NRG Texas Power LLC
1201 Fannin
Houston, Tx 77002

OCTOBER 7, 2013

VIA EMAIL TRANSMITTAL

Ms. Melanie Magee
Air Permit Section
U.S. EPA Region 6, 6PD-R
1445 Ross Avenue, Suite 1200
Dallas, Texas 75202-2733

RE: **Supplement to Combustion Turbine BACT Analysis**
Greenhouse Gas Emissions
Peaking Turbines, P.H. Robinson Generating Station
Galveston County, Texas
NRG Texas Power LLC

Dear Ms. Magee:

NRG Texas Power LLC (NRG Texas) is submitting the enclosed supplement to our request for a Prevention of Significant Deterioration (PSD) permit for our proposed installation of gas-fired combustion turbines at the P.H. Robinson Generating Station located in Galveston County, Texas.

We believe that our application is complete and respectfully request EPA complete its review in an expedited manner. Should you have questions concerning this application, or require further information, please do not hesitate to contact me at (713) 537-2146 or craig.eckberg@nrgenergy.com.

Sincerely,

C. R. Eckberg

Craig R. Eckberg
Senior Manager
Environmental Business

Enclosure(s)

NRG Texas P.H. Robinson Peaking Project
GHG PSD Permit Application
Supplement to Combustion Turbine BACT Analysis

NRG Texas Power LLC (NRG Texas) submitted a federal Prevention of Significant Deterioration (PSD) application to U.S. EPA in February 2013 for the construction of a super-peaking[1] electric generating facility with very limited hours of operation using simple cycle, natural gas-fired combustion turbines with sufficiently low capital cost in order to ensure an economically viable return on investment.

The purpose of this supplemental information is to further demonstrate the fundamental objectives and basic design of the project proposed by NRG Texas and show how alternate generation options are not economically viable. This supplement to the BACT analysis is presented in this context. Alternative raw materials, production processes, or products that would be inconsistent with these fundamental objectives or basic design would impermissibly redefine the source and are not a part of the BACT analysis.

NRG Texas defined the proposed project to meet market requirements in its service area, based on its view of the current and future fundamentals of the ERCOT market, with the potential for a rate of return on its investment that is necessary to support new generation assets. The proposed electric generating units, which are existing combustion turbines that will be relocated from a site in Mississippi, are available at a capital cost that makes the project economically viable. The unique definition of this project is necessary in order to support existing generator resources during periods of increasing peak power demand in the deregulated Texas ERCOT market, which is distinguishable from other electric markets within the State of Texas and elsewhere. Notably, the ERCOT market differs from the traditional regulated utilities in the Southwest Power Pool (SPP) (Entergy and service territories in East Texas) and Western Electricity Coordinating Council (WECC) (El Paso Electric Company and service territories in West Texas), as discussed in greater detail below.

The Texas ERCOT electricity market is primarily a competitive generation and retail supply market. In this market design, the generators' only sources of revenues are through the sales of energy and ancillary services to market participants. The market participants are largely competitive retail electric providers that have short term contracts with their customers

[1] The term "super-peaking" is used in the power generation field to refer to generating units designed to run during only the small number of hours when electricity demand in a market is at its highest.

and are unable to enter into long term supply arrangements with generators. There is no capacity market and there is no regulatory recovery for capital investment. There is no formal capacity planning or integrated resource plan for either the generators or the retail electric providers to ensure compliance with reserve margin needs. The market relies entirely on the willingness of generation owners and developers to deploy capital to meet the desired reserve targets. A generation developer such as NRG Texas must have a view that it can meet its capital return based on its forward market views.

