Attachment to Appendix Z

Comment Letters #2 - #19

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August 10, 2015

Philip M. Fine, PhD
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Comments on Preliminary Draft Staff Report
Proposed Amendments to Regulation XX
Regional Clean Air Incentives Market (RECLAIM)
NOx RECLAIM – SCRs for FCCUs
Document No. 14-045-7

Dear Mr. Fine,

We have completed a first pass review of the above captioned report's discussion of SCR applications to district SCRs and have identified several misstatements and/or misunderstandings of the information provided by our company, under contract from SCAQMD, which may have material impact on the conclusions drawn by staff in the report. It is my intent in this letter to clarify the most glaring misstatements/misunderstandings of the information we provided to the district both in our final report (Doc. No. 14-045-4, Nov. 26, 2014) which summarized the data on a non-confidential basis, and the details provided on a confidential basis to the district and individually to each of the refineries.

We stated, quite clearly, in the final report and in subsequent discussions with staff, that we agree that 2 ppmvd (3% O_2) NOx emissions is a justifiable emission level for SCR applications to FCCUs, Fired Heaters, Boilers, Gas Turbines and TGU/SRUs, with caveats. While a few existing units can meet this guideline under current operating conditions, many more, similarly designed units have not demonstrated similar low emissions capabilities. With the exception of Gas Turbine installations (which have an equivalent emission level of 6 ppmv @ 3% O_2) most low emission SCRs in service today, being built today and even those being designed today carry manufacturer's guarantees to meet a NOx limit of 5 vppm @ 3% O_2. In spite of the limited number of units (other than gas turbines) operating at or below 2 vppm NOx, we believe that it is possible to achieve these levels, but to guarantee long term reliable performance (refineries typically operate 24/7 for periods of 4 to 6 years) it is prudent and quite possibly necessary to design future SCRs to increase residence time, improve NH_3 distribution, improve overall flue gas flow distribution, add catalyst, etc. SCAQMD staff agrees with this concept but we have strong disagreement as to how much change from current SCR designs will be required to achieve the sought after NOx reductions not only on day one but at the end of year one and year five and beyond.

NEC's engineers have extensive experience in process development, equipment development and project development for the refining and petrochemical industry in the manufacturing and air pollution control areas. The experience level of the engineers who completed our technology and project cost evaluations is 51, 37 and 8 years. It is exactly this experience base, and past successful work with the district, that caused you to look to NEC to develop "cost guidance" for evaluating the refining sector. We find it very surprising therefore, that staff essentially ignored our recommendations and continued to use what we feel are unrealistically low costs for NOx control projects for district refineries.

Comments on FCCU SCR Costs

Appendix F presents a review of NEC's analysis for FCCU SCR costs by SCAQMD staff. It concludes that NEC's estimated costs for NOx control are excessive and gives the following reasons for this assessment:

- NEC recommends using three catalyst beds and designing for superficial gas velocities of 10 ft/sec vs SCR vendor proposals which have less catalyst and 20% higher superficial velocities.
- NEC conditions budgetary quotations from manufacturers for the accuracy of the quote, the accuracy of the project basis and for the application of refining industry standards for construction of the equipment. This is characterized by staff as: "Adding a "mark-up" factor, or a bid conditioning factor of 1.35 to increase the costs".
- NEC includes the cost of installation of the SCR in its estimate to arrive at a direct material and labor cost for the SCR component of a project at 75% of the equipment cost. Characterized by staff as: "Adding another 75% increase in labor to the costs of the manufacturer's SCR.".
- NEC used incorrect FCCU feed rates in developing comparisons to AQMD PWVs.

The following paragraphs address each of staff's objections and provide additional information and clarifications to address what we perceive as staff's misunderstanding of the information presented in our final report.

Basis for Catalyst Addition and
Velocity Reductions vs Vendor Budget Quotes

All FCCU SCR catalyst beds are in the range of 3 - 4' deep, all are prone to plugging by catalyst and/or ABS and all have limitations on allowable pressure drop, so superficial velocity is a good basis for comparison between units. The district has three operating FCCU SCRs. All units have two catalyst beds and operate at superficial gas velocities in the range of 8 to 13 ft/sec. Two of the three units, operating at superficial velocities of 12 and 13 ft/sec do not achieve emissions of 2 vppm @ 3% O_2. The other unit, highlighted in the draft report, achieves less than 2 vppm @ 3% O_2 operating at a superficial velocity of 7.7 ft/sec. The "good" unit is operating with inlet NOx levels which are 50%

of design or lower and at lower than design flue gas flows. There are several ways to bring the two "non-performing" units into compliance with the revised standard, each with different costs and different overall performance impacts. NEC was not commissioned to do an evaluation of individual units and propose improvement options, but rather to make an assessment of what it would take, cost wise, to reliably achieve the 2 ppmv limit for grass roots SCR installations. Based on the experience of operating units in the district, and our direct experience with FCCU units for other clients (due to confidentiality agreements we cannot divulge client identities and specific locations) reliably achieving 2 vppm NOx emissions in an FCCU over a five year run will require the addition of catalyst and will be designed for superficial velocities of 10 ft/sec or less. Considering that SCR catalyst vendors have not developed and guaranteed a specific SCR design for 2 ppmvd @ 3% O_2 NEC feels that it is prudent to assume that a third bed of catalyst (SCR or ASC) and cross section designed to achieve a maximum superficial velocity of 10 ft/sec is sufficient to characterize the most likely cost of a SCR unit capable of achieving 2 ppmvd in a typical refinery FCCU environment. *The impact of the increased cross sectional area and the addition of a third bed of catalyst on the cost of an SCR installation has been overstated by district staff as a 284% increase in catalyst volume over manufacturer's estimates. The increase over manufacturer's budget estimates/proposals is actually 92%, one half of staff's reported delta.*

Staff's SCR Design Comparison Did Not Accurately Reflect NEC's "Typical" FCCU SCR Design

Staff used an incorrect basis for comparing NEC's typical FCCU SCR with district units in Table F.3. A revised comparison, using data from Refineries 1, 5 and 6 is shown below.

Table 1 (F. 3 Showing NEC Typical SCR)
Performance Information of Existing SCRs

	Refinery 1	Refinery 5	Refinery 6	NEC Typical
FCC Feed Rate, kBPD	95	71	84	55
SCR Inlet Flue Gas Flow, ACFS	6,585	5,525	9,685	3,848
SCR Manufacturer	1	3	2	--
No. Catalyst Layers	2	2	2	3
Catalyst Volume, ft^3	6,200	2,975(1)	6,200(5)	4,600
Design Inlet NOx, ppmv	133(2)/40-80(3)	150	35	45
Design Outlet NOx, ppmvd	--	17	6	2
NOx Measured, ppmvd	<2	15-17	5.6 – 6.4	1.5 (Est.)
Superficial Gas Velocity, fps	7.4	13.3	11.6	10.0
Space Velocity, 1/hr	3,823(6)	6,686(4)	5,624(5)	3,011
Removal Efficiency	95 - 97%(3)	89%	83%	97%

Notes:

1. Staff incorrectly stated catalyst volume as 2,391 ft^3 in Table F.3. 2,975 ft^3 catalyst volume confirmed by NEC with Refinery 5 and via review of SCR data provided by Refinery 5 to SCAQMD.
2. Design value reported as 155 ppmv @ 0% O_2. Value presented in table is corrected to 3% O_2.

3. Measured outlet NOx value of <2 ppmv corresponds to operation of unit with inlet NOx in the range indicated. Removal efficiency based on range of actual operation.
4. Staff reports space velocity value of 2,974/hr in table F.3.
5. Confidential data provided by SCAQMD staff is insufficient to calculate the catalyst volume for this unit without making the following assumption on the depth of a catalyst module which we assume to be 45". Staff used ½ of this value in Table F.3 corresponding to catalyst bed depth (catalyst element height) of 22.5". Recommend staff confirm catalyst volume with Refinery 6.
6. Confidential data on unit design and performance, provided by SCAQMD staff, used to calculate inlet volumetric flow and space velocity. Values differ from staff's entries in Table F.3.

In their review, staff is suggesting that NEC's typical SCR is overdesigned and as a result overpriced. Staff's comparisons suggest an overdesign factor of as much as 284%. We do not agree with this assessment. As can be seen in Table 1, NEC's typical SCR should be able to achieve 97% NOx reduction by virtue of the addition of catalyst at higher gas velocities than the SCR operating at Refinery 1. The typical SCR design provides an approximate 21% margin in space velocity over the Refinery 1 SCR design primarily due to the addition of a third catalyst bed. The addition of a third bed has inherent performance advantages in that it provides for partial redistribution of unreacted NH_3 and NOx versus further cross sectional area additions. If it is determined that the incremental cost of specially fabricated catalyst modules (shorter depth) is low, some further optimization may be possible to reduce SCR cost. It is worth noting that the ~21% catalyst margin will have a 12% overall TIC and PWV cost impact.

Basis of the: *"mark-up" factor, or a bid conditioning factor of 1.35 to increase the costs"*

The following paragraphs provide background for NEC's use of a 35% conditioning factor for vendor equipment quotes at early stages of projects. These concepts were discussed with SCAQMD staff during reviews of our report and in subsequent follow-up phone conversations and e-mails. Due to the extensive discussion around this topic we are mystified by staff's characterization of this "bid conditioning factor" as, and here I paraphrase, 'an undefined and therefore invalid cost increase'.

Obtaining budgetary quotations from vendors for their equipment is part of the process of developing cost estimates for any project. At the early stages of projects, or when general information is sought, vendors are not provided comprehensive design basis information and therefore do not have a complete picture of the operating envelope for their proposed equipment. In these instances, some vendors will use costs from recent projects and "factor" them to the provided process conditions, other vendors may develop estimates based on equipment designed specifically to meet the provided process conditions. In either eventuality, the vendor is providing a quality estimate with reasonable accuracy (about +/- 10%) for the specified process conditions, without providing a performance guarantee and without review of the specific codes and standards applicable to refinery installations.

As project definition improves the process basis becomes fixed, equipment sizes become more reliable, performance guarantees are finalized, and vendor quote accuracy improves. Industry experience shows that at the early stages of a project, basis uncertainty alone, necessitates the addition of a 15 – 25% conditioning factor to a vendor's budget quote, in addition to other bid conditioning factors, to account for the difference seen between early equipment bids and final, full definition, performance guaranteed, equipment bids based on a definitive project basis.

Refineries are built to a more rigorous set of standards than typical air pollution control equipment which makes projects in the refining sector slightly more expensive than typical industrial projects. Standards which will have an impact on either the SCR design, the structural support design, location of equipment, internal and external maintenance access, etc., are likely to increase Direct SCR M&L costs. At this stage of project definition a factor of 10% is added to a vendor's equipment bid to account for the cost of meeting local plant standards.

