ATTACHMENT 3

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

New York Independent System Operator, Inc. **Docket No. ER14-500-000**

AFFIDAVIT OF
CHRISTOPHER D. UNGATE

Mr. Christopher D. Ungate declares:

1. I have personal knowledge of the facts and opinions herein and if called to testify could and would testify competently hereto.

I. Purpose of this Affidavit

2. The purpose of my Affidavit is to discuss:
    a. The estimation of capital and operating and maintenance ("O&M") costs for Selective Catalytic Reduction ("SCR") emission control equipment on F-Class combustion turbine technology, specifically the Siemens SGT6-5000F(5) turbine;
    b. The estimation of the cost of the 45-second fuel swap requirement for the Siemens SGT6-5000F(5) turbine in Zone J;
    c. The assumed effectiveness in reducing NOx emissions of an SCR on a combustion turbine when the turbine is fired with ultra-low sulfur diesel ("ULSD");
    d. Interconnection cost estimates in Zone J;
    e. The dual fuel assumption for the proxy unit in the G-J Locality; and
    f. The environmental permitting strategy assumed for the Siemens SGT6-5000F(5) turbine without an SCR in the Rest of State ("ROS").

II. Qualifications

3. I am a Senior Principal Management Consultant with Sargent & Lundy LLC ("Sargent & Lundy" or "S&L") and have over thirty-five years of experience in electric utility operations, planning, and consulting. I earned a B.S. and M.S. in Civil Engineering from the Massachusetts Institute of Technology, and an M.B.A from the University of Tennessee at Knoxville. I am a registered professional engineer in the State of Tennessee.

4. In my position with S&L, I support regional transmission organizations and utility clients with cost and performance estimates of new entrant technologies that are used in the development of administratively determined demand curves and integrated resource plans. I also am involved in financial modeling and analysis for the assessment of power generation technologies, project development, asset transactions, and operational reviews. I perform due diligence reviews of new technology development, new projects, and modification and refurbishment of existing facilities.

5. Prior to joining Sargent & Lundy in 2006, my professional work experience included management of generation resource planning for a 30,000 MW portfolio of nuclear, coal, hydro and gas generation. I managed the development of annual power supply plans, monthly cost forecast updates, and system reliability analyses. I also held positions in hydro operations business planning; re-engineering and process improvement initiatives in utility planning and operations; and laboratory and prototype testing for hydro and thermal generating plants.

6. I managed Sargent & Lundy's recent and ongoing efforts with respect to the 2007, 2010 and 2013 NYISO update processes for the NYISO ICAP Demand Curves. As part of

that work, I managed the estimation of capital costs, fixed operations and maintenance costs, and other fixed costs for quantifying the cost of new entry in NYISO Zones G, J and K, and Rest of State ("ROS"). I also managed the estimation of the operating performance of new entry technologies in these Zones.

7. My resume is attached as Exhibit CDU-1 hereto.

III. Estimation of Capital and O&M Costs for an SCR on the Siemens SGT6-5000F(5) Turbine

8. I reviewed the Protest of Indicated Suppliers[1] who state that "the cost estimates for the F Class Frame with SCR … appear significantly flawed in a number of respects." To support this statement, the Indicated Suppliers cite the NYISO Staff Report, which states that the costs for the F Class Frame with SCR prepared by S&L "may be understated since no adjustments were made for failed catalysts, increased O&M due to unproven technology, EFORd impacts, etc."

9. S&L estimated capital costs for the proxy unit based on the Class 4 cost estimate methodology defined by AACE.[2] A Class 4 estimate is characterized as a Study or Feasibility estimate and is appropriate for the Demand Curve Study because the actual site of the proxy unit is unknown and detailed engineering of the proxy unit has not been performed. Consequently, we based our cost estimates on a set of assumptions about the site and the proxy unit technology, as described in Section II of the NERA and Sargent & Lundy ICAP Demand Curve Study Report[3] ("NERA/S&L Report").

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[1] Astoria Generating Company, L.P. ("Astoria Generating") and the NRG Companies.

[2] Cost Estimate Classification System—As Applied in Engineering, Procurement, and Construction for the Process Industries, AACE International Recommended Practice No 18R-97, 2005.

[3] *See* "Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator," August 2, 2013, prepared by NERA Economic Consulting; also

S&L used a conceptual design it has developed for similar combustion turbine technologies as the basis for estimating the cost of the proxy unit. The design includes quantities for equipment, materials and labor hours that we modified to align with the assumptions for the proxy unit technology and location.

10. Using this approach, we adjusted the conceptual design for an SCR based on Demand Curve Study assumptions, such as the turbine technology (affecting exhaust flow and temperature), simple or combined cycle, the need for air tempering, etc. We estimated a package price that included Ductwork; SCR and CO Catalysts; Ammonia Handling, Preparation and Injection System; Dilution Air Fans (if required); Stack; Silencer; Controls; and Continuous Emissions Monitoring System. We estimated the package price based on recent project experience and trends in pricing for major components (e.g., catalyst).

11. The same approach was used for estimating the cost of the SCR for the LMS100, the SGT6-5000F(5) in simple cycle, and the SGT6-5000F(5) in combined cycle. In each case, we further assumed that the SCR would operate successfully, *i.e.*, would reduce NOx emissions to comply with environmental requirements, would not require extraordinary maintenance due to equipment failures or more frequent overhauls, and would not contribute to EFORd any more than other combustion turbine units fitted with an SCR.

12. We had no basis for assuming greater O&M cost impacts for the SGT6-5000F(5) in simple cycle due to the addition of the SCR. If the SCR in such an application failed or

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available at http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_icapwg/meeting_materials/2013-08-13/Demand Curve FINAL Report 8-2-13.pdf experienced operating problems, we would expect that an owner would investigate the root cause of the failure or problem, and then develop and apply a solution before resuming operation. The solutions could include changes in operating procedures; modification of the SCR; replacement of components, such as catalyst; more frequent overhauls; and other approaches. Since there is no operating experience that permits the development of a likely scenario, we assumed that the O&M costs of operating performance of an SCR on a simple cycle SGT6-5000F(5) turbine would be similar to SCR installations on smaller combustion turbines.

13. In October, we discussed our capital cost estimate for the SCR portion of the SGT6-5000F(5) in simple cycle with Marc Chupka and Anthony Licata. It was later reviewed by Mitsubishi Power Systems Americas, Inc. ("MPSA") during the development of the Brattle report. Both Chupka and Licata found the cost estimate to be reasonable. MPSA staff indicated that the S&L cost estimate for the SCR was conservatively high, but was appropriate for needs of a project developer seeking financing.[4]

IV. Estimation of the Cost of the 45-second Fuel Swap Requirement for the Siemens SGT6-5000F(5) Turbine in Zone J

14. I reviewed the Protest of Indicated Suppliers and the Affidavit of Liam Baker[5] who question the capability of the Siemens SGT6-5000F(5) turbine to switch from firing natural gas to firing ULSD within the 45-second time period required in Zone J. They

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[4] Personal communication, Rand Drake, MPSA, October 25, 2013.

[5] The Baker Affidavit is referenced in the Protest of Astoria Generating Company, L.P. ("Astoria Generating") and the NRG Companies (together, the "Indicated Suppliers") filed in this docket.

also question the basis for a two percent cost adder to account for adding dual fuel capability to an F Class Frame.

15. During the preparation of the NERA/S&L Report, S&L reviewed the capability of the GE LMS100, Wartsila 18V50DF and Siemens SGT6-5000F(5) technologies to meet the Consolidated Edison requirement that dual fuel units be capable of switching from natural gas to ULSD in 45 seconds. At that time, we found that the LMS100 and 18V50DF could meet this requirement, but the SGT6-5000F(5) could not meet the requirement at this time.

