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September 27, 2013

-VIA ELECTRONIC FILING -

Ms. Ann Cole
Commission Clerk
Florida Public Service Commission13
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

Re: Docket No. 130007-EI

Dear Ms. Cole:

I enclose for electronic filing in the above docket the prefiled rebuttal testimony and exhibits of Florida Power and Light Company witnesses Juan E. Enjamio, Terry J. Keith, Randall R. LaBauve and William L. Yeager.

Consistent with the directions provided by Staff to parties, FPL will deliver separately five (5) copies of the prefiled rebuttal testimony and exhibits of witnesses to Charles Murphy, the lead Staff attorney for the above docket.

If there are any questions regarding this transmittal, please contact me at 561-304-5639.

Sincerely,

s/ John T. Butler
John T. Butler

Enclosure
cc: Counsel for Parties of Record (w/encl.)

CERTIFICATE OF SERVICE
Docket No. 130007-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by hand delivery (*), electronic mail and United States mail this 27th day of September 2013, to the following:

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By: s/ John T. Butler
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BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 130007-EI
FLORIDA POWER & LIGHT COMPANY

SEPTEMBER 27, 2013

ENVIRONMENTAL COST RECOVERY

REBUTTAL TESTIMONY & EXHIBITS OF:

JUAN E. ENJAMIO
TERRY J. KEITH
RANDALL R. LABAUVE
WILLIAM L. YEAGER

IN SUPPORT OF PETITION FOR APPROVAL OF
NO_2 COMPLIANCE PROJECT

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF JUAN E. ENJAMIO

DOCKET NO. 130007-EI

SEPTEMBER 27, 2013

Q. Please state your name and business address.

A. My name is Juan E. Enjamio. My business address is 9250 West Flagler Street, Miami, Florida 33174.

Q. By whom are you employed and what is your position?

A. I am employed by Florida Power & Light Company ("FPL") as Supervisor of Integrated Analysis in the Resource Assessment & Planning Department.

Q. Have you previously testified in this docket?

A. Yes. I have.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring the following exhibit which is attached to my rebuttal testimony:

JEE-6 Updated results of the economic evaluation

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my rebuttal testimony is to respond to erroneous assertions in the testimony of the Florida Industrial Power Users Group ("FIPUG") witness Jeffry Pollock related to FPL's petition to recover costs associated with its proposed NO_2 Compliance Project ("Project") through the Environmental Cost Recovery Clause ("ECRC").

Q. Please summarize your rebuttal testimony.

A. FPL has examined all available options to achieve NO_2 Compliance, including the proposals to purchase power from or purchase the power plant facility of DeSoto, and has determined that the proposed NO_2 Compliance Project remains the most cost effective option for FPL and its customers. As further explained in the direct and rebuttal testimonies of FPL witnesses LaBauve and Keith, the purpose of this Project is to comply with an environmental requirement, unlike FPL's modernization projects, and the Project is therefore appropriate for cost recovery through the ECRC.

Q. In his testimony Mr. Pollock states that it is unclear whether FPL examined all available options to the Project proposed by FPL. Could you explain whether FPL evaluated all available options, including non-FPL generating facilities?

A. Yes. FPL did consider all available options, including existing non-FPL generation facilities. These options included three FPL alternatives, which were:

- The Retrofit Option – Retrofit the gas turbines ("GTs") and add emission controls such as Selective Catalytic Reduction ("SCR") to meet the new emission standards.
- Retirement Option – Retire the GTs and advance the in-service date of FPL's next generating unit, which is a new combined cycle unit, as needed to meet the 20% reserve margin reliability criteria.
- Combustion Technology Change Option – Retire the GTs and replace with new technology combustion turbines that provide quick-start capacity.

These alternatives are described in greater detail in my direct testimony in this docket.

FPL also reviewed whether any existing non-FPL generation facilities could be viable alternatives in addition to its own three proposed alternatives. This analysis considered either purchasing power from or purchasing outright non-FPL generation facilities. FPL concluded that there were no existing facilities that could be considered as viable options from a technical perspective. This conclusion was based on the fact that, to be a viable candidate, a generation facility would need to meet two system reliability criteria: (1) it must be located in the specific relevant geographic area, and (2) it must be able to provide quick-start capacity to the system.

Q. Can you explain why generation needs to be in a specific geographic area?

A. Yes. The geographical criterion is based on local transmission reliability requirements in Miami-Dade and Broward Counties, and in the Fort Myers area. These requirements were described in more detail in my direct testimony, but I will provide a summary below.

Miami-Dade and Broward Counties are heavily populated, with the highest concentration of customer load in FPL's service territory. By 2016, these two counties will have approximately 10,100 MW of load. Generation in the same area is expected to be about 6,200 MW by summer of 2016. The balance of load not served by generation in the area will be served from power imported from outside the area through transmission lines. The capability of the transmission system to import power into Miami-Dade and Broward Counties is limited to about 6,400 MW. If the GT generation in Broward County is retired and not replaced in the same geographic area, there is a loss of 1,260 MW in local generation. Transmission reliability simulations indicate that this lost capacity must be replaced with at least 1,000 MW of local generation.

Similarly, the operation of gas turbines at Fort Myers Plant is required to maintain voltage support for the loss of the Fort Myers combined cycle unit. Additional transmission reliability simulations have indicated that if the existing gas turbines at Fort Myers were to be retired, a minimum of 600 MW of CT generation is needed in the same geographic area to maintain adequate FPL system reliability for an outage of the Fort Myers combined cycle unit.

Q. Did FPL identify any existing non-FPL generation facilities that would meet this geographic criterion?

A. Yes. Four facilities were identified that would meet this criterion. These are listed below:

- Miami-Dade Resource Recovery in Miami-Dade County, 77MW
- Broward South Resource Recovery in Broward County, 66 MW
- Broward North Resource Recovery in Broward County, 68 MW
- DeSoto County Generating Company (LS Power) in DeSoto County, 310 MW

Q. Regarding the second criterion, please explain why any generation options for this Project need to provide quick-start capacity to the system.

A. FPL is a participant in the Florida Reserve Sharing Group ("FRSG") whose purpose is to share the burden of having to carry additional available generation in order to be prepared for the sudden loss of a generating facility. As a result, FPL is required to provide about 400 MW of contingency generation reserves, an amount that is based on the size of the largest unit in the state. For the loss of one of the FRSG participants' generating units, FPL is required to have available and, if necessary, provide this amount of reserve capacity to the system, within 15 minutes after the loss of the unit. For the loss of an FPL generating unit, FPL is also required to replace the full capacity of the unit within 30 minutes after its loss. The alternative to having quick-start generation capacity is to carry all of these reserves as spinning reserves in generators on-line thereby requiring the commitment of more generation than needed to serve load and operating these generators in a less economic fashion that would result in much higher fuel costs.

Q. Did any non-FPL generation facilities meet this quick-start criterion?

A. No. FPL considered the four non-FPL generation facilities that I previously identified as meeting the geographic criterion and determined that they would not be able to provide the required quick-start performance, *i.e.*, be off-line and then be able to start quickly enough and produce the required amounts of generation within the 15 and 30 minute required intervals. The three resource recovery facilities utilize steam generation technology that is clearly unsuited to quick-start operation. The DeSoto generation facility consists of CTs, but they utilize older technology that does not have the control systems and equipment needed to respond as required to meet this criterion. Therefore, based on the information available at the time of FPL's filing in this docket, FPL concluded that none of these four facilities could be considered as a viable option to provide the generation capacity needed for this compliance project.

Q. Since the time when the ECRC filing was made in this docket, has FPL conducted further analysis as to whether the DeSoto facility is a viable option to replace existing gas turbines?

A. Yes. Since the ECRC filing was made, FPL has received additional information on this facility both from LS Power, the parent of DeSoto, and from its own due-diligence efforts. The information obtained from LS Power includes an offer to FPL for the purchase of the DeSoto facility, in which LS Power most recently has committed to make upgrades that are said to support quick-start capability for the

CTs. Based on analysis of this additional information, and considering that it meets the geographic criterion, FPL has modeled the DeSoto unit as though it is capable of meeting the quick-start requirement. The LS Power offers and the information that FPL has received about the DeSoto facility are discussed further in the rebuttal testimony of FPL witness Yeager.

Q. Can you describe how you performed the economic evaluation?

A. Yes. FPL has developed four additional alternatives using the DeSoto CTs. The first two of these alternatives assume that FPL would buy the DeSoto facility in 2014, as proposed to FPL by LS Power. The last two of these alternatives assume that FPL would enter into a ten-year power purchase agreement ("PPA") starting in 2014, on the terms that LS Power has proposed. These four alternatives are described further below:

1. The first DeSoto alternative assumes that, in addition to purchasing the DeSoto facilities in 2014, FPL will build two 200 MW class CTs at Fort Myers in 2016. This combination will result in approximately 700 MW of CT capacity at Fort Myers and DeSoto.

2. The second DeSoto alternative assumes that in addition to purchasing DeSoto in 2014, FPL will build two 150 MW class CTs at Fort Myers in 2016. This combination will result in approximately 600 MW of CT capacity at Fort Myers and DeSoto. This combined capacity of 600 MW represents approximately the same amount of capacity FPL assumed would be required in its own proposal for three 200 MW class CTs at Fort Myers.

3. The third DeSoto alternative assumes that FPL enters into a ten-year PPA with DeSoto starting in 2014, and FPL will build two 200 MW class CTs at Fort Myers in 2016. This combination will result in approximately 700 MW of CT capacity at Fort Myers and DeSoto in 2016. In 2024, when the PPA is terminated, FPL will then build one 200 MW class CT at Fort Myers to replace the lost PPA capacity. At that point, total capacity at Fort Myers will be 600 MW.

4. The fourth DeSoto alternative assumes that FPL enters into a ten-year PPA with DeSoto starting in 2014, and FPL will build two 150 MW class CTs at Fort Myers in 2016. This combination will result in approximately 600 MW of CT capacity at Fort Myers and DeSoto in 2016. In 2024, when the PPA is terminated, FPL would then build two 150 MW class CT at Fort Myers to replace the lost PPA capacity.

The DeSoto cost information used in this evaluation is based on the revised proposal from LS Power that is Exhibit WLY-2 of FPL witness Yeager's rebuttal testimony. Mr. Yeager also discussed in his rebuttal testimony the uncertainty that exists concerning additional costs that FPL would have to incur to operate the DeSoto facility and FPL's estimate of approximately $20 million of upfront costs that FPL would need to incur to bring the facility up to the standard of FPL's generating fleet. Since FPL's filing in this docket and based on industry responses to a request for proposals ("RFP") for CTs, FPL has also obtained more accurate information on the costs of CT technologies. This up-to-date information results in extended maintenance intervals and hence lower capital-part cost estimates for the type of CTs that FPL proposes to install at Lauderdale and Ft. Myers. I have updated the economic evaluation of the three FPL options that was presented in my direct testimony to reflect these lower costs and have also used the lower costs in evaluating the combined DeSoto/Fort Myers alternatives. All of my economic evaluations of the DeSoto alternatives and the FPL Project continue to assume that the Broward County GTs will be changed out for five new 200 MW CTs at Lauderdale Plant.

Q. What are the results of the evaluation of the DeSoto alternatives?

A. FPL conducted its economic evaluation of the seven alternatives under consideration (the original three FPL alternatives and the four new DeSoto alternatives) by computing the cumulative present value of revenue requirement ("CPVRR") for each alternative. The alternative that results in the lowest CPVRR is the one that will result in lowest cost to FPL's customers over the life of the projects.

The results of the economic evaluation, presented in Exhibit JEE-6, show that FPL's Combustion Technology Change Option continues to be the lowest cost option for FPL and its customers, when compared to all the other alternatives. This option results in $48 million lower CPVRR than the first DeSoto purchase alternative and $70 million lower CPVRR than the second DeSoto purchase alternative. When compared to the DeSoto alternatives which assume a 10 year PPA, the FPL Project results in $56 million lower CPVRR than the third alternative, and $142 million lower in CPVRR than the fourth alternative. The testimony of FPL witness Yeager discusses the serious concerns FPL would have with attempting to rely on a PPA for quick-start capacity that is needed to maintain system reliability. My economic analysis confirms that, even if one set aside those serious reliability concerns, the

DeSoto PPA alternatives would not be economically attractive for FPL and its customers.

Based on the results of this economic evaluation, I conclude that FPL's proposal to implement the Combustion Technology Change Option through the NO_2 Compliance Project continues to be in the best interest of FPL's customers, as it would result in the lowest cost impact while providing greater certainty of operation, as described in the testimony of FPL witness Yeager.

Q. In his testimony, FIPUG witness Pollock suggests that FPL's proposed project is essentially a modernization project just like other FPL modernization projects. Is this true?

A. No. Mr. Pollock states that the proposed NO_2 Compliance Project and the FPL modernization projects (and more specifically the Port Everglades modernization) are similar in nature as they both result in the replacement of old generation, and because both projects must meet transmission and system reliability criteria. Mr. Pollock goes on to argue that the NO_2 Compliance Project should be treated the same as the Port Everglades modernization project, *i.e.*, cost recovery through base rates and not the ECRC.

Mr. Pollock's argument fails to recognize important distinctions between the projects. FPL's modernization projects were constructed to meet load as well as reliability requirements in addition to providing major fuel savings opportunities as a result of improved efficiencies. These modernization projects resulted in the addition of generation capacity to FPL's system. The NO_2 Compliance Project, on the other hand, is being undertaken directly and solely as the most cost-effective way to comply with an environmental regulation, the new 1-hour NO_2 standard. The Project is not needed to meet load and reliability obligations; the existing GTs serve that role perfectly well. In fact, the Project will result in a *reduction* in total FPL system capacity. The Project also is not motivated by fuel savings through lower heat rates. The units – be they the existing GTs or the new CTs - operate infrequently; thus, fuel savings is not an overriding factor.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF TERRY J. KEITH

DOCKET NO. 130007-EI

SEPTEMBER 27, 2013

Q. Please state your name and business address.

A. My name is Terry J. Keith and my business address is 9250 West Flagler Street, Miami, Florida 33174.

Q. By whom are you employed and what is your position?

A. I am employed by Florida Power & Light Company ("FPL" or "the Company") as Director, Cost Recovery Clauses in the Regulatory Affairs Department.

Q. Have you previously testified in this docket?

A. Yes, I have.

Q. Are you sponsoring any exhibits to your rebuttal testimony?

A. Yes. I am sponsoring Exhibit TJK-5 - Revised Commission Forms from FPL's 2013 Actual/Estimated True-up and 2014 Projections filings.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to respond to the testimony of the Florida Industrial Power Users Group ("FIPUG") witness Jeffry Pollock related to FPL's petition to recover costs associated with its proposed NO_2 Compliance Project ("Project") through the Environmental Cost Recovery Clause ("ECRC").

Q. Please summarize your testimony.

A. My testimony responds to a number of flawed arguments offered by Mr. Pollock in support of his position that the Project does not qualify for cost recovery under the ECRC. Indeed, nothing in Mr. Pollock's testimony provides a valid basis for disqualifying the Project for ECRC recovery.

Q. Mr. Pollock's testimony argues that the Commission should reject FPL's petition to recover costs associated with the Project because it does not meet the third of the Commission's criteria for cost recovery through the ECRC as set forth in Order No. PSC-94-0044-FOF-EI: none of the expenditures in question are being recovered through some other cost recovery mechanism or through base rates. Do you agree with Mr. Pollock's conclusion?

A. No. In his testimony, Mr. Pollock asserts that costs associated with FPL's existing GTs at the Fort Myers ("PFM"), Port Everglades ("PPE") and Fort Lauderdale ("PFL") plants and related transmission infrastructure are currently being recovered through FPL's base rates and any higher costs that may be associated with the proposed replacement capacity and transmission interconnections would also be properly recovered in base rates. He apparently considers this a double recovery that would be inconsistent with the third criterion.

Mr. Pollock is correct that costs associated with the GTs at PFM, PPE and PFL are included in FPL's current base rates. However, those costs are being incurred independent of the costs associated with the Project. FPL will continue to operate the GTs as needed for peaking capacity until the new CTs are ready to take their place, which is not scheduled to occur until 2016. Beginning to implement the Project now does not impact the costs that FPL is incurring and will continue to incur for the GTs until the time that the new CTs go into service. The CT costs are separate and independent of the GT costs captured in base rates; there is no double recovery.

Q. Mr. Pollock states that "…the Project costs are the type of cost that is typically collected in base rates, and this practice should not be changed at this point in time." Do you agree that ECRC recovery of the NO_2 Compliance Project would constitute a change in Commission practice?

A. No, I do not. Since 1993, FPL and other Florida IOUs have petitioned the Commission for ECRC recovery of projects designed to comply with various new environmental requirements. For recovery through the ECRC, the type of cost is not the determining factor; it is whether the project is designed to meet the requirements of a new environmental mandate. Thus, if the project is being undertaken solely to meet a new environmental requirement, it should qualify for ECRC recovery under the second criteria established by the Commission, regardless of the type of cost.

The purpose for replacing the combustion technology of the old GTs with new, high-efficiency and low-emission CTs as proposed in the Project is not to increase generation capacity (the Project will actually reduce generation capacity) but rather is for the sole purpose of complying with a new environmental regulation (the 1-hour NO_2 standard). As such, the costs associated with the NO_2 Compliance Project are appropriate for recovery through the ECRC, unless those specific costs are being recovered in base rates. There are no costs associated with the Project in FPL's current base rates. The costs associated with the NO_2 Compliance Project are clearly incremental and could not have been anticipated at the time FPL prepared its 2013 test year projections and, as explained by FPL witness LaBauve, they must be incurred as a result of an environmental regulation.

What appears to be confusing Mr. Pollock is the nature of the environmental compliance alternative that FPL has chosen. If adding emission controls to the existing GTs had turned out to be the lowest cost option, there would be little debate as to whether the costs of those controls were properly recoverable through the ECRC. FPL considered adding emission controls to the existing GTs and concluded that for some of the GTs it was technically infeasible and for the rest it would be more costly than replacing the GTs with the new CTs. FPL should not be subjected to a cost recovery penalty simply because it chose a lower cost compliance option for the benefit of customers that happens to involve changing out the GTs in favor of lower emission combustion technology on the three sites.

Q. Mr. Pollock claims that FPL's current request for ECRC recovery of the NO_2 Compliance Project is similar to its request for recovery through the ECRC of costs associated with the steam turbine upgrade at Scherer Unit 4, which the Commission denied. Do you agree?

A. No. On August 2, 2010, FPL requested recovery through the ECRC of costs associated with a turbine upgrade at Scherer Unit 4. The installation of the new high pressure rotor to the turbine generator would allow FPL to generate 35 MW of additional output that would offset the loss of MWs resulting from the installation of pollution control equipment (baghouse, scrubber and selective catalytic reduction equipment), which was determined to be the most cost-effective option to remain in compliance with the EPA's Clean Air Interstate Rule ("CAIR") and the Georgia Multipollutant Rule.

In that case, the Commission denied FPL's request because it concluded that the turbine upgrade was a discretionary project, and the costs associated with it were not environmental compliance costs required by a known environmental rule or regulation. The environmental requirement, EPA's CAIR and Georgia Multipollutant Rule, was satisfied by the implementation of the most cost-effective option, the installation of pollution control equipment, in order for Scherer Unit 4 to remain in compliance and continue operating, it did not require that FPL take steps to increase the unit's output in order to offset the lost output resulting from the pollution control equipment. As such, the Commission concluded that there was no direct nexus or link between the cost of the turbine upgrade and the environmental rules with which FPL was complying.