Within the ERCOT market, Texas has a capacity need for low cost peaking generation to address projected capacity shortfalls at peak demand times and to manage the growing wind generation fleet, which is highly intermittent. According to ERCOT, the generation reserve margin will drop to 11.6% in 2015, far short of the 13.75% of reserves needed to maintain current reliability standards.[2] A recent study performed by the Brattle Group[3] indicates the reserve margin in the ERCOT market is expected to decline to an average of 8% over the next few years under the current market design. As demonstrated in ERCOT's 2012 ERCOT Loss of Load Study[4] ("LOLE Study"), as reserve margins decrease the probability of reliability events increase exponentially. The LOLE study estimates outage events are reduced by 90% when moving from an 8.4% reserve margin to a 13.5% reserve margin. Furthermore, the duration of any reliability events that do occur will be shortened with higher reserve margins. For example, the LOLE study estimated that a 2.6% reduction in reserve margin in 2016 will double the number of events and triple the expected amount of unserved energy.[5] Thus the addition of electric generation capacity such as the Robinson peaking units is critical in order to maintain reliable and economic supply of power to the market consumers.

In contrast to the ERCOT market, traditional regulated markets exist in WECC and SPP, which together encompass the non-ERCOT area of Texas and states immediately adjacent. The regulated utilities in these areas are required by state utility commissions or the electric

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[2] ERCOT ISO "*Report on the Capacity, Demand, and Reserves in the ERCOT Region* (May 1, 2014), available at http://www.ercot.com/content/news/presentations/2013/CapacityDemandandReserveReport-May2013.pdf.

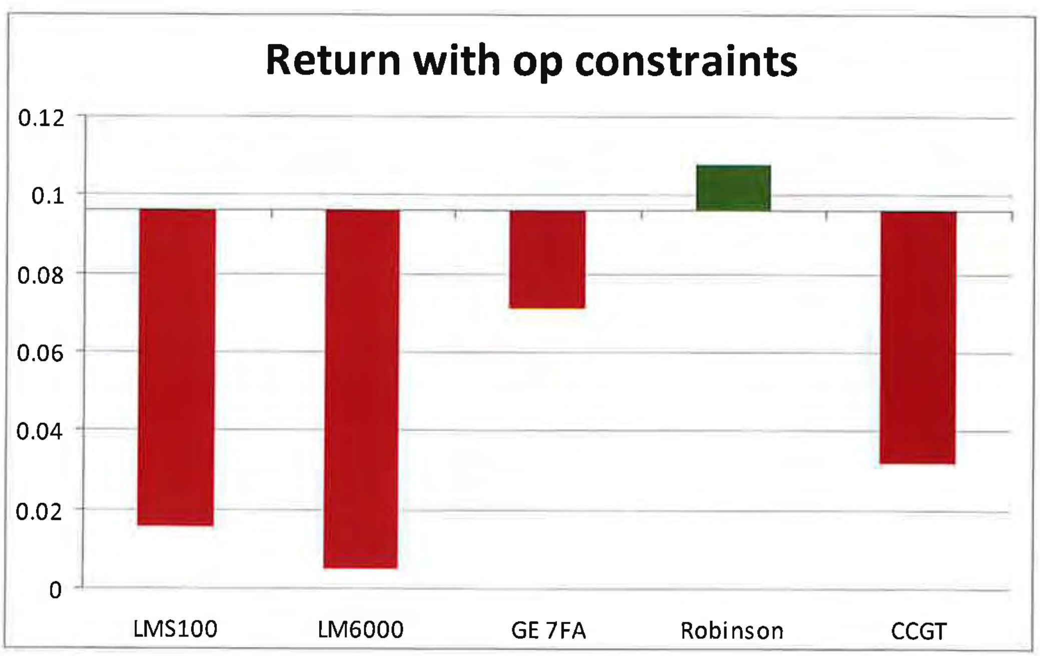
[3] The Brattle Group, "*Customer Cost Comparison*" memorandum ("Brattle Cost Comparison") filed in Texas PUC Project 40000 (September 4, 2012), avaialble at http://interchange.puc.state.tx.us/WebApp/Interchange/application/dbapps/filings/pgSearch_Results.asp?TXT_CNTR_NO=40000&TXT_ITEM_NO=294.

[4] ECCO International, "*2012 ERCOT Loss of Load Study*" ("LOLE Study") Results, at 6, Table 2 (March 8, 2013), available at http://www.ercot.com/content/news/presentations/2013/ERCOT%20Loss%20of%20Load%20Study-2013.pdf.