The 1.35 "mark-up" or bid conditioning factor used in NEC's cost work-up for all SCR projects (FCCU, Heaters/Boilers, etc.) is not an arbitrary factor used to inflate costs, as implied in Appendix F, but is actually the low end of a time tested and proven means to determine the actual cost of a piece of equipment after full project definition is complete, including application of local industry standards to the design of the equipment, performance guarantees are offered and firm pricing for equipment components is provided by the vendor.

Basis for: *"Adding another 75% increase in labor to the costs of the manufacturer's SCR."*

Another cost factor discussed with SCAQMD staff, and apparently dismissed as a simple adder to make costs appear high, is the cost of actually installing the equipment supplied by the SCR vendor in the plant. The vendor does not do construction and does not quote the cost of field assembly in their quote which only covers fabrication and supply of the equipment, in this case the SCR catalyst, support frames, ammonia injection grid and the carbon steel box.

The labor cost factor used in NEC's development of project costs is applied to the SCR vendor's factored estimate to account for the labor required to install the manufacturer's equipment at the site, transportation, taxes, tie-ins, insulation, access, structural steel, etc. Installation labor for equipment can range from a low of about 30% of the equipment cost to as much as 200% of direct equipment cost depending on the complexity of the equipment, the material it is made of and other equipment specific factors. In general, low cost equipment manufactured of low cost materials have higher installation percentages than highly complex equipment made of high cost materials. As a reference point, "Applied Cost Engineering", Clark F. D. and Lorenzoni A. B.; Marcel Decker Inc., 1978, uses a factor of 2.2 times direct material costs to estimate the direct M&L cost of a fired heater installation, a factor of 3.0 times direct material costs to estimate the direct M&L cost of a pump installation and a factor of 2.9 to estimate the direct M&L cost of a distillation tower. Due to the simplicity of the SCR equipment and its use of low cost materials we have used an installation labor cost factor of 0.75 (75%) to account for physical installation of the SCR, structural steel, fit-up of ducting, connection of piping, foundations, excavation, instrumentation, insulation, equipment storage, etc. This factor does not account for any costs associated with: demolition of existing equipment, modification of existing equipment, labor inefficiencies attributed to working in an operating plant, relocation and/or modification to underground utilities, piping, piping supports, ammonia storage facilities, control system additions, instrumentation wiring, conduit, power wiring, area paving, area lighting, area utilities, safety facilities, sootblowers, etc.. The cost of these items is rolled up into the overall TIC factor applied to escalate SCR M&L costs to a total project cost.

TIC Factor

SCAQMD staff disputes NEC's use of a TIC factor of 4.5 to convert direct M&L costs for the SCR into TIC for the SCR PROJECT. This factor is a reasonable estimate for project items not specifically identified in the direct M&L costs (indirect costs, engineering and owner's costs, labor productivity, ancillary equipment and systems, revamp items, duct work, area paving, lighting, utilities, safety systems, control system connections and programming, instrumentation, sootblowers, etc.) As a point of reference, the TIC factor used by NEC, in this analysis, is 90% of the average TIC factor of 4.9 used to estimate SOx control costs in NEC's SOx RECLAIM report.

NEC Estimated FCCU Feed Rates from
Flue Gas Rate Data Provided by SCAQMD
Correction of NEC PWVs Required

SCAQMD staff is correct in pointing out that NEC used incorrect design capacities in developing the FCCU SCR costs shown in section 1.2 of NEC's non-confidential report (14-045-4, November 26, 2014). NEC back calculated expected FCCU rates from flue gas flow rate data provided by AQMD staff to obtain estimated FCCU sizes. The following table presents a revision to the report table based on corrected FCCU sizes as indicated by district staff. Also included in the table is an update to the cost of a Grass Roots SCR for Refinery 6 based on a comparison of flue gas rates to the SCR versus the typical (base case) SCR. Revised NEC estimates provided in Table 2 do not include any reduction to NEC's original cost estimate model.

Table 2 (Restatement of Table F.2)
Estimates of PWV Correcting NEC Values for FCCU Feed Rates

Facility	FCCU Feed, kBPD	AQMD's Estimate, $M	Revised NEC Estimate, $M	Ratio: NEC/AQMD
5	71	33	43(2)	1.3
6	90	57	62(1)(2)	1.09
7	55	27	37	1.37
4	34/36(3)	16	28	1.75
9	55	19	37	1.95
Total		152	207	1.36

Notes:

1. The PWV shown includes the impact of additional flue gas from a CO boiler but does not include the incremental flue gas from another source which is fed to the existing SCR.
2. Costs shown are for grass roots (new) SCR additions to existing FCCUs. Existing units may be modified to reduce compliance costs below those indicated.
3. Staff report throughput is 34 kBPD. Published unit capacity is 36 kBPD.

**Staff Evaluation of NEC PWVs vs. Refinery 1 SCR Costs
Does Not Factor In Project Scope Differences**

Staff provided a review of NEC's cost estimates based on a comparison to the cost provided for Refinery 1's SCR to demonstrate that NEC's estimating method is overly conservative. In this comparison staff claims that NEC's cost tool over predicts the cost of this installation by $11M (27%). The difficulty in comparing a specific project to a generalized curve is that the project has a specific scope which in most cases is different than the assumed scope of the "typical" project. This is the case for the SCR installation at Refinery 1 which, according to Refinery 1 personnel, did not include the cost for waste heat boiler modifications. Subtracting this component from the TIC for a typical FCCU SCR installation and recalculating PWV yields a cost of $45.45M which is 10.8% higher than staff's cost work-up on this project of $41M, not the 26% difference indicated in Appendix F. Staff had the WHB cost information NEC used in our estimates, we do not understand why they did not make the PWV comparison on the same basis.

**Staff Evaluation of NEC PWVs vs. Refinery 9 SCR Costs
Misstates Vendor and NEC Information**

Staff also provided a review of NEC's cost estimates based on staff's assessment of differences between the data provided by an SCR vendor to staff and NEC for an installation at Refinery 9. In staff's evaluation of the data provided by the vendor they incorrectly calculate the total catalyst volume to be 3,100 ft^3 vs the actual vendor proposal which provided only 2,400 ft^3. Staff also incorrectly calculates NEC's estimated catalyst volume at 12,697 ft^3 vs an actual value of 4,600 ft^3 (1.92 x vendor proposal, see previous discussion on catalyst volumes and specification of a third bed).

**Comments on Staff's Determination of
PWVs for FCCU SCRs**

I would like to take the opportunity to provide a few comments on SCAQMD staff's determination of PWVs for FCCU SCRs.

1. In using the costs provided for Refinery 1's SCR staff is assuming that all district SCRs can be installed without any impact on upstream equipment and that installation of the SCR can be executed in an open, non congested area. Refinery 1's SCR was installed prior to the installation of a large ESP, which occurred around 2006. If the SCR was to be installed today, or at any time after installation of the large ESP, costs would be higher due to productivity debits associated with working in a congested area and quite possibly even higher due to the need to move or modify some equipment to make the installation possible. In the most extreme case the SCR and ducting may have to be field erected from small fabricated assemblies due to access constraints.

2. Staff used a 0.7 power factor to scale the costs for Refinery 1's SCR project to different sizes. Costs for FCCU regenerator flue gas systems scale more accurately when a figure of around 0.6 is used. The effect of using a larger scale factor is a greater reduction in project costs for all projects with the differences getting proportionately greater the further one gets from the base case unit size. In essence using the 0.7 factor instead of 0.6, in this particular evaluation, will decrease costs for all units and will disproportionately decrease the cost of smaller units.

3. In using vendor budget quotes for SCRs, staff needs to add erection labor to the vendor quote. There is no indication that this is done in staff's analysis.

4. Staff does not condition the vendor's quotes to account for operational conditions, including unit upsets, and other project unknowns which will have direct bearing on SCR design details, performance and costs. An allowance must also be made for the accuracy inherent in vendor's budget quotations, which does not appear anywhere.

5. The PWVs provided for Refinery 7 and Refinery 9 are $27M and $19M respectively. There is an apparent inconsistency in these numbers as the stated capacity for each of these units is 55 kBPD. Units of the same capacity should have PWVs close to one another not differing by 42%. Staff should check these numbers and ensure that the SCR project scope differences between these two units can explain the large difference in cost.

In the interest in getting our comments into your hands as soon as possible we will provide comments on Staff's review of our SCR estimates for other applications in the district in one or more separate letters.

I am looking forward to discussing the items identified in this letter with SCAQMD staff and invite them to meet with us at our office in Montville, NJ.

Sincerely,

James P. Norton
President & CEO

cc: *NEC – Montville, NJ*
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C. Gleason – Chevron Phillips
M. Hodges - Valero
T. Kruzich - Chevron
S. Moyer – Holly Frontier
D. Pavlich – P66
D. Price - Tesoro
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Chevron El Segundo Refinery
J. Doyle
S. Worley
R. Spackman

ExxonMobil Torrence Refinery
S. Holm
P. Sheng

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September 4, 2015

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Comments on Preliminary Draft Staff Report
Proposed Amendments to Regulation XX
Regional Clean Air Incentives Market (RECLAIM)
NOx RECLAIM – SCRs for Fired Heaters & Boilers
Document No. 14-045-8

Dear Mr. Fine,

We have completed a review of the above captioned report's discussion of SCR applications to district Refinery Fired Heaters and Boilers and have identified several misstatements and/or misunderstandings of the information provided by our company, under contract from SCAQMD, which may have material impact on the conclusions drawn by staff in the report. It is my intent in this letter to clarify the most glaring misstatements/misunderstandings of the information we provided to the district both in our final report (Doc. No. 14-045-4, Nov. 26, 2014) which summarized the data on a non-confidential basis, and the details provided on a confidential basis to the district and individually to each of the refineries.

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NH_3 distribution, improve overall flue gas flow distribution, add catalyst, etc. SCAQMD staff agrees with this concept but we have strong disagreement as to how much change from current SCR designs will be required to achieve the sought after NOx reductions not only on day one but at the end of year one and year five and beyond.

NEC's engineers have extensive experience in process development, equipment development and project development for the refining and petrochemical industry in the manufacturing and air pollution control areas. The experience level of the engineers who completed our technology and project cost evaluations is 51, 37 and 8 years. It is exactly this experience base, and past successful work with the district, that caused you to look to NEC to develop "cost guidance" for evaluating the refining sector. We find it very surprising therefore, that staff essentially ignored our recommendations and continued to use what we feel are unrealistically low costs for NOx control projects for district refineries.