In contrast, the EPA's new 1-hour NO_2 standard requires that FPL reduce the emissions at the PFM, PFE and PFL sites that result currently from operation of the old generation combustion technology of the existing GTs. As discussed in the direct testimony and rebuttal testimony of FPL witness Enjamio, FPL has explored alternatives to accomplish the required emission reduction and has concluded that replacing the combustion technology of the existing GTs with highly efficient, low-emission CTs will achieve environmental compliance at the lowest cost for customers. The Project is not a discretionary activity to supplement FPL's required compliance strategy – the Project *is* the compliance strategy. The nexus between the Project and the 1-hour NO_2 standard could not be more direct.

Q. Mr. Pollock claims that Staff's recommendation to deny Gulf Power Company's ("Gulf") request for recovery through the ECRC of costs associated with transmission upgrades at Plant Crist and Plant Smith is also similar to FPL's request for ECRC recovery of the NO_2 Compliance Project. Do you agree?

A. No. Mr. Pollock's attempt to draw a parallel between the two situations for purposes of ECRC recovery fails to focus on key distinctions. In addition, Staff's recommendation is yet to be considered and ruled on by the Commission. The Staff recommendation in the Gulf case is based on a conclusion that there was not a direct nexus between the transmission upgrades and the environmental requirement in question (the Mercury and Air Toxics Standards or "MATS" rule). That driving rationale behind the Staff recommendation in Gulf's case is totally absent with FPL's Project -

FPL's Project is directly and exclusively aimed at complying with the 1-hour NO_2 standard. FPL can't run its GTs at all after 2016 without violating the NO_2 standard. The nexus between the environmental requirement and the mandate to retire the GTs is simple and direct. On the other hand, in the Gulf recommendation, Staff's position is that the scrubber at Plant Crist, which is already in place, is the direct link to compliance with the MATS rule, not the transmission upgrades. Staff notes that Gulf will be able to utilize coal-fired operation of the Plant Crist units and remain in compliance with MATS requirements by utilizing the scrubber.

Although the transmission upgrades at Plant Smith will allow the operation of the units in economic dispatch, Staff believes that these upgrades are ultimately motivated by system reliability considerations rather than environmental compliance activities such as retirement and replacement or the addition of emission controls, which would still be necessary in order to comply with the MATS rule.

As I have stated earlier in my testimony, the direct and specific purpose of FPL's Project is to meet the EPA's 1-hour NO_2 standard.

Q. Mr. Pollock states in his testimony that "FPL is not required to invest in the Project in order to comply with the new NO_2 standard. All that is required of FPL to comply with the standard is to cease operating the GTs, except to provide black start capacity." Is this a realistic way to assess the eligibility of the Project for ECRC recovery?

A. No. In almost all instances, a utility could comply with new emission limitations by simply shutting down the plants that exceed those limitations. However, the Commission has on numerous occasions allowed the cost of emission control equipment to be recovered through the ECRC based on the conclusion that it is in the customers' best interest to install that equipment rather than shut down the affected plants. For example, in Order No. PSC-04-0986-PAA-EI, issued in Docket No. 040750-EI on October 11, 2004, the Commission approved recovery through the ECRC of costs associated with retrofit activities for NOx emission reductions at TECO's Big Bend Station versus repowering or shutting down three of the four units at the station. As was discussed in detail in the direct testimony of FPL witness Enjamio, replacing the old and inefficient combustion technology of FPL's GTs with the new, highly efficient and low-emission CTs is the most cost-effective option to comply with the new environmental regulation, significantly less expensive to customers than simply retiring the GTs and accelerating the next planned combined cycle generating unit.

Q. If the Commission approves recovery through the ECRC of the NO_2 Compliance Project, Mr. Pollock recommends that costs be allocated to customers as an equal percentage base rate increase applied to all base charges and base credits contemporaneously. Do you agree with that approach?

A. No. Mr. Pollock recommends that if the Commission were to approve recovery through the ECRC of the NO_2 Compliance Project, costs associated with the Project should be allocated to FPL's customers based on the same methodology that the Commission approved in Order No. PSC-13-0023-S-EI, issued in Docket No. 120015-EI on January 14, 2013, for recovery of base rate costs associated with the Cape Canaveral, Riviera and Port Everglades modernization projects. This mechanism is referred to as the Generation Base Rate Adjustment ("GBRA"). The GBRA is used for short-term recovery of the costs for new power plants, until those plants are rolled into base rates after the end of the settlement term. The allocation of GBRA recoveries to rate classes on an equal-percentage basis is intended to preserve the status quo for cost of service and rate design until those topics are revisited in the next base rate case.

His recommendation is inconsistent with Section 366.8255, Florida Statutes, which was enacted into law on April 13, 1993 and established the environmental cost recovery clause. The statute authorizes the recovery of prudently incurred environmental compliance costs through the environmental cost recovery factor. Subsection 4 of the Statute states:

> "Environmental compliance costs recovered through the environmental cost-recovery factor shall be allocated to the customer classes using the criteria set out in s. 366.06(1), taking into account the manner in which similar types of investment or expense were allocated in the company's last rate case."

As discussed throughout my direct and rebuttal testimony, the sole and direct purpose of the Project is environmental compliance. Costs for the

Project therefore should be recovered consistent with the approved statute for ECRC recovery. Accordingly, FPL is proposing that the capital costs of the Project be allocated to rate classes based on the approved demand allocation methodology used for production plant in its last base rate proceeding, which is the 12 CP and 1/13 method, that allocates most costs (12/13ths) based on each customer class's contribution to the 12 monthly system peak hours.

In the August 1, 2013 filing of its 2013 Actual/Estimated True-Up and in the August 30, 2013 filing of its 2014 ECRC projections, FPL included $22,356 and $6.5 million respectively, associated with return requirements on Construction Work in Progress ("CWIP") associated with the Project, which were allocated to rate classes based on 12 CP demand instead of the 12 CP and 1/13 method. Therefore, included as Exhibit TJK-5 are revised Forms 42-1E, 2E, 3E, 6E, 7E, 1P, 3P and 7P reflecting the appropriate allocation method.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF RANDALL R. LABAUVE

DOCKET NO. 130007-EI

SEPTEMBER 27, 2013

Q. Please state your name and address.

A. My name is Randall R. LaBauve and my business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

Q. Have you previously testified in this docket?

A. Yes.

Q. Are you sponsoring any rebuttal exhibits in this docket?

A. Yes. I am sponsoring Exhibit RRL-8 - Additional Clarification Regarding Applicability of Appendix W Modeling Guidance for the 1-hour NO_2.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony addresses inaccuracies in the direct testimony provided by Jeffry Pollock on behalf of the Florida Industrial Power Users Group ("FIPUG"), and Carolyne Wass and Kathy A. French on behalf of DeSoto Generating Company LLC.

Q. Please summarize your rebuttal testimony.

A. Contrary to Mr. Pollock's testimony, there is a clear and direct nexus between the 2010 1-hour NO_2 National Ambient Air Quality Standard ("NAAQS") and the highly efficient, low-emission combustion turbines ("CTs") that FPL proposes to install at the Lauderdale and Fort Myers facilities under the NO_2 Compliance Project. Those CTs are not ancillary to compliance with the environmental standard; rather, they are the lowest cost environmental compliance measure. Contrary to statements by Mr. Pollock, the Environmental Protection Agency's ("EPA") exemption from modeling for NAAQS compliance that applies to intermittent sources, including emergency generators, would not exempt the existing gas turbines ("GTs") at the Lauderdale, Fort Myers and Port Everglades facilities.

Contrary to statements by Ms. Wass and Ms. French, the 1-hour NO_2 NAAQS is final and enforceable within Florida, such that major sources (including FPL's GTs at the Lauderdale, Fort Myers and Port Everglades facilities) are currently subject to that standard.

REBUTTAL TO FIPUG WITNESS POLLOCK

Q. What initial observations do you have with respect to FIPUG witness Pollock's testimony?

A. Mr. Pollock's conclusion that there is no direct nexus between FPL's proposed project and a new environmental project is simply wrong. First, the Florida Department of Environmental Protection's ("FDEP") adoption of the 1-hour NO_2 NAAQS applies directly to operation of the existing GTs at the three sites. Second, reduction of emissions from the existing GTs at all three facilities is needed to bring off-site air quality impacts within the level permitted under the 1-hour NO_2 NAAQS.

As I explained in my direct testimony, EPA's promulgation of a new 1-hour NO_2 NAAQS of 100 parts per billion (ppb) was to ensure that public health is protected with an adequate margin of safety. The FDEP's adoption of the new standard was required to ensure that air quality within Florida is protective of human health in compliance with Clean Air Act requirements. Compliance with the new 1-hour NO_2 NAAQS requires that FPL reduce emissions at the Lauderdale, Fort Myers and Port Everglades plant sites. Like virtually all EPA and FDEP requirements, the new standard does not dictate precisely how FPL must achieve the emission reductions. This means that FPL has discretion to choose the best emission reduction strategy taking into account cost-effectiveness and system requirements. As discussed by FPL witnesses Enjamio and Yeager, FPL's evaluation concluded that replacing the older, inefficient combustion technology of the existing GTs with new highly efficient and low emission CTs is the best option for customers. Quite simply the CTs that FPL proposes to install under the NO_2 Compliance Project *are* the environmental compliance measure rather than being merely ancillary to compliance as the Commission concluded with respect to FPL's Scherer Turbine Upgrade project and as the Commission Staff has recommended with respect to Gulf Power Company's transmission upgrade project.

Q. Do you agree with Witness Pollock's conclusion that the 1-hour NO_2 NAAQS does not apply to the existing units?

A. No. Witness Pollock incorrectly concludes that the 1-hour NO_2 NAAQS does not apply to the existing GTs because of his mistaken belief that the sole purpose of those units is to provide black-start capability for FPL's system. Rather, the primary purpose of the GTs is to provide quick-start peaking generation. Likewise, FPL's proposed peaking CTs are intended to provide quick-start peaking generation, with black-start capability provided either by a retained GT or separate on-site emergency generator for unit startup.

While the EPA has specifically exempted Emergency Generators from modeling requirements for offsite NO_2 impacts in its guidance to EPA Regional Air Division Directors (Exhibit RRL-8), operation of either the existing GTs or the proposed CTs to provide peak generation to the grid requires that the units comply with all EPA promulgated NAAQS levels because their operation for extended periods to provide peak generation disqualifies them from the definition of "Emergency Generators."

REBUTTAL TO DESOTO WITNESS FRENCH

Q. Do you have any initial observations with respect to DeSoto witness French's testimony?

A. Yes. Ms. French incorrectly concludes that the 1-hour NAAQS for NO_2 is a proposed rather than final standard and that the DeSoto facility is not subject to that standard.

Q. Do you agree with witness French that the 1-hour NO_2 NAAQS is not final?

A. No. EPA finalized their revision to the NO_2 NAAQS by adopting a new 1-hour standard, which was published on February 10, 2010 (75 FR 6474). The final rule became effective 60 days later on April 12, 2010. On January 20, 2012 EPA made designations of "attainment" or "unclassifiable" for the new standard. On January 22, 2013 the FDEP provided notice confirming that its State Implementation Plan adequately addresses the requirements of section 110 of the Clean Air Act with respect to the implementation of the 1-hour NO_2 NAAQS. The standard is clearly final and in effect for Florida.

Q. Do you agree with witness French that the 1-hour NO_2 NAAQS does not apply to the DeSoto facility?

A. No. All major sources are subject to the NAAQS requirements, and hence the 1-hour NO_2 standard, either under the Prevention of Significant Deterioration Program (40 CFR Part 51.230) or because of measured or modeled impacts under the NAAQS program (40 CFR Part 50.1). FPL can find no regulatory exclusion from the applicability of the 1-hour NO_2 NAAQS for the DeSoto facility.

Q. Witness French asserts that DeSoto County, Florida, where the DeSoto facility is located, is currently classified by EPA as being in "attainment" status. Does "attainment" status affect the applicability of the 1-hour NO_2 NAAQS?

A. No. Stationary sources such as the DeSoto facility and FPL's Lauderdale, Fort Myers and Port Everglades facilities must not cause the ambient air quality to exceed the limit set under the 1-hour NO_2 NAAQS at the site boundary regardless of whether the sources are located in areas that are designated as "attainment" or "non-attainment". As defined by 40 CFR 50.1(l), an exceedence with respect to a NAAQS is defined as "one occurrence of a measured or modeled concentration that exceeds the specified concentration level of such standard for the averaging period specified by the standard" irrespective of the attainment status of an area.

REBUTTAL TO DESOTO WITNESS WASS

Q. What observation do you have with respect to DeSoto witness Wass's testimony?

A. Similar to DeSoto witness French, Ms. Wass mistakenly concludes that the 1-hour NO_2 NAAQS is not yet final, stating that FPL's project is being proposed *"…in advance of possible implementation of the EPA's 1-Hour National Ambient Air Quality Standard (NAAQS) for Nitrogen Dioxide (NO_2)."* For the reasons I just discussed, the 1-hour NO_2 NAAQS is definitively final and neither Ms. French nor Ms. Wass points to anything that would call the finality of that standard into question.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF WILLIAM L. YEAGER

DOCKET NO. 130007-EI

SEPTEMBER 27, 2013

Q. Please state your name and business address.

A. My name is William L. Yeager and my business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

Q. By whom are you employed and what is your position?

A. I am employed by NextEra Energy, Inc. as Executive Vice President of Engineering, Construction and Integrated Supply Chain ("ISC").

Q. Please describe your duties and responsibilities in your current position.

A. I am responsible for engineering and construction of all generation projects for NextEra Energy, Inc., including all generation projects for Florida Power & Light Company ("FPL" or the "Company"), as well as all start-up activities. I am also responsible for all procurement for FPL, including the equipment and parts necessary for maintenance, repairs and upgrades of generating units.

Q. Please describe your education and professional experience.

A. I received a Bachelor of Mechanical Engineering degree from the Georgia Institute of Technology in 1982. I received an MBA from the University of South Florida in 2003. I am a registered Professional Engineer in the State of Florida and a member of the American Society of Mechanical Engineers.

My 31 years of work experience have involved the design, engineering and construction of electrical power plants, in which I have held numerous positions with increasing responsibilities. My career began as a mechanical engineer with FPL in 1982. In 1987, I was lead engineer for the preliminary engineering phase of Lauderdale Units 4 and 5, two 400 MW combined cycle repowered units that came on line in 1992.

From 1988 to 1991, I was the Project Engineering Manager for FPL's Martin Combined Cycle Project. Following the completion of Martin 3 and 4 in 1991, I held various management positions at the FPL Martin Plant site. In 1995, I became Operations Manager for NextEra Energy Resource's predecessor, ESI Energy, Inc., an unregulated affiliate of FPL. This included operations responsibilities for fossil fuel power plants, including natural gas, oil and coal, and renewable energy power plants, including wind, solar and wood by-products.

From 1997 to 1999, I was a General Manager within the Power Generation Division of FPL responsible for providing engineering for combustion turbines ("CTs") and balance of plant components. In this role I had responsibilities for combustion turbine-related power plants which included simple cycle and combined cycle plants. From 1999 through 2001, I was Plant General Manager of FPL's Manatee Plant.

From 2001 to 2005, I was the Director of Engineering in the Engineering and Construction Division with overall responsibility for the engineering of all FPL power plant projects.

In 2006, I was named Vice President of Engineering and Construction. I was responsible for the engineering, construction and start-up of all power plant projects for NextEra Energy, Inc. This position included overall responsibility for reviewing, monitoring and performing any technical evaluations on all generation technology options for FPL. This included providing technology assessments, which would include the estimation of construction costs, operating costs, and performance projections such as heat rate, output, availability and reliability, requiring an understanding of the most current technology advancements. In 2011, I was named Vice President of ISC, responsible for all procurement for NextEra Energy, Inc., including FPL. I was then promoted to my current position as Executive Vice President of Engineering, Construction and ISC.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to respond to the direct testimony of Carolyne Wass and Kathy French filed on behalf of DeSoto County Generating Company, LLC ("DeSoto"). Specifically, I rebut the claim that the sale of the DeSoto facility or energy and capacity from the DeSoto facility could more economically meet the objectives of FPL's NO_2 Compliance Project.

Q. Are you sponsoring any exhibits to your rebuttal testimony?

A. Yes. I am sponsoring the following exhibits:

- Exhibit WLY-1: Initial Draft Terms and Conditions from LS Power (Confidential)
- Exhibit WLY-2: Revised Draft Terms and Conditions from LS Power (Confidential)

Q. Please summarize your testimony.

A. FPL received an offer from LS Power Development, LLC ("LS Power"), the owner of DeSoto, to purchase the DeSoto facility or enter into a purchase power agreement ("PPA") to buy energy, capacity and ancillary services from the DeSoto facility as a partial alternative to constructing new CTs at the Lauderdale and Fort Myers plant sites under FPL's proposed NO_2 Compliance Project. The LS Power offer terms are not final, and despite the due diligence FPL has been able to conduct on the facility to date, important details are still not known about the present state of the DeSoto facility and upcoming capital improvement and maintenance plans. Nonetheless, our review thus far has produced enough information to enable FPL to conduct an economic evaluation of the DeSoto proposals. The results of this evaluation, presented by FPL witness Enjamio, demonstrate that FPL's proposed NO_2 Compliance Project remains the most economic choice for FPL's customers.

Q. Please describe the DeSoto site and facility.

A. The DeSoto generating facility is located in Arcadia, Florida, and is interconnected to FPL's transmission system. The generating facility consists of two General Electric ("GE") 7241 FA CTs operating in simple-cycle configuration with a total summer net generating capacity of 310 megawatts ("MW").

It is important to note that the DeSoto facility does not provide nearly the amount of capacity that FPL needs for reliability purposes to make up for the retirement of the existing gas turbines ("GTs") at the Lauderdale, Fort Myers and Port Everglades plants under the proposed NO_2 Compliance Project. For this reason, it is incorrect for witness Wass to present the purchase of the DeSoto facility or a PPA from DeSoto as an alternative to FPL's entire project. Rather, FPL would be required to continue with a substantial portion of its proposed project *in addition* to the DeSoto purchase or PPA, even assuming such a transaction were viable. The limited extent to which DeSoto, if it were a viable option, could substitute for the planned CTs is described in the rebuttal testimony of FPL witness Enjamio.

Q. Did FPL consider purchasing the DeSoto facility or a PPA from the facility as a potential option when it was initially identifying and evaluating alternatives to comply with the 1-hour NO_2 standard?

A. Yes. As discussed in the testimony of FPL witness Enjamio, FPL conducted an initial screening evaluation of existing generating facilities that were located in either the Fort Myers or Miami-Dade County-Broward County areas, to determine if those facilities could make a technically viable contribution to the capacity need resulting from retiring the existing GTs. DeSoto was one of the facilities considered in that screening evaluation.

FPL determined at the time, however, that DeSoto could not make a technically viable contribution. While DeSoto met the geographic criterion due to its proximity to the Fort Myers site, it did not meet the technical criterion as it currently lacks quick-start capability. Therefore, it was not considered for further evaluation as part of FPL's determination of the most cost-effective environmental compliance alternative.

Q. Did FPL receive an offer from LS Power?

A. Yes. Subsequent to FPL filing its petition and supporting testimony in this docket, FPL received an offer from LS Power to sell FPL the DeSoto facility. The offer was provided to FPL on July 31, 2013. The terms of the offer are included in my confidential Exhibit WLY-1. Alternatively, LS Power offered to enter into a 10-year PPA agreement with FPL. The terms of the proposed PPA also are included in the confidential Exhibit WLY-1. FPL reviewed the terms of the offer and emphasized to LS Power the importance of quick-start capability for further consideration of the DeSoto facility.