16. Based on experience with other projects, S&L determined that there was no inherent reason that the SGT6-5000F(5) could not be modified to switch from firing natural gas to firing ULSD within 45 seconds because an F-Class combustion turbine from a competing manufacturer had been modified for this capability. Consequently, we assumed the SGT6-5000F(5) could be so modified, and increased the estimated package price of the turbine in our cost estimate by 2 percent to reflect the additional cost for this feature.[6] The selection of a 2 percent adder was based on S&L experience working with clients and turbine vendors, and represents a reasonable estimate of ordering a turbine with this feature.

17. In general, we developed the assumptions for the proxy peaking units so they will be most representative of costs that any developer of that proxy unit technology could expect throughout each Demand Curve region (*i.e.*, each of the three localities and in the rest of state). The assumptions are also intended to allow application of the proxy

[6] Subsequent to completion of the NERA/S&L report, we learned that Siemens had advised Licata Energy & Environmental Consulting, Inc., that it offers an option that would meet the 45-second fuel transfer requirement.

unit broadly within the capacity region to avoid unduly limiting the number of sites to which it could be located.

V. Performance of an SCR When the Turbine is Fired with ULSD

18. I have reviewed the Protest of IPPNY and the Affidavit of Daniel Ott[7] who commented on the NOx emissions control implications associated with the requirement that the proxy unit must have dual fuel capability to burn both natural gas and ULSD. Specifically, they question whether an SCR-fitted, F-class frame burning fuel oil can control NOx emissions to levels required under New York State law. Mr. Ott states that an F-class frame turbine with SCR will need to reduce NOx by 90%, to 4.2 parts per million by volume, corrected to 15% oxygen ("ppmvd"), to meet the Lowest Achievable Emissions Rate ("LAER") when burning fuel oil.

19. When calculating the emissions from combustion turbines, S&L assumed that ULSD is only the back-up fuel and would be used no more than 30 days per year. The emissions calculations that are shown in the NERA/S&L report reflect the following assumptions: 25 ppmvd uncontrolled emissions from the LMS100 when fired on ULSD; 42 ppmvd uncontrolled NOx emissions from the SGT6-5000F(5) when fired on ULSD; and a 90% NOx removal efficiency for the SCR.

20. On September 30, 2013, subsequent to the publication of the NERA/S&L report, Siemens announced that its SGT6-5000F(5) turbine has demonstrated 25 ppmvd uncontrolled NOx emissions when fired on fuel oil.[8] Consequently, the emissions

[7] The Ott Affidavit is referenced in the Protest of IPPNY filed in this docket.

[8] "Siemens gas turbine SGT6-5000F demonstrates 25 ppm NOx emissions on fuel oil," Siemens AG, Fossil Generation Division, press release, September 30, 2013.

shown in the NERA/S&L report for alternatives that are based on the SGT6-5000F(5) turbines are overstated.

VI. Interconnection Cost Estimates in Zone J

21. I reviewed the Motion to Intervene of the New York Transmission Owners[9] who comment that interconnection costs that the proxy unit would incur under equilibrium conditions in Zone J are overstated.[10] Specifically, the NYTOs state that:

   a. The calculation of average stand-alone ("SA") System Upgrade Facilities ("SUFs") should be modified to exclude gas insulated switchgear ("GIS") because the estimates of Energy and Ancillary Services revenues prepared by NERA are based only on open air substations;

   b. It is inappropriate to include the unusually high cost of System Protection SUF for the South Pier Improvement Project in the calculation of average System Protection SUFs incurred by the proxy unit because South Pier rejected its cost allocation; and

   c. The calculation of average headroom payments (payments made to Developers who paid for SUFs that had capacity in excess of their needs and which are used by the proposed project ("Headroom payments")) incurred by the proxy unit should be modified to reflect that Headroom values have depreciated

[9] Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., Long Island Power Authority, New York Power Authority, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation (referred to herein as the "New York Transmission Owners" or "NYTOs").

[10] *See* Attachment D to Motion of Intervene of NYTOs.

significantly since the Class Year ("CY") 2009/10 and that the facilities for which Headroom payments must be made (*i.e.*, the series reactors) would potentially not be needed at the level of capacity surplus utilized to determine the Cost of New Entry ("CONE").

22. S&L prepared SUF cost estimates for the Zone J proxy plant using the same methodology documented in my March 29, 2011, affidavit providing SUF cost estimates for the ICAP Demand Curve peaking plant in Zone J for the 2010 Demand Curve Study.[11] That update was prepared in response to the Federal Energy Regulatory Commission ("Commission") order that directed the NYISO to address the certain arguments concerning the NYISO's Demand Curve filing in November 2010.[12]

23. The following interconnection cost components were estimated for the interconnection of the Zone J proxy unit.

    a. SA SUFs costs, constructed by the developer, for the expansion of an existing substation at the point of interconnection ("POI") to accommodate the proxy unit;

    b. Protection SUFs costs at the POI or at locations removed from the POI that are needed to assure system reliability;

    c. Other interconnection costs, including costs of connecting the Connecting Transmission Owner Attachment Facilities ("CTO AF") to the transmission system at the POI; and

    d. Headroom payments.

[11] Affidavit of Christopher D. Ungate, March 29, 2013.

[12] *New York Independent System Operator, Inc.*, 134 FERC ¶ 61,058 (2011) at P. 140 ("January Order").

24. S&L prepared an SA SUF cost estimate for Zone J based on the expansion of an existing substation at three locations: Rainey, a 345 kV open air substation; Hudson Avenue, a 138 kV open air substation; and East 179th Street, a 138 kV GIS substation. For each we estimated the cost of circuit breakers, disconnect switches, transformers, and relays to connect the proxy unit at each substation. S&L used the same cost estimating assumptions used in the NERA/S&L Report, with the exception of the contingency.[13] A contingency of 20 percent was applied because, in addition to expected uncertainties due to price variations in labor, materials and equipment, and adjustments in materials quantities, the site conditions, configuration of the existing substation equipment, and specific equipment configuration needed for interconnection, are uncertain. The cost of protection SUFs, CTO AFs and Headroom payments for the proxy unit were estimated as the average of the cost of protection SUFs, CTO AFs and Headroom payments from Facilities Studies conducted for eight representative projects from CY 2009, 2010 and 2011. The interconnection costs for the proxy unit addition in Zone J are shown in the table below.

Cost Category	**138 kV open air**	**345 kV open air**	**138 kV GIS**
SA SUFs	$3,942,000	$5,366,000	$10,904,000
Protection SUFs	$3,057,000	$3,057,000	$3,057,000
Headroom	$1,027,000	$1,027,000	$1,027,000
CTO AF	$2,188,000	$2,188,000	$2,188,000
Total	$10,214,000	$11,638,000	$17,176,000

[13] NERA/S&L Report at 43.

25. No specific location for the peaking plant addition in NYC is assumed as part of the Demand Curve reset analysis. In keeping with the intention to allow application of the proxy unit broadly with the capacity zone and to avoid unduly limiting the number of sites to which it could be located, I used the average of the three cases shown in the table (138 kV open air, 345 kV open air, and 345 kV GIS), or $13,009,000, as the cost of SUFs for the proxy unit in Zone J. This is reasonably representative of the interconnection costs for the proxy unit addition.