Comments on Heater SCR Project Costs

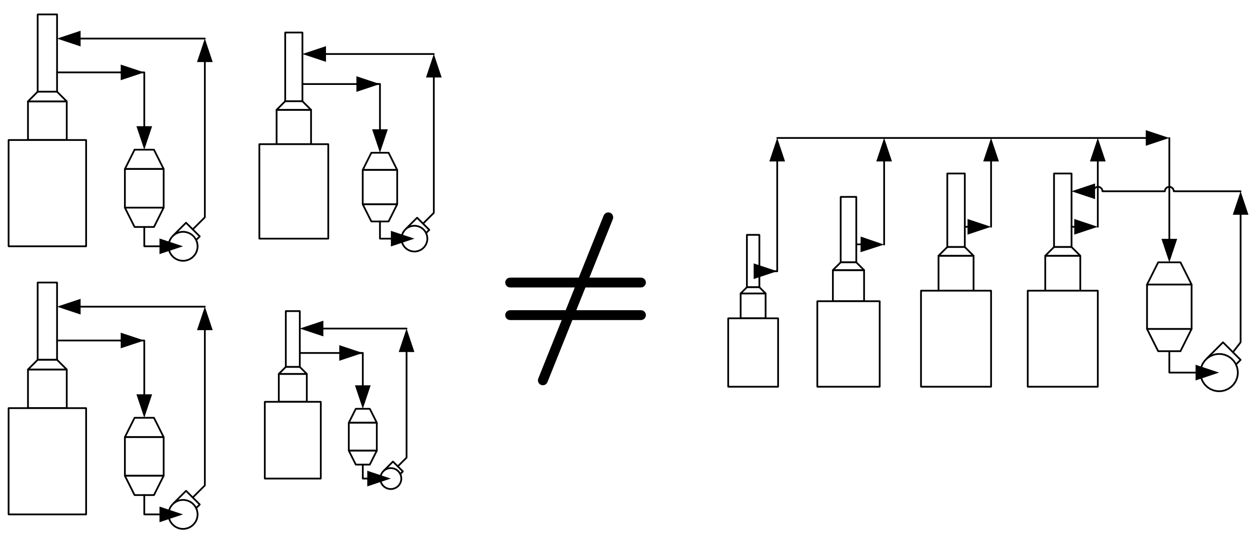
Appendix G to Staff's Draft Report presents a review of NEC's analysis of Heater and Boiler SCR costs by SCAQMD staff. It concludes that NEC's estimated costs for NOx control are excessive and gives the following reasons for this assessment:

- NEC recommendations did not include an assessment of the efficacy and cost of alternative NOx control technologies.
- NEC developed TIC estimates using a direct M&L multiplier of 4.5 vs staff's use of a TIC factor of 3.87.
- NEC used SCR catalyst and enclosure costs, obtained from SCR suppliers, for FCCU applications and used these costs as a basis for estimating the cost of heater and boiler SCRs.
- NEC recommends including space for four catalyst beds and designing for superficial gas velocities of 10 ft/sec.
- NEC included costs for new CEMS in their project cost estimates.
- NEC's costs estimates for smaller heaters and boilers are biased high by specification of ammonia systems which are too large for these small units.
- NEC's operating costs are biased high due to the cost of catalyst replacement which is higher if/when with higher installed catalyst volumes.
- NEC's estimates are skewed high because they are higher than staff's estimates which are conservative in the base case.
- NEC conditioned budgetary quotations from manufacturers for the accuracy of the quote, the accuracy of the project basis and for the application of refining industry standards for construction of the equipment.

- NEC includes the cost of installation of the SCR in its estimate to arrive at a direct material and labor cost for the SCR component of a project at 75% of the equipment cost. Characterized by staff as: “additional labor”.

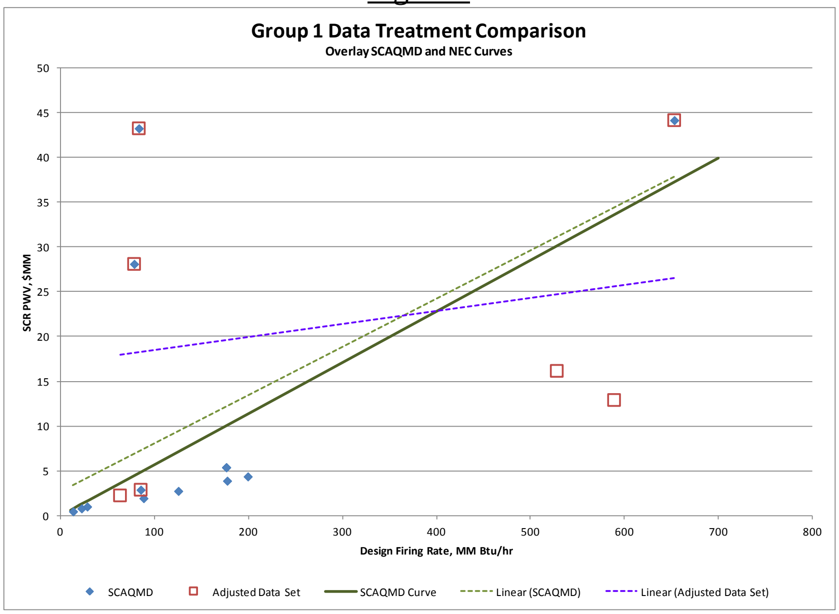
Before getting caught up in the minutia of Appendix G, I want to first present an overall picture of the PWV estimates developed by AQMD staff and those developed by NEC. The first thing we noticed in reviewing staff’s use of refinery cost survey data, was that PWVs for SCR installations servicing multiple heaters were broken down and allocated to each heater based on design firing rate. This was done to obtain data points for SCR installation costs for individual heaters as a function of heater design firing rate. The problem with parsing the data in this manner is that it assumes that project costs for multiple heater installations and single heater installations are equivalent. They are not. Sharing an SCR between heaters is always lower cost than installing an SCR on each heater. We estimate that multiple heater SCR installations can cost as much as 30 to 70% of single heater installations with the savings coming from a reduction in SCR box steel and structural support, a reduction in the number of fans required for the installation, a reduction in foundations, ammonia distribution piping, controls, etc.

I believe that the following sketch provides a much better explanation of the difference between multiple and single heater SCR installations:



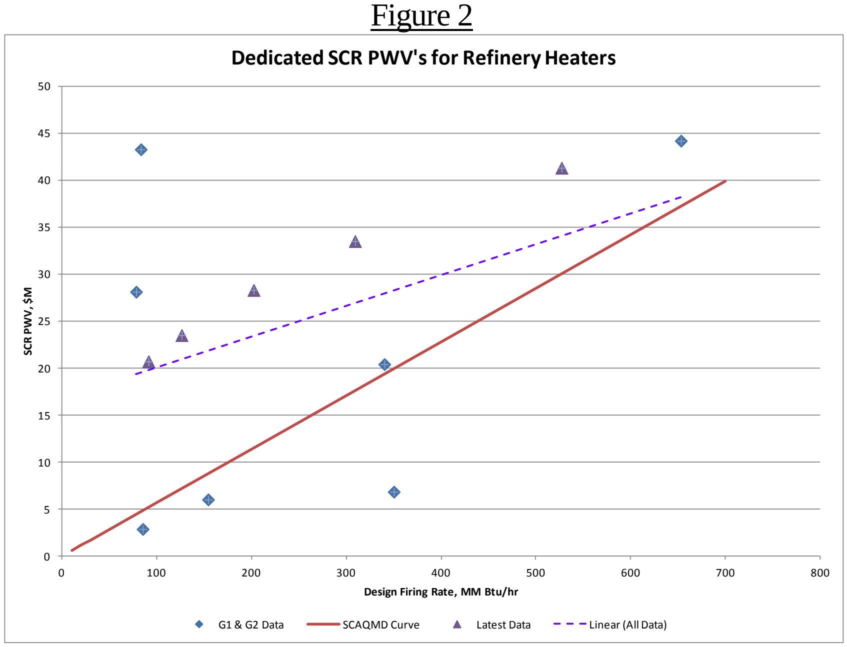
The following figures provide an illustration of the effect of staff’s cost allocation assumption on the estimated PWVs of small heaters. Figure 1 presents two sets of survey cost data denoted as Group 1 data in the draft report. The data set named SCAQMD includes the parsed PWV data for three of the seven best performing SCRs in the district resulting in a total of fourteen data points. The data set named “Adjusted Data Set” combines the duties of the seven heaters which share SCRs into three data points yielding a total of seven data points. The revised data points represent SCR systems designed for a heater with a size equal to the combined firing rate of all the heaters sharing the SCR. Linear regressions of the parsed and non-parsed data are shown as dashed lines in the figure. The solid line is staff’s PWV relationship. While the data is widely scattered and does not curve fit very well (R^2 = 0.3 for curve fit of parsed data and 0.05 for non-parsed data) the slopes of the two curves are very different and indicate that staff's correlation likely under predicts PWVs for heaters smaller than 400 MM Btu/hr; quite a different conclusion than that drawn in the draft report.

Figure 1



Norton Engineering understands that the number of survey project and operating cost data points on high performing SCR units is both limited and scattered and that additional information is needed and has been used by staff to generate more representative PWVs for refinery heaters. Figure 2 provides a comparison of staff's PWV correlation with available Group 1, Group 2 and additional SCR project cost estimate data provided to AQMD by a district refinery during NEC's review. All data are for dedicated SCR installations.

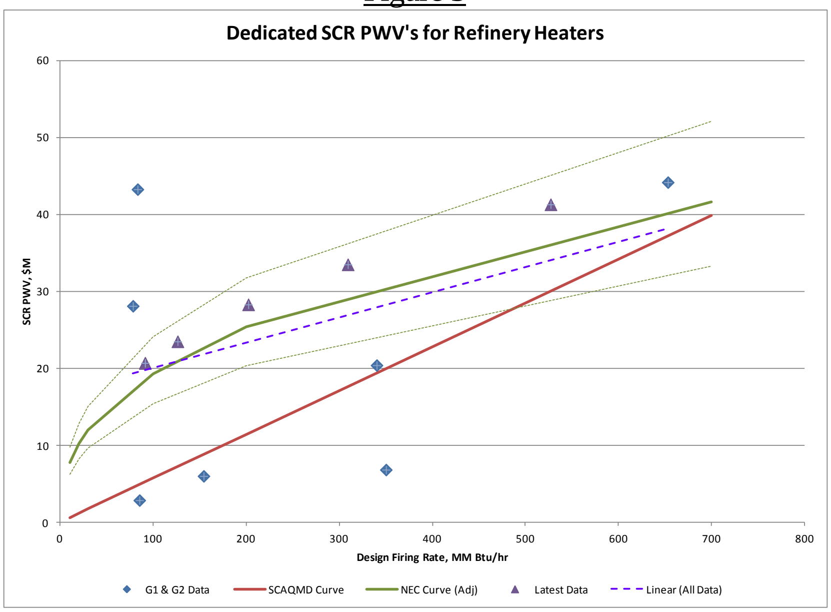
Figure 2



The purple dashed line in the figure represents a linear regression line for all the chart data. As with Figure 1, the large scatter in the data makes the correlation, any correlation, almost meaningless. The conclusion we can reliably draw from this chart is that staff's PWV correlation under predicted PWVs (based on actual and estimated TICs) in eight out of twelve instances, over predicted PWVs in one out of twelve instances and was accurate in three out of twelve instances. If staff's correlation was conservative we would expect that it would over predict PWVs more often than it under predicted PWVs. That is clearly not the case.