Q. Did LS Power provide a revised offer?

A. Yes. On August 28, 2013, FPL received a revised offer that included LS Power installing GE's "Fast Start OpFlex" package prior to transfer of ownership to FPL in an effort to meet FPL's quick-start criterion. The offer also included a new proposed sales price set forth in confidential Exhibit WLY-2. The draft PPA terms remained unchanged and likewise are reflected in this exhibit.

Q. Does FPL consider the offer final at this point?

A. No. Both offers were presented in documents titled "Draft Terms and Conditions Summary."

Q. What review did the Company undertake of the proposal?

A. Once LS Power had revised the proposal to address FPL's need for quick-start capability, FPL personnel promptly conducted a site visit to examine the facility and meet with the LS Power asset manager as well as the NAES plant manager. NAES is the third-party operator of the DeSoto facility. Additionally, FPL requested and reviewed over 200 documents, including Generating Availability Data System ("GADS") information, inspection and maintenance reports, permits, title and deed information, aerial photos, and inventory data.

Finally, as explained in the rebuttal testimony of FPL witness Enjamio, FPL has performed economic analyses of the DeSoto proposals as a partial substitute for the CTs that FPL proposes to construct at the Fort Myers plant in order to change out the combustion technology of the existing GTs.

Q. Please describe some of the key factors identified through FPL's review that may affect the cost of adding quick-start capability to the DeSoto plant and/or the assurance that the facility in fact can provide the necessary quick-start capability when and as needed.

A. During its site visit, FPL learned that LS Power has installed non-GE parts in its GE units. Additionally, one of the CTs has an older, rebuilt rotor. Finally, there is documentation of corrosion inside the compressor section of the DeSoto turbines, which presents a reliability risk for the model of turbines at DeSoto. FPL requested from LS Power a copy of the proposal from GE outlining the upgrades that would be performed on the plant to meet FPL's quick-start criteria and performance guarantees from GE. LS Power has not provided a copy of the proposal for our review.

Q. What assumptions regarding the costs and operating characteristics of the DeSoto facility did FPL witness Enjamio use in his economic evaluation?

A. The economic evaluation relies upon the August 28, 2013 revised DeSoto proposal, to the extent it contains the necessary information. However, additional information about DeSoto's costs and operational characteristics required for the evaluation was obtained through FPL's inspection of the facility, review of operating and maintenance documentation, and from FPL's independent research or knowledge where necessary.

Q. Can FPL be confident that it has identified all of the costs that it might have to incur in order to own and operate the DeSoto facility at the high level of reliability required for the facility to be treated as a quick-start resource?

A. No. FPL had to make certain assumptions regarding capital investments that would need to be made at the DeSoto facility as well as assumptions regarding O&M costs during the DeSoto facility's remaining life. These O&M assumptions are more uncertain than similar types of assumptions FPL has to make for new units, including the CTs it plans to install for its NO_2 Compliance Project, because of the age of the DeSoto facility and much remains unknown about the current state of the DeSoto facility components and upcoming maintenance requirements.

For example, FPL does not know the planned, detailed scope of work that DeSoto intends to have performed in order to add quick-start capability to its facility. The scope of this work, and how it is implemented, will impact whether additional capital investments would need to be made by FPL and how much FPL would have to spend to operate and maintain the plant going forward. Similarly, FPL does not know what types of activities are planned for the upcoming maintenance outage, which LS Power claims will result in a facility that is "in like-new condition in many respects." LS Power has described this as a "major" outage, but during the due diligence visit it was described to FPL as only a "hot gas path outage," which involves more limited maintenance activities. Finally, questions exist with respect to the history, model, vintage, and design of the DeSoto CT components that would be included with the sale of the facility – some of which are refurbished components that were swapped out of another out of state LS Power generating unit as to which FPL has only very limited information. These uncertainties have the potential to increase the operating costs for the DeSoto facility substantially and/or degrade the facility's operating reliability.

Q. What additional capital costs did FPL assume it would have to incur to bring the condition of the DeSoto facility into line with FPL's generating fleet?

A. FPL assumed it would have to spend $20 million to mitigate fleet reliability risks that are known to exist for the type and vintage of CTs at DeSoto and to address the uncertainties discussed above.

Q. Please explain how the O&M costs that FPL assumed for the DeSoto facility differ from the O&M costs assumed for the CTs included in FPL's NO_2 Compliance Project.

A. The DeSoto O&M costs are primarily driven by three factors: (i) costs associated with maintaining a completely separate site; (ii) costs associated with the additional DeSoto staff; and (iii) costs caused by the older turbine technology. The older turbine technology requires a shorter maintenance interval schedule, which increases maintenance costs (both O&M and capital replacement).

Q. What were the results of Mr. Enjamio's economic evaluation?

A. Mr. Enjamio ran various scenarios to consider the relative economics of a purchase of the DeSoto facility or a PPA from the DeSoto facility. His evaluation shows that it would be significantly more expensive for FPL's customers on a Cumulative Present Value of Revenue Requirements ("CPVRR") basis to purchase DeSoto or enter into a PPA as a partial substitute for the proposed new CTs at Fort Myers. The scenarios that Mr. Enjamio evaluated show that FPL's proposed NO_2 Compliance Project is \$48 million less expensive for customers than purchasing the DeSoto facility as a partial substitute and \$56 million less expensive for customers than entering into a PPA from the DeSoto facility as a partial substitute. And, as I discussed previously, the DeSoto facility might be even more expensive to customers depending on how the uncertainties about the facility's condition are resolved.

Q. Would the purchase of the DeSoto facility be more costly than FPL's proposed NO_2 Compliance Project even without the assumed $20 million in needed capital expenditures?

A. Yes. As detailed in Mr. Enjamio's testimony, the CPVRR for each of the DeSoto options exceeds FPL's NO_2 Compliance Project by substantially more than the CPVRR impact of the $20 million in assumed capital expenditures. In other words, even if FPL did not have to make these additional capital expenditures and FPL assumed $0 additional capital costs, FPL's NO_2 Compliance Project would still be significantly more cost-effective than the DeSoto options.

Q. Could LS Power's PPA proposal meet a portion of FPL's environmental compliance requirements along with quick-start capabilities at a lower cost?

A. No. The PPA on its own would provide no firm guaranty that the quick-start capability would or could be provided. Quick-start capability is required to maintain the integrity of the electrical grid during periods of plant forced outages or capacity shortages. It is essential that quick-start units start and operate reliably to prevent system emergencies. While performance guarantees can be included in a PPA with financial penalties for non-compliance, the owner/operator of the plant has their economic interests in mind first and foremost. This makes it difficult to assure in a PPA that plant maintenance, repair and operation is being performed with the reliability of the electrical grid in mind first and foremost.

Additionally, and perhaps more fundamentally, there is no PPA that can provide the same degree of assurance as an FPL owned, maintained, and operated unit that FPL and its customers will have quick-start capability when needed. When a provider fails to furnish capacity and/or energy under a PPA, there is an opportunity to obtain replacement power from other market providers. In the case of quick-start capability, however, if the unit fails to meet the need when the capability is called upon, there is neither time nor opportunity to obtain substitute quick-start service.

Q. Does FPL plan to undertake additional diligence or review to continue considering the DeSoto options?

A. No. Because the DeSoto options do not appear to be more economic than FPL's proposed NO_2 Compliance Project, FPL does not believe it would be productive to proceed with these activities. Nonetheless, if FPL were to continue with its due diligence, at a minimum, FPL would need to undertake the following activities: (i) review the GE detailed scope for adding quick-start capability; (ii) obtain a recent borescope inspection with special focus on corrosion pitting in the compressor section of both turbines; (iii) review the detailed scope of work planned for the upcoming hot gas path outage on both turbines; and (iv) determine whether new parts or refurbished parts will be installed during the upcoming hot gas path outage. This information would need to be thoroughly evaluated before FPL could feel comfortable that the DeSoto facility is a reliable source of quick-start power for FPL's customers.

Q. Based on your testimony and Mr. Enjamio's analysis, what is your conclusion about the DeSoto facility?

A. FPL's proposed NO_2 Compliance Project is superior to any scenario that includes the purchase of the DeSoto facility or a PPA from the DeSoto facility, even if one disregards the many uncertainties about the condition of the facility and its suitability as a quick-start asset upon which FPL could rely confidently to meet unexpected system needs.

Q. Does this conclude your testimony?

A. Yes, it does.

Updated Results of the Economic Evaluation

(millions, CPVRR, 2013$, 2013-2047)

Resource Plan	System Costs: Fixed Costs*	System Costs: Variable Costs**	System Costs: Total Costs	Difference from Lowest Cost Plan
Replace	$15,845	$94,665	$110,509	--
Retire	$17,318	$94,232	$111,550	$1,041
Hybrid	$15,943	$94,669	$110,612	$102

	Resource Plan	System Costs: Fixed Costs*	System Costs: Variable Costs**	System Costs: Total Costs	Difference from Lowest Cost Plan
1	DeSoto Ownership with two 200 MW CTs at FM	$15,834	$94,724	$110,557	$48
2	DeSoto Ownership with two 150 MW CTs at FM	$15,914	$94,665	$110,579	$70
3	DeSoto PPA with two 200 MW CTs at FM in 2016, and one 200 MW CT in 2024 (to replace expiring DeSoto PPA)	$15,900	$94,665	$110,565	$56
4	DeSoto PPA with two 150 MW CTs at FM in 2016, and two 150 MW CTs in 2024 (to replace expiring DeSoto PPA)	$15,987	$94,665	$110,652	$142

* Generation system fixed costs include: capital, capacity payments, fixed O&M, capital replacement, and firm gas transportation. (Note that Turkey Point 6 & 7 generation and transmission capital costs are assumed to be zero in this analysis for all resource plans.)

** Generation system variable costs include: variable O&M, plant fuel, FPL system fuel, and environmental compliance costs.

ENVIRONMENTAL COST RECOVERY

REVISED COMMISSION FORMS 42-1E, 42-2E, 42-3E, 42-6E AND 42-7E
JANUARY 2013 - DECEMBER 2013

REVISED COMMISSION FORMS 42-1P, 42-3P AND 42-7P
JANUARY 2014 - DECEMBER 2014

TJK-5
DOCKET NO. 130007-EI
FPL WITNESS: TERRY J. KEITH
EXHIBIT ______
PAGES 1-11

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE ACTUAL / ESTIMATED TRUE-UP AMOUNT FOR THE PERIOD

FORM: 42-1E

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	2013
1. Over/(Under) Recovery for the Current Period (Form 42-2E Page 2, Line 5)	($3,611,110)
2. Interest Provision (Form 42-2E Page 2, Line 6)	($3,445)
3. Sum of Current Period Adjustments (Form 42-2E, Page 2, Line 10)	$0
4. Actual/Estimated True-up to be refunded/(recovered)	($3,614,555)

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE ACTUAL / ESTIMATED TRUE-UP AMOUNT FOR THE PERIOD

FORM: 42-2E

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Total
1. ECRC Revenues (net of Revenue Taxes)	$15,883,634	$14,661,658	$14,427,592	$15,886,017	$17,887,417	$19,000,114	$21,096,983	$20,953,377	$20,293,258	$18,923,972	$17,158,512	$16,767,289	$212,939,823
2. True-up Provision (Order No. PSC-12-0613-FOF-EI)	$82,044	$82,044	$82,044	$82,044	$82,044	$82,044	$82,044	$82,044	$82,044	$82,044	$82,044	$82,044	$984,532
3. ECRC Revenues Applicable to Period (Lines 1 + 2)	$15,965,679	$14,743,702	$14,509,637	$15,968,061	$17,969,461	$19,082,159	$21,179,027	$21,035,421	$20,375,302	$19,006,016	$17,240,557	$16,849,333	$213,924,355
4. Jurisdictional ECRC Costs													
a. O&M Activities (Form 42-5E, Line 9)	$2,159,432	$1,833,028	$1,130,927	$1,945,905	$2,026,985	$2,005,921	$2,181,328	$2,766,042	$2,121,731	$2,261,534	$2,082,969	$2,104,959	$24,620,761
b. Capital Investment Projects (Form 42-7E, Line 9)	$15,299,325	$15,216,534	$21,907,697	$15,426,105	$15,454,731	$15,487,917	$15,500,320	$15,568,527	$15,664,156	$15,741,576	$15,788,131	$15,859,683	$192,914,704
c. Total Jurisdictional ECRC Costs	$17,458,757	$17,049,562	$23,038,625	$17,372,011	$17,481,716	$17,493,839	$17,681,648	$18,334,569	$17,785,886	$18,003,110	$17,871,101	$17,964,643	$217,535,465
5. Over/(Under) Recovery (Line 3 - Line 4c)	($1,493,078)	($2,305,860)	($8,528,988)	($1,403,950)	$487,746	$1,588,320	$3,497,379	$2,700,852	$2,589,416	$1,002,906	($630,544)	($1,115,310)	($3,611,110)
6. Interest Provision (Form 42-3E, Line 10)	$83	($44)	($454)	($740)	($728)	($579)	($412)	($261)	($133)	($47)	($42)	($89)	($3,445)
7. Prior Periods True-Up to be (Collected)/Refunded	$984,532	($590,508)	($2,978,456)	($11,589,942)	($13,076,677)	($12,671,703)	($11,166,007)	($7,751,083)	($5,132,536)	($2,625,297)	($1,704,482)	($2,417,112)	$984,532
a. Deferred True-Up (Form 42-1A, Line 7) [1]	$1,227,750	$1,227,750	$1,227,750	$1,227,750	$1,227,750	$1,227,750	$1,227,750	$1,227,750	$1,227,750	$1,227,750	$1,227,750	$1,227,750	$0
8. True-Up Collected /(Refunded) (See Line 2)	($82,044)	($82,044)	($82,044)	($82,044)	($82,044)	($82,044)	($82,044)	($82,044)	($82,044)	($82,044)	($82,044)	($82,044)	($984,532)
9. End of Period True-Up (Lines 5+6+7+7a+8)	$637,242	($1,750,706)	($10,362,192)	($11,848,927)	($11,443,953)	($9,938,257)	($6,523,333)	($3,904,786)	($1,397,547)	($476,732)	($1,189,362)	($2,386,805)	($3,614,555)
10. Adjustments to Period Total True-Up Including Interest	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11. End of Period Total Net True-Up (Lines 9+10)	$637,242	($1,750,706)	($10,362,192)	($11,848,927)	($11,443,953)	($9,938,257)	($6,523,333)	($3,904,786)	($1,397,547)	($476,732)	($1,189,362)	($2,386,805)	($3,614,555)

[1] From FPL's 2012 Final True-up filed on April 1, 2013.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE ACTUAL / ESTIMATED TRUE-UP AMOUNT FOR THE PERIOD

FORM: 42-3E

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Total
1. Beginning True-Up Amount (Form 42-2E, Lines 7 + 7a + 10)	$2,212,282	$637,242	($1,750,706)	($10,362,192)	($11,848,927)	($11,443,953)	($9,938,257)	($6,523,333)	($3,904,786)	($1,397,547)	($476,732)	($1,189,362)	N/A
2. Ending True-Up Amount before Interest (Line 1 + Form 42-2E, Lines 5 + 8)	$637,159	($1,750,662)	($10,361,738)	($11,848,186)	($11,443,225)	($9,937,677)	($6,522,922)	($3,904,525)	($1,397,415)	($476,685)	($1,189,320)	($2,386,716)	N/A
3. Total of Beginning & Ending True-Up (Lines 1 + 2)	$2,849,441	($1,113,419)	($12,112,444)	($22,210,379)	($23,292,152)	($21,381,631)	($16,461,178)	($10,427,859)	($5,302,201)	($1,874,232)	($1,666,052)	($3,576,078)	N/A
4. Average True-Up Amount (Line 3 x 1/2)	$1,424,721	($556,710)	($6,056,222)	($11,105,189)	($11,646,076)	($10,690,815)	($8,230,589)	($5,213,929)	($2,651,100)	($937,116)	($833,026)	($1,788,039)	N/A
5. Interest Rate (First Day of Reporting Month)	0.05000%	0.09000%	0.10000%	0.08000%	0.08000%	0.07000%	0.06000%	0.06000%	0.06000%	0.06000%	0.06000%	0.06000%	N/A
6. Interest Rate (First Day of Subsequent Month)	0.09000%	0.10000%	0.08000%	0.08000%	0.07000%	0.06000%	0.06000%	0.06000%	0.06000%	0.06000%	0.06000%	0.06000%	N/A
7. Total of Beginning & Ending Interest Rates (Lines 5 + 6)	0.14000%	0.19000%	0.18000%	0.16000%	0.15000%	0.13000%	0.12000%	0.12000%	0.12000%	0.12000%	0.12000%	0.12000%	N/A
8. Average Interest Rate (Line 7 x 1/2)	0.07000%	0.09500%	0.09000%	0.08000%	0.07500%	0.06500%	0.06000%	0.06000%	0.06000%	0.06000%	0.06000%	0.06000%	N/A
9. Monthly Average Interest Rate (Line 8 x 1/12)	0.00583%	0.00792%	0.00750%	0.00667%	0.00625%	0.00542%	0.00500%	0.00500%	0.00500%	0.00500%	0.00500%	0.00500%	N/A
10. Interest Provision for the Month (Line 4 x Line 9)	$83	($44)	($454)	($740)	($728)	($579)	($412)	($261)	($133)	($47)	($42)	($89)	($3,445)

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE ACTUAL / ESTIMATED TRUE-UP AMOUNT FOR THE PERIOD

FORM: 42-6E

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

VARIANCE REPORT OF CAPITAL INVESTMENT PROJECTS - RECOVERABLE COSTS

(1)	(2)	(3)	(4)	(5)
PROJECT #	ECRC - 2013 Actual Estimated - Revised	ECRC - 2013 Original Projection [b]	Dif. ECRC - 2013 Original Projection [c]	% Dif. ECRC - 2013 Original Projection [d]
1. Description of Investment Projects				
2 - Low NOX Burner Technology	$179,343	$177,872	$1,472	0.8%
3b - Continuous Emission Monitoring Systems	$506,273	$518,983	($12,710)	(2.4%)
4b - Clean Closure Equivalency	$1,287	$1,270	$17	1.4%
5b - Maintenance of Stationary Above Ground Fuel Storage Tanks	$927,405	$907,131	$20,274	2.2%
7 - Relocate Turbine Lube Oil Underground Piping to Above Ground	$1,462	$1,447	$15	1.0%
8b - Oil Spill Clean-up/Response Equipment	$142,826	$159,618	($16,792)	(10.5%)
10 - Relocate Storm Water Runoff	$7,969	$7,846	$124	1.6%
12 - Scherer Discharge Pipeline	$53,284	$52,573	$712	1.4%
20 - Wastewater Discharge Elimination & Reuse	$84,989	$84,240	$750	0.9%
NA - Amortization of Gains on Sales of Emissions Allowances	($88,008)	($86,317)	($1,690)	2.0%
21 - St. Lucie Turtle Nets	$106,955	$120,414	($13,459)	(11.2%)
22 - Pipeline Integrity Management	$288,573	$342,928	($54,355)	(15.9%)
23 - SPCC - Spill Prevention, Control & Countermeasures	$1,580,104	$1,562,026	$18,078	1.2%
24 - Manatee Reburn	$3,181,092	$3,130,961	$50,131	1.6%
25 - Pt. Everglades ESP Technology	$21,395,838	$21,326,855	$68,982	0.3%
26 - UST Remove/Replacement	$9,647	$10,909	($1,262)	(11.6%)
31 - Clean Air Interstate Rule (CAIR) Compliance	$60,360,882	$59,839,942	$520,940	0.9%
33 - MATS Project	$12,161,650	$12,011,159	$150,491	1.3%
34 - St Lucie Cooling Water System Inspection & Maintenance	$0	$17,946	($17,946)	(100.0%)
35 - Martin Plant Drinking Water System Compliance	$25,364	$24,932	$432	1.7%
36 - Low-Level Radioactive Waste Storage	$722,406	$744,133	($21,727)	(2.9%)
37 - DeSoto Next Generation Solar Energy Center	$17,023,620	$16,630,525	$393,095	2.4%
38 - Space Coast Next Generation Solar Energy Center	$8,028,940	$7,890,598	$138,342	1.8%
39 - Martin Next Generation Solar Energy Center	$48,039,922	$47,298,902	$741,020	1.6%
41 - Manatee Temporary Heating System	$8,295,577	$1,270,783	$7,024,794	552.8%
42 - Turkey Point Cooling Canal Monitoring Plan	$390,204	$383,311	$6,894	1.8%
44 - Martin Plant Barley Barber Swamp Iron Mitigation	$18,486	$18,168	$318	1.7%
45 - 800 MW Unit ESP	$13,419,268	$12,603,853	$815,416	6.5%
53 - PROPOSED - NO2 Compliance	$22,356	$0	$22,356	N/A
2. Total Investment Projects - Recoverable Costs	$196,887,715	$187,053,006	$9,834,709	5.3%