[5] LOLE Study at 20.

service control areas where they operate to maintain sufficient generation reserves under participant membership agreements and operational standards. More importantly for the analysis at hand, these utilities are afforded the certainty of knowing that capital costs for new generation will be recovered through regulated rates paid by their customers.

In determining which generating technology to deploy for the Robinson project, NRG Texas evaluated several natural gas-fired combustion turbine models. As detailed below, NRG Texas considered the efficiencies, capital cost to install, potential revenue sources, operating costs and the targeted "super peak" hours before arriving at the decision to install the GE 7E turbines that are currently located in Mississippi. NRG Texas has significant experience with operating GE 7E or like turbines and the selection of the GE 7E turbines for the Robinson project will provide fleet operational and maintenance efficiencies gained by use of a like technology. Currently, the NRG Texas fleet has sixteen similar GE 7E, EA or B gas turbines in operation at multiple operating facilities. By using similar technology in our fleet, NRG Texas can leverage best practices, spare parts, and other operational efficiencies. These turbines represent the only identified generating technology which meets the project definition, including the related requirements for low capital cost and economic viability. The figure below provides the economic return of each simple cycle turbine model considered by NRG Texas, as well as the economic return of a combined cycle turbine facility.



The long-standing policy of U.S. EPA regarding the responsibility of the project proponent in defining the scope and purpose of the project was eloquently described by the U.S EPA's Environmental Appeals Board (EAB) in the *Prairie State* decision:

> The real conflict here concerns who is the appropriate entity to identify the facility's purpose or basic design. Petitioners essentially maintain that this role falls to [the permitting authority], independent of how the applicant articulates the project in its permit application…
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> Petitioners' argument, however, does not explain how the permit issuer is to identify the proposed Facility's basic purpose and, thus, it offers no clear standard for doing so. We must reject this approach and instead conclude the statute contemplates that the permit issuer looks to how the permit applicant defines the proposed facility's purpose or basic design in its application, at least where that purpose or design is objectively discernable, as it is here.
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> Our conclusion flows from the specific statutory words and phrases identified both by Petitioners and OAR and from Congress' establishment of the PSD program as a permitting system that is initiated by an application from the owner or operator of a proposed source…
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> The specific statutory words in the definition of BACT (i.e., processes, methods, systems, and techniques) that Petitioners point to as including the "means" but excluding the "facility's 'end,' 'object,' 'aim,' or 'purpose'" from BACT review must not be read in isolation, but instead are a part of a permit application process that requires the "proposed facility" to be subject to BACT. In this context, the permit applicant initiates the process and, in doing so, we conclude, defines the proposed facility's end, object, aim, or purpose – that is the facility's basic design, which no doubt will be reflected in the permit applicant's schematic design for the proposed facility.
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> For these reasons, we conclude that the permit issuer appropriately looks to how the applicant, in proposing the facility, defines the goals, objectives, purpose, or basic design for the proposed facility. Thus, the permit issuer must be mindful that BACT, in most cases, should not be applied to regulate the applicant's objective or purpose for the proposed facility, and therefore, the permit issuer must discern which design elements are inherent to that purpose, articulated for reasons independent of air quality permitting, and which design elements may be changed to achieve pollutant emissions reductions without disrupting the applicant's basic business purpose for the proposed facility.

This EAB decision was upheld by the U.S. Court of Appeals for the Seventh Circuit.[6]

More recently, and specifically in the context of GHG BACT determinations for proposed natural gas-fired combustion turbines at electric generating facilities, U.S. EPA has reiterated

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[6] *Sierra Club v. EPA*, 499 F.3d 653 (7th Cir. 2007).

the need to defer to the project proponent in identifying the generating technology which best meets the scope and purpose of the project. For example:

- In making the BACT determination for the Cheyenne Prairie Generating Station, U.S. EPA accepted the applicant's proposal to use simple cycle combustion turbines with an efficiency of 37.6 percent rather than more efficient turbines in order to achieve "consistency with other locations." U.S. EPA specifically observed that the selection of a fleet of like turbines for different locations provides advantages with knowledge of maintenance and operations, stocking of spare parts, and ability to swap turbines between locations.[7]

- In making the BACT determination for the Pio Pico Energy Center, U.S. EPA accepted the applicant's proposal to use simple cycle combustion turbines rather than more efficient combined-cycle technology because the latter would be inconsistent with the business purpose and fundamental design elements of the project. U.S. EPA heavily relied on the proposed project's purpose as providing "peaking and load-shaping resources."[8]

Baseline for BACT

On September 20, 2013, U.S. EPA proposed Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units ("EGU GHG NSPS").[9] The proposal is relevant to this BACT analysis because, by definition, the emission limitation established as BACT for the combustion turbines can be no less stringent than any applicable standard under 40 CFR Part 60. It should be noted that the proposed EGU GHG NSPS does not establish the legal floor for any BACT determination because it is not a final action, as explained by U.S. EPA in the preamble to the proposed rule.[10] Moreover, even if the EGU GHG NSPS were finalized as proposed prior to issuance of the PSD permit for the Robinson project, the emission standard proposed by 40 CFR § 60.4326 would not establish a floor for this BACT determination because it is not applicable to the proposed combustion

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[7] "Statement of Basis for Permit Number: PSD-WY-000001-2011.001." May 21, 2012. (Final permit issued Sept. 27, 2012.)
[8] *In re: Pio Pico Energy Center* (PSD Appeal Nos. 12-04 through 12-06). U.S. EPA, Environmental Appeals Board. August 2, 2013.
[9] Standards for Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units (pre-publication version dated Sept. 20, 2013), available at http://www2.epa.gov/sites/production/files/2013-09/documents/20130920proposal.pdf.
[10] Ibid at pp. 307-310.

turbines. Specifically, two of the applicability criteria set forth at proposed 40 CFR § 60.4305(c) are not met:

- Each of the turbines was constructed in the 1970's, well before the applicability date in the EGU GHG NSPS; and
- Because of the limited hours of operation, none of the turbines will supply one-third or more of its potential electric output or more than 219,000 MWh net-electrical output to a utility distribution system on a 3 year rolling average basis.

Supplemental Cost Analysis

As described in the NRG Texas GHG PSD permit application, EPA's 5-step process for conducting a top-down BACT analysis was followed for the project. NRG Texas asserts that the originally submitted analysis is complete; and for the reasons described above, use of alternative turbines to those proposed would constitute an impermissible redefinition of the business purpose and design of the project, and therefore is not within the required scope of a BACT analysis. However, NRG Texas has elected to supplement Step 4 (Evaluation of Control Technologies in Order of Most Effective to Least Effective) of the combustion turbine BACT analysis with a cost effectiveness analysis performed as if alternative turbines were viewed as emissions control options. The evaluation was done by defining the proposed GE 7E turbines as the base case, and calculating the cost effectiveness, in dollars per ton of GHG emissions avoided, of installing and operating more efficient turbines. The analysis is presented in Table 1.

Three alternative turbine models were considered: GE LMS100, GE LM6000, and GE 7FA.05. There were two components included in the cost analysis: 1) installed capital cost, and 2) fuel cost. For each turbine option, the estimated installed capital cost in $/kW was multiplied by the nominal installed 390,000 kW capacity of the proposed peaking plant to put the capital cost of all options on an equivalent basis. The annualized capital cost of each option was then determined by multiplying the installed capital cost by a capital recovery factor of 0.0944 (20 year equipment life at 7% annual interest rate).

The annual fuel cost for each turbine option was estimated based on the summertime heat rate (Btu/kwh) of the turbine and the 10% average annual capacity factor which the proposed plant will be limited to on a three-year average basis.

