating continuously at peak load over the lifetime of the turbine.

Based on the projected annual operating profile and equipment design specification provided by the project owner, the GHG BACT calculation for the HBEP was determined in pounds of CO_2 per MWh of energy output (on a gross basis). Included in this calculation is the inherent degradation in turbine performance over the lifetime of the HBEP. The HBEP has concluded that the BACT for GHG emissions is an emission rate of 1,082 pounds CO_2/MWhr of gross energy output, and a total annual CO_2 emissions limit of 3,161,785 metric tons per year. Degradation over time and turndowns, startup, and shutdown are incorporated into these limits.

SECTION 4

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