[a] The 12-Month Totals on Form 42-7E

[b] The approved projected amount in accordance with FPSC Order No. PSC-12-0613-FOF-EI

[c] Column (2) - Column (3)

[d] Column (4) / Column (3)

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE ACTUAL / ESTIMATED TRUE-UP AMOUNT FOR THE PERIOD

FORM: 42-6E

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

VARIANCE REPORT OF CAPITAL INVESTMENT PROJECTS - RECOVERABLE COSTS

(1)	(2)	(3)	(4)	(5)
	ECRC - 2013 Actual Estimated - Revised	ECRC - 2013 Original Projection	Dif. ECRC - 2013 Original Projection	% Dif. ECRC - 2013 Original Projection
2. Total Investment Projects - Recoverable Costs	$196,887,715	$187,053,006	$9,834,709	5.3%
3. Recoverable Costs Allocated to Energy	$37,349,571	$36,557,787	$791,783	2.2%
4. Recoverable Costs Allocated to Demand	$159,538,145	$150,495,219	$9,042,926	6.0%
7. Jurisdictional Energy Recoverable Costs	$36,614,673	$35,838,468	$776,205	2.2%
8. Jurisdictional Demand Recoverable Costs	$156,300,031	$147,440,643	$8,859,388	6.0%
9. Total Jurisdictional Recoverable Costs for Investment Projects	$192,914,704	$183,279,110	$9,635,594	5.3%

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE ACTUAL / ESTIMATED TRUE-UP AMOUNT FOR THE PERIOD

FORM: 42-7E

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

CAPITAL INVESTMENT PROJECTS-RECOVERABLE COSTS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Monthly Data													Method of Classification	
	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount	Energy	Demand
1. Description of Investment Projects [(a)]															
2 - Low NOX Burner Technology	$15,358	$15,278	$15,199	$15,119	$15,039	$14,960	$14,933	$14,852	$14,772	$14,691	$14,611	$14,531	$179,343	$179,343	
3b - Continuous Emission Monitoring Systems	$41,622	$40,928	$41,252	$41,575	$41,171	$40,781	$41,608	$42,631	$43,344	$43,946	$43,787	$43,627	$506,273	$506,273	
4b - Clean Closure Equivalency	$120	$107	$107	$107	$106	$106	$106	$106	$106	$106	$105	$105	$1,287	$99	$1,188
5b - Maintenance of Stationary Above Ground Fuel Storage Tanks	$78,063	$77,022	$76,854	$76,686	$76,518	$76,349	$77,059	$77,529	$77,933	$77,970	$77,797	$77,625	$927,405	$71,339	$856,066
7 - Relocate Turbine Lube Oil Underground Piping to Above Ground	$124	$124	$123	$123	$122	$122	$122	$121	$121	$120	$120	$119	$1,462	$112	$1,349
8b - Oil Spill Clean-up/Response Equipment	$12,521	$10,945	$11,480	$11,570	$11,519	$11,391	$11,318	$11,365	$11,755	$12,392	$13,025	$13,545	$142,826	$10,987	$131,839
10 - Relocate Storm Water Runoff	$669	$668	$666	$665	$664	$662	$666	$665	$663	$662	$660	$659	$7,969	$613	$7,356
12 - Scherer Discharge Pipeline	$4,496	$4,483	$4,470	$4,457	$4,445	$4,432	$4,449	$4,436	$4,423	$4,410	$4,397	$4,384	$53,284	$4,099	$49,186
20 - Wastewater Discharge Elimination & Reuse	$8,153	$7,020	$7,006	$6,993	$6,980	$6,967	$7,012	$6,998	$6,985	$6,972	$6,958	$6,945	$84,989	$6,538	$78,452
NA - Amortization of Gains on Sales of Emissions Allowances	($9,298)	($8,935)	($8,571)	($8,209)	($7,847)	($7,483)	($7,197)	($6,829)	($6,461)	($6,093)	($5,725)	($5,357)	($88,008)	($88,008)	
21 - St. Lucie Turtle Nets	$8,880	$8,879	$8,878	$8,876	$8,874	$8,872	$8,960	$8,956	$8,951	$8,947	$8,943	$8,939	$106,955	$8,227	$98,728
22 - Pipeline Integrity Management	$21,692	$21,663	$21,632	$21,600	$21,569	$21,538	$21,699	$24,661	$27,783	$28,151	$28,314	$28,272	$288,573	$22,198	$266,376
23 - SPCC - Spill Prevention, Control & Countermeasures	$140,549	$128,968	$128,754	$128,539	$128,282	$128,025	$131,233	$133,442	$133,287	$133,144	$133,012	$132,869	$1,580,104	$121,546	$1,458,557
24 - Manatee Reburn	$266,953	$266,420	$265,887	$265,353	$264,820	$264,287	$265,910	$265,371	$264,832	$264,292	$263,753	$263,214	$3,181,092	$3,181,092	
25 - Pt. Everglades ESP Technology	$1,882,982	$1,824,113	$1,813,577	$1,803,041	$1,792,505	$1,781,969	$1,776,238	$1,765,587	$1,754,935	$1,744,283	$1,733,631	$1,722,979	$21,395,838	$21,395,838	
26 - UST Remove/Replacement	$809	$808	$806	$805	$803	$801	$806	$805	$803	$802	$800	$798	$9,647	$742	$8,905
31 - Clean Air Interstate Rule (CAIR) Compliance	$4,982,662	$4,974,553	$5,017,160	$5,037,401	$5,023,774	$5,013,783	$5,054,646	$5,056,072	$5,053,975	$5,051,954	$5,047,192	$5,047,708	$60,360,882	$4,643,145	$55,717,737
33 - MATS Project	$1,017,821	$1,017,078	$1,015,314	$1,013,480	$1,011,646	$1,009,813	$1,016,591	$1,014,905	$1,013,315	$1,011,795	$1,010,287	$1,009,605	$12,161,650	$935,512	$11,226,139
34 - St Lucie Cooling Water System Inspection & Maintenance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
35 - Martin Plant Drinking Water System Compliance	$2,122	$2,119	$2,116	$2,113	$2,109	$2,106	$2,121	$2,118	$2,115	$2,112	$2,108	$2,105	$25,364	$1,951	$23,413
36 - Low-Level Radioactive Waste Storage	$59,169	$59,096	$59,059	$59,037	$59,147	$59,411	$60,052	$59,974	$59,895	$59,817	$59,739	$68,009	$722,406	$55,570	$666,836
37 - DeSoto Next Generation Solar Energy Center	$1,437,131	$1,437,026	$1,428,604	$1,426,665	$1,423,681	$1,419,413	$1,417,967	$1,414,256	$1,410,440	$1,406,627	$1,402,812	$1,398,998	$17,023,620	$1,309,509	$15,714,111
38 - Space Coast Next Generation Solar Energy Center	$676,722	$675,457	$673,019	$671,622	$670,174	$668,128	$669,882	$668,183	$666,485	$664,787	$663,089	$661,391	$8,028,940	$617,611	$7,411,329
39 - Martin Next Generation Solar Energy Center	$4,027,403	$4,018,489	$4,009,758	$4,002,146	$3,994,410	$3,986,429	$4,000,821	$3,998,168	$3,996,448	$3,996,623	$3,998,417	$4,010,810	$48,039,922	$3,695,379	$44,344,543
41 - Manatee Temporary Heating System	$80,878	$84,798	$6,850,466	$184,178	$234,957	$235,417	$105,961	$105,236	$104,510	$103,784	$103,059	$102,333	$8,295,577	$638,121	$7,657,456
42 - Turkey Point Cooling Canal Monitoring Plan	$32,603	$32,560	$32,518	$32,475	$32,433	$32,391	$32,645	$32,602	$32,559	$32,516	$32,473	$32,430	$390,204	$30,016	$360,189
44 - Martin Plant Barley Barber Swamp Iron Mitigation	$1,546	$1,544	$1,542	$1,539	$1,537	$1,535	$1,546	$1,544	$1,542	$1,539	$1,537	$1,535	$18,486		$18,486
45 - 800 MW Unit ESP	$822,529	$828,601	$881,599	$935,777	$953,517	$1,024,637	$1,102,350	$1,185,379	$1,301,232	$1,399,430	$1,468,406	$1,515,811	$13,419,268		$13,419,268
53 - PROPOSED - NO2 Compliance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$22,356	$22,356	$1,720	$20,636
2. Total Investment Projects - Recoverable Costs	$15,614,280	$15,529,813	$22,359,275	$15,743,733	$15,772,958	$15,806,840	$15,819,505	$15,889,132	$15,986,748	$16,065,779	$16,113,307	$16,186,346	$196,887,715	$37,349,571	$159,538,145

[(a)] Each project's Total System Recoverable Expenses on Form 42-8E, Line 9.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE ACTUAL / ESTIMATED TRUE-UP AMOUNT FOR THE PERIOD

FORM: 42-7E

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

CAPITAL INVESTMENT PROJECTS-RECOVERABLE COSTS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
2. Total Investment Projects - Recoverable Costs	$15,614,280	$15,529,813	$22,359,275	$15,743,733	$15,772,958	$15,806,840	$15,819,505	$15,889,132	$15,986,748	$16,065,779	$16,113,307	$16,186,346	$196,887,715
3. Recoverable Costs Allocated to Energy	$3,166,278	$3,104,101	$3,615,712	$3,092,997	$3,083,550	$3,070,371	$3,062,578	$3,052,427	$3,041,617	$3,030,634	$3,018,773	$3,010,532	$37,349,571
4. Recoverable Costs Allocated to Demand	$12,448,003	$12,425,712	$18,743,564	$12,650,736	$12,689,407	$12,736,469	$12,756,927	$12,836,705	$12,945,131	$13,035,145	$13,094,534	$13,175,813	$159,538,145
5. Retail Energy Jurisdictional Factor	98.03238%	98.03238%	98.03238%	98.03238%	98.03238%	98.03238%	98.03238%	98.03238%	98.03238%	98.03238%	98.03238%	98.03238%	
6. Retail Demand Jurisdictional Factor	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	
7. Jurisdictional Energy Recoverable Costs [a]	$3,103,977	$3,043,024	$3,544,568	$3,032,139	$3,022,878	$3,009,958	$3,002,318	$2,992,367	$2,981,770	$2,971,003	$2,959,375	$2,951,297	$36,614,673
8. Jurisdictional Demand Recoverable Costs [b]	$12,195,348	$12,173,510	$18,363,129	$12,393,966	$12,431,853	$12,477,960	$12,498,002	$12,576,161	$12,682,386	$12,770,573	$12,828,757	$12,908,387	$156,300,031
9. Total Jurisdictional Recoverable Costs for Investment Projects	$15,299,325	$15,216,534	$21,907,697	$15,426,105	$15,454,731	$15,487,917	$15,500,320	$15,568,527	$15,664,156	$15,741,576	$15,788,131	$15,859,683	$192,914,704

[a] Line 3 x Line 5

[b] Line 4 x Line 6

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
TOTAL JURISDICTIONAL AMOUNT TO BE RECOVERED

FORM: 42-1P

ESTIMATED FOR THE PERIOD: JANUARY 2014 THROUGH DECEMBER 2014

(1)	(2)	(3)	(4)	(5)
	Energy	CP Demand	GCP Demand	Total
1. Total Jurisdictional Revenue Requirements for the projected period				
a. Projected O&M Activities [a]	$12,564,194	$10,716,546	$2,185,000	$25,465,740
b. Projected Capital Projects [b]	$34,126,264	$158,631,343	$0	$192,757,606
c. Total Jurisdictional Revenue Requirements [c]	$46,690,458	$169,347,888	$2,185,000	$218,223,346
2. True-up for Estimated Over/(Under) Recovery [d]	($806,046)	($2,776,701)	($31,808)	($3,614,555)
3. Final True-up Over/(Under) [e]	$229,589	$987,970	$10,190	$1,227,750
4. Total Jurisdictional Amount to be Recovered/(Refunded) [f]	$47,266,915	$171,136,619	$2,206,618	$220,610,152
5. Total Projected Jurisdictional Amount Adjusted for Taxes [g]	$47,300,947	$171,259,838	$2,208,207	$220,768,991

[a] FORM 42-2P, Page 3, Lines 7 through 9

[b] FORM 42-3P, Page 5, Lines 7 through 9

[c] Lines 1a + 1b

[d] For the current period January 2013 - December 2013 (FORM 42-1E, Line 4, revised on September 27, 2013)

[e] For the period January 2012 - December 2012 (FORM 42-1A, Line 7, filed on April 1, 2013)

[f] In the projection period January 2014 - December 2014 (Line 1 - Line 2 - Line 3)

[g] Line 4 x Revenue Tax Multiplier 1.00072

Note: Allocation to energy and demand in each period are in proportion to the respective period split of costs.
True-up costs are split in proportion to the split of actual demand-related and energy-related costs from respective true-up periods.

Totals may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE PROJECTION AMOUNT

FORM: 42-3P

ESTIMATED FOR THE PERIOD: JANUARY 2014 THROUGH DECEMBER 2014

CAPITAL INVESTMENT PROJECTS - RECOVERABLE COSTS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Monthly Data													Method of Classification	
PROJECT #	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount	Energy	Demand
1. Description of Investment Projects															
2 - Low NOX Burner Technology	$14,450	$14,370	$14,289	$14,209	$14,128	$14,048	$13,967	$13,887	$13,806	$13,726	$13,645	$13,565	$168,089	$168,089	
3b - Continuous Emission Monitoring Systems	$43,468	$43,308	$43,907	$44,503	$44,335	$45,114	$45,888	$45,710	$45,532	$45,354	$45,176	$44,997	$537,290	$537,290	
4b - Clean Closure Equivalency	$105	$104	$104	$104	$103	$103	$103	$103	$102	$102	$102	$101	$1,236	$95	$1,141
5b - Maintenance of Stationary Above Ground Fuel Storage Tanks	$77,452	$77,280	$82,457	$87,626	$87,438	$87,250	$87,062	$86,875	$86,687	$86,499	$86,311	$86,123	$1,019,059	$78,389	$940,670
7 - Relocate Turbine Lube Oil Underground Piping to Above Ground	$119	$118	$118	$117	$117	$116	$116	$115	$115	$114	$114	$113	$1,394	$107	$1,287
8b - Oil Spill Clean-up/Response Equipment	$13,653	$13,588	$13,524	$13,459	$13,903	$13,890	$13,954	$14,187	$14,258	$14,322	$14,139	$14,045	$166,921	$12,840	$154,081
10 - Relocate Storm Water Runoff	$658	$656	$655	$653	$652	$651	$649	$648	$646	$645	$644	$642	$7,798	$600	$7,199
12 - Scherer Discharge Pipeline	$4,371	$4,358	$4,345	$4,332	$4,319	$4,306	$4,293	$4,280	$4,267	$4,254	$4,241	$4,228	$51,594	$3,969	$47,626
20 - Wastewater Discharge Elimination & Reuse	$6,932	$6,918	$6,905	$6,892	$6,878	$6,865	$6,852	$6,838	$6,825	$6,811	$6,798	$6,785	$82,298	$6,331	$75,968
NA - Amortization of Gains on Sales of Emissions Allowances	($5,044)	($4,786)	($4,528)	($4,269)	($4,011)	($3,752)	($3,494)	($3,236)	($2,977)	($2,719)	($2,461)	($2,202)	($43,479)	($43,479)	
21 - St. Lucie Turtle Nets	$8,935	$8,930	$8,926	$8,922	$8,918	$8,913	$8,909	$11,805	$14,697	$14,686	$14,674	$49,929	$168,244	$12,942	$155,302
22 - Pipeline Integrity Management	$28,231	$28,189	$28,406	$28,623	$28,581	$28,539	$28,497	$28,454	$28,412	$28,370	$28,328	$28,286	$340,915	$26,224	$314,691
23 - SPCC - Spill Prevention, Control & Countermeasures	$132,703	$132,528	$132,353	$132,177	$132,002	$131,826	$131,650	$131,475	$131,299	$131,134	$130,982	$130,817	$1,580,946	$121,611	$1,459,335
24 - Manatee Reburn	$262,675	$262,136	$261,596	$261,057	$260,518	$259,979	$259,440	$258,900	$258,361	$257,822	$257,283	$256,744	$3,116,511	$3,116,511	
25 - Pt. Everglades ESP Technology	$1,712,327	$1,701,675	$1,691,024	$1,680,372	$1,669,720	$1,659,068	$1,648,416	$1,637,764	$1,627,112	$1,616,461	$1,605,809	$1,595,157	$19,844,905	$19,844,905	
26 - UST Remove/Replacement	$797	$795	$794	$792	$790	$789	$787	$785	$784	$782	$781	$779	$9,454	$727	$8,727
31 - Clean Air Interstate Rule (CAIR) Compliance	$5,047,470	$5,039,862	$5,033,676	$5,030,281	$5,029,671	$5,026,106	$5,019,591	$5,013,072	$5,006,549	$5,000,021	$4,993,489	$4,986,952	$60,226,739	$4,632,826	$55,593,913
33 - MATS Project	$1,008,420	$1,006,944	$1,006,328	$1,005,840	$1,005,023	$1,003,721	$1,002,284	$1,000,807	$999,178	$997,537	$995,844	$994,102	$12,026,029	$925,079	$11,100,950
34 - St Lucie Cooling Water System Inspection & Maintenance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
35 - Martin Plant Drinking Water System Compliance	$2,102	$2,098	$2,095	$2,092	$2,089	$2,085	$2,082	$2,079	$2,075	$2,072	$2,069	$2,065	$25,003	$1,923	$23,080
36 - Low-Level Radioactive Waste Storage	$73,988	$73,891	$126,677	$167,885	$167,669	$167,453	$167,237	$167,022	$166,806	$166,590	$166,375	$166,159	$1,777,752	$136,750	$1,641,002
37 - DeSoto Next Generation Solar Energy Center	$1,395,187	$1,391,378	$1,387,570	$1,383,799	$1,380,015	$1,376,214	$1,372,414	$1,368,617	$1,364,821	$1,361,028	$1,357,236	$1,353,446	$16,491,725	$1,268,594	$15,223,131
38 - Space Coast Next Generation Solar Energy Center	$659,693	$657,995	$656,296	$654,598	$652,900	$651,202	$649,504	$647,806	$646,108	$644,410	$642,711	$641,013	$7,804,236	$600,326	$7,203,910
39 - Martin Next Generation Solar Energy Center	$4,016,576	$4,006,283	$3,996,191	$3,986,298	$3,976,205	$3,967,125	$3,958,041	$3,948,669	$3,939,297	$3,928,998	$3,918,698	$3,908,399	$47,550,780	$3,657,752	$43,893,027
41 - Manatee Temporary Heating System	$101,608	$100,882	$100,157	$99,431	$98,706	$97,353	$41,790	$41,509	$41,228	$40,948	$40,667	$40,386	$844,665	$64,974	$779,690
42 - Turkey Point Cooling Canal Monitoring Plan	$32,387	$32,344	$32,301	$32,258	$32,216	$32,173	$32,130	$32,087	$32,044	$32,001	$31,958	$31,915	$385,815	$29,678	$356,136
44 - Martin Plant Barley Barber Swamp Iron Mitigation	$1,532	$1,530	$1,528	$1,526	$1,523	$1,521	$1,519	$1,516	$1,514	$1,512	$1,509	$1,507	$18,237		$18,237
45 - 800 MW Unit ESP	$1,552,116	$1,563,154	$1,583,001	$1,626,279	$1,738,819	$1,843,226	$1,884,251	$1,916,042	$1,937,424	$1,956,145	$1,975,733	$1,998,365	$21,574,555		$21,574,555
53 - PROPOSED - NO2 Compliance	$93,567	$144,849	$213,738	$282,626	$287,481	$404,395	$525,339	$543,892	$727,651	$913,775	$1,102,969	$1,307,230	$6,547,511	$503,655	$6,043,856
2. Total Investment Projects - Recoverable Costs	$16,286,475	$16,311,381	$16,424,434	$16,552,481	$16,640,708	$16,830,277	$16,903,272	$16,921,707	$17,094,620	$17,263,398	$17,435,822	$17,661,648	$202,326,224	$35,708,710	$166,617,514

Note: Totals may not add due to rounding.