Figure 3 is a repeat of Figure 2 including NEC's proposed PWV correlation and the cost bands recommended for use in estimating complex and simple, single heater – single SCR PWVs.

Figure 3



NEC's proposed correlation provides PWV estimates for dedicated SCR projects which are more representative that staff's proposed correlation, matches up pretty well with the linear correlation of all data and, is not overly conservative. Six data points are higher cost than predicted by NEC's correlation, four are lower cost and two are predicted pretty accurately. When the complexity bands are used, the correlation under predicts in two of 12 cases, over predicts in four of twelve cases and is "accurate" in six of twelve cases.

For the specific case of smaller heaters (<100 MMBtu/hr heat release) NEC's correlation shows a very steep slope indicating that costs for small heater SCR installations rapidly increase with increasing heater size. This size sensitivity is expected as fixed project costs and non-size dependent project costs are normally a higher percentage of small projects than they are of larger projects. Staff's proposed correlation does not show this trend and therefore can be expected to significantly under predict PWVs for smaller heaters.

The following paragraphs address each of staff's comments and objections and provide additional information and clarifications to address what we perceive as staff's misunderstanding of the information presented in our final report. While the items covered in the following paragraphs may be open to interpretation, our previous analysis of available cost data indicates that any changes SCAQMD staff might want to make to NEC's "typical fired heater and boiler project basis" will likely necessitate changes to equipment definition, equipment cost or estimate cost factors to improve the cost correlation with Group 1, Group 2 and subsequent project cost data.

Scope of NEC's Review of AQMD Staff's
Preliminary Draft Report – September 23, 2014

This comment seems irrelevant to the current discussion as Staff's entire discussion on refinery heaters and boilers is focused on SCR installations as BARCT for the 2 vppm emission limit. We discussed this with staff during our work and staff agreed that any dilution of our effort to evaluate these alternative technologies would not be desirable.

Using FCC SCR Costs Increased Heater &
Boiler SCR Cost Estiamtes

Staff provided NEC with heater and boiler SCR cost data from vendors for review. In our discussions with SCR vendors we focused on the more severe FCC applications and obtained detailed information on SCR costs for these applications. Much less data was available from staff's contact with SCR vendors. Attempts were made to obtain clarifications from SCR vendors which were either not received or received after issuance of NEC's report. In reviewing the design and operation of the best heater in the district (1.6 vppm outlet NOx) we found that inlet gas velocities were similar to our recommendations for FCCU SCRs while catalyst volumes were significantly less. Using the FCCU SCR cost as a basis NEC estimated and added the cost of and ID fan, an ammonia storage tank, and a new CEMS for each SCR project. We then factored the cost as described previously to arrive at a total project cost. We then compared the result of this method to available data on past and planned projects, Group 1, Group 2 and recent refinery estimates, and found the accuracy of this method to be reasonable and more accurate than staff's PWV correlation. Considering the scatter in the data and the relative good accuracy of the methodology we did not go further in refining any underlying assumptions or our cost estimating technique.

NEC TIC Factor of 4.5 vs.
Staff TIC Factor of 3.87

Details of how NEC developed the factored estimates we used to generate TICs and ultimately PWVs for heater and boiler SCR installations have been described at length in our SOx RECLAIM cost review report (Non-Confidential Report No. SCAQMD 10-014-04 dated June 10, 2010). All of the factors used in this analysis are consistent with those used for our SOx RECLAIM assessment. Additional discussion is also available in our letter of August 10, 2015 commenting on AQMD staff's assessment of NEC's FCC SCR PWVs.

It appears that staff relied on SCR vendor cost data (Group 3 data) to generate SCR project costs for heaters and boilers without adjusting vendor costs for the budgetary nature of the estimates, the screening level of the process data provided to the vendor, the cost of equipment installation or the need for ancillary equipment such as ducting, fans and controls. All of these components are typically included in a cost estimate before the addition of TIC factors which cover, undefined equipment and systems, indirect project costs, engineering, project management, operator training, start-up spares, civil works and site preparation, project contingency, shipping and taxes. Staff's use of a TIC factor of 4.0 applied to the budget cost of the SCR provided by a vendor is not adequate to cover the cost of the entire SCR project.

Basis for SCR Catalyst Increase and Velocity Reductions vs Vendor Budget Quotes

The district has 7 SCRs installed on 14 fired heaters, achieving 1.6 to 3.5 ppmv NOx @ 3% O_2. The best performing unit treats flue gas from four heaters with a combined total design firing rate of 589 MM Btu/hr and is designed to treat flue gas to achieve 5 vppm NOx at this rate. Reported operation of this unit is 65% of design when achieving <2 vppm NOx emissions. Low firing rate operation decreases superficial and space velocities across/through the SCR versus design conditions (lower flue gas mass flows and lower flue gas temperatures vs design) lower velocities and space velocities translate into improved unit performance. In addition, lowering heater firing rates cools the heater firebox which also decreases inlet NOx levels to the SCR.

More important to the current discussion on SCR application to achieve 2 vppm emissions limits is the use of design data for this unit by staff, to extrapolate catalyst volumes and system costs for design of new units. Since the "base" unit is operated at 65% of design, any use of this data in an extrapolation to other applications needs to account for the lower than design operating conditions. It is not apparent from our review of staff's assessments if they have made this adjustment which will be a minimum 54% increase in the costs of the base unit.

NEC looked at the available operating data and the SCR manufacturer's information provided by staff for our assessment. We interviewed the SCR owners and made the assessment, based on information obtained during these interviews and our experience in developing oil processing, infrastructure and environmental control projects for over 20 years in the US and International refining industry, that estimating typical SCR sizes, based on the design conditions for the best SCR in the district, which isn't operating anywhere near its design condition would result in specifying/costing units which were too small. The question of catalyst volume then became one of how much additional catalyst might be needed to ensure long term reliable operation of an SCR. For refiners this translates into an SCR design which does not limit refinery or unit operation at any time between scheduled turnarounds.

Final determination of SCR catalyst volume for a typical refinery heater application requires making a flue gas throughput correction to the base case design, as note above, and making adjustment to catalyst volumes quoted by vendors where catalyst change out times are shorter than five to six years. To achieve the long run lengths required in refinery applications, refiners will increase catalyst volumes to offset declining catalyst performance. This is done in the design of every fixed catalyst bed system in the refinery. Based on the vendor information provided by AQMD staff a doubling of vendor catalyst volumes would be needed to ensure reliable operation in excess of five years. The minimum adjustment to achieve 2 vppm NOx and long unit operating life is therefore 3x (1/0.65 * 2) typical vendor specified or currently installed catalyst volumes.

NEC included a total of four catalyst beds for 2vppm NOx designs when three beds will likely prove adequate. Our inclusion of the fourth bed was to provide operating flexibility to ensure long term compliance while burning variable composition refinery fuel gas. This bed added 11 ft to the height of a typical SCR compared with a three bed unit. Elimination of this bed will reduce proposed SCR height by less than 20% and will not have any impact on the cross sectional area of the catalyst bed. Adjusting the SCR cost to reflect this change will necessitate a change in TIC estimating methodology to improve the correlation with Group 1, Group 2 and subsequent project cost data (Figure 3).

Cost of New CEMS vs Upgrade

NEC did not have any data on the status/condition of existing CEMS and therefore included the cost of a new CEMS, CEMS enclosure, stack platforms, access, etc. in the heater and boiler SCR project TIC estimates. A reduction in this cost will necessitate a change in estimating methodology to improve the correlation with Group 1, Group 2 and subsequent project cost data (Figure 3).

Specification of "Large" Ammonia Storage
Tanks Biases Costs for Small Heaters High

A stand alone ammonia storage system will include a storage tank with sufficient volume to receive a full truck load of ammonia while operating with a heel sufficient to run the associated SCR for a defined, short, period of time. Local bulk ammonia suppliers suggest a minimum tank size of 11,000 gallons. NEC used this tank size as the basis for all district SCRs without increasing size for larger heaters which will receive ammonia deliveries more frequently.

NEC did not include the likely cost savings impact of centralized ammonia storage and distribution systems in our analysis. While on the surface it appears that significant savings can be gained from such systems, the need for long runs of small bore piping on existing pipe racks, through operating units, with frequent pipe supports (small bore piping cannot span typical pipe rack supports and needs multiple intermediate supports) and requiring significant scaffolding to be erected, makes ammonia distribution from centralized storage facilities nearly as costly as dedicated storage, and in some cases more expensive. For this reason, dedicated storage is a more reasonable option during early stages of project definition.

High Catalyst Replacement Costs
Skewed NEC PWVs High

Staff is correct in their assessment that high catalyst volumes (FCCU SCR basis) in NEC's basis yielded high catalyst replacement costs and increased PWVs for heaters and boilers. A correction to annual operating costs should be made to correct this error. When this is done PWVs estimated by NEC's correlation will drop and will under predict Group 1, Group 2 and subsequent project cost data. An adjustment in NEC's TIC estimating method will be required to reestablish prediction accuracy for PWV (Figure 3).

NEC's Estimates are Higher Than
Staff's "Conservative" PWVs

Staff has incorrectly used NEC's PWV correlation to demonstrate a reported 250+% difference in cost for a refinery SCR. Table G. 8 is recreated below with an additional column showing the correct use of NEC's correlation for PWV.

Table G. 8A – SCR Costs Estimated by Staff and NEC for Four Process Heaters Vented to a Common Stack (Shared SCR)

Heater	Rating MM Btu/hr	Staff's Approach Upperbound PWV	NEC's Approach PWV	Corrected NEC Approach PWV
D471	177	$11 M	$27 M	--
D472	125	$11 M	$23 M	--
D473	88	$5.5 M	$20 M	--
D3031	199	$11M	$28 M	--
Total	589	$38.5 M	$99 M	$43.2 M

As discussed previously in this letter we expect the SCR project cost for shared units to be less than what would be calculated for each individual unit. Costs should be more in line with the cost of an SCR for the total fired duty of the heaters feeding the SCR. In this case the difference between staff and NEC is 12% not 250+%.