26. NYTOs state that the calculation of average SA SUFs should be modified to exclude GIS substation estimates because the estimates of Energy and Ancillary Services revenues prepared by NERA are based only on open air substations. The energy or ancillary service prices used by NERA are not dependent on whether the substation at the point of price observation is an open air or GIS substation. As mentioned above, we developed the assumptions for the calculation of SUFs so they would be representative of costs that the developer of a new entry unit could expect in Zone J and to not unduly limit the number of sites to which the new entry unit could be located. Our estimate would not be representative if we excluded the cost of SA SUFs for GIS substations from the average.

27. NYTOs state that it is inappropriate to include the unusually high cost of System Protection SUFs for the South Pier Improvement Project in the calculation of average System Protection SUFs incurred by the proxy unit because South Pier rejected its cost allocation. The eight-project sample of projects that we used for protection SUFs, CTO AFs and Headroom payments is representative of the range of each of these costs that

the developer of a new entry unit in Zone J could encounter. While the South Pier project had higher than average protection SUF costs, it had lower than average CTO AF and Headroom payment costs. Excluding South Pier would not have a significant impact on the total of the average protection SUF, CTO AF and Headroom payment costs. This supports our rationale for using the average of the eight projects. We also note that South Pier was included in the average of protection SUFs, CTO AFs and Headroom payments for the 2010 Demand Curve interconnection costs for Zone J previously approved by the Commission.

28. The NYTOs state that the facilities for which Headroom payments must be made (*i.e.*, the series reactors) would potentially not be needed at the level of capacity surplus utilized to determine the CONE. Including Headroom payments as a category of interconnection costs is reasonable because it is a potential cost of the developer to interconnect. The average of recent history of Headroom payments results in a reasonable estimate of these costs for the Demand Curve peaking plant because the CONE for the peaking plant is not based on a specific POI or a specific set of conditions and, therefore, the details of a specific interconnection location cannot be used to compute a specific cost.

29. The NYTOs also state that the calculation of average Headroom payments incurred by the proxy unit should be modified to reflect that Headroom values have depreciated significantly since the CY 2009/10. The effect of this depreciation has been taken into account by including CY 2011 in the average for Headroom payments. The average of the Headroom Payments included in the 2010 Demand Curve interconnection costs for

Zone J was $3,250,000.[14] As shown in the above table, the average, when including CY 2011, is $1,027,000. We believe the modification requested by the NYTOs has already been taken into account.

VII. Dual Fuel Assumption for the Proxy Unit in the G-J Locality

30. I reviewed the Protest of Multiple Intervenors ("MI") and the City of New York ("City") arguing that the assumption of dual fuel capability for the proxy unit in the G-J Locality is unreasonable and unwarranted. They argue that a new natural gas fired facility would be highly unlikely to connect directly to a local distribution company, but instead would connect directly to an interstate pipeline, which does not require dual fuel capability.

31. In keeping with the intention to allow application of the proxy unit broadly with the capacity zone and to avoid unduly limiting the number of sites to which it could be located, we recommended the dual fuel assumption so as not to constrain the options for siting a new natural gas fired generation facility in the G-J Locality. Assuming no backup fuel capability would eliminate the siting options for the proxy plant on the local distribution company networks in the region because their tariffs require dual fuel capability. That would restrict the siting options to a fewer number of sites that could be found within a reasonable distance from an interstate pipeline and would require the new entrant to obtain firm pipeline capacity. The capital cost of dual fuel capability in the G-J Locality, as shown in the NERA/S&L report, is approximately $8,500,000. The gas interconnection cost estimate of $5,395,000 includes only a short (less than 0.5 mile) pipeline to connect to either a local distribution company network or to an

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[14] Affidavit of Christopher D. Ungate, March 29, 2013, at p 26.

interstate pipeline. An incremental cost of approximately $8,500,000 for dual fuel capability was judged as more economical than purchasing firm pipeline capacity and, possibly, in addition, constructing a lateral pipeline of a much greater length (at a cost of approximately $2-3 million per mile) to expand the range of available siting options.

VIII. Environmental Permitting Strategy for the Siemens SGT6-5000F(5) Turbine Without SCR in the ROS

32. I have reviewed the Protest of IPPNY and the Protest of the New York Supplier & Environmental Advocate Group ("NY-SEA Group"), including the Affidavit of Mr. Scott Anderson.[15] In general, both IPPNY and NY-SEA Group argue that the environmental permitting and environmental approval assumptions that underlie NYISO's recommendation of the simple cycle SGT6-5000F(5) turbine without SCR as the proxy unit for ROS is not realistically achievable under current and proposed State and federal initiatives, including the siting procedures of New York State Public Service Law Article 10.

33. The NERA/S&L Report concludes that a single-unit simple cycle SGT6-5000F(5) turbine plant designed to operate exclusively on natural gas could meet all applicable environmental regulations and obtain all environmental approvals in ROS without SCR for NOx control. The simple-cycle natural gas-fired unit would be equipped with dry-low NOx combustion controls to achieve controlled NOx emissions of 9 ppmvd @ 15% O_2, and would accept federally enforceable permit conditions that limit annual operation

[15] The Anderson Affidavit was submitted as an attachment to the Protest of the New York Supplier & Environmental Advocate Group ("NY-SEA Group").

of the unit to approximately 1,058 – 1,075 hours.[16] The federally enforceable permit limits would ensure that annual NOx emissions from the unit remain below the applicable Project Significance Thresholds provided in the New Your State Department of Environmental Conservation's (NYSDEC's) New Source Review regulations at 6 NYCRR Part 231. The NERA/S&L Report proposes an annual operating hour cap of 950 hours for the simple-cycle SGT6-5000F(5) peaking unit in ROS for the purposes of estimating the energy and ancillary services revenues for the plant. The annual operating hour limit also ensures that annual NOx emissions remain below the applicable project significance thresholds. On August 20, 2013, S&L and NYISO staff met with NYDEC staff, who confirmed the feasibility of this approach for the ROS area. The approach of taking a federally enforceable operating limit to ensure that emissions remain below the applicable project significance thresholds is referred to as permitting a "synthetic minor source." This approach occurs in practice in New York State, and was used for the ROS proxy unit in the 2010 and 2007 Demand Curve Reset Studies.

34. NY-SEA Group, supported by Mr. Anderson's affidavit, argue that NYISO's recommended proxy unit (*i.e.*, a SGT6-5000F(5) simple-cycle combustion turbine without SCR control) for ROS cannot be considered "economically viable" or a "unit that could be constructed practically" in light of environmental requirements associated with NOx permitting, greenhouse gas ("GHG") permitting, operational considerations

[16] NERA/S&L Report at 33 – 35.

and financing challenges that must be weighted.[17] In his affidavit supporting this conclusion, Mr. Anderson argues that:

- A simple cycle combustion turbine without SCR is unlikely to obtain a Certificate of Environmental Compatibility and Public Need ("Certificate") due to the requirement to minimize or avoid environmental impacts "to the maximum extent practicable" in accordance with the New York State Public Service Law Article 10 – Siting of Major Electric Generating Facilities. Specific Article 10 requirements noted by Mr. Anderson include GHG thresholds and requirements, and the requirement to conduct cumulative air quality impact modeling to demonstrate compliance with all applicable National Ambient Air Quality Standards ("NAAQS").
- There is a risk that future additional emission controls would be required during the 20-year operational life of a new peaking unit installed without SCR, and the costs of these additional controls would significantly change the economics of the generator such that it may no longer be economically feasible to operate.[18]

35. As a general response, all of the points brought up by Mr. Anderson were identified and discussed during the stakeholder review process for the Demand Curve Study, including the environmental issues that must be addressed in order to obtain the necessary air permits and approvals to construct the facility. These issues include GHG thresholds and requirements (including the potential requirement to prepare a GHG Best Available Control Technology ("BACT") determination), NOx BACT requirements, the

[17] NY-SEA Group Protest at 2.