Revised 9/27/13

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE PROJECTION AMOUNT

FORM: 42-3P

ESTIMATED FOR THE PERIOD: JANUARY 2014 THROUGH DECEMBER 2014

CAPITAL INVESTMENT PROJECTS - RECOVERABLE COSTS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
2. Total Investment Projects - Recoverable Costs	$16,286,475	$16,311,381	$16,424,434	$16,552,481	$16,640,708	$16,830,277	$16,903,272	$16,921,707	$17,094,620	$17,263,398	$17,435,822	$17,661,648	$202,326,224
3. Recoverable Costs Allocated to Energy	$3,005,179	$2,995,933	$2,993,490	$2,990,395	$2,978,204	$2,975,308	$2,968,316	$2,956,958	$2,958,284	$2,959,497	$2,960,923	$2,966,223	$35,708,710
4. Recoverable Costs Allocated to Demand	$13,281,296	$13,315,448	$13,430,944	$13,562,087	$13,662,505	$13,854,969	$13,934,957	$13,964,749	$14,136,336	$14,303,901	$14,474,899	$14,695,425	$166,617,514
5. Retail Energy Jurisdictional Factor	95.56846%	95.56846%	95.56846%	95.56846%	95.56846%	95.56846%	95.56846%	95.56846%	95.56846%	95.56846%	95.56846%	95.56846%	
6. Retail Demand Jurisdictional Factor	95.20688%	95.20688%	95.20688%	95.20688%	95.20688%	95.20688%	95.20688%	95.20688%	95.20688%	95.20688%	95.20688%	95.20688%	
7. Jurisdictional Energy Recoverable Costs [a]	$2,872,004	$2,863,167	$2,860,832	$2,857,874	$2,846,223	$2,843,456	$2,836,774	$2,825,919	$2,827,187	$2,828,345	$2,829,709	$2,834,774	$34,126,264
8. Jurisdictional Demand Recoverable Costs [b]	$12,644,708	$12,677,223	$12,787,183	$12,912,040	$13,007,645	$13,190,884	$13,267,038	$13,295,402	$13,458,765	$13,618,298	$13,781,100	$13,991,056	$158,631,343
9. Total Jurisdictional Recoverable Costs for Investment Projects	$15,516,712	$15,540,390	$15,648,015	$15,769,914	$15,853,868	$16,034,340	$16,103,811	$16,121,322	$16,285,952	$16,446,644	$16,610,809	$16,825,830	$192,757,606

[a] Line 3 x Line 5

[b] Line 4 x Line 6

Note: Totals may not add due to rounding.

FORM: 42-7P

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF ENVIRONMENTAL COST RECOVERY CLAUSE FACTORS

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
RATE CLASS	Percentage of KWH Sales at Generation (%) [(a)]	Percentage of 12 CP Demand at Generation (%) [(b)]	Percentage of GCP Demand at Generation (%) [(c)]	Energy Related Cost ($) [(d)]	CP Demand Related Cost ($) [(e)]	GCP Demand Related Cost ($) [(f)]	Total Environmental Costs ($) [(g)]	Projected Sales at Meter (KWH) [(h)]	Environmental Cost Recovery Factor ($/KWH) [(i)]
RS1/RTR1	52.46263%	59.39700%	56.89823%	24,815,321	101,723,212	1,256,430	127,794,964	55,459,739,543	0.00230
GS1/GST1/WIES1	5.79516%	5.33799%	5.71049%	2,741,165	9,141,826	126,100	12,009,091	6,126,227,507	0.00196
GSD1/GSDT1/HLFT1	24.36773%	21.52753%	21.97738%	11,526,167	36,868,018	485,306	48,879,491	25,762,255,228	0.00190
OS2	0.01081%	0.00869%	0.04504%	5,113	14,874	995	20,981	11,759,080	0.00178
GSLD1/GSLDT1/CS1/CST1/HLFT2	10.02174%	8.79365%	9.45590%	4,740,378	15,059,996	208,806	20,009,180	10,605,576,674	0.00189
GSLD2/GSLDT2/CS2/CST2/HLFT3	2.31534%	1.71255%	1.78386%	1,095,178	2,932,911	39,391	4,067,480	2,471,381,071	0.00165
GSLD3/GSLDT3/CS3/CST3	0.16147%	0.11940%	0.13745%	76,376	204,489	3,035	283,901	177,440,887	0.00160
SST1T	0.08062%	0.06761%	0.16221%	38,133	115,791	3,582	157,506	88,591,459	0.00178
SST1D1/SST1D2/SST1D3	0.00906%	0.00700%	0.03254%	4,285	11,984	718	16,988	9,856,390	0.00172
CILC D/CILC G	2.84404%	2.01186%	2.06157%	1,345,256	3,445,516	45,524	4,836,295	3,036,047,195	0.00159
CILC T	1.19614%	0.81466%	0.86645%	565,783	1,395,178	19,133	1,980,094	1,314,450,655	0.00151
MET	0.08517%	0.07679%	0.08253%	40,287	131,513	1,822	173,622	92,658,992	0.00187
OL1/SL1/PL1	0.59653%	0.08920%	0.75285%	282,163	152,757	16,624	451,545	630,606,760	0.00072
SL2, GSCU1	0.05357%	0.03607%	0.03349%	25,341	61,774	740	87,854	56,633,687	0.00155
Total				47,300,947	171,259,838	2,208,207	220,768,991	105,843,225,128	0.00209

[(a)] From Form 42-6P, Col 12

[(b)] From Form 42-6P, Col 13

[(c)] From Form 42-6P, Col 14

[(d)] Total Energy $ from Form 42-1P, Line 5, Column 2

[(e)] Total CP Demand $ from Form 42-1P, Line 5, Column 3

[(f)] Total GCP Demand $ from Form 42-1P, Line 5, Column 4

[(g)] Col 5 + Col 6 + Col 7

[(h)] Projected KWH sales for the period January 2014 through December 2014.

[(i)] Col 8 / Col 9

Note: There are currently no customers taking service on Schedules ISST1(D) or ISST1(T). Should any customer begin taking service on these schedules during the period, they will be billed using the applicable SST1 Factor.

Totals may not add due to rounding.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
RESEARCH TRIANGLE PARK, NC 27711

MAR 0 1 2011

OFFICE OF
AIR QUALITY PLANNING
AND STANDARDS

MEMORANDUM

SUBJECT: Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard

FROM: Tyler Fox, Leader
Air Quality Modeling Group, C439-01

TO: Regional Air Division Directors

INTRODUCTION

On January 22, 2010, EPA announced a new 1-hour nitrogen dioxide (NO_2) National Ambient Air Quality Standard (1-hour NO_2 NAAQS or 1-hour NO_2 standard) that is attained when the 3-year average of the 98th-percentile of the annual distribution of daily maximum 1-hour concentrations does not exceed 100 ppb at each monitor within an area. The final rule for the new 1-hour NO_2 NAAQS was published in the Federal Register on February 9, 2010 (75 FR 6474-6537), and the standard became effective on April 12, 2010 (EPA, 2010a). A memorandum was issued on June 29, 2010, clarifying the applicability of current guidance in the *Guideline on Air Quality Models* (40 CFR Part 51, Appendix W) for modeling NO_2 impacts in accordance with the Prevention of Significant Deterioration (PSD) permit requirements to demonstrate compliance with the new 1-hour NO_2 standard.

This memorandum supplements the June 29, 2010 guidance memo by providing further clarification and guidance on the application of Appendix W guidance for the 1-hour NO_2 standard. Note that while the discussion of NO_x chemistry options in this memo is exclusive to the 1-hour NO_2 standard, the discussion of other topics in this memo should apply equally to the 1-hour SO_2 standard, accounting for the slight differences in the form of the 1-hour NO_2 and SO_2 standards[1]. In summary, the memo:

1. Clarifies procedures for demonstrating compliance with the 1-hour NO_2 NAAQS based on the form of the standard, including significant contribution analyses using the interim Significant Impact Level (SIL) established in the June 29, 2010 memo,

[1] The 1-hour NO_2 standard is based on the 98^{th}-percentile (8^{th}-highest) of the annual distribution of maximum daily 1-hour values, whereas the 1-hour SO_2 standard is based on the 99^{th}-percentile (4^{th}-highest) of the annual distribution of maximum daily 1-hour values.

and details updates to the AERMOD model with an internal post-processor option that supports such analyses.

2. Provides clarification on the use and acceptance of Tier 2 and Tier 3 options for NO_2, including updated model evaluation results for the OLM and PVMRM options incorporated in the AERMOD model.
3. Recommends that compliance demonstrations for the 1-hour NO_2 NAAQS address emission scenarios that can logically be assumed to be relatively continuous or which occur frequently enough to contribute significantly to the annual distribution of daily maximum 1-hour concentrations based on existing modeling guidelines, which provide sufficient discretion for reviewing authorities to not include intermittent emissions from emergency generators or startup/shutdown operations from compliance demonstrations for the 1-hour NO_2 standard under appropriate circumstances.
4. Provides additional clarification and a more detailed discussion of the factors to consider in determination of background concentrations as part of a cumulative impact assessment including identification of nearby sources to be explicitly modeled.
5. Recommends an appropriate methodology for incorporating background concentrations in the cumulative impact assessment for the 1-hour NO_2 standard and details updates to the AERMOD model with an option to include temporally-varying background concentrations within the modeling analysis.

PROCEDURES FOR DEMONSTRATING COMPLIANCE WITH 1-HOUR NO_2 NAAQS

Compliance with the 1-hour NO_2 NAAQS is based on the multiyear average of the 98th-percentile of the annual distribution of daily maximum 1-hour values not exceeding 100 ppb. The 8th-highest of the daily maximum 1-hour values across a year is an unbiased surrogate for the 98th-percentile[1]. The AERMOD dispersion model, EPA's preferred model for near-field applications under Appendix W, was recently modified (version dated 11059) to fully support the form of the 1-hour NO_2 NAAQS, as well as other analyses that may be needed in order to demonstrate that a source does not cause or contribute to a violation of the NAAQS based on the interim SIL established in the June 29, 2010, memorandum.

<u>Application of Interim SIL to Project Impacts</u>

Using the interim 1-hour NO_2 SIL, a permit applicant can determine: (1) whether, based on the proposed increase in NO_x emissions, a cumulative air quality analysis is required; (2) the area of impact within which a cumulative air quality analysis should focus; and (3) whether the proposed source's NO_x emissions will contribute to any modeled violation of the 1-hour NO_2 NAAQS identified in the cumulative analysis.

To determine initially whether a proposed project's emissions increase will have a significant impact (resulting in the need for a cumulative impact assessment), the June 29, 2010, memorandum recommended that the interim SIL should be compared to either of the following:

- The highest of the 5-year averages of the maximum modeled 1-hour NO_2 concentrations predicted each year at each receptor, based on 5 years of National Weather Service data; or
- The highest modeled 1-hour NO_2 concentration predicted across all receptors based on 1 year of site-specific meteorological data, or the highest of the multi-year averages of the maximum modeled 1-hour NO_2 concentrations predicted each year at each receptor, based on 2 or more years, up to 5 complete years of available site-specific meteorological data.

Since the form of the standard is based on the annual distribution of daily maximum 1-hour values, the maximum contribution that a project could make to the air quality impact at a receptor is the multiyear average of the highest 1-hour values at that receptor. If the multiyear average of the highest 1-hour values is below the SIL at all receptors, then the project could not contribute significantly to any modeled violations of the 1-hour NO_2 NAAQS, thus exempting that project from the cumulative impact assessment.

Application of Interim SIL to Cumulative Impact Assessment

If a project's impacts exceed the SIL at any receptors based on this initial impact analysis, then a cumulative impact assessment should be completed to determine whether the project will cause or contribute to any modeled violations of the NAAQS. While not common practice in the past, given the more complex analysis procedures associated with the form of the 1-hour NO_2 NAAQS, we deem it appropriate and acceptable in most cases to limit the cumulative impact analysis to only those receptors that have been shown to have significant impacts from a proposed new source based on the initial SIL analysis, assuming that the design of the original receptor grid was adequate to determine all areas of ambient air where the source could contribute significantly to modeled violations. This may especially be appropriate for the 1-hour NO_2 standard since the initial modeling of the project emissions without other background emission sources may have a tendency to overestimate ambient NO_2 concentrations, even under Tier 3 applications, by understating the potential ozone limiting influence of the background NO_x emissions. If modeled violations of the NAAQS are found based on the cumulative impact assessment, then the project's contribution to all modeled violations should be compared to the interim SIL to determine whether the project causes or contributes to any of the modeled violations.

In past guidance (EPA, 1988), EPA has indicated that the significant contribution analysis should be based on a source's contribution to the modeled violation paired in time and space. The form of the 1-hour NO_2 NAAQS complicates this analysis since the modeled violation is based on a multiyear average of the annual distribution of daily maximum 1-hour values, i.e., a particular modeled violation at a particular receptor represents an average based on specific hours on specific days from each of the five years of meteorological data (for National Weather Service (NWS) data). It is important to point out here that the significant contribution analysis is not limited to analyzing the source's contribution associated only with the modeled design value based on the 98th-percentile cumulative air quality impact at the receptor, but rather must examine all cases where the cumulative impact exceeds the NAAQS at or below the 98th-

percentile. In some cases a source's contribution to the 98th-percentile of the daily maximum 1-hour values from the cumulative impact (i.e., the cumulative impact value or modeled design value that is compared to the NAAQS) may be below the SIL, while the source's contribution to cumulative impacts below the 98th-percentile but above the NAAQS could exceed the SIL. Therefore, the significant contribution analysis should examine every multiyear average of daily maximum 1-hour values, beginning with the 8th-highest (98th-percentile)[2], continuing down the ranked distribution until the cumulative impact is below the NAAQS. Since the form of the standard is based on the annual distribution of daily maximum 1-hour values, the significant contribution analysis should be limited to the distribution of daily <u>maximum</u> 1-hour values, i.e., the 2nd, 3rd, 4th-highest 1-hour values during the day, and so on, are not considered in this analysis. In addition, for applications with more than one year of meteorological data, the significant contribution analysis should only examine ranks paired across the years, i.e., the multiyear average of the N^{th}-highest values across each of the years processed. The recent update to the AERMOD model (dated 11059) includes an option (the MAXDCONT keyword) to automatically perform this contribution analysis (EPA, 2010b), examining the contribution from project emissions to the cumulative impacts at each receptor across a user-specified range of ranked values, paired in time and space, as an internal post-processor within the model. Other options are available in the recent AERMOD update that identify the specific data periods contributing to the cumulative modeled impacts at each receptor.

<u>Applicability of Ambient Monitoring Requirements to Modeling Demonstrations</u>

The June 29, 2010 memo addressed one aspect of the applicability of ambient monitoring requirements, set forth in Appendix S to 40 CFR Part 50 in relation to the 1-hour NO_2 standard[3], to modeling applications to demonstrate compliance with the NAAQS, namely the use of 3 years of ambient monitoring data as the basis for attainment of the NAAQS using monitoring vs. the use of 5 years of meteorological data for modeling demonstrations of compliance with the NAAQS. Specifically, the June 29, 2010 memo indicated that "*Although the monitored design value for the 1-hour NO_2 standard is defined in terms of the 3-year average, this definition does not preempt or alter the Appendix W requirement for use of 5 years of NWS meteorological data or at least 1 year of site specific data. The 5-year average based on use of NWS data, or an average across one or more years of available site specific data, serves as an unbiased estimate of the 3-year average for purposes of modeling demonstrations of compliance with the NAAQS. Modeling of 'rolling 3-year averages,' using years 1 through 3, years 2 through 4, and years 3 through 5, is not required*."

We would also like to emphasize that other aspects of the ambient monitoring requirements for the 1-hour NO_2 standard should <u>not</u> be applied for modeling analyses to demonstrate compliance with the NAAQS. For example, Appendix S addresses the data completeness requirements for monitored NO_2 concentrations, procedures for handling missing data periods, and conventions for rounding of monitored values. Appendix S specifies that a sampling day is complete if at least 75 percent of the hourly values are valid and a quarter is complete if at least 75 percent of the sampling days have complete data, and establishes calculation procedures for identifying the monitored design value that should be compared to the

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[2] For the 1-hour SO_2 standard the analysis should begin with the 4th-highest, or 99th-percentile value.
[3] Appendix T to 40 CFR Part 50 addresses ambient monitoring requirements for the 1-hour SO_2 standard.

NAAQS. While the requirements of Appendix S are appropriate in the context of ambient monitoring, application of these requirements and procedures to a dispersion modeling analysis is not appropriate and may conflict with modeling guidance in many cases. Appendix W provides guidance on data completeness for meteorological data which specifically addresses the needs of dispersion modeling, including procedures that are explicitly implemented within the meteorological processor and dispersion model to account for missing data due to calm winds or other factors. Adjustments to the calculation procedures for determining the modeled design value for comparison to the NAAQS based on Appendix S data completeness criteria is not appropriate. The EPA Model Clearinghouse has also issued guidance in the past that modeled concentrations should not be rounded before comparing the modeled design value to the NAAQS. The fundamental point to recognize here is that ambient monitoring requirements/procedures and dispersion modeling guidance/procedures address different issues and needs relative to each aspect of air quality assessment, and are often motivated by different concerns and exigencies.

APPROVAL AND APPLICATION OF TIERING APPROACH FOR NO_2

Given the stringency of the 1-hour NO_2 standard relative to the annual standard, many more permit applicants may find it necessary to use the less conservative Tier 2 or Tier 3 approaches in order to demonstrate compliance with the new NAAQS rather than relying on the Tier 1 assumption of full conversion. The June 29, 2010 memo highlighted some of the potential issues that may need to be addressed in the application of these less conservative assumptions for estimating ambient NO_2 impacts, relative to the Tier 1 option of full conversion, and clarified the status of the Tier 3 PVMRM and OLM approaches available as non-regulatory-default options within the AERMOD model.