Based on the data which staff purports to use to "calibrate" their conservative PWV correlation for fired heaters and boilers, staffs correlation is neither calibrated nor conservative. NEC has provided AQMD with a reasonable correlation for estimating the cost of SCR installations on refinery heaters and boilers as validated by the same data set staff is using. We agree that operating costs for heater and boiler SCRs should be reduced in the PWV calculation to correct the operating cost impact of over specification of catalyst volume. After making this correction (staff has the TIC correlation) we recommend staff use the resulting PWV correlation to estimate the cost of heater and boiler NOx control.

It is a shame that NEC and AQMD find themselves disagreeing on so many items in a public forum. I wish that we had discussions on more of the specifics of our review of AQMD's draft report and our recommendations for changes to the way cost estimates were prepared between November 2014 and July 2015. Perhaps we could have clarified and/or resolved some of these issues prior to AQMD staff developing the draft report and the recommendations which are based on the cost evaluations in question. It would have certainly made everyone's life a little easier.

I am looking forward to discussing the items identified in this letter with SCAQMD staff and invite them to meet with us at our office in Montville, NJ.

Sincerely,

James P. Norton
President & CEO

cc:

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P. M. Corritori
J. A. Norton
R. S Todd, PhD
D. Vizzuso
S. Zhang, PhD
Z. Zhang

NEC – Swedesboro, NJ
W. A. Lincoln
C. A. Steves

NEC – New Orleans, LA
S. G. Haydel

AFPM – Washington, DC
A. Adams – AFPM
C. Gleason – Chevron Phillips
M. Hodges - Valero
T. Kruzich - Chevron
S. Moyer – Holly Frontier
D. Pavlich – P66
D. Price - Tesoro
K. Saffell - Valero
B. Williams - AFPM

Chevron El Segundo Refinery
J. Doyle
S. Worley
R. Spackman

ExxonMobil Torrence Refinery
S. Holm
P. Sheng

Paramount Refining Co.
K. Gleason
H. Chang

P66 LAR
K. Beruldsen
S. Micucci

Tesoro Carson / Wilmington
S. Stark
F. Colcord
D. Kurt

Valero LA Refinery
N. Irwin
M. Smith

WESPA
S. Gornick

VIA ELECTRONIC MAIL

August 21, 2015

Dr. Philip Fine
Deputy Executive Officer
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

SUBJECT: NOx RECLAIM INDUSTRY COALITION COMMENTS ON CURRENT DISTRICT STAFF PROPOSED AMENDMENTS TO REGULATION XX DATED JULY 21, 2015

Dear Dr. Fine:

The following trade associations in representing their members have joined together to form the NOx RECLAIM Industry Coalition ("the Coalition"):

California Asphalt Pavement Association (CalAPA)
California Construction & Industrial Materials Association (CalCIMA)
California Council for Environmental and Economic Balance (CCEEB)
California Manufacturers and Technology Association (CMTA)
California Metals Coalition (CMC)
California Small Business Alliance (CSBA)
Regulatory Flexibility Group (RFG)
Southern California Air Quality Alliance (SCAQA)

Western States Petroleum Association (WSPA)
Los Angeles Business Federation (BizFed)

Members of the Coalition have been actively following the District staff proposals regarding a NOx RECLAIM shave ostensibly being proposed to reflect advances in Best Available Retrofit Control Technology ("BARCT") between 2005 (the last NOx RECLAIM shave) and today. Following the release of the preliminary draft staff report and the proposed amendments to Regulation XX on July 22, 2015, the Coalition members believed it necessary to make these written comments and ensure that staff is fully aware of our concerns and that those concerns are included in the administrative record.

PROPOSED SHAVE AMOUNTS AND TIMING

District staff has proposed the following shave implementation schedule:

Year	Shave amount (tons/day)
2016	4
2017	0
2018	2
2019	2
2020	2
2021	2
2022	2

A shave of 4 tons per day in 2016 does not allow any time whatsoever for facilities to develop and implement emission reduction measures. Indeed, it could potentially put many of the RECLAIM facilities at risk of non-compliance with their respective RECLAIM caps, resulting in deductions from their 2017 RTC allocations. Moreover, the District expects that the bulk of the BARCT emission reductions will be made at the refineries[1]. At NOx RECLAIM Working Group meetings, staff has conceded that those reductions will not be achievable for several years into the future, at the earliest, due to the complexity of the permitting and siting issues and the magnitude of the construction activities necessary to achieve the BARCT levels projected by District staff. Thus, it is illogical to require the largest shave amount to occur at the earliest possible date.

The Coalition understands that the District has committed itself in the currently operative AQMP to implement a certain level of NOx reductions from the RECLAIM universe as a contingency measure if the District failed to attain the 24 hour PM2.5 NAAQS by the end of 2014. However, there is no commitment in the AQMP to make a 4-ton per day shave in 2016. Indeed, the AQMP contemplated a 2-3 ton per day reduction in Phase I and another 1-2 tons per day in Phase II. (Preliminary Draft Staff Report, page 2). Moreover, the AQMP specifically considered <u>and rejected</u> whether such an early action shave should remove all "excess" RTCs (i.e., the entire

[1] SCAQMD PDSR, Proposed Amendments to NOx RECLAIM, July 21, 2015, page 18.

"gap"). Rather, it was determined that only a 2-ton per day reduction was appropriate. Accordingly, the Coalition believes that the shave amount for the period 2016-2017 should be no more than 2 tons per day, and that there is no reason that all two tons have to be shaved in 2016. In fact, given that 2016 is almost upon us, and certainly will be by the time the amendments are adopted, it may be appropriate not to make any adjustments to 2016 allocations. Finally, we believe that the public record supports the view that the Governing Board approved the AQMP and CMB-01 with the understanding that if the 24 hour PM2.5 NAAQS was not attained, no more than 2 tons per day would be removed and that additional NOx reductions from RECLAIM would not be needed as a contingency measure to meet this purpose.

With respect to the total amount of the shave, the Coalition continues to believe that shaving a total of 14 tons per day of RTCs from the RECLAIM market in order to achieve the 8.79 tons per day reductions the District seeks to obtain as a BARCT adjustment is neither necessary nor justified.[2] We understand that District staff believes that the BARCT reductions won't occur unless almost the entire "gap" between RTC holdings and reported NOx emissions has been eliminated. History has shown that the staff is incorrect on this assessment. As shaves have been implemented, emissions have gone down to reflect past BARCT adjustments, even as the "gap" has remained relatively stable at 5-9 tons per day. A shave of 14 tons per day is excessive and risks destroying the RECLAIM market.

Finally, when implementing the shave, the amounts in the early years should be smaller and larger increments should be reserved for later years, to allow the BARCT installations to be implemented.

COST EFFECTIVENESS

The Coalition continues to believe that a 25 year useful life assumption (used consistently for all equipment in this proposed rulemaking) is not appropriate for all equipment. Additionally, we believe that the District staff has underestimated the cost for several equipment categories. District staff minimizes control costs by using a cost-effectiveness calculation[3] that is not used by the California Air Resources Board and most other major California air districts. Additionally, the use of a $50,000 per ton figure as the cost threshold is more than twice the $22,500 per ton threshold applied to command-and-control regulated sources. This is inconsistent with Health and Safety Code Section 39616 which requires that the RECLAIM program "not result in disproportionate impacts, measured on an aggregate basis, on those stationary sources included in the program compared to other permitted stationary sources in the district's plan for attainment."

We also note that Norton Engineering (the third party independent contractor retained by the District to review and assess the District staff's cost effectiveness determinations) has raised

[2] The Coalition does not believe that the 8.79 tons per day figure is necessarily the correct number. We continue to take issue with the SCAQMD staff's cost-effectiveness calculations for a number of source categories and understand that Norton Engineering, the SCAQMD's third party BARCT evaluator, continues to have issues with the staff analysis as well. This will be discussed separately in this letter.
[3] The use by SCAQMD of the discounted cash flow (DCF) method as well as generous assumptions regarding useful life and interest rates result in cost effectiveness figures that show lower costs per ton of emissions reduced than other, more accepted, calculation methods.

questions regarding the District staff's cost effectiveness determinations and its dismissal of Norton Engineering's analyses when those analyses showed higher costs than the District staff's evaluation showed[4].

NEED FOR THE "GAP"

Our analysis has shown that even if the District staff concluded that NO BARCT improvements had been made between 2005 and today, the staff's methodology would result in 6 tons per day of NOx RTCs being removed from the program. RTCs being removed under the District's methodology would include those needed for:

- NSR Holding Requirements
- Electric Grid Reliability and Implementation of AQMP Attainment Strategies (i.e., large scale electrification to replace current combustion processes)
- Post-2023 Growth
- Investor Holdings
- Shutdowns
- ERC Conversions

Additionally, there are significant questions regarding whether the District staff's proposed 10% compliance margin is sufficient. A 10% compliance margin will likely be insufficient to assure sufficient liquidity to maintain a functioning market in light of the removal of the above listed RTCs from the program.

We are also concerned that RTCs reflecting investor holdings and ERC conversions are proposed to be "taken" by the District as a result of the District's BARCT shave methodology with no analysis of the financial impact or the costs associated with such a taking[5].

We understand that District staff is working with electric power generators to address the NSR holding requirement issue[6]. While the Coalition agrees that something must be done to address the NSR holding requirement, the current proposal is a complicated attempt to address a problem that only arises because the District staff is trying to eliminate the "gap" altogether. One of the complicating factors associated with the current staff proposal is that it would allow the Adjustment Account to be utilized both to address the NSR holding requirement and to cover actual emissions from power plants under certain contingencies. This brings into question whether or not the Adjustment Account will be adequately funded to cover potential demand. Furthermore, the proposal is fraught with risk because it needs EPA approval, which is not assured. The Coalition believes that the size of the shave should not include RTCs that are required to be held for NSR holding purposes. However, if the District insists on going forward with its proposal, no amounts of RTCs held by electric power generators to satisfy their NSR holding requirements should be shaved unless and until EPA approval is finalized.

[4] NEC-SCAQMD letter dated August 10, 2015.
[5] SCAQMD PDSR, Proposed Amendments to NOx RECLAIM, July 21, 2015, Chapter 4.
[6] SCAQMD Staff stated meetings were being held with power-related stakeholders at the June 4 and July 9, 2015 working group meetings.

In summary, the District's proposed shave goes way beyond what is required to comply with the Health and Safety Code requirements with respect to a BARCT adjustment and runs the risk of repeating the program "meltdown" of 2000-2001 during the power crisis when insufficient RTCs were available.