[18] Anderson Affidavit at 3.

requirement to demonstrate compliance with all applicable NAAQS, and the Article 10 siting requirements.

36. With respect to the GHG thresholds and requirements, Mr. Anderson argues that a "frame unit is not as efficient as an aeroderivative unit and as a result a developer choosing to construct a frame unit runs the risk that the unit would not be permitted" due the EPA's position with respect to GHG BACT requirements.[19] Mr. Anderson references EPA guidance, as well as written comments submitted by EPA on permit applications that involve GHG emissions from combined cycle combustion turbines, to conclude that energy efficiency will be a significant component of any GHG BACT determination.[20]

37. S&L took into consideration GHG BACT requirements in its NERA/S&L Report. BACT is a case-by-case analysis that takes into consideration the technical feasibility of available control technologies, as well as control technology costs and cost-effectiveness. The BACT analysis for a natural gas-fired simple cycle peaking unit would include a comparison of the thermal efficiency of the proposed unit to the thermal efficiency of other potentially available combustion turbines; however, the BACT analysis provides the proponent with an opportunity to explain why the proposed turbine is the most efficient unit available for the proposed source. The NERA/S&L Report includes a general discussion of the factors that would influence a BACT determination, including costs and cost-effectiveness, and clearly points out that Mr. Anderson's predicted outcome (*i.e.*, aeroderivative required as BACT for GHG control)

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[19] Anderson Affidavit at 10.

[20] *Id.*

is not a forgone conclusion. I have included, as Exhibit CDU-2, a brief example of the approach that would be followed to develop a GHG BACT analysis for the proxy plant. As the example shows, a GHG BACT analysis for a natural gas-fired simple cycle peaking unit that operates 950 hours/year would likely conclude that cost impacts would preclude aeroderivative combustion turbines as BACT for GHG control. In other words, replacing the proposed frame combustion turbine with aeroderivative combustion turbines would not be a cost-effective GHG control option.

38. Mr. Anderson also argues that the GHG thresholds and risks may be compounded in New York because Article 10 requires exhaustive consideration of project environmental impacts and available mitigations and alternatives.[21] However, it is also reasonable to assume that the Article 10 standard of "maximum extent practicable" would include cost and cost-effectiveness components, similar to the top-down BACT analysis. As noted above, and detailed in Exhibit CDU-2, the increased costs associated with using aeroderivative combustion turbines in lieu of a frame combustion turbine for a simple cycle peaking plant are significant, and the cost-effectiveness of the aeroderivative option for GHG control on such a project would be in the range of $1,015 per ton. These costs are disproportionately high, and cost impacts would be part of the Siting Board's evaluation of options available to minimize environmental impacts to the maximum extent practicable.

39. It is important to note as well, and Mr. Anderson fails to do so in his affidavit, that New York State participates in the Regional Greenhouse Gas Initiative or "RGGI". RGGI includes a GHG emissions cap-and-trade program that limits GHG emissions from

[21] Anderson Affidavit at 11.

power plants. The RGGI price for GHG emission allowances in July 2013 was $3.21/ton, significantly below the cost of GHG emission control achieved by substituting a simple cycle frame combustion turbine with simple cycle aeroderivative combustion turbines. Although any new electric generating source in the State of New York would be required to meet the Article 10 siting requirements, nothing in the Siting Board regulations would preclude permitting a simple cycle frame peaking unit in ROS.

40. NY-SEA and Mr. Anderson note that Article 10 also requires that air quality impact analyses must be prepared for a proposed Article 10 facility to demonstrate, among other things, that the proposed project will not cause or contribute to a violation of any applicable NAAQS.[22] NAAQS comments focus on the 1-hour NO_2 standard. NY-SEA argues that because the 1-hour standard is a short-term limit, as opposed to an annual limit, the 950 hours/year cap proposed for the proxy unit is of no consequence.[23] Instead, NY-SEA argues, the unit would have to be modeled at its maximum hourly NOx output, and that the frame machine without SCR may not be able to demonstrate compliance with the 1-hour standard.[24]

41. S&L agrees that impact modeling that ensures the proposed project would not cause a violation of any NAAQS would be required for any new major source to obtain an NYSDEC air permit and to meet the Article 10 siting requirements. However, nothing in the Article 10 legislation suggests that the proposed project would have to demonstrate anything in addition to NAAQS compliance for the Article 10 siting process. In fact, under the predecessor Article X siting legislation, certificates were

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[22] NY-SEA at 17.

[23] *Id.*

[24] *Id.* See also, Anderson Affidavit at 22.

conditioned upon a finding by the Siting Board that the proposed project had obtained the necessary pre-construction permits from the NYSDEC. In addition, S&L has found that frame machines, such as the Siemens SGT6-5000F(5), with full load controlled NOx emission rates in the range of 9 ppm when firing natural gas, are able to demonstrate compliance with all applicable NAAQS, including the 1-hour NO_2 standard. In fact, we have found that the rapid start machines, which reach emissions compliant load within approximately 10 minutes of initial firing, are more readily able to demonstrate compliance with the 1-hour NO_2 standard during startup than units that have higher combustion NOx emissions (e.g., 25 ppm) and rely on SCR for additional NOx control. Units that rely on SCR for NOx control require additional time during a startup to heat the SCR catalyst and initiate ammonia injection for NOx control. During this time, NOx emissions will be higher and compliance with the 1-hour standard may be difficult to demonstrate.

42. Mr. Anderson also argues that the proxy unit technology and environmental control equipment should be selected to comply with potential future environmental regulations, including more stringent ozone NAAQS and other possible regulatory changes.[25] However, in this and previous Demand Curve reset studies, the environmental control assumptions for the proxy unit have been based on regulations that are in force at the time of the study. This approach has been taken because it is not possible to know what controls may or may not be needed to meet potential future regulations. As Mr. Anderson acknowledges in his affidavit, there is no way to reliably predict when new environmental regulations may be implemented, and it often takes

[25] Anderson Affidavit at 21.

several years for environmental regulations to be proposed and agreed upon by the EPA through the Clean Air Act State Implementation Plan process.[26] Furthermore, other regulatory initiatives, which Mr. Anderson did not address, may affect air quality in New York without triggering the need for additional controls on generating units located in New York. For example, the Cross State Air Pollution Rule (CSAPR) may be reinstated, or EPA may publish the Clean Air Interstate Rule (CAIR) replacement rule. Both of these regulatory initiatives would reduce the interstate transport of air pollutants that contribute to ozone nonattainment in New York State, but would not necessarily require existing units in New York to install retrofit air pollution controls. Because of this uncertainty of the regulatory requirements and implementation timelines, we did not evaluate environmental controls based on assumptions concerning future regulatory requirements that may be imposed on natural gas fired combustion turbines.

43. Article 10 requires a finding by the Siting Board that a proposed facility minimizes or avoids adverse environmental effects "to the maximum extent practicable." Although the term "maximum extent practicable" is not defined in Article 10, Mr. Anderson concludes that strict emission controls such as BACT would be favored over somewhat less strict controls such as RACT, particularly if the technologies were comparably priced.[27] S&L agrees that the Article 10 siting process would favor strict environmental controls, similar to those required by NYSDEC as BACT. However, just as the determination of BACT includes an evaluation of costs and cost-effectiveness, use of the word "practicable" in Article 10 connotes consideration of costs and cost-

[26] Anderson Affidavit at 15.