In order to ease the burden on permit applicants in addressing the need to demonstrate compliance with the 1-hour NO_2 NAAQS, as well as the burden on the permitting authority in reviewing such applications, we offer additional discussion and recommendations in relation to the use of Tier 2 and Tier 3 options. Specifically, we recommend the following:

- Use of 0.80 as a default ambient ratio for the 1-hour NO_2 standard under Tier 2 without additional justification by applicants; and

- General acceptance of 0.50 as a default in-stack ratio of NO_2/NO_x for input to the PVMRM and OLM options within AERMOD, in the absence of more appropriate source-specific information on in-stack ratios.

The following sections explain these recommendations in more detail and also discuss the relative merits of the PVMRM and OLM options, clarifying that we have not indicated any preference of one option over the other. We also provide updated model evaluation results for the PVMRM and OLM options in AERMOD that lend further credence to the use of these Tier 3 options for 1-hour NO_2 compliance demonstrations. We anticipate that these recommendations and updated model evaluations will simplify and facilitate the process of gaining approval for use of these non-regulatory default options in AERMOD.

Tier 2 Ambient Ratio Method (ARM) for NO-to-NO_2 Conversion

Regarding the Tier 2 option of applying an ambient ratio to the Tier 1 result, the June 29, 2010 memo cautioned against use of the 0.75 national default ratio recommended in Appendix W for the annual standard for estimating hourly NO_2 impacts, without some justification of the appropriateness of that assumption. We still do not consider 0.75 as an appropriate default ambient ratio for the 1-hour standard, but several references cite ambient ratios of about 0.80 for hourly NO_2/NO_x (e.g., Wang, et al., 2011; Janssen, et al., 1991), and we believe it would be appropriate to accept that as a default ambient ratio for the 1-hour NO_2 standard. Consideration was given to adopting the default equilibrium ratio of 0.90 incorporated in the PVMRM option as an hourly ARM, but we do not consider that to be an appropriate choice since it is the maximum ratio applied on a source-by-source and hourly basis, irrespective of the predicted hourly NO_x concentration, whereas the Tier 2 ARM of 0.80 would be applied to the maximum cumulative hourly NO_x concentration.

Tier 3 Options for NO-to-NO_2 Conversion

The June 29, 2010 memo clarified that the OLM and PVMRM options in the AERMOD model should be considered as Tier 3 applications under Section 5.2.4 of Appendix W. Also, since the OLM and PVMRM methods are currently implemented as non-regulatory-default options within the AERMOD dispersion model (Cimorelli, *et al.*, 2004; EPA, 2004; EPA, 2010b), their use requires justification and approval by the Regional Office on a case-by-case basis, pursuant to Sections 3.1.2.c, 3.2.2.a, and A.1.a(2) of Appendix W. The June 29 memo also highlighted the importance of two key model inputs for both the OLM and PVMRM options in the context of the 1-hour NO_2 standard, namely the in-stack ratios of NO_2/NO_x emissions and background ozone concentrations. This section provides additional discussion of these key inputs for OLM and PVMRM and also clarifies the similarities and differences between these methods and discusses their relative merits for purposes of demonstrating compliance with the 1-hour NO_2 standard.

As noted in the June 29, 2010 memo, limited evaluations of PVMRM have been completed which show encouraging results, but the amount of data currently available is too limited to justify a designation of PVMRM as a refined method for NO_2 (Hanrahan, 1999; MACTEC, 2005). Furthermore, the original evaluations focused on model performance for annual averages since the only NO_2 standard in effect at the time was annual. We have recently updated the evaluations to reflect the current AERMOD modeling system components and extended them to examine model performance for hourly NO_2 concentrations. Preliminary results from these recent evaluations are presented in Attachment A.

While the limited scope of the available field study data imposes limits on the ability to generalize conclusions regarding model performance, these preliminary results of hourly NO_2 predictions for Palaau and New Mexico show generally good performance for the PVMRM and OLM/OLMGROUP ALL options in AERMOD. We believe that these additional model evaluation results lend further credence to the use of these Tier 3 options in AERMOD for estimating hourly NO_2 concentrations, and we recommend that their use should be generally accepted provided some reasonable demonstration can be made of the appropriateness of the key inputs for these options, the in-stack NO_2/NO_x ratio and the background ozone concentrations. Although well-documented data on in-stack NO_2/NO_x ratios is still limited for many source categories, we also feel that it would be appropriate in the absence of such source-specific in-stack data to adopt a default in-stack ratio of 0.5 as being adequately conservative in most cases and a better alternative to use of the Tier 1 full conversion or Tier 2 ambient ratio options. This value appears to represent a reasonable upper bound based on the available in-stack data. We hope that over time the range of source categories for which in-stack ratio information is available increases and the quality of such information will improve.

These preliminary model evaluation results also serve to highlight a point worth emphasizing, which is that the PVMRM option in AERMOD is not inherently superior to the OLM option for purposes of estimating cumulative ambient NO_2 concentrations. The June 29, 2010 memo indicated that both PVMRM and OLM should be considered as Tier 3 options, but did not indicate any preference between these two options. Both PVMRM and OLM simulate the same basic chemical mechanism of ozone titration, the interaction of NO with ambient ozone (O_3) to form NO_2 and O_2. The main distinction between PVMRM and OLM is the approach taken to estimate the ambient concentrations of NO and O_3 for which the ozone titration mechanism should be applied. For isolated elevated point sources, the PVMRM option does represent a more refined treatment of ozone titration since it estimates the NO and O_3 available for conversion based on simulating the actual volume of the instantaneous plume as it is transported downwind. As a result, this method will generally provide a more realistic simulation of the NO-to-NO_2 conversion rate along the path of the plume for a particular source, accounting for the influence of meteorological conditions on the entrainment of O_3 associated with growth of the plume. However, the algorithm incorporated in PVMRM for determining which plumes “compete” for available ozone for multi-source applications has not been thoroughly validated, and as shown in the model evaluation results for New Mexico, PVMRM may not always provide a “better” answer than the OLM option.

The PVMRM algorithm as currently implemented may also have a tendency to overestimate the conversion of NO to NO_2 for low-level plumes by overstating the amount of ozone available for the conversion due to the manner in which the plume volume is calculated. The plume volume calculation in PVMRM does not account for the fact that the vertical extent of the plume based on the vertical dispersion coefficient may extend below ground for low-level plumes. This overestimation of the volume of the plume could contribute to overestimating conversion to NO_2. The PVMRM option has further limitations for area source applications, especially for elongated area sources that may be used to simulate road segments. In these cases, the lateral extent of the plume used in calculating the plume volume depends on the projected width of the area source, even if only a portion of the area source actually impacts a nearby receptor. This again would tend to overestimate the volume of the plume for purposes of determining the amount of ozone available for conversion of NO to NO_2, and would likely overestimate ambient NO_2 concentrations. In light of these issues, a series of volume sources rather than elongated area sources is recommended for simulating NO_2 impacts from roadway emissions with PVMRM, especially for receptors located relatively close to the roadway. Furthermore, the OLM option with OLMGROUP ALL was used to estimate NO_2 concentrations from mobile source emissions modeled as area sources for the Atlanta area as part of the EPA’s

Risk and Exposure Assessment (REA) for the most recent NO_2 NAAQS review (EPA, 2008). Results of model-to-monitor comparisons from the REA show generally good performance, suggesting that use of OLM with OLMGROUP ALL is appropriate for modeling such emissions.

TREATMENT OF INTERMITTENT EMISSIONS

Modeling of intermittent emission units, such as emergency generators, and/or intermittent emission scenarios, such as startup/shutdown operations, has proven to be one of the main challenges for permit applicants undertaking a demonstration of compliance with the 1-hour NO_2 NAAQS. Prior to promulgation of the new 1-hour NO_2 standard, the only NAAQS applicable for NO_2 was the annual standard and these intermittent emissions typically did not factor significantly into the modeled design value for the annual standard. Sources often take a 500 hour/year permit limit on operation of emergency generators for purposes of determining the potential to emit (PTE), but may actually operate far fewer hours than the permitted limit in many cases and generally have not been required to assume continuous operation of these intermittent emissions for purposes of demonstrating compliance with the annual NAAQS. Due in part to the relatively low release heights typically associated with emergency generators, an assumption of continuous operation for these intermittent emissions would in many cases result in them becoming the controlling emission scenario for determining compliance with the 1-hour standard.

EPA's guidance in Table 8-2 of Appendix W involves a degree of conservatism in the modeling assumptions for demonstrating compliance with the NAAQS by recommending the use of maximum allowable emissions, which represents emission levels that the facility could, and might reasonably be expected to, achieve if a PSD permit is granted. However, the intermittent nature of the actual emissions associated with emergency generators and startup/shutdown in many cases, when coupled with the probabilistic form of the standard, could result in modeled impacts being significantly higher than actual impacts would realistically be expected to be for these emission scenarios. The potential overestimation in these cases results from the implicit assumption that worst-case emissions will coincide with worst-case meteorological conditions based on the specific hours on specific days of each of the years associated with the modeled design value based on the form of the hourly standard. In fact, the probabilistic form of the standard is explicitly intended to provide a more stable metric for characterizing ambient air quality levels by mitigating the impact that outliers in the distribution might have on the design value. The February 9, 2010, preamble to the rule promulgating the new 1-hour NO_2 standard stated that "it is desirable from a public health perspective to have a form that is reasonably stable and insulated from the impacts of extreme meteorological events." 75 FR 6492. Also, the Clean Air Science Advisory Committee (CASAC) "recommended a 98^{th}-percentile form averaged over 3 years for such a standard, given the potential for instability in the higher percentile concentrations around major roadways." 75 FR 6493.

To illustrate the importance of this point, consider the following example. Under a deterministic 1-hour standard, where the modeled design value would be based on the highest of the second-highest hourly impacts (allowing one exceedance per year), a single emission episode lasting 2 hours for an emergency generator or other intermittent emission scenario could determine the modeled design value if that episode coincided with worst-case meteorological conditions. While the probability of a particular 2-hour emission episode actually coinciding with the worst-case meteorological conditions is relatively low, there is nonetheless a clear linkage between a specific emission episode and the modeled design value. By contrast, under the form of the 1-hour NO_2 NAAQS only one hour from that emission episode could contribute to the modeled design value, i.e., the daily maximum 1-hour value. However, by assuming continuous operation of intermittent emissions the modeled design value for the 1-hour NO_2 NAAQS effectively assumes that the intermittent emission scenario occurs on the specific hours of the specific days for each of the specific years of meteorological data included in the analysis which factor into the multiyear average of the 98th-percentile of the annual distribution of daily maximum 1-hour values. The probability of the controlling emission episode occurring on this particular temporal schedule to determine the design value under the probabilistic standard is significantly smaller than the probability of occurrence under the deterministic standard; thereby increasing the likelihood that impact estimates based on assuming continuous emissions would significantly overestimate actual impacts for these sources.

Given the implications of the probabilistic form of the 1-hour NO_2 NAAQS discussed above, we are concerned that assuming continuous operations for intermittent emissions would effectively impose an additional level of stringency beyond that intended by the level of the standard itself. As a result, we feel that it would be inappropriate to implement the 1-hour NO_2 standard in such a manner and recommend that compliance demonstrations for the 1-hour NO_2 NAAQS be based on emission scenarios that can logically be assumed to be relatively continuous or which occur frequently enough to contribute significantly to the annual distribution of daily maximum 1-hour concentrations. EPA believes that existing modeling guidelines provide sufficient discretion for reviewing authorities to exclude certain types of intermittent emissions from compliance demonstrations for the 1-hour NO_2 standard under these circumstances.

EPA's *Guideline on Air Quality Models* provides recommendations regarding air quality modeling techniques that should be applied in preparation or review of PSD permit applications and serves as a "common measure of acceptable technical analysis when supported by sound scientific judgment." 40 C.F.R. Part 51, Appendix W, section 1.0.a. While the guidance establishes principles that may be controlling in certain circumstances, the guideline is not "a strict modeling 'cookbook'" so that, as the guideline notes, "case-by-case analysis and judgment are frequently required." Section 1.0.c. In particular, with respect to emissions input data, section 8.0.a. of Appendix W establishes the general principle that "the most appropriate data available should always be selected for use in modeling analyses," and emphasizes the importance of "the exercise of professional judgement by the appropriate reviewing authority" in determining which nearby sources should be included in the model emission inventory. Section 8.2.3.b.

For the reasons discussed above, EPA believes the most appropriate data to use for compliance demonstrations for the 1-hour NO_2 NAAQS are those based on emissions scenarios that are continuous enough or frequent enough to contribute significantly to the annual distribution of daily maximum 1-hour concentrations. Section 8.1.1.b of the guideline also provides that "[t]he appropriate reviewing authority should be consulted to determine appropriate source definitions and for guidance concerning the determination of emissions from and techniques for modeling various source types." When EPA is the reviewing authority for a permit, for the reasons described above, we will consider it acceptable to limit the emission scenarios included in the modeling compliance demonstration for the 1-hour NO_2 NAAQS to those emissions that are continuous enough or frequent enough to contribute significantly to the annual distribution of daily maximum 1-hour concentrations. Consistent with this rationale, the language in Section 8.2.3.d of Appendix W states that "*[i]t is appropriate to model nearby sources only during those times when they, by their nature, operate at the same time as the primary source(s) being modeled.*" While we recognize that these intermittent emission sources <u>could</u> operate at the same time as the primary source(s), the discussion above highlights the additional level of conservatism in the modeled impacts inherent in an assumption that they do <u>in fact</u> operate simultaneously and continuously with the primary source(s).

The rationale regarding treatment of intermittent emissions applies for both project emissions and any nearby or other background sources included in the modeling analysis. However, this rationale does <u>not</u> apply to the load analysis recommended in Table 8-2 of Appendix W, since various operating loads are not by design intended to be intermittent. Appendix W, Section 8.1.2.a. With respect to the operating level, for the proposed new or modified source, Table 8-2 calls for using "[d]esign capacity or federally enforceable permit condition." With respect to nearby sources, the guidelines call for estimating emissions based on "[a]ctual or design capacity (whichever is greater), or federally enforceable permit condition." Footnote 3 to the table notes that "[o]perating levels such as 50 percent and 75 percent of capacity should also be modeled to determine the load causing the highest concentration." The justification for not including certain intermittent operations described in this memo does not apply to these guidelines that address analyzing the load causing the highest concentration.

We recognize that case-specific issues and factors may arise that affect the application of this guidance, and that not all facilities required to demonstrate compliance with the 1-hour NO_2 NAAQS will fit within the scenario described above with clearly defined continuous/normal operations vs. intermittent/infrequent emissions. Additional discretion may need to be exercised in such cases to ensure that public health is protected. For example, an intermittent source that is permitted to operate up to 500 hours per year, but typically operates much less than 500 hours per year and on a random schedule that cannot be controlled would be appropriate to consider under this guidance. On the other hand, an "intermittent" source that is permitted to operate only 365 hours per year, but is operated as part of a process that typically occurs every day, would be less suitable for application of this guidance since the single hour of emissions from each day could contribute significantly to the modeled design value based on the annual distribution of daily maximum 1-hour concentrations. Similarly, the frequency of startup/shutdown emission scenarios may vary significantly depending on the type of facility. For example, a large base-load power plant may experience startup/shutdown events on a relatively infrequent basis whereas as a peaking unit may go through much more frequent startup/shutdown cycles. It may be appropriate to apply this guidance in the former case, but not the latter.

Another aspect of intermittent emissions worth noting is the distinction between intermittent emissions that can be scheduled with some degree of flexibility vs. intermittent emissions that cannot be scheduled. For example, a portion of emissions from an emergency generator are likely to be associated with regular testing of the equipment that may be required to ensure its reliable operation, while that portion of emergency generator emissions associated with actual emergency use typically cannot be scheduled. In this case it may be appropriate to include a permit condition that restricts operation of the emergency generator during testing to certain hours of the day, which may mitigate that source's contribution to ambient NO_2 levels based on dispersion conditions. Limiting operation to specific time periods is an appropriate permit condition under Appendix W guidance and would not constitute a "dispersion technique" subject to Section 123 of the CAA. In this case the portion of the emissions associated with scheduled testing can be accounted for more realistically by limiting the hours modeled to account for meteorological conditions that are more representative of actual operations.

Another approach that may be considered in cases where there is more uncertainty regarding the applicability of this guidance would be to model impacts from intermittent emissions based on an average hourly rate, rather than the maximum hourly emission. For example, if a proposed permit includes a limit of 500 hours/year or less for an emergency generator, a modeling analysis could be based on assuming continuous operation at the average hourly rate, i.e., the maximum hourly rate times 500/8760. This approach would account for potential worst-case meteorological conditions associated with emergency generator emissions by assuming continuous operation, while use of the average hourly emission represents a simple approach to account for the probability of the emergency generator actually operating for a given hour. Also note that the contribution of intermittent emissions to annual impacts should continue to be addressed as in the past to demonstrate compliance with the annual NO_2 standard.

A final point of clarification regarding intermittent emissions that deserves some emphasis is that the guidance provided here in relation to determining compliance with the 1-hour NO_2 NAAQS through dispersion modeling has no effect on or relevance to the existing policies and guidance regarding excess emissions that may occur during startup and shutdown, where such excess emissions violate applicable emission limitations[4]. In other words, all emissions from a new or modified source are subject to the applicable permitted emission limits and may be subject to enforcement action regarding such excess emissions, regardless of whether a portion of those emissions are not included in the modeling demonstration based on the guidance provided here.

Given the added complexity of the technical issues that arise in the context of demonstrating compliance with the 1-hour NO_2 NAAQS through dispersion modeling, we strongly encourage adherence to the recommendations in Section 10.2.1. of Appendix W that "*[e]very effort should be made by the Regional Office to meet with all parties involved in either a SIP revision or a PSD permit application prior to the start of any work on such a project. During this meeting, a protocol should be established between the preparing and reviewing parties to define the procedures to be followed, the data to be collected, the model to be used, and the analysis of the source and concentration data.*"

[4] While excess emissions during malfunctions are also addressed in the policy related to excess emissions, Appendix W explicitly excludes emissions due to malfunction from the modeling analysis to demonstrate compliance with the NAAQS, unless the excess emissions are the result of poor maintenance, careless operation, or other preventable conditions. See Section 8.1.2.a, footnote a.

DETERMINING BACKGROUND CONCENTRATIONS

Unless a facility can demonstrate that ambient impacts associated from its emissions will not exceed the appropriate SIL, a cumulative analysis of ambient impacts will be necessary, and the determination of background concentrations to include in that cumulative impact assessment will be a critical component of the analysis. The June 29, 2010 memorandum addressed some aspects of this issue, but given the stringency of the new 1-hour NO_2 standard, the "margin for error" in this aspect of the analysis is much smaller than it has been in the past. As a result, we believe it is necessary to provide additional clarification and a more detailed discussion of the factors associated with this aspect of the permitting process. We hope that this additional discussion will serve to more clearly define some of the key steps and considerations in the process that could form the basis of a generic modeling protocol. We also provide suggestions regarding some of the documentation related to this component of the modeling analysis that may facilitate and expedite the review process.