ENERGY EFFICIENCY PROJECTS

As we stated in our June 19, 2015 comment letter, the Coalition strongly opposes any effort to further reduce RTC allocations due to "energy efficiency projects" that have or would reduce NOx emissions. Any reduction in NOx emissions not strictly required by BARCT should be encouraged and the benefits of making those reductions retained by the facility operator making them. For the District to consider taking away RTCs due to reductions in emissions occurring from efforts to improve energy efficiency would be a true manifestation of "no good deed goes unpunished."

CONCLUSION

We look forward to continuing to work with the District staff to develop a RECLAIM shave that represents a true BARCT adjustment while not endangering the life of the RECLAIM program. RECLAIM has been extremely successful in reducing NOx emissions from stationary sources while providing them the flexibility to make reductions in the most cost effective manner. We are very concerned that the severe reductions in RTCs currently being proposed by District staff go beyond adjusting for new BARCT and will result in facilities being subjected to the same RTC shortages that plagued the program in 2000-2001.

Respectfully,

Curtis L Coleman

Curtis L. Coleman
Executive Director, Southern California Air Quality Alliance
On behalf of the NOx RECLAIM Industry Coalition

cc: Dr. Barry Wallerstein, SCAQMD
SCAQMD Governing Board Members

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August 20, 2015

Mr. Joe Cassmassi
Planning & Rules Director
Planning, Rule Development & Area Sources
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

Re: Comments on Proposed Amendments to Regulation XX, NOx RECLAIM

Dear Mr. Cassmassi:

We are writing on behalf of Southwest Generation Operating Company, LLC ("SWG") and its subsidiary Harbor Cogeneration Company, LLC ("HCC"), which owns a power plant located at the Port of Long Beach at 505 Pier B Street, Wilmington, California (Harbor Cogeneration Plant). The plant is listed as one of the top 90 percent of RTC holders that would be subject to a 47% "shave" in NOx RECLAIM Trading Credit ("RTC") holdings under the proposed amendments to South Coast Air Quality Management District (the "District") Regulation XX released by staff on July 20-22, 2015.

Basis for HCC Comments

The stated purpose of the proposed amendments to Regulation XX is to reduce NOx emissions from the universe of RECLAIM facilities by 2022 in line with current best available retrofit control technology (BARCT). The District staff has decided that the best way to achieve this goal is by reducing the holdings of the largest RECLAIM NOx holders in the basin. This includes the Harbor Cogeneration Plant and over 50 other power plants, refiners, industrial facilities and investors.

As HCC has discussed with District staff, its primary concern and the basis for submitting this comment letter is the District's proposal that the baseline date from which the "shave" will be taken be retroactive to RTC holdings as of March 20, 2015. The first time HCC was made aware that staff was proposing the March 20, 2015 baseline date was just prior to the public workshop on July 22, 2015. We understand the desire to establish a baseline to prevent manipulation through multi-step disposition and re-acquisition strategies. However, the current staff proposal to establish a retroactive baseline date without prior advance notice constitutes an unprecedented *ex post facto* action that unfairly disadvantages entities that have made good faith trades subsequent to the proposed baseline date.

Relevant Rule Language

In its rollout of the proposed amendments to Regulation XX, the District issued proposed revisions to Rules 2002 and 2005 on July 20, 2015, followed by proposed revisions to Rules 2011 and 2012 on July 21, 2015. The primary amendments are in Proposed Amended Rule (PAR) 2002. In paragraph (f), Annual Allocations for NOx and SOx and Adjustments to RTC Holdings, the proposed amendments to subparagraph (f)(1)(C) would apply to the Harbor Cogeneration Plant. The relevant proposed amended text of subparagraph (f)(1)(C) states:

> (C) The Executive Officer will adjust NOx RTC holdings, as of (Date of Amendment) for compliance years 2016 and thereafter by multiplying the amount of RTC holdings as of *March 20, 2015* by the following adjustment factors for the relevant compliance year to each of the Facility Permit Holder listed in Table 8 to obtain tradable/usable and non-tradable/non-usable holdings: . . . (emphasis added)

We understand the need to set a baseline date in order to establish the inventory and identify potentially affected sources. However, choosing a retroactive baseline date without prior advance notice of the proposed date would be an *ex post facto* action that unfairly disadvantages entities, like HCC, that made good faith economic decisions in reliance on the rules in place at the time.

An *ex post facto* law or regulation is one that retroactively changes the legal consequences or status of actions that were committed, or relationships that existed, before the enactment of the law or regulation. Article I, Sec. 9 of the California Constitution prohibits the passage of *ex post facto* laws. Furthermore, in In re Lomax, 66 Cal. App. 4th 639, 643 (1st Dist. 1998) (citing *People v. Armitage*, 194 Cal. App. 3d 405, 414 (1987); *Flemming v. Oregon Bd. of Parole*, 998 F.2d 721, 726 (9th Cir. 1993), the court held that "Regulations have the force and effect of law and thus are subject to ex post facto prohibitions" of the state constitution. It is therefore unambiguous that the Constitutional prohibition on *ex post facto* laws applies to agency regulations, such as those of the District. The current proposal runs afoul of that prohibition by retroactively changing the legal consequences and status of trades that were made in good faith and without advance notice of the proposed March 20, 2015 baseline date.

Impact on Facility Planning and Engineering

The District's proposed retroactive baseline date of March 20, 2015 frustrates plans that HCC, and perhaps others, have developed and begun to implement to achieve early emission reductions, thereby undermining the purpose of the RECLAIM program and the proposed amendments. HCC's planning window for engineering upgrades and plant performance improvements is a multi-year exercise. In order to accomplish their business goals, they implemented trades of their NOx RTC holdings this year that were completed after March 20,

2015. These trades were made to fund planned plant upgrades, including emission reduction strategies and possible plant expansions. This strategy is completely consistent with the market concept of the RECLAIM program. If the District were to retroactively reduce HCC's NOx RTC holdings, it would also retroactively alter the premises upon which they based their decisions to improve the plant during 2016 to 2020 such that those decisions may not make financial sense.

We are aware that other facilities in the basin have sold RECLAIM NOx perpetuity streams after the March 20, 2015 date. Presumably, the sales were used to finance upgrades to their facilities which would reduce emissions in the future (the fundamental purpose of this rule). The way PAR 2002 currently stands, like HCC, these entities would be penalized for their early actions to become more efficient and less polluting. The examples provided below illustrate some of the adverse consequences associated with the District's proposed action.

Example 1: A non-refining facility that held 100,000 pounds of NOx perpetuity RTCs on March 19, 2015 would be subject to a 47% shave. If this entity sold 50,000 pounds of NOx RTCs on March 25, 2015 to finance an upcoming project to reduce emissions, it would still be shaved 47,000 pounds based on its holdings of 100,000 pounds as of March 20, 2015. This would leave that facility with an allocation of only 3,000 pounds in 2022, far less than the facility originally planned. In this example the facility expected to reduce its emissions by half, finance a project with the proceeds from the sale of their future excess credits, and retain an allocation of emissions for future use. This example describes an action that should be applauded, rather than penalized, by the District because the facility is cutting its emissions.

Example 2: A facility may have sold all of its RTC holdings after the proposed baseline date, but before the shave date. For example, a facility may have held 100,000 pounds of NOx perpetuity RTCs on March 19, 2015 and sold all RTCs on March 25, 2015. The entity would be shaved 47,000 pounds of RTCs, but it has no remaining RTCs in its account. How would the District implement the shave? Would the District follow the RTCs and apply the shave to the purchaser, or would the facility "owe" 47,000 pounds of RTCs?

These are just a couple of examples of the potential consequences of the District's proposed action. We would expect the trading, selling and buying examples to be as numerous as the varied operations of the affected sources.

Baseline Date for RTC Holdings Should Be Date of Amendment

We urge the District to work with the affected sources to establish a baseline date that is not earlier than the date of adoption of the rule amendments. This would provide clarity to businesses making financial and operational decisions, and stability to the District in establishing a credible inventory. In no case should the effective date to determine baseline RTC holdings be earlier than the effective date of amendment.

LATHAM&WATKINS LLP

We appreciate the opportunity to submit these comments and look forward to working with the District to refine and implement the proposed amended rules. If you have any questions please contact me or Bob Louallen, HCC's Senior Environmental Compliance Engineer at (702) 239-3712.

Kind regards,

Michael Carroll
of Latham & Watkins LLP

cc: Bob Louallen

August 21, 2015

Kevin Orellana, AQ Specialist
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Subject: Comments on Proposed NOx RECLAIM Amendments

Dear Mr. Orellana and Ms. Pham:

Please find herein comments on the draft RECLAIM Rule language dated July 22, 2015.

NEW EMISSION FACTORS FOR RULE 219 EXEMPT EQUIPMENT

We support the District's August 19th proposal for new provisions in Rule 2012 Chapter 4 to allow equipment certified by either U.S. EPA, CARB, or SCAQMD to use an emission factor other than the default factor of 130 lb/mmscf to report NOx emissions.

Currently, when a RECLAIM facility installs an SCAQMD Rule 1146.2 certified hot water heater, they are directed by District staff to report their RECLAIM and Annual Emissions Report (AER) emissions using a default emission factor of 130 lbs NOx/MMscf natural gas (equivalent to ~102 ppm of NOx), even though the unit has been certified by the SCAQMD to be "less than or equal to 20 ppm of NOx emissions (at 3% O2, dry)…" per Rule 1146.2. The estimated emissions factor associated with 20 ppm is approximately 25 lbs/MMscf, which is less than the 2010 ending emission factor. Manufacturers may not sell heaters for use in the District unless it complies with Rule 1146.2. We support that the RECLAIM rules are proposed to be modified to allow accurate reporting of emissions for R219 exempt equipment.

RULE 219 EXEMPT EQUIPMENT REPORTING

The District's August 19th proposal for certified Rule 219 exempt equipment indicates source tests may be required to verify lower emissions. We request that no source test shall be required for certified equipment. The SCAQMD specifies the emission certification process and accepts the documentation provided by the manufacturer as adequate to demonstrate compliance with the emission standards of Rule 1146.2. Certified heaters/boilers have been available on the market for years, tested by the manufacturers, low NOx combustion technology is achieving well under 30 - 55 ppmv, and the heat input ratings of Rule 219 equipment are small. Moreover, facilities may have multiple small boilers onsite, and given the unit cost to source test is approximately \$3,000-\$4,000, this presents an unnecessary cost burden on these facilities. We request that the SCAQMD forego the requirement to source test small boilers and accept the emission certifications as adequate to document NOx emission concentrations for use in the RECLAIM program.