[27] Anderson Affidavit at 6.

effectiveness. Economic impacts and cost-effectiveness are important considerations in a BACT analysis, and these impacts must be determined on a case-by-case basis. The proponent of a simple cycle natural gas-fired peaking unit in ROS would clearly have the opportunity to evaluate GHG emissions, NOx emissions, ambient air quality impacts, control technology costs, and the cost of alternative simple cycle combustion turbines, and justify why the proposed turbines are the most efficient and cost-effective units available for the proposed project. It is also important to point out that the recently enacted Article 10 legislation is not as novel or revolutionary as NY-SEA and Mr. Anderson suggest. During the 2007 and 2010 Demand Curve resets, during which S&L addressed environmental requirements for proxy peaking units, the same siting requirements applied to the proxy plants selected. The State Environmental Quality Review Act ("SEQRA") applied to the siting of power plants throughout New York State prior to the enactment of the new Article 10 siting laws. Like Article 10, SEQRA also required that the agencies approving the proposed project make a finding that "to the maximum extent practicable, adverse environmental effects revealed in the environmental impact statement process will be minimized or avoided." (See NYS ECL §8-0109.)

44. NY-SEA Group and Mr. Anderson conclude that it is unlikely that the Siting Board would issue a Certificate for a simple cycle natural gas-fired combustion turbine without SCR in ROS. However, there is no precedence upon which to base this conclusion, and, to my knowledge, the Siting Board has never denied an application to site such a unit. To conclude that the Siting Board would not issue a Certificate for such a unit requires one to predict what the Siting Board will do as it implements the

recently revised Article 10 requirements. NY-SEA Group acknowledges that "developers do not know how the current siting process will be conducted for fossil-fired facilities and cannot predict with reasonable certainty how the Siting Board will approach emissions controls technology."[28] In fact, Mr. Anderson contacted an Administrative Law Judge on the Siting Board and learned that: (1) no fossil fuel generation projects are under review at this time, and no fossil fuel generation projects have submitted applications to the Siting Board since the re-enactment of Article 10; and (2) to date, no determinations have been made by the Siting Board under Article 10 for fossil fuel electric generating facilities.[29]

45. In his affidavit, Mr. Anderson cites to ten projects for which the Siting Board issued Certificates under the previous version of Article 10 (*i.e.*, Article X) to support his conclusion that an SCR would be required for NOx control on a simple cycle natural gas-fired combustion turbine. However, all ten of the projects referenced were combined-cycle combustion turbine plants. Combined-cycle projects are significantly different from simple cycle projects permitted to operate a limited number of hours. None of the Siting Board decisions referenced by Mr. Anderson relate to issuing a Certificate for a natural gas-fired simple cycle peaking unit, and there is not precedent upon which to conclude that a natural gas-fired simple cycle peaking unit could not receive all required environmental permits and approvals in ROS without SCR.

This concludes my Affidavit.

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[28] NY-SEA Group at 17.

[29] Anderson Affidavit at 6.

EXHIBIT CDU-1

CHRISTOPHER D. UNGATE RESUME

CHRISTOPHER D. UNGATE
Senior Principal Management Consultant
Sargent & Lundy Consulting

EDUCATION

University of Tennessee, Master of Business Administration, 1984
Massachusetts Institute of Technology, M.S. Civil Engineering, 1974
Massachusetts Institute of Technology, B. S. Civil Engineering, 1973

REGISTRATIONS

Professional Engineer - Tennessee

EXPERTISE

Utility Planning
Technology Evaluation
Market Analysis
Decision Analysis
Asset Valuation and Due Diligence
Generation Portfolio Analysis
Risk Analysis
Expert Witness

RESPONSIBILITIES

Mr. Ungate is accountable for Sargent & Lundy offerings in the Utility Planning business segment. He develops and evaluates integrated resource plans and associated analyses to identify and evaluate the optimum power supply options. He reviews and evaluates power supply planning and procurement options such as generation options available in the region (potential greenfield or plant expansion options), the viability of siting and permitting new nuclear, coal, gas, wind, solar, biomass or other alternative generation, the prospects for purchase of existing assets, and the potential for partnering with other load serving entities or power generators. He also assesses the potential and/or required renewable energy resource options, the state of transmission planning and upgrade programs, recent wholesale prices in the Client's load zone, and the fuel market and transportation capacities. He assures consistency with the Client's long-term plans and objectives and Client-specific economic factors (such as standard inflation, inflation, discount, or escalation rates).

Mr. Ungate develops models and analyses utilized in the assessment of power generation technologies, project development, asset transactions, operational reviews, and facility modifications and refurbishment projects. He bases the models on appropriate economic, project, operating, and client-specific inputs related to base-case scenarios, as well as associated sensitivity analyses. He also reviews existing models and analyses to determine if they are reasonable and appropriate, and to evaluate or develop resulting conclusions and recommendations. He also performs system reliability studies, load forecasting, and market evaluations in support of utility planning or other Client needs. He evaluates and develops plans to optimize the utilization of renewable energy resources with thermal generating units. He also performs due diligence reviews of new technology development, new projects, modifications and refurbishment of existing facilities, asset transactions, and operational assessments.

EXPERIENCE

Mr. Ungate has over 35 years of experience in engineering and planning for electric utilities. Since joining Sargent & Lundy in 2006, his assignments have included:

UTILITY PLANNING

- **Maui Electric Company**
  - Conducted a Generation Asset Assessment Study to review the condition of Maui Electric's generating facilities and the impact of the expected changes in usage resulting from increasing amounts of intermittent renewable resources. Each unit's remaining useful life and performance was assessed given the expected operational demands. Operational and maintenance adjustments were proposed to maximize the performance and useful life of the units.

- **Grand Haven Board of Light and Power and Zeeland Board of Public Works**
  - Prepared individual Integrated Resource Plans for two Michigan municipal utilities as part of a single study. Parts of the study related to their location in Ottawa County Michigan were common to both utilities. Integrated resource strategies were developed that included equipment maintenance and replacement recommendations and a recommended resource portfolio for the next twenty years. Potential resource options included existing and new non-renewable generation facilities, renewable energy resources, energy conservation and demand reduction programs, and long-term power purchase agreements or shared ownership options in large economies-of-scale facilities. Risk analysis was performed to evaluate how portfolio options performed under varying fuel and market prices, and environmental regulatory scenarios.

- **Tennessee Valley Authority**
  - Supported preparation of the Need for Power and Alternatives sections of the Integrated Resource Plan. Developed Need for Power and Alternatives sections for Environmental Impact Statements for Sequoyah Nuclear Plant Relicensing and Bellefonte Nuclear Plant Unit 1 that were prepared concurrently.

- **PSEG**
  - Developed the need for power and energy alternatives analyses to satisfy the NUREG 1555 requirements for Environmental Reports associated with an Early Site Permit Application for a new nuclear plant project. Responded to NRC questions on need for power and alternatives at the environmental site audit. Prepared responses to Requests for Additional Information.

- **Oklahoma Municipal Power Authority**
  - Reviewed the analysis of power supply options completed by OMPA staff, including a review of the annual revenue requirements derived by the OMPA power supply planning model, assessment of various options for power purchase agreements,

analysis of power plant self-build and joint ownership options, evaluation of a potential transmission upgrade, and analysis of the impact of long-term changes in fuel prices and environmental regulations.

- **SaskPower**
  - Supervised a review of corporate resource planning processes. Processes and work products were compared to state-of-the-art utility industry examples and gaps identified. Recommendations for process improvements were prepared.

- **Tennessee Valley Authority**
  - Developed the need for power analysis to satisfy the NUREG 1555 requirements for Environmental Reports associated with a Combined Operating License Application for a new nuclear plant project.