The annualized capital cost of installing each of the more efficient turbine options was calculated by subtracting the annualized capital cost of the proposed turbines from the annualized capital cost of each option. Similarly, the annual fuel cost savings of each turbine option was calculated by subtracting the annual fuel cost for each option from the annual fuel cost for the proposed turbines. The net annual cost of each control option was then calculated by subtracting the annual fuel cost savings from the incremental capital cost.

The total annual GHG emission rate (tpy of CO_2e) for each turbine option was then calculated using the same 10% annual capacity factor and summertime heat rate used to estimate annual fuel costs. The CO_2e emissions reduction (avoided) associated with each turbine option was then calculated by subtracting the annual CO_2e emissions for each option from the annual CO_2e emissions for the proposed turbines. Finally, the cost effectiveness of each option was calculated by dividing the total net annual cost of the option by the annual CO_2e emissions that would be avoided by implementing the option.

As shown in Table 1, this analysis yields cost effectiveness values ranging from $90/ton of CO_2e emission reduction for the GE 7FA.05 turbines to $978/ton of CO_2e emission reduction for the GE LM6000 turbines. Again, these options would fundamentally redefine the project and as such are not emissions control options *per se*; however, even if alternative turbines were viewed as such, these costs are well outside the range of cost effectiveness values considered to be reasonable and acceptable in BACT determinations for control of GHG emissions. For example:

- In making the GHG BACT determination for ETC Jackson, U.S. EPA determined that control of GHG emissions at a cost effectiveness of $81/ton is not BACT because it is "economically unreasonable."[11]
- In making the GHG BACT determination for Copano Processing, U.S. EPA determined that control of GHG emissions at a cost effectiveness of $54/ton is not BACT because it is "economically prohibitive."[12]

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[11] Statement of Basis: Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit for the Energy Transfer Company, Jackson County Gas Plant, Permit Number PSD-TX-1264-GHG. U.S. EPA Region 6, March 2012.

[12] Statement of Basis: Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit for the Copano Processing, L.P., Houston Central Gas Plant, Permit Number: PSD-TX-104949-GHG. U.S. EPA Region 6, December 2012. (Cost effectiveness calculated based on listed cost of $10.9 million/yr for annual emission reduction of 202,000 tons per year.)

- In making the GHG BACT determination for the City of Palmdale, U.S. EPA determined that control of GHG emissions at a cost effectiveness of $45/ton is not BACT because it is "economically infeasible."[13]

Pursuant to long-standing policy of U.S. EPA, cost effectiveness as described above is the appropriate metric for evaluating economic and environmental impacts in Step 4 of a top-down BACT analysis. The draft 1990 NSR Workshop Manual, which sets forth the 5-step top-down process used by NRG Texas in its permit application, includes the following statements regarding consideration of cost effectiveness:

> Average and incremental cost effectiveness are the two economic criteria that are considered in the BACT analysis.
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> [F]or 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.[14]

The agency's policy regarding cost effectiveness as the appropriate metric for evaluating economic and environmental impacts in BACT analyses has been applied consistently in formal adjudicative decisions. For example, the EAB upheld the decision of the permitting authority to reject a widely-applied control technique for a New York power plant because the control technique was not cost effective at that particular plant,[15] but remanded the final PSD permit decision for Masonite because the permitting authority had based its decision on an incomplete cost-effectiveness analysis.[16]

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[13] Responses to Public Comments on the Proposed Prevention of Significant Deterioration Permit for the Palmdale Hybrid Power Project. U.S. EPA Region 9, October 2011. (Cost effectiveness calculated based on listed cost of $78 million/yr for annual emission reduction of 1.7 million tons per year.)

[14] *1990 NSR Manual* at p. I.B.31. The importance of this document in establishing U.S. EPA policy regarding BACT determinations was recently recognized by the U.S. EPA Environmental Appeals Board: "The analytical rigor demanded by Congress has found widely adopted expression in a guidance manual issued by EPA's Office of Air Quality Planning and Standards in 1990. While not binding Agency regulation or the required vehicle for making a BACT determination, the NSR Manual offers the 'careful and detailed analysis of [BACT] criteria' required by the CAA and regulations. For this reason, it has guided state and federal permitting authorities on PSD requirements and policy for many years." *In re: Northern Michigan University*, February 18, 2009. (Internal citations omitted.)