RTU REPORTING

We do not see that the District is proposing any changes to the electronic reporting requirements for NOx Major Sources. The current requirements are specified in 2012 Appendix A, Chapter 7 – Remote Terminal Unit (RTU) Electronic Reporting. This section of the rule requires facilities to use dial-up modem technology to transmit a text string that must be very specifically formatted. The use of dial up modems as telecommunication devices is woefully outdated. It is becoming difficult even to find dial-up modem systems and components since their functionality has been replaced by better technology. Moreover, the very specific text file formatting is very challenging and error prone whenever text files must be written for transmittal to correct previously reported emissions. We have wasted hours of time working with this antiquated system which is still required by the regulation. We urgently request that the District update their electronic reporting system to allow more modern and easy to use technology.

CONCLUSION

Thank you for considering these comments. We would be glad to meet with you and the RECLAIM team to discuss these important issues. Should you have any questions or concerns, please contact me at (949) 248-8490 x511.

Sincerely,

Kathy Prokey

Kathy Prokey
Sr. Engineer
Yorke Engineering, LLC
(949) 248-8490 x225

cc: Judy Yorke, Yorke Engineering, LLC
Pete Moore, Yorke Engineering, LLC
Russ Kingsley, Yorke Engineering, LLC

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August 21, 2015

BY EMAIL AND U.S. MAIL

Philip M. Fine, Ph.D.
Deputy Executive Officer
South Coast Air Quality Management District
21865 E. Copley Drive
Diamond Bar, CA 91765

Re: Comment Letter on NOx RECLAIM Shave Proposal; Cities of Burbank and Pasadena

Dear Dr. Fine:

On behalf of the City of Burbank, Department of Water and Power ("BWP"), and the City of Pasadena, Water and Power Department ("PWP) (collectively "the Cities"), we are submitting the following comments on your staff's draft proposed amendments to Regulation XX, Regional Clean Air Incentives Market ("RECLAIM") ("NOx shave proposal"), published on July 21, 2015. While the NOx shave proposal appears to include provisions that would mitigate some of its worst impacts on the Cities' well-controlled power plants, it still does not provide the needed certainty that adequate RECLAIM Trading Credits ("RTCs") will be available at a reasonable price to cover these plants' anticipated emissions and other needs related to resource adequacy and utility-specific operating contingencies. We would like to suggest some improvements to the proposal that would provide the needed certainty and address other issues.

Both Cities operate their own power plants containing peaking units, and BWP also operates the Magnolia Power Plant ("MPP"), a baseload unit, on behalf of the Southern California Public Power Authority ("SCPPA"). Participants in MPP include Burbank, Pasadena, and four other municipalities. The Cities operate these power plants to serve their municipal customers. RTCs are required not only to cover anticipated annual emissions, but also to meet resource adequacy needs and prepare for utility-specific operating contingencies, such as grid reliability, increased cycling to support integration of renewables, and potential electrification of the transportation system. Unlike other industrial facilities operating under the RECLAIM program, the Cities' power plants are obligated to operate to serve load. If they are unable to serve load, there may be blackouts with serious adverse economic and other consequences.

The staff proposal would require a 47% reduction in the NOx RTC allocations for these power plants. The proposed reductions are so severe that insufficient RTCs would remain to cover Pasadena's and MPP's anticipated emissions, not to mention RTCs needed for resource adequacy and utility-specific operating contingencies.

As you know from our discussions during the Working Group process preceding the proposal, the Cities have requested that their power plants be excluded from the proposed NOx shave. This request is rooted in history and fairness. The Cities have already achieved the goals of the RECLAIM program, and more should not be asked of them.

The Cities have already reduced NOx emissions as much as feasible with the installation of Best Available Control Retrofit Technology ("BARCT") at their existing units, at a cost of over $28 million. In fact, these reductions were achieved over ten years ago pursuant to a command-and-control rule, Rule 2009. These reductions were required in the wake of the energy crisis of 2001, which led to an increase in power plant operation for which adequate RTCs were not available. BWP also has installed Best Available Control Technology ("BACT") at its Lake 1 unit and at MPP, and PWP has under construction a boiler replacement project that also will have BACT installed. The Cities cannot make any further cost-effective NOx emissions reductions. When and if the shave results in a shortage of RTCs to cover operating needs, the Cities would not have the option of installing more control equipment. Instead, all they could do is purchase additional RTCs, if available, or fail to meet load.

Moreover, the Cities are ahead of schedule in meeting the state's requirement that all electricity retailers serve at least 33% of their load with renewable energy no later than 2020. Burbank is already at 34% renewables, and Pasadena is at 28% renewables with a goal of reaching 40% by 2020.

While the Cities therefore believe they should not be subject to the proposed NOx shave, they acknowledge that with appropriate safeguards, the potential adverse impacts of the proposed shave on the Cities' power plants could be substantially avoided. It appears that the staff proposal addresses one important adverse impact: the requirement that MPP hold enough NOx RTCs to cover its maximum rated capacity at the beginning of each compliance year ("NSR holding requirement"), in the face of a 47% reduction in its NOx allocations. The proposal would apparently relieve MPP and other "new," post-1993 facilities from that requirement by providing for an "Adjustment Account" that will meet this requirement on a programmatic basis [see Proposed Amended Rule ("PAR") 2002(f)(4)]. But the proposal only partly addresses the other major potential adverse impact: the prospect that adequate NOx RTCs will not be available at a reasonable price to cover these power plants' anticipated emissions and other needs related to resource adequacy and utility-specific operating contingencies.

In the remainder of this letter, we will address these potential adverse impacts, and other issues as well.

1. Power Plants Need Quicker Access to Non-tradable/Non-usable NOx RTCs If Needed to Cover Annual Emissions

The staff proposal provides for a non-tradable/non-usable adjustment factor to be reflected in the permit for each facility subject to the 47% shave, including power plants, topping out at 0.335 in 2022 [PAR 2002(f)(1)(C)]. As we understand the proposal, it means that up to a 0.335 fraction of each facility's current allocation of RTCs would be made usable and tradable, and therefore available to cover annual emissions, in the event that the Executive Officer determines that the 12-month rolling average price of NOx RTCs exceeds $15,000 per ton (or $7.50 per pound) and after the Governing Board concurs in that determination [PAR 2002(f)(1)(F)]. No fee would be charged for these additional RTCs.

Based on the experience of power plants during the energy crisis of 2000-2001, this cumbersome, two-step process for releasing these RTCs to cover annual emissions appears to be too slow to avoid skyrocketing spot prices or an outright shortage of RTCs for power plants to either cover annual emissions or demonstrate resource adequacy. We understand that the Los Angeles Department of Water and Power will be presenting a more detailed description of how the two-step process for releasing RTCs during the energy crisis of 2000-2001 did not avoid high prices and shortages of RTCs at that time.

The Cities therefore suggest that a provision be added allowing power plants to request that some or all of this pool of non-tradable, non-usable RTCs be converted to usable but non-tradable RTCs, in exchange for a fee of $7.50 per pound. Once converted, the RTCs could be used to cover annual emissions or meet resource adequacy needs for the year in which the request is made, but they could not be traded. In addition, the power plant also would not be allowed to trade any of its own RTC allocation for the year in which the request to convert is made.

The fee serves two purposes. First, it gives power plants the incentive to rely on the RTC market if the spot price remains below $7.50 per pound. As long as the spot price of RTCs remains below that level, power plants will not have an economic incentive to make a request to convert. Instead, they will rely on the RTC market to acquire additional needed RTCs. But if the spot price rises above $7.50 per pound, then they will have an incentive to make a request, if they deem it prudent to do so. Of course, power plants would be free to wait for the slower two-step process to unfold regarding the 12-month rolling average price, and obtain additional unrestricted RTCs without a fee, if they deem that to be the more prudent course.

The fee also serves the purpose of providing the District with funds to achieve additional NOx reductions from other sources, including mobile sources, for which cost-effective reductions cannot otherwise be obtained.

We understand that in response to questions posed at the Working Group meeting on August 19, District staff indicated it is their intention that the non-tradable, non-usable RTCs be removed from each facility's permit after 2022. If these RTCs are indeed removed from the permits, then the suggested provision discussed above would be of little or no use to the Cities, because it is precisely in the last year or two of the NOx shave, and in later years, that these RTCs are most likely to be needed. The Cities therefore also suggest that these non-tradable, non-usable RTCs, or some significant portion of them, remain on power plant permits after 2022.

Attachment 1 to this letter contains an example of rule language that might be used for a provision allowing the conversion of non-tradable, non-usable RTCs to usable but non-tradable status.

2. Power Plants Should Have Access to the "Adjustment Account" to Cover Annual Emissions

As mentioned earlier, the staff proposal contains an "Adjustment Account" enabling post-1993 power plants to meet the NSR holding requirement on a programmatic basis. We understand that staff estimates that 1 to 1 ½ tons of RTCs will be needed for this account [see Draft Staff Report at p. 33]. We suggest that the RTCs in this account also be made available to affected facilities to cover their annual emissions, in exchange for a fee of $7.50 per pound. There does not appear to be any impediment to allowing the RTCs involved to serve both purposes.

As in the case of a request to convert non-tradable, non-usable RTCs to usable but non-tradable RTCs, the fee serves the dual purpose of giving power plants the incentive to rely on the RTC market if the spot price remains below $7.50 per pound, and also providing the District with funds to achieve additional NOx reductions from other sources for which cost-effective reductions cannot otherwise be obtained.

This use of the "Adjustment Account" could be viewed as an alternative to the suggested provision regarding the non-tradable, non-usable RTCs discussed above.

Attachment 2 to this letter contains an example of rule language that might be used to allow RTCs in the "Adjustment Account" to both meet the NSR holding requirement and be available to cover annual emissions.

3. Provisions Involving Delayed RATA Tests Due to Extenuating Circumstances

The Cities appreciate the staff proposal to allow postponement of a relative accuracy test audit ("RATA") when a major source is physically incapable of being operated. [PAR 2012, Appendix A, Attachment C, Section (B)(2)] Allowing postponement by rule provision would make it unnecessary for the Cities to incur the expense of petitioning the Hearing Board for a variance to allow postponement of the test. However, the Cities would like to suggest two changes to the conditions that apply to the postponement.