PLANNING AND MARKET STUDIES

- **New York Independent System Operator**
  - Estimated the cost of new entrant peaking units used in the updating of demand curves for the NYISO capacity market in 2007, 2010 and 2013. Estimated going forward costs of existing generation used in determining need for market power mitigation. Estimated cost of new entry for proposed projects used to determine need for buyer side mitigation. Assisted in development of technical assessment process supporting a determination of whether a generator could transfer interconnection service rights when proposing to repower a generating unit.

- **New England Power Generators Association**
  - Estimated the cost of new entrant peaking units in New England for a NEPGA proposal to revise the basis for capacity payments in ISO-NE.

- **GenOn Energy**
  - Estimated the cost of new entrant peaking and combined cycle units in two PJM zones to support GenOn's comments on PJM's CONE pricing proposal. Made presentation to and answered questions from participants in FERC Settlement Conference held to develop an agreement on the value of CONE.

- **Eskom**
  - Surveyed major equipment suppliers with capabilities to support a large coal-fired project in Africa to assess the potential effect of current and projected production capacity, resource availability, and transportation requirements on project schedule, quality, and costs.

- **EPB**
  - Conducted seminars on selected generation, transmission and electricity market topics to prepare senior management on current trends and issues.

- **Confidential Client**
  - Led the preparation of a business plan for a client considering whether to develop a fleet of generating plants based on small modular nuclear reactor technology.

- **Confidential Client**
  - Estimated potential market volume for a cable manufacturer exploring entering the utility market.

DUE DILIGENCE STUDIES

- **Confidential Client**
  - Reviewed the operating history, environmental and regulatory requirements, contractual agreements, and technical and financial model inputs for two natural gas fired plants in support of a potential sale.

- **Seven States Power Corporation**
  - Reviewed the performance history, environmental and regulatory requirements, contractual agreements, and operations and maintenance activities and plans for two natural gas fired combined cycle plants in support of a potential acquisition.

- **Confidential Client**
  - Reviewed the operating history, environmental and regulatory requirements, and contractual agreements, and identified potential operational limitations, plant upgrades, and expected operating life for four coal or natural gas fired cogeneration plants in support of a potential transaction.

- **National Economic Research Associates**
  - Forecast capital and operations and maintenance (O&M) costs for an existing coal plant as input to an appraisal of the plant's market value being conducted by NERA. The scope of work included the review of any necessary environmental retrofits, upgrades, etc. as required for compliance with federal or state environmental regulation and the investments required for ongoing operations assuming a remaining useful life of 20 years.

ALTERNATIVES ANALYSIS

- **NV Energy**
  - Developed simple and combined cycle natural gas fired capacity expansion options at six brownfield sites in Clark County, NV, to support development of the Integrated Resource Plan. Factors considered in the development of options included emissions, water availability, transmission constraints, natural gas availability, and the shape and amount of space available at the site.

- **San Miguel Electric Cooperative**
  - Conducted study of generation alternatives to meet federal and state requirements for justification of new coal project.

- **CPS Energy**
  - Developed cost and performance assumptions for alternative technologies for use in integrated resource planning studies. Compared published estimates of costs for new nuclear plants.

- **Entegra Power Services**
  - Conducted a planning study of adding 300 MW of natural gas-fired peaking capacity to an existing power station in the southwest US. Estimated capital costs, operating performance, and operations and maintenance (O&M) costs for three aeroderivative combustion turbine models with and without selective catalytic reduction (SCR), and two frame combustion turbine models without SCR.

- **South Mississippi Electric Power Association**
  - Reviewed renewable energy alternatives for this G&T cooperative in anticipation of future Renewable Portfolio Standard requirements. Directed the evaluation of responses to an RFP for renewable energy and capacity.

- **Department of Energy and Sandia Renewable Energy Laboratory**
  - Updated the 2003 report, "Assessment of Parabolic Trough and Power Tower Solar Technology Cost and Performance Forecasts" with the Dish technology.

- **Oklahoma Gas & Electric**
  - Contributed to the analysis of generating alternatives for a study of how to reduce carbon emissions from the OG&E generating portfolio.

RISK ANALYSIS

- **Various Clients**
  - Analyzing the risks associated with the cost, schedule, and performance impacts of proposed projects.

- **Globeleq**
  - Identified and quantified key drivers of increases in capital estimates for coal fired power plants.

- **American Electric Power**
  - Identified and compared key characteristics of new nuclear plant technologies. Assessed the risk of each technology relative to client objectives.

- **Allegheny Energy**
  - Developed a comprehensive risk analysis model to determine the expected outage days, generation and costs for a fleet of supercritical coal-fired units based on a high level condition assessment. The objectives were to assess the impacts of the risk issues and associated mitigation projects and to provide support for the development of capital spending plans.

- **Confidential Client**
  - Led a due diligence study of a potential investment in temporary power services to countries with developing economies based on diesel engine technology.

Prior to joining Sargent & Lundy, Mr. Ungate had over 30 years of experience at the Tennessee Valley Authority in a variety of engineering and planning assignments. Examples of assignments include the following:

POWER SUPPLY PLANNING

- Directed supply planning for 30,000 MWs of nuclear, coal, gas, renewable, and hydro generation, and determined peak season power purchase requirements. Directed the preparation of power supply plans, and the valuation of capacity additions, major projects, product offerings, and bulk power transactions. Plans provided the basis for purchase and sale decisions; fuel purchase and inventory decisions; and hedging strategies for the commodity book.
- Led environmental controls optimization study to determine least cost approach to meeting CAIR/CAMR requirements for TVA's 15,000 MW coal generation portfolio. Alternatives included mothballing of units; increased allowance purchases; modified capital improvement programs; re-powering; and replacement with capacity and energy purchases from gas-fired units. Developed approach that resulted in reduction of projected end of period debt by more than $1 billion.
- Provided cost analysis for product pricing for industrial customers. Determined analytical approach and oversaw analyses to determine value of interruptible products, standby power, customer co-generation, long vs. short term contracts, and dispersed power products.

BUSINESS AND STRATEGIC PLANNING

- Directed business planning for portfolio of 109 conventional hydropower units at 29 sites and four pumped storage units. Portfolio supplies 10-15% of company sales with 5000 MWs of capacity. Forced outage rates, recordable injury incident rates, and reportable environmental events were increasing over the previous six years. Developed a five year business plan to increase resources to facilitate the transition to a process management maintenance strategy, and to integrate plant modernization and automation projects to change technology and workflow at the plants.
- Directed the first reassessment of the operating policies of Tennessee Valley Authority reservoirs since the system was designed in the 1930's. Stakeholders were concerned about water quality issues affecting the reservoirs and about the adverse impact of lake levels on property values and recreation-oriented businesses. Led initiative to redefine operating policies, examine environmental concerns, expand public interest and support, and more effectively meet the needs of multi-state customer base. Directed the development of an operating scheme that preserved hydropower value while improving summer lake levels for recreation and increasing minimum flows for water quality.
- Developed competitive analysis for an electric utility. Customers seeking choice of energy suppliers created need for a credible competitive analysis for electric utility monopoly. Price to customers was above competitive energy suppliers. Loss of customer load would create the risk of not recovering the high fixed costs of generation built to serve former customers. Quantified the competitive threat, and identified the circumstances under which loss of customers was most likely.

PROJECT ENGINEERING

- Directed 40-50 engineers, technicians and building trades conducting laboratory and prototype testing of thermal and hydro plant performance problems. Responsible for daily operating management, laboratory safety, quality assurance, human resources, technology acquisition and facilities management.