[15] *In re: Inter-Power of New York, Inc.* (PSD Appeal Nos. 92-8 and 92-9). U.S. EPA, Environmental Appeals Board. Mar. 16, 1994. Notably, the EAB made the following observation: "[The petitioner's] contention that cost-effectiveness is not a relevant consideration and that Inter-Power should be required to pay for the lowest sulfur coal it can afford is without merit. As discussed in detail at the outset of this decision, EPA has historically and consistently viewed cost-effectiveness to be a proper basis for rejecting a control option, without regard to an individual source's financial status."

[16] *In re: Masonite Corporation.* (PSD Appeal No. 94-1). U.S. EPA, Environmental Appeals Board.

Table 1 Cost Effectiveness of Using Higher Efficiency Turbines

Parameter	Proposed Turbines	LMS100 Turbines[1]		LM6000 Turbines[2]		7FA.05 Turbines[3]		CC Turbines[4]	
			Difference		Difference		Difference		Difference
Capital Cost									
Installed Capacity (kw)	390,000	390,000	NA	390,000	NA	390,000	NA	390,000	NA
Installed Cost ($/kw)	$362	$1,735	$1,373	$1,967	$1,605	$575	$213	$960	$598
Installed Cost ($)	$141,000,000	$676,650,000	$535,650,000	$767,130,000	$626,130,000	$224,250,000	$83,250,000	$374,400,000	$233,400,000
Capital Recovery Factor[5]	0.0944	0.0944	NA	0.0944	NA	0.0944	NA	0.0944	NA
Annualized Capital Cost	**$13,310,400**	**$63,875,760**	**$50,565,360**	**$72,417,072**	**$59,106,672**	**$21,169,200**	**$7,858,800**	**$35,343,360**	**$22,032,960**
Fuel Cost									
Annual Output (MWh/yr)	279,388	279,388	NA	279,388	NA	279,388	NA	279,388	NA
Fuel Cost ($/MMbtu)	$4.00	$4.00	NA	$4.00	NA	$4.00	NA	$4.00	NA
Net Plant Heat Rate (Btu/kwh)	13,191	9,058	-4,133	9,735	-3,456	10,147	-3,044	7,322	-5,869
CO_2e (lb/MMbtu)	117.0	117.0	NA	117.0	NA	117.0	NA	117.0	NA
Fuel Use (MMBtu/yr)	3,685,406	2,530,696	-1,154,710	2,719,842	-965,565	2,834,949	-850,457	2,045,678	-1,639,728
Annual Fuel Cost ($/yr)	**$14,741,625**	**$10,122,784**	**-$4,618,841**	**$10,879,366**	**-$3,862,259**	**$11,339,798**	**-$3,401,828**	**$8,182,714**	**-$6,558,911**
Total Annual Cost ($/yr)	**$28,052,025**	**$73,998,544**	**$45,946,519**	**$83,296,438**	**$55,244,413**	**$32,508,998**	**$4,456,972**	**$43,526,074**	**$15,474,049**
Emissions									
CO_2e Emissions (tpy)	**215,596**	**148,046**	**67,551**	**159,111**	**56,486**	**165,845**	**49,752**	**119,672**	**95,924**
Cost Effectiveness ($/ton)			**$680**		**$978**		**$90**		**$161**

1 Installed Cost for LMS100 turbines from Black & Veatch, LM6000 and LMS100 Characterization, Colorado PUC E-Filings System, July 6, 2011.

2 Installed Cost for LMS6000 turbines from Black & Veatch, LM6000 and LMS100 Characterization, Colorado PUC E-Filings System, July 6, 2011.

3 Installed Cost for 7FA.05 turbines from internal NRG engineering analysis, 2013.

4 Installed Cost for Combined Cycle turbines from internal NRG engineering analysis, 2013.

5 Capital Recovery Factor is based on 20 year life and 7% interest rate.