The goal of the cumulative impact assessment should be to demonstrate with an adequate degree of confidence in the result that the proposed new or modified emissions will not cause or significantly contribute to violations of the NAAQS. In general, the more conservative the assumptions on which the cumulative analysis is based, the more confidence there will be that the goal has been achieved and the less controversial the review process will be from the perspective of the reviewing authority. As less conservative assumptions are implemented in the analysis, the more scrutiny those assumptions may require and the review process may tend to be lengthier and more controversial as a result. We expect that by providing a more detailed discussion of the factors to be considered in the cumulative impact assessment, permit applicants and permitting authorities will be able to find the proper balance of the competing factors that contribute to this analysis.

<u>Identifying Nearby Sources to Include in Modeled Inventory</u>

As noted in the June 29, 2010 memo, Section 8.2.3 of Appendix W emphasizes the importance of professional judgment by the reviewing authority in the identification of nearby and other sources to be included in the modeled emission inventory, and establishes "a significant concentration gradient in the vicinity of the source" under consideration as the main criterion for this selection. Appendix W also suggests that "the number of such [nearby] sources is expected to be small except in unusual situations." See Section 8.2.3.b. In light of this guidance, the June 29, 2010 memo cautioned against the literal and uncritical application of very prescriptive procedures for identifying which background sources should be included in the modeled emission inventory for NAAQS compliance demonstrations, such as those described in Chapter C, Section IV.C.1 of the draft *New Source Review Workshop Manual* (EPA, 1990). This caution should not be taken to imply that the procedures outlined in the NSR Workshop Manual are flawed or inappropriate in themselves. Cumulative impact assessments based on following such procedures will generally be acceptable as the basis for permitting decisions, contingent on an appropriate accounting for the monitored contribution. Our main concern is that following such procedures in a literal and uncritical manner may in many cases result in cumulative impact assessments that are overly conservative and could unnecessarily complicate the permitting process in some cases. Such procedures might be characterized as being sufficient in most cases, but not always necessary to fulfill the requirements of a cumulative impact assessment.

A fundamental challenge in developing more detailed general guidance on the issue of determining background concentrations as part of a cumulative impact assessment is that the factors that need to be considered are very case-specific in nature. These factors include foremost the nature of the source being permitted, including the source characteristics and local meteorological and topographical factors that determine the spatial and temporal patterns of the source's ambient impacts. The initial significant impact assessment should serve to characterize these factors, and we would suggest the following:

1. As a standard practice contour plots of modeled concentrations should be prepared which clearly depict the impact area of the source, preferably overlaid on a map of the area that identifies key geographical features that may influence the dispersion patterns. The concentration contour plot also serves to visually depict the concentration gradients associated with the source's impact.
2. We also recommend that the controlling meteorological conditions for the project impacts be identified as clearly as possible. The probabilistic form of the 1-hour NO_2 standard complicates this assessment somewhat, but the recent update to the AERMOD model includes new model output options (MAXDAILY and MXDYBYYR keywords) that identify the specific time periods on which the modeled design value is based.
3. As an aid to interpreting this information, we also suggest including the location of the meteorological monitoring station used in the modeling analysis on the plot of source impacts, as well as a wind rose depicting general flow patterns.

If a cumulative impact assessment is required due to the source's impacts exceeding the interim SIL, the applicant will need to identify and acquire data on the two main components of the cumulative impact assessment, namely the location and emissions from nearby background sources that may need to be included in the modeled component of the cumulative ambient impact assessment, and the location and magnitude of air quality data from ambient NO_2 monitors located within the area. Section 8.2.1.b of Appendix W states that "[t]ypically, air quality data should be used to establish background concentrations in the vicinity of the source(s) under consideration." Section 8.2.1.c further states that "[i]f the source is not isolated, it may be necessary to use a multi-source model to establish the impact of nearby sources." While many applications will be required to include both monitored and modeled contributions to adequately account for background concentrations in the cumulative analysis, we believe that these statements imply a preference for use of ambient air quality data to account for background concentrations where possible.

Many of the challenges and more controversial issues related to cumulative impact assessments arise in the context of how best to combine a monitored and modeled contribution to account for background concentrations. Addressing these issues requires an assessment of the spatial and temporal representativeness of the background monitored concentrations for purposes of the cumulative impact assessment and the potential for double counting of impacts from modeled sources that may be contributing to the monitored concentrations. This assessment may involve significant technical details which could complicate the review process. Therefore, the more thoroughly and clearly these issues are documented the more efficient and effective the review process is likely to be.

A key point to remember when assessing these issues is their interconnectedness – the question of which nearby background sources should be included in the cumulative modeling analysis is inextricably linked with the question of what ambient monitoring data is available and what that data represents in relation to the application. Furthermore, the question of how to appropriately combine monitored and modeled concentrations (temporally and spatially) to determine the cumulative impact depends on a clear understanding of what the ambient monitored data represents in relation to the modeled emission inventory. A more detailed temporal pairing of monitored and modeled concentrations may be acceptable in one case given the extent of the modeled emission inventory, while a more conservative assumption for combining monitored and modeled concentrations using high ranked monitored concentrations may be sufficient to justify a more limited modeling inventory. As noted above, the stringency of the new standard may require a more detailed and refined analysis of these issues in order to demonstrate compliance with the standards than was necessary in the past, and these refinements will generally increase the burden on the applicant to adequately demonstrate that the net result of the analysis is protective of the standard. A detailed analysis and explanation of any potential bias to the net result introduced by proposed refinements will be important to facilitate the review process. The issues associated with determining an appropriate method for combining modeled and monitored contributions to a cumulative impact assessment are discussed in more detail in the next section.

Building on the geographical information recommended above for the initial SIL analysis, we suggest including the following documentation:

1. A geographical depiction of the location and magnitude of nearby emission sources, along with the location and magnitude of any ambient monitored data as part of the documentation submitted with a cumulative impact assessment.
2. Depicting the impact area and pattern of the project impacts on such a figure along with a wind rose should be useful in assessing many of the issues touched on above, such as what nearby sources are likely to cause significant concentration gradients in the vicinity of the project source, or more specifically in the areas of high impacts associated with the project source. This figure should also help to identify what nearby source’s impacts are likely to be adequately represented in the available monitored data and the potential for double counting of impacts from modeled background sources if certain ambient background data are used.
3. In addition to a standard wind rose, pollution roses (i.e., a depiction of monitored pollutant concentrations as a function of wind direction and/or other meteorological factors) should also be useful for purposes of assessing the representativeness of the monitoring background concentrations in relation to the cumulative impact assessment.

Finally, we reiterate the importance of close coordination with the appropriate reviewing authority in the determination of nearby or other sources to include in the modeled emission inventory.

Significant Concentration Gradient Criterion

While Appendix W (Section 8.2.3.b) identifies “a significant concentration gradient in the vicinity of the source” as the sole criterion in relation to determining which nearby sources should be explicitly modeled as part of the cumulative impact assessment, little else has been written to explain what “significant” means in this context or even what the relevance of a “significant concentration gradient” is for this purpose. In fact, Appendix W states that no attempt was made to “comprehensively define” the term, “owing to both the uniqueness of each modeling situation and the large number of variables involved in identifying nearby sources.” Section 8.2.3.b. Nothing has fundamentally changed to alter this characterization, but given the issues and challenges arising from the implementation of the new 1-hour NO_2 standard, we feel compelled to offer some additional explanation regarding what this guidance means and how it should be applied.

One definition of the term “gradient” that applies in this context is “the rate of change of a physical quantity . . . with distance[5].” In this case the physical quantity is the ground-level concentration of the pollutant being assessed. The first point worth noting is that the gradient of the ground-level concentration has two dimensions, a longitudinal (along-wind) gradient and a lateral (cross-wind) gradient. Appendix W makes no distinction as to which gradient is more important or whether both gradients should be considered. Before offering any suggestions on that question, it might be helpful to offer some thoughts on the question of why a significant concentration gradient is mentioned as the sole criterion. Since an ambient monitor is limited to characterizing air quality at a fixed location, the impact from a nearby source that causes a significant concentration gradient in the vicinity of the project source is not likely to be characterized very well by the monitored concentration in terms of its potential for contributing to the cumulative modeled design value due to the high degree of variability of the source’s impact. In this sense both the longitudinal and lateral gradients could be of importance. However, since the location of impacts from a particular source relative to other sources being modeled or relative to the ambient monitor location is strongly influenced by the transport wind direction, relatively minor changes in wind direction can result in significant changes in modeled concentrations at a particular time and point in space, such as the monitor location. The longitudinal gradient will also vary as a result of changes in wind speed and atmospheric stability, but in general the impact of this longitudinal variability on concentrations at a particular time and point in space will be less significant than the variability associated with the lateral gradient. From this perspective it would appear that the lateral gradient may be more important to consider for purposes of assessing which background sources should be explicitly modeled.

Concentration gradients associated with a particular source will generally be largest between the source location and the distance to the maximum ground-level concentrations from the source. Beyond the maximum impact distance, concentration gradients will generally be much smaller and more spatially uniform. A general “rule of thumb” for estimating the distance

[5] Webster's New World College Dictionary, Copyright © 2010 by Wiley Publishing, Inc., Cleveland, Ohio.

to maximum 1-hour impact and the region of significant concentration gradients that may apply in relatively flat terrain is approximately 10 times the source release height. For example, the maximum impact area and region of significant concentration gradients associated with a 100 meter stack in flat terrain would be approximately 1,000 meters downwind of the source, with some variation depending on the source characteristics affecting plume rise. However, the potential influence of terrain on maximum 1-hour pollutant impacts may also significantly affect the location and magnitude of concentration gradients associated with a particular source. Even accounting for some terrain influences on the location and gradients of maximum 1-hour concentrations, these considerations suggest that the emphasis on determining which nearby sources to include in the modeling analysis should focus on the area within about 10 kilometers of the project location in most cases. The routine inclusion of all sources within 50 kilometers of the project location, the nominal distance for which AERMOD is applicable, is likely to produce an overly conservative result in most cases.

The relative importance of the lateral vs. the longitudinal gradient will also depend on terrain effects and other factors, such as the atmospheric stability associated with worst-case impacts. The importance of the lateral gradient relative to the longitudinal gradient will generally increase for sources where maximum hourly impacts occur under stable conditions due to the narrowness of the plume under such conditions. The contour plots of modeled design values suggested above provide a method for examining concentration gradients more explicitly. The AERSCREEN model should also serve as a useful tool for identifying the worst-case meteorological conditions for individual sources, as well as determining locations of maximum impact and areas of significant concentration gradients.

A final point to mention in relation to this topic is that the pattern of concentration gradients can vary significantly based on the averaging period being assessed. In general, concentration gradients will be smaller and more spatially uniform for annual averages than for short-term averages, especially hourly averages. The spatial distribution of annual impacts around a source will typically have a single peak “downwind” of the source based on the prevailing wind direction, except in cases where terrain or other geographical effects are important. By contrast, the spatial distribution of peak hourly impacts will typically show several localized concentration peaks with more significant gradients. The number of peaks and the magnitude of the gradients will be somewhat smaller for modeled design values based on the form of the 1-hour NO_2 standard than for overall peak hourly values, due to the smoothing effect of using a multiyear average of the 98^{th}-percentile from the annual distribution of daily maximum values. One implication of these differences between long-term and short-term concentration patterns is that the factors affecting which sources should be included in the modeled inventory and the method for combining modeled with monitored concentrations are more complex for the 1-hour NO_2 standard than for the annual standard.

While we hope this discussion provides some useful insight into this issue, we also caution against interpreting this guidance too literally or too narrowly, and emphasize that a “large number of variables” (Appendix W, Section 8.2.3.b) are involved in this assessment.

COMBINING MODELED RESULTS AND MONITORED BACKGROUND TO DETERMINE COMPLIANCE

One important aspect of the cumulative impact assessment that also deserves further discussion and entails new challenges with the 1-hour NO_2 NAAQS is the method for combining modeled concentrations with monitored background concentrations to determine the cumulative ambient impact. The June 29, 2010 memo indicated that a “first tier” assumption for a uniform monitored background contribution that may be applied without further justification is to add the overall highest hourly background NO_2 concentration (across the most recent three years) from a representative monitor to the modeled design value[6] for comparison to the NAAQS. Use of a single uniform monitored background contribution is the simplest approach to implement since it can be applied outside of the modeling system. We recognize that use of the overall highest hourly background concentration may be overly conservative in many cases, but that conservatism also provided the basis for indicating that this approach could be used without further justification. As explained above, the more conservative the assumptions on which the cumulative analysis is based, the more confidence there will be that the goal of demonstrating that the source will not cause or contribute to violations of the NAAQS has been achieved and the less controversial the review process will be from the perspective of the reviewing authority. The June 29, 2010 memo also indicated that additional refinements to this “first tier” approach based on some level of temporal pairing of modeled and monitored values may be considered on a case-by-case basis, with adequate justification and documentation. Given the importance of this aspect of the analysis and the challenges that have arisen in application of the guidance to date, we feel compelled to offer additional guidance on this issue.

While the “first tier” assumption from the June 29, 2010 memo of using a uniform monitored background contributions based on the overall highest hourly background NO_2 concentration should be acceptable without further justification in most cases, we recognize that this approach could be overly conservative in many cases and may also be prone to reflecting source-oriented impacts from nearby sources, increasing the potential for double-counting of modeled and monitored contributions. Based on these considerations, we believe that a less conservative “first tier” for a uniform monitored background contribution based on the monitored design value from a representative monitor should be acceptable in most cases. The monitored NO_2 design value, i.e., the 98^{th}-percentile of the annual distribution of daily maximum 1-hour values averaged across the most recent three years of monitored data[7], should be used irrespective of the meteorological data period used in the dispersion modeling. This somewhat less conservative “first tier” for a uniform monitored background contribution retains the advantage of being relatively easy to implement.

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[6] The 1-hour NO_2 “modeled design value” refers to the highest (across all modeled receptors) of the 5-year average of the 98^{th}-percentile (8^{th}-highest) of the annual distribution of daily maximum 1-hour values based on NWS meteorological data, or the multiyear average of the 98^{th}-percentile of the annual distribution of daily maximum 1-hour values based on one or more complete years (up to 5 years) of site-specific meteorological data. The1-hour SO_2 “modeled design value” follows the same form except that the multiyear averages of the 99^{th}-percentile (4^{th}-highest) values are used.

[7] The monitored design value for the 1-hour SO_2 standard is based on the 99^{th}-percentile of the annual distribution of daily maximum 1-hour values averaged across the most recent three years of monitored data.

Depending on the circumstances of a particular application, use of a "first tier" assumption for a uniform monitored background contribution may represent a level of conservatism that would obviate the need to include any background sources in the modeled inventory if, for example, the number of nearby sources which could contribute to the cumulative impact is relatively few and the available ambient monitor would be expected to reflect their cumulative impacts reasonably well or conservatively in relation to the modeled design value based on the project emissions. At the other extreme, if the background source inventory included in the modeling is complete enough and background levels due to mobile sources and/or minor sources that are not explicitly modeled is expected to be small, an analysis based solely on modeled emissions and no monitored background might be considered adequate for purposes of the cumulative impact assessment.

One of the important factors to consider in relation to this issue is that the standard is based on the annual distribution of daily maximum 1-hour values, which implies that diurnal patterns of ambient impacts could play a significant role in determining the most appropriate method for combining modeled and monitored concentrations. For example, if the daily maximum 1-hour impacts associated with the project emissions generally occur under nighttime stable conditions whereas maximum monitored concentrations occur during daytime convective conditions, pairing modeled and monitored concentrations based on hour of day should provide a more appropriate and less conservative estimate of cumulative impacts than a method that ignores this diurnal pattern. This situation could occur for applications dominated by low-level sources and for elevated releases subject to plume impaction on nearby complex terrain. It is also important to consider the role of NO_x chemistry for applications using the Tier 3 options in AERMOD since diurnal patterns of background ozone concentrations may also factor into the diurnal patterns of modeled impacts. Given the potential contribution of background ozone levels to the temporal variability of modeled impacts, the seasonal variability of background monitored values could also be important. Incorporating a seasonal component to the variability of background monitored concentrations will also account for some of the variability in meteorological conditions that may contribute to high hourly impacts.

Another situation where understanding the temporal variability of modeled vs. monitored concentrations could be important in determining the most appropriate method for combining modeled and monitored concentrations is where contributions from mobile source emissions contribute significantly to either the monitored background concentrations and/or the modeled concentrations. In these cases, diurnal variability of emissions associated with morning and afternoon rush hours could contribute to the temporal variability of ambient impacts in addition to meteorological factors associated with the dispersion and conversion of NO_x emissions. Since rush hours tend to be relatively fixed in terms of time of day and also occur near the transitions from nighttime stable to daytime convective conditions, and vice versa, incorporating a seasonal or monthly element to the temporal variability should account for the variable effect that dispersion conditions may have depending on whether rush hour occurs during stable or convective hours.

With these general considerations in mind, we now examine the following guidance in relation to the use of background monitored concentrations in a cumulative impact assessment, from Section 8.2.2 of Appendix W, which applies to applications for isolated sources and for the contribution of "other sources" consisting of "[t]hat portion of the background attributable to all other sources (e.g., natural sources, minor sources and distant major sources)" in a multi-source area:

> b. Use air quality data collected in the vicinity of the source to determine the background concentration for the averaging times of concern. Determine the mean background concentration at each monitor by excluding values when the source in question is impacting the monitor. The mean annual background is the average of the annual concentrations so determined at each monitor. For shorter averaging periods, the meteorological conditions accompanying the concentrations of concern should be identified. Concentrations for meteorological conditions of concern, at monitors not impacted by the source in question, should be averaged for each separate averaging time to determine the average background value. Monitoring sites inside a 90° sector downwind of the source may be used to determine the area of impact. One hour concentrations may be added and averaged to determine longer averaging periods.
>
> c. If there are no monitors located in the vicinity of the source, a ''regional site'' may be used to determine background. A ''regional site'' is one that is located away from the area of interest but is impacted by similar natural and distant man-made sources.

The key principle in this guidance in relation to short-term averaging periods is to determine background concentrations associated with "meteorological conditions accompanying the concentrations of concern." The concentrations thus determined "should be averaged for each separate averaging time to determine the average background value."