- Conducted field tests and physical modeling studies on the effects of thermal generating plants on rivers and reservoirs. Contributed to preparation of several environmental statements impacting authorizations for plant operations and discharge.

MEMBERSHIPS

Board of Examiners, Tennessee Quality Award, 1997-99

PUBLICATIONS

"Baseload Generation Capital Cost Trends," Electric Power Conference, May 2007.

"Resolving Conflicts in Reservoir Operations: Some Lessons Learned at the Tennessee Valley Authority," American Fisheries Society symposium, 1996.

"Tennessee Valley Authority's Clean Water Initiative: Building Partnerships for Watershed Improvement," Journal of Environmental Planning and Management, 39(1), 1996.

"'Equal Consideration' at TVA: Changing System Operations to Meet Societal Needs," Hydro Review, July 1992.

"Reviewing the Role of Hydropower in TVA Reservoir Operations," with Douglas H. Walters, Waterpower '91, An International Conference on Hydropower, Denver, Colorado, 1991.

"TVA's Lake Improvement Plan: Reviewing the Operating Objectives of TVA's Reservoir System," National Conference on Hydraulic Engineering, Nashville, Tennessee, July 1991.

"Tennessee River and Reservoir System Operation and Planning Review, Final Environmental Impact Statement," with TVA staff, December 1990.

"Field and Model Results for Multiport Diffuser Plume," with Charles W. Almquist and William R. Waldrop, American Society of Civil Engineers Specialty Conference on Verification of Mathematical and Physical Models, University of Maryland, August 1978.

"Mixing of Submerged Turbulent Jets at Low Reynolds Number," with Gerhard Jirka and Donald R. F. Harleman, M.I.T. Ralph M. Parsons Laboratory, Report No. 197, February 1975.

EXHIBIT CDU-2

Exhibit CDU-2 to Christopher D. Ungate Affidavit

Description of the Best Available Control Technology (BACT) Analysis Process for the Control of Greenhouse Gas (GHG) Emissions from a Natural Gas-Fired Simple Cycle Combustion Turbine

Both the NYISO and NERA/S&L Reports correctly state that the proposed proxy unit in the ROS (i.e., Siemens SGT6-5000F(5) simple-cycle combustion turbine without SCR) would be required, as part of the NYSDEC air permitting process, to conduct a Best Available Control Technology (BACT) analysis for the control of greenhouse gas (GHG) emissions (the "GHG BACT"). The BACT analysis is a project-specific examination of air pollution control technologies or techniques with the practical potential to reduce emissions of the regulated air pollutant under evaluation. BACT is defined as an emissions limitation based on the maximum degree of reduction which the permitting authority, on a case-by-case basis, determines is achievable for the proposed source taking into account energy, environmental, and economic impacts and other costs.[1] The primary guidance utilized in the preparation of a BACT analysis is the Environmental Protection Agency's (EPA's) *New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting*, Draft, October 1990 (the "NSR Manual").

The NSR Manual describes a "top-down" approach to determine BACT controls for new emission sources. In general, the top-down BACT process involves the following steps for each pollutant subject to regulation:

1. Identify all potential control technologies;
2. Eliminate technically infeasible control options;
3. Rank the remaining control technologies by control effectiveness;
4. Evaluate the control technologies, starting with the most effective for:
   - economic impacts,
   - energy impacts, and
   - environmental impacts;
5. Select BACT

In March 2011, EPA published additional guidance to assist permit applicants in addressing the prevention of significant deterioration (PSD) and BACT requirements for GHG emissions (the "March

[1] See, 40 CFR 52.21(b)(12).

2011 PSD Guidance").[2] The March 2011 PSD Guidance reiterates the continued use of the top-down BACT process to determine BACT for GHG emissions, and includes additional guidance specific to the evaluation of GHG controls. This exhibit provides a brief overview of procedures that would be used to prepare a GHG BACT analysis for a new stationary source of emissions, and identifies some of the technical and economic issues that would be taken into consideration in a GHG BACT analysis for a proposed natural gas-fired simple-cycle peaking unit.

The first step in the top-down BACT process is to identify all "available" control options. Available control options are those air pollution control technologies or techniques that have the potential for practical application to the emissions unit and the regulated pollutant under evaluation.[3] Historically, EPA has placed potentially applicable control alternatives evaluated in a BACT analysis into the following three categories:

- Inherently lower-emitting processes/practices/designs;
- Add-on controls; and
- Combinations of inherently lower emitting processes/practices/designs and add-on controls.[4]

EPA's March 2011 PSD Guidance notes that the GHG BACT analysis should consider potentially applicable control techniques from each of the three categories. However, EPA acknowledged that the Step 1 list of options need not necessarily include inherently lower-emitting processes, practices, or designs that would fundamentally redefine the nature of the source proposed by the permit applicant.[5] The March 2011 PSD Guideline notes that "[i]n circumstances where there are varying configurations for a particular type of source, the applicant should include in the application a discussion of the reasons why that particular configuration is necessary to achieve the fundamental business objectives for the proposed project."[6] For example, "the permitting authority can consider the intended function of an electric generating facility as a baseload or peaking unit in assessing the fundamental business purpose of a permit applicant."[7]

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[2] U.S.EPA, PSD and Title V Permitting Guidance for Greenhouse Gases, Office of Air Quality Planning and Standards, EPA-457/B-11-001, March 2011.

[3] U.S.EPA, March 2011 PSD Guidance, pg. 24.

[4] *Id.,* at 25

[5] *Id*., at 26. See also, *In re Prairie State Generating Company*, 13 E.A.D. 1, 23 (EAB 2006).

[6] U.S.EPA, March 2011 PSD Guideline, pg. 27.

[7] *Id*. See also, *In re Prairie State Generating Company*, 13 E.A.D. at 25 (recognizing the distinction between sources designed to provide base load power and those designed to function as peaking facilities).

EPA guidance makes it clear that certain design aspects of a proposed project are beyond the reach of a BACT analysis. For example, a BACT analysis for a proposed simple-cycle peaking plant would not require consideration of a combined-cycle configuration. Peaking plants are designed to provide power during periods of peak demand and provide load-following capabilities needed to mitigate for grid instability. To meet these objectives, peaking units must be designed to respond rapidly to demand changes and must be designed for numerous and rapid startups and shutdowns. Simple-cycle combustion turbines can meet these fundamental project objectives and are ideally suited as peaking units, while combined-cycle units may not have the ability to meet these project objectives. Based on EPA guidance, combined-cycle technologies would be outside the scope of the BACT analysis for a proposed peaking plant, and combined-cycle units would not be included in Step 1 of the BACT analysis.

Simple-cycle combustion turbines would be capable of meeting the goals and objectives of a proposed peaking project. Simple-cycle combustion turbines are available from a number of large equipment vendors, including General Electric, Siemens, Rolls-Royce, MHI, and others. Combustion turbines capable of meeting all project objectives (e.g., availability, size, cycling capabilities, startup/shutdown requirements, etc.) would be included in Step 1 of the GHG BACT analysis.

Step 2 would include an evaluation of the technical feasibility and effectiveness of each alternative, and Step 3 would rank the technically feasible and available combustion turbines by effectiveness. With respect to GHG emissions, available simple-cycle combustion turbines would be ranked by thermal efficiency, as the more efficient units would emit less GHG (primarily carbon dioxide, CO_2) on a net megawatt energy output basis (i.e., lb CO_2/MW). Once ranked, Step 4 of the top-down process provides for an evaluation of the economic, energy, and environmental impacts of the available alternatives.

The NERA/S&L Report notes that, in simple-cycle mode, aeroderivative combustion turbines such as the LMS100 are somewhat more efficient than the larger frame machines. Because CO_2 emissions are a direct function of the quantity of fuel fired, more efficient combustion turbines would emit less CO_2 on a lb/MW basis. For example, at full load the LMS100 simple-cycle combustion turbine will emit approximately 1,085 lb CO_2 per gross MW output (lb/MWh) or approximately 1,240 pounds on a net output basis (lb/MW net). By comparison, the Siemens SGT6-5000F combustion turbine in simple-cycle mode produces approximately 1,209 lb/MWh and 1,123 lb/MW net. Thus, from an effectiveness point of view, the aeroderivative combustion turbine would be ranked higher than the frame machine.

Step 4 of the top-down BACT analysis includes an evaluation of the economic, energy, and environmental impacts of the available control technologies. Both beneficial and adverse impacts should be assessed and, where possible, quantified. In the event that the most effective control alternative is shown to be inappropriate due to energy, environmental, or economic impacts, the basis for this finding is documented and the next most stringent alternative evaluated. This process continues until the technology under consideration cannot be eliminated by any source-specific environmental, energy, or economic impacts.

The economic impact assessment performed as part of the BACT analysis examines the cost-effectiveness of each control technology, on a dollar per ton ($/ton) of pollutant removed basis. Annual emissions using a particular control device are subtracted from base case emissions to calculate tons of pollutant controlled per year. Annual costs are calculated by adding annual operation and maintenance (O&M) costs to the annualized capital cost of an option. Cost effectiveness ($/ton) of an option is simply the annual cost (dollars per year ($/yr)) divided by the annual pollution controlled (tons per year (tpy)).

The NERA/S&L Report includes both capital and O&M costs for each combustion turbine option. The report shows that aeroderivative combustion turbines, although somewhat more efficient than the frame machines, are significantly more expensive on a $/kW installed cost basis. For example, the total capital investment required to install an LMS100 combustion turbine in Zone F was estimated to be $1,432/kW compared to a total capital investment of $718/kW for the SGT6-5000(F) (simple-cycle without SCR).[8] Furthermore, aeroderivative combustion turbines are typically smaller than the frame machines. For example, a nominal 200 MW peaking facility would require the installation of two LMS100s (with a net capacity of approximately 91.8 MW net each), but only a single SGT-6-5000(F) frame machine (with a net capacity of approximately 206.5 MW net).

The economic impact of installing an aeroderivative combustion turbine in lieu of a frame machine would be evaluated in Step 4 of the top-down BACT evaluation. The following table provides an example of the cost-effectiveness evaluation that would be prepared to evaluate the effectiveness of the aeroderivative option to reduce GHG emissions from the proposed peaking facility. Emissions and costs provided in the following table were taken from the NERA/S&L Report, and were adjusted to taking account an annual limit on the hours of operation of 950 hours/year.

[8] NERA/S&L Report, page 46.

		Frame SGT6-5000F(5) w/o SCR	Aeroderivative Two LMS100 PA w/ SCR	Difference
Net Plant Capacity	MW	206.500	183.600	
Annual Hours of Operation	hours	950	1,068	
Annual Starts	starts	150	150	
Potential Annual Gross Output	MW/yr	196,175	196,175	
CO_2 Emission Rate	lb/MW net	1,240	1,123	
Potential Annual CO_2 Emissions	tpy	121,629	110,152	11,477
Total Capital Investment	MM$	$ 148,346	$ 262,976	
Capital Recovery Factor(1)	OAQPS	0.092	0.092	
Capital Cost Amortization	$/yr	$ 13,647,800	$ 24,193,800	
Total Fixed O&M	$/kW-yr	$ 18.00	$ 28.26	
Total Fixed O&M	$/yr	$ 3,718,000	$ 5,189,000	
Total Variable O&M	$/MWh	$ 0.25	$ 5.38	
	$/start	$ 9,164	$ -	
		$ 1,424,000	$ 1,055,000	
Total Annual O&M		$ 5,142,000	$ 6,244,000	
Total Annual Cost(2)	$/yr	$ 18,789,800	$ 30,437,800	$ 11,648,000
Average Cost-Effectiveness(3)	$/ton			1,015

(1) For this evaluation a capital recovery factor of 0.092 was calculated based on an economic life of 20 years and an interest rate of 7%. See, U.S.EPA OAQPS Control Cost Manual, 6th ed, EPA 453/B-96-001, January 2002, Chapter 2 – Cost Estimation: Concepts and Methodology, equation 2.8a.

(2) Total Annual Costs include fixed and variable O&M as well as the annualized capital recovery cost.

(3) Cost-effectiveness is the difference in total annual costs divided by the annual reduction in CO_2 emission.

Based on the preliminary economic impact evaluation summarized above, the average cost-effectiveness of the aeroderivative option for reducing GHG emissions from a nominal 200 MW simple-cycle peaking facility limited to 950 hours/year operation would be approximately $1,015/ton. To justify elimination of an alternative based on economic impact, the applicant should demonstrate that costs of pollutant removal ($/ton) are disproportionately high when compared to the cost of control for the pollutant in recent BACT determinations.[9]

The costs of controlling GHG emission from simple-cycle combustion turbines have not been established through the PSD permitting and BACT determination process. However, the cost-effectiveness of substituting an aeroderivative combustion turbine in lieu of a frame combustion turbine for GHG control is clearly disproportionately higher. One benchmark that could be used to make this determination would be to compare project-specific control cost-effectiveness to the cost of Regional Greenhouse Gas

[9] NSR Manual at B.45.

Initiative (RGGI) CO_2 allowances. The RGGI $/ton price for CO_2 emission allowances in July 2013 was $3.21, several orders of magnitude below the calculated cost-effectiveness of the aeroderivative option for GHG control.

A second benchmark that could be used would be EPA's calculated "social cost" of carbon (SCC). EPA and other federal agencies use the SCC to estimate the climate benefits of rulemakings. EPA describes the SCC is an estimate of the value of damages avoided for a small emission reduction in CO_2 emissions.[10] Depending on the assumptions used to calculate the SCC, the most recent SCC estimates, updated in 2013 for the year 2015, range between $12 and $116/ton. The SCC is meant to be a comprehensive estimate of climate change damages and includes changes in net agricultural productivity, human health and property damages from increased flood risk, and may not be readily applied to a BACT cost-effectiveness evaluation. Nevertheless, the cost-effectiveness of the aeroderivative option for the control of GHG emissions is clearly disproportionately even when compared to EPA's estimate of the SCC.

Although a comprehensive GHG BACT analysis would require a more thorough evaluation of project goals and objectives, available technologies and control technologies, and project-specific costs and cost-effectiveness, the outline provided above shows that economic impacts would likely preclude aeroderivative combustion turbines as BACT for GHG controls for a proposed nominal 200 MW natural gas-fired peaking facility. Project proponents would have an opportunity to provide this type of evaluation and explain why the proposed turbine is the most efficient and cost-effective for the proposed source.

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[10] See, http://www.epa.gov/climatechange/EPAactivities/economics/scc.html.

ATTESTATION

I am the witness identified in the foregoing affidavit. I have read the affidavit and am familiar with its contents. The facts set forth therein are true to the best of my knowledge, information, and belief.

Christopher D. Ungate

Christopher D. Ungate

MELISSA R. CLARY
STATE OF TENNESSEE
NOTARY PUBLIC
KNOX COUNTY

Subscribed and sworn to before me
this 7 day of January 2014

Melissa R Clary

Notary Public

My commission expires: My commission expires July 8, 2014