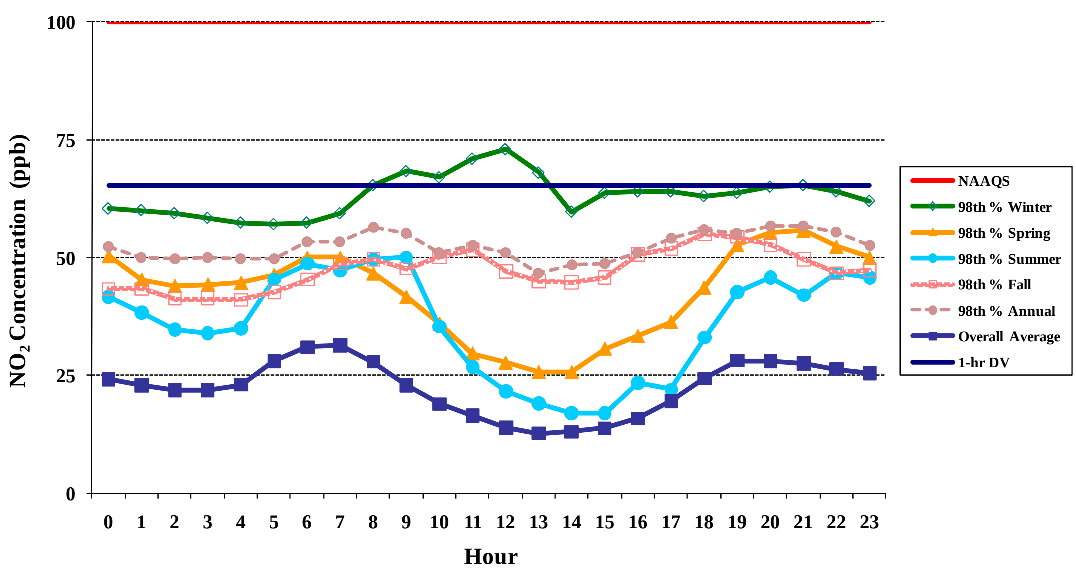
Based on this guidance, we believe that an appropriate methodology for incorporating background concentrations in the cumulative impact assessment for the 1-hour NO_2 standard would be to use multiyear averages of the 98th-percentile[8] of the available background concentrations by season and hour-of-day, excluding periods when the source in question is expected to impact the monitored concentration (which is only relevant for modified sources). For situations involving a significant mobile source component to the background monitored concentrations, inclusion of a day-of-week component to the temporal variability may also be appropriate. The rank associated with the 98th-percentile of daily maximum 1-hour values should be generally consistent with the number of "samples" within that distribution for each combination based on the temporal resolution but also account for the number of samples "ignored" in specifying the 98th-percentile based on the annual distribution. For example, Table 1 in Section 5 of Appendix S specifies the rank associated with the 98th-percentile value based on the annual number of days with valid data. Since the number of days per season will range from 90 to 92, Table 1 would indicate that the 2nd-highest value from the seasonal distribution should be used to represent the 98th-percentile. On the other hand use of the 2nd-highest value for each season would effectively "ignore" only 4 values for the year rather than the 7 values "ignored" from the annual distribution. Balancing these considerations we recommend that background values by season and hour-of-day used in this context should be based on the 3rd-highest value for each season and hour-of-day combination, whereas the 8th-highest value should be used if values vary by hour-of-day only. For more detailed temporal pairing, such as season by hour-of-

[8] The 99th-percentile should be used for the 1-hour SO_2 standard.

day and day-of-week or month by hour-of-day, the 1st-highest values from the distribution for each temporal combination should be used.[9]

Figure 1 shows the background monitored concentrations by season and hour-of-day for the Salt Lake City, UT monitor for the period 2005-2007 based on these recommendations. The values labeled "Average Winter", "Average Spring", etc. are the 3-year averages of the 3rd-highest values by hour-of-day for each season; the values labeled "Average 98th %" (the dashed line) are the 3-year average of the 8th-highest values by hour-of-day only; and the values labeled "Overall Average" are the averages across all values by hour-of-day. These results illustrate the significant temporal variability captured by the multiyear averages of the 98th-percentile values by season and hour-of-day. Also note that values for the 98th-percentile by hour-of-day only show little variation by hour-of-day, while values by season and hour-of-day show significant diurnal variability for some seasons.

Figure 1. Monitored Background Concentrations for Salt Lake City, UT Monitor
2005-2007 One-Hour NO_2 Concentrations



It should also be noted here that the conventions regarding observation reporting time differ between ambient air quality monitoring, where the observation time is based on the hour-beginning convention (EPA, 2009; see Section 3.20), and meteorological monitoring where the observation is based on the hour-ending convention (EPA, 2000; see Section 7.1). Thus, ambient monitoring data reported for hour 00 should be paired with modeled/meteorological data for hour 01, etc. The recent update to the AERMOD model (dated 11059) provides an option (the BACKGRND keyword on the SO pathway) to include temporally-varying background concentrations within the cumulative impact assessment based on these temporal factors, similar

[9] For 1-hour SO_2 analyses, use the 2nd-highest value for each season and hour-of-day combination, or the 4th-highest value for hour-of-day only. Use the 1st-highest value for more detailed pairing, such as month by hour-of-day or season by hour-of-day and day-of-week.

to the options that have been available in previous versions of the model to vary source emissions using the EMISFACT keyword. We believe that this technique provides a reasonable and efficient method for ensuring that the monitored contribution to the cumulative impact assessment will be representative of the "meteorological conditions accompanying the concentrations of concern" since the monitored values will be temporally paired with modeled concentrations based on temporal factors that are associated with meteorological variability, but will also reflect worst-case meteorological conditions in a manner that is consistent with the probabilistic form of the 1-hour NO_2 standard. The use of multiyear-averaged monitored values for the meteorological conditions of concern is consistent with the language in Appendix W related to this issue, and also consistent with the intent of using monitored background concentrations, which is to reflect the contribution from natural or regional levels of pollution and the net contribution of minor emission sources which are not explicitly accounted for in the modeled inventory.

Since several applications have come to our attention proposing to combine monitored background and modeled concentrations on an hour-by-hour basis, using hourly monitored background data collected concurrently with the meteorological data period being processed by the model, we feel compelled to include a discussion of the potential merits and concerns regarding such an approach. On the surface this approach could be perceived as being a more "refined" method than what is recommended above, and therefore more appropriate. However, the implicit assumption underlying this approach is that the background monitored levels for each hour are spatially uniform and that the monitored values are fully representative of background levels at each receptor for each hour. Such an assumption clearly ignores the many factors that contribute to the temporal and spatial variability of ambient concentrations across a typical modeling domain on an hourly basis. Therefore we do not recommend such an approach except in rare cases of relatively isolated sources where the available monitor can be shown to be representative of the ambient concentration levels in the areas of maximum impact from the proposed new source. Another situation where such an approach may be justified is where the modeled emission inventory clearly represents the majority of emissions that could potentially contribute to the cumulative impact assessment and where inclusion of the monitored background concentration is intended to conservatively represent the potential contribution from minor sources and natural or regional background levels not reflected in the modeled inventory. In this case, the key aspect which may justify the hour-by-hour pairing of modeled and monitored values is a demonstration of the overall conservatism of the cumulative assessment based on the combination of modeled and monitored impacts. Except in rare cases of relatively isolated sources, a single ambient monitor, or even a few monitors, will not be adequately representative of hourly concentrations across the modeled domain to preclude the need to include emissions from nearby background sources in the modeled inventory.

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ATTACHMENT A

Summary of AERMOD Model Performance for 1-hour NO2 Concentrations

As noted in the June 29, 2010 memo, limited evaluations of the Plume Volume Molar Ratio Method (PVMRM) for estimating conversion of NO to NO_2 have been completed which show encouraging results, but the amount of data currently available is too limited to justify a designation of PVMRM as a refined method for NO_2 (Hanrahan, 1999; MACTEC, 2005). The original evaluations of PVMRM also focused on model performance for annual averages since the only NO_2 standard in effect at the time was annual. These evaluations have recently been updated to reflect the current AERMOD modeling system components and extended to examine model performance for hourly NO_2 concentrations and to include the Ozone Limiting Method (OLM). Preliminary results from these recent evaluations are presented below in the form of Q-Q plots of ranked hourly NO_2 concentrations for the two monitors included in the New Mexico Empire Abo field study and for the single monitor included in the Palaau, HI field study. Evaluation results are also summarized in the form of predicted vs. observed 1-hour Robust Highest Concentrations (RHC), a model evaluation metric that represents an exponential tail fit to the top 26 ranked values in the distribution of hourly concentrations. Note that the OLM results presented here incorporate an equilibrium NO_2/NO_x ratio of 0.90, consistent with the PVMRM option.

Figures A-1 and A-2 show results in the form of hourly Q-Q plots for the North monitor and the South monitor, respectively, from the New Mexico field study based on the Tier 1 option of full conversion of NO to NO_2, the OLM option applied on a source-by-source basis, the OLM option applied using OLMGROUP ALL (OLMGRP), as recommended in the June 29, 2010, NO_2 clarification memorandum, and the PVMRM option. The New Mexico results clearly show the conservatism associated with the Tier 1 assumption of full conversion and the OLM option on a source-by-source basis, with both options showing a significant bias to overpredict hourly NO_2 concentrations. The OLMGRP option exhibits the best performance for both New Mexico monitors, with nearly unbiased results for the North monitor and a slight bias to overpredict for the South monitor. The PVMRM option shows significantly better performance than full conversion or source-by-source OLM for both monitors, but not as good performance as the OLMGRP option.

Figure A-3 shows the hourly Q-Q plot for Palaau based on the same range of options shown in Figures A-1 and A-2. Similar to the New Mexico results, the Tier 1 option of full conversion and the OLM option applied on a source-by-source basis show a significant bias to overpredict hourly NO_2 concentrations at Palaau. The PVMRM option shows the best performance for this field study with very good agreement between predicted and observed concentrations. The use of the OLMGRP option clearly improves model performance as compared to application of the OLM option on a source-by-source basis, with the peak predicted concentrations within a factor of 2 higher than observed. These Q-Q plot comparisons are consistent with the comparisons of RHCs summarized in Table A-1, where the average (geometric mean) ratios of Predicted/Observed RHCs for PVMRM and OLMGRP are about 1.5 and 1.2, respectively, and the average RHC ratios for OLMGRP and FULL conversion are much higher at 4.5 and 5.0.

Since these Tier 3 options in AERMOD are intended to estimate the conversion of ambient NO to NO_2, it is also useful to compare the modeled vs. observed NO_2/NO_x ratios since offsetting errors in dispersion vs. conversion could mask poor model performance. Table A-2 summarizes the observed vs. predicted NO_2/NO_x ratios for the three monitors included in these Palaau and New Mexico field studies. These results are generally consistent with the hourly Q-Q plots of NO_2 concentrations, and clearly indicate that the OLM option on a source-by-source basis significantly overestimates the conversion of NO to NO_2. However, results for the New Mexico South monitor are interesting in that the PVMRM option shows much better agreement with observed NO_2/NO_x ratios than the OLMGRP option, whereas the OLMGRP option indicates better performance than PVMRM in terms of hourly NO_2 concentrations.

These preliminary model evaluation results of hourly NO_2 predictions for Palaau and New Mexico show generally good performance for the PVMRM and OLMGROUP ALL options in AERMOD; however, it should be emphasized that these results are very limited in terms of the number of monitors. Although the scope of the field study data is limited, this level of model performance on a paired-in-space basis is impressive, especially for the PVMRM option at Palaau and for the OLMGROUP ALL option for the North monitor at New Mexico. We believe that these additional model evaluation results lend further credence to the use of these Tier 3 options in AERMOD for estimating hourly NO_2 concentrations and to the recommendation to use the OLMGROUP ALL option whenever OLM is applied.

Figure A-1. AERMOD Model Evaluation - New Mexico North Monitor - Hourly NO2 Q-Q Plot

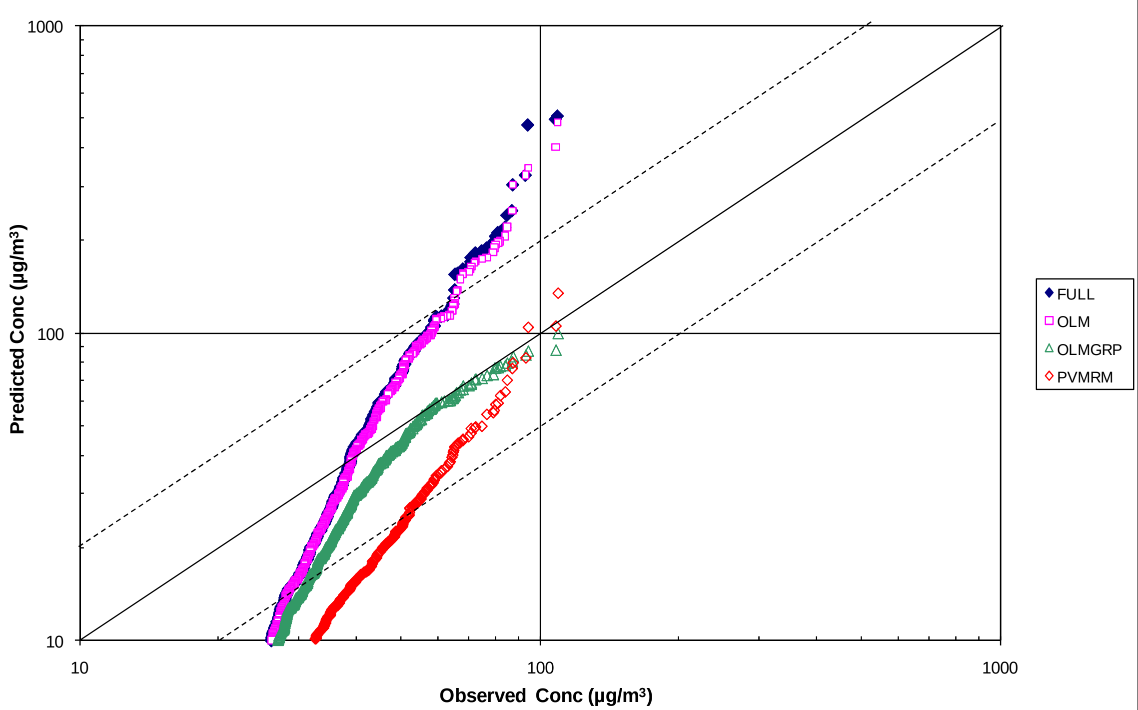
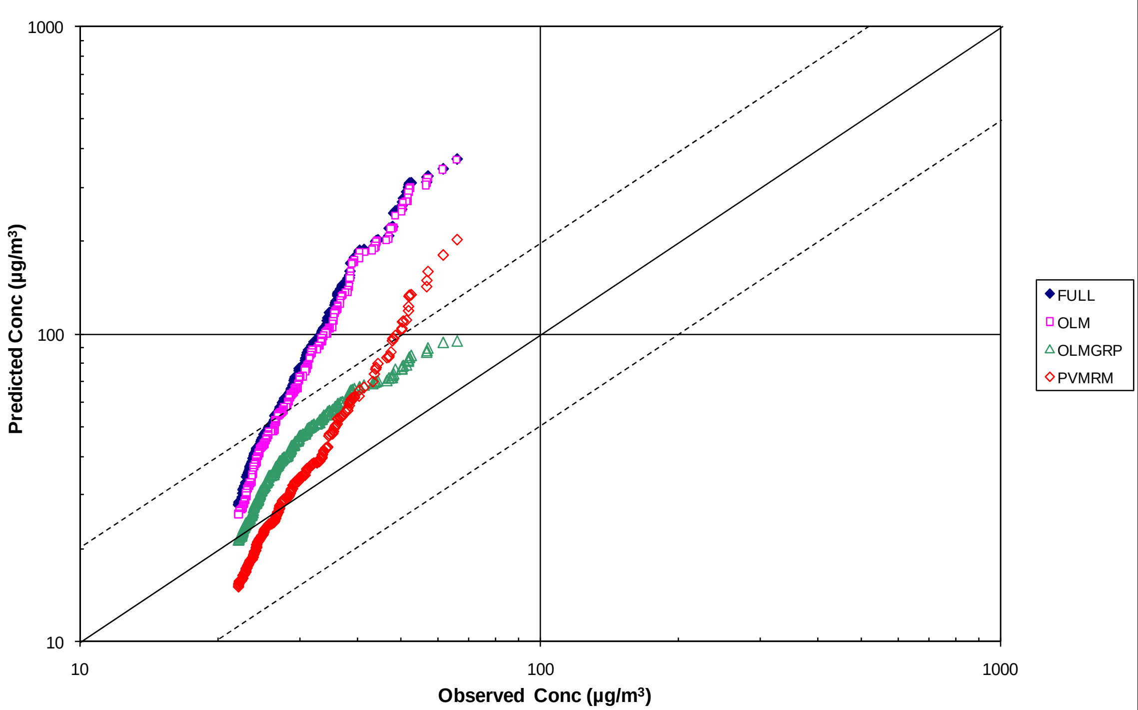


Figure A-2. AERMOD Model Evaluation - New Mexico South Monitor - Hourly NO2 Q-Q Plot



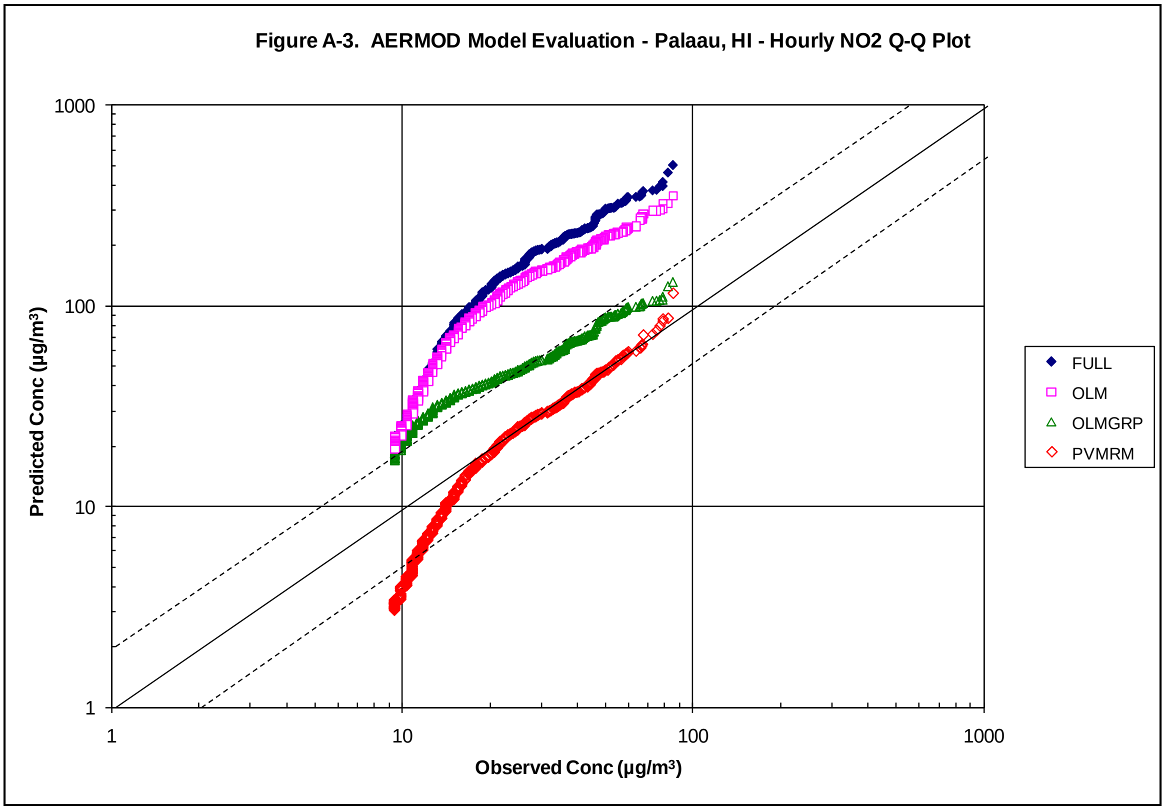


Table A-1. 1-hour NO_2 Robust Highest Concentrations (µg/m^3)

	Observed	PVMRM	OLMGRP	OLM	FULL
New Mexico Abo North Monitor RHC	117.87	116.26	108.38	444.87	449.24
New Mexico Abo South Monitor RHC	70.10	218.98	104.81	440.96	454.68
Hawaii Palaau Monitor RHC	95.42	101.57	113.18	368.57	480.38
Geometric Mean Pred/Obs RHC	---	1.486	1.177	4.510	4.993

Table A-2. Average Unpaired NO_2/NO_x Ratios for Monitored Values of $NO_x > 20$ ppb

	Monitored NO_2/NO_x	PVMRM NO_2/NO_x	OLMGRP NO_2/NO_x	OLM NO_2/NO_x
New Mexico Abo North Monitor (n=772)	0.455	0.377	0.669	0.976
New Mexico Abo South Monitor (n=262)	0.363	0.437	0.491	0.950
Hawaii Palaau Monitor (n=672)	0.138	0.163	0.376	0.854
Geometric Mean Pred/Obs Ratios	---	1.056	1.756	3.263

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