First, the due date for performing the RATA should be 30 days, rather than 14 days, from the re-firing of the major source. The additional time is needed in some circumstances to perform tests on the source to ensure reliable and safe operation. [See PAR 2012, Appendix A, Attachment C, Section (B)(2)(c)]

Second, the proposed requirement to disconnect and flange the fuel feed lines is unnecessary and costly. The proposed requirement is unnecessary because the fuel meters are required to be maintained, associated fuel records are required to be kept, and stack emissions are continuously monitored and recorded. So there are multiple sources of data to rely on to verify that the source is not operating. The proposed requirement is costly and time consuming because significant manpower and equipment would be needed to meet it. There also may be health and safety risks if asbestos-containing materials are encountered in the work. The Cities therefore suggest that this requirement be deleted. [See PAR 2012, Appendix A, Attachment C, Section (B)(2)(c)]

4. Other Comments and Questions

a. Provisions Involving the Non-tradable, Non-usable Adjustment Factor

i. The staff proposal should be clarified to provide that the 12-month rolling average RTC price that may trigger release of the non-tradable, non-usable RTCs is the "weighted" average. [PAR 2002(f)(1)(E)]

ii. The staff proposal speaks of determining the 12-month rolling average RTC price for all trades in the "current compliance year." It is not clear how this language would apply to a 12-month rolling average price when the 12 months in question straddle two adjacent compliance years. [PAR 2002(f)(1)(E)]

iii. In PAR 2002(f)(1)(F), the correct cross-reference appears to be to PAR 2002(f)(1)(E), not PAR 2002(f)(1)(F).

b. Provisions Involving the "Adjustment Account"

i. The staff proposal includes a provision allowing access to "Adjustment Account" RTCs for the purpose of compliance with annual emissions during a State of Emergency as declared by the Governor. [see PAR 2002(f)(5)] This provision raises several questions:

(1) How is the account to be funded for this purpose, and with what quantity of RTCs? As we indicated earlier, we understand that staff estimates that 1 to 1 ½

tons will be needed to meet the NSR holding requirement. Will additional amounts be added to fund the account to allow compliance with annual emissions?

(2) Why is access to RTCs limited to a State of Emergency declared by the Governor, as opposed to a State of Emergency declared by a local government official, such as a Mayor?

(3) We understand that in response to questions raised at the Working Group meeting on August 19, District staff indicated that RTCs in this account can be used both to meet the NSR holding requirement and to cover annual emissions. If our understanding is correct, then the rule language needs to be clarified.

(4) It may not be appropriate for the Executive Officer to have unfettered discretion to determine the amount and distribution of RTCs. By making these determinations, he would in effect decide which power plants generate electricity during a State of Emergency. Such decisions may be beyond his authority and expertise. It is important, moreover, that every power plant have access to the RTCs it needs to meet its operating requirements.

The Cities appreciate your consideration of these comments. Please let us know if you have any questions.

Sincerely,

Charles F. Timms, Jr.

cc: Jill Whynot, Assistant Deputy Executive Officer (via email)

ATTACHMENT 1

Proposed Amended Rule 2002(f)(1)(G) shall be added to read as follows:

"Notwithstanding the provisions of subparagraph (f)(1)(F), upon the request of a Power Producing Facility, all or a portion of the facility's non-tradable/non-usable NOx RTCs specified in subparagraph (f)(1)(C) shall be converted to usable but non-tradable NOx RTCs for the purpose of compliance with the facility's emissions, or to meet resource adequacy needs, for the year for which the request is made, for a user fee of $7.50 per pound (or $15,000 per ton) of NOx RTCs. Any facility making such a request shall not sell any of its NOx RTC allocation for the year for which the request is made."

Later subparagraphs will need to re-numbered to accommodate this new subparagraph.

ATTACHMENT 2

Proposed Amended Rule 2002(f)(6) shall be added to read as follows:

"Notwithstanding the provisions of subparagraph (f)(5), upon the request of a Power Producing Facility, the Executive Officer shall allow the facility access to Adjustment Account RTCs for the purpose of compliance with the facility's annual emissions, or to meet resource adequacy needs, for a user fee of $7.50 per pound (or $15,000 per ton) of NOx RTCs. These Adjustment Account RTCs are non-tradable. Any facility making such a request shall not sell any of its NOx RTC allocation for the year for which the request is made."

SCEC

August 26, 2015

Philip M. Fine, Ph.D.
Deputy Executive Officer
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, California 91765

Subject: **Backstop Measures for Municipal Utilities Operating Under RECLAIM SCEC 2564.2001**

Dear Dr. Fine:

South Coast Environmental Company (SCEC) offers the following comments on behalf of the Cities of Anaheim, Colton and Riverside. All three Cities operate power generating stations that are regulated under RECLAIM.

The Cities of Anaheim, Colton and Riverside (the Cities) operate modern facilities that already incorporate Best Available Control Technology (BACT) or Best Available Retrofit Control Technology (BARCT). Municipal power generators have an obligation to provide power to the communities they serve and cannot simply cut back operations due to SCAQMD policies or the implications of SCAQMD's actions on RTC costs and availability. Unlike many facility operators in the South Coast Air Basin that can respond to the proposed NO_X shave by installing new technology or reducing operations, these municipal utilities can only purchase additional NO_X RTCs in order to operate at permitted levels should their existing inventory of credits be discounted. Because of the limited compliance strategies available to municipal utilities and the unique circumstances we face in a regulatory program that is dominated by private sector operators, the Cities feel that they should have been excluded from the RTC reduction proposed by SCAQMD, but we also understand that safeguards can be built into Regulation XX to reduce the impacts of RTC reduction for municipal utilities.

Throughout the rule development process the Cities have stressed that safeguards proposed by SCAQMD to counter the impacts of the RTC reduction must offer certainty that credits will be available when needed, and that those credits can be obtained swiftly and efficiently. The Cities' concerns stem from the uncertainties we will face in the upcoming years as our peaking units are called upon for more frequent run sequences in support of the increased reliance upon renewable resources in the region.

Given that SCAQMD continues to propose a reduction of the Cities' RTC holdings, complementing rule language to ease the burden of the NSR holding requirement for new facilities and to ensure that credits are easily available in the event of RECLAIM or power market upset are critical to the Cities' continued ability to meet their mission as municipal power generators. The Cities appreciate the steps that SCAQMD has taken so far toward meeting the unique needs of municipal power generators, but also recognize that additional thought must be given to several concepts already laid out in Rule 2002. The Cities encourage SCAQMD to continue to refine proposed amendments to Rule 2002 with due consideration of the Cities' needs and we offer these comments for SCAQMD's consideration as it proceeds with its rule development effort.

<u>Rule 2002 (f)(1) - Non-tradable / Non-usable Holdings</u>

SCAQMD proposes to reestablish a non-tradable / non-usable holding account to complement the reduction of available RTCs. Permit holders would be able to access the holding account only after two conditions are met. First the 12-month rolling average RTC price must exceed $15,000 per ton. Second, the SCAQMD Governing Board must direct staff to convert the holdings to tradeable / usable credits.

Responsiveness of Mitigating Actions

The Cities are concerned that rolling average RTC price may trail too far behind sudden RTC price increases and the requirement to obtain Governing Board authorization to convert the holdings to tradeable and useable credits may not be suitably responsive to our needs as municipal utilities. In other words, the Cities' need for certainty and swift access to RTCs may be jeopardized and we will be forced to participate in a market with escalating costs and limited RTC availability until the point that the $15,000 threshold is reached. By the time the SCAQMD responses are implemented, it will be too late to undo the damage to the utilities and local communities.

Request for Flexibility in Accessing Non-tradeable / Non-useable Holdings

The Cities understand that other municipal utilities have suggested to SCAQMD that we should have discretionary use of our non-tradeable / non-usable credits for our own use, but not to be sold or transferred to other entities. Those proposals vary from making the credits available at no cost to making them available for a mitigation fee of $7.50 per pound, which is equivalent to the trigger price of $15,000 per ton. The fee would be paid only if the holdings are accessed prior to the rolling average price being reached. If the $7.50 fee were to be assessed, municipal utilities would in effect, access their non-tradeable / non-useable credits only if spot market prices escalate above that rate and would otherwise rely upon the market for any required RTCs.

The Cities are supportive of the proposals to expand access to credits and believe that they would be beneficial to the utilities, SCAQMD and the RECLAIM program in general. By providing access to these credits in advance of a market upset, SCAQMD would provide municipal utilities the certainty needed to meet our mission at a reasonable cost and the limited access of utilities to their non-tradeable credits may actually prevent market upsets that would trigger the widespread release of non-tradeable / non-useable credits to all RECLAIM operators. Finally, if utilities are assessed a fee of for their use of their non-tradeable / non-useable credits in advance of the 12-month price trigger being reached, the proceeds would be available to SCAQMD to facilitate voluntary NOx emission reductions. Those reductions may be more cost-effective than what would otherwise be obtained within the RECLAIM program.

Sunset of Non-tradeable / Non-useable Holdings

The Cities understand that SCAQMD proposes to discontinue the non-tradeable / non-useable holdings in the year 2022. Given the uncertainty presented by increased integration of renewable resources and regional electrification, the Cities ask SCAQMD to provide for continued utilization of the non-tradeable / non-useable holdings, at least for municipal utilities.

<u>Rule 2002 (f)(4) & (5) RTC Adjustment Account</u>

SCAQMD proposes to establish an RTC adjustment account that would serve two purposes. The first is to provide a store of credits that new power generating facilities can use to demonstrate compliance with the NSR holding requirement of Rule 2005 (Rule 2002 (f)(4)). The second purpose of the adjustment account is to make credits available to all power generators in response to an electrical emergency (Rule 2002 (f)(5)). During the August 19 public consultation, SCAQMD indicated that it plans to further refine the provisions of Rule 2002 that deal with the proposed adjustment account. The Cities suggest that the following concepts be given additional consideration.

Compatibility of Dual Purposes

The Cities appreciate that SCAQMD is proposing alternatives that would ease the NSR holding requirement burden and also provide additional RTCs in the event of an emergency. However, it is not clear that both purposes can be simultaneously served, given the amount of RTCs that SCAQMD proposed to allocate to the account. The Cities ask that SCAQMD clarify how the account can be available for emergency use by all power producers, without jeopardizing the ability of new facilities to make the NSR holding demonstration.

During the working group meeting, SCAQMD advised that the proposed funding level of 1 – 1.5 tons/day reflects the amount of reduced RTCs that are currently held by new facilities for the offset demonstration. If the funding of the account reflects the reduced RTCs, rather than the entire PTE for these facilities, it is unclear how the adjustment account can be used by existing facilities (pre 1993 installations) during an emergency without jeopardizing the ability of new facilities to make the NSR demonstration.

Authority to Declare an Energy Emergency

SCAQMD initially proposed that RTCs in the adjustment account would be available to power generators upon an emergency declaration made by the Governor of California, but has committed to investigate concepts that would allow other parties to make such declarations.

August 26, 2015
Dr. Philip Fine
South Coast AQMD

Additional entities or authorities should be allowed to declare the presence of an energy emergency at both a regional and local level. Many emergencies requiring local power generation may exist within the boundaries of a city and state or regional authorities may not be able to investigate and make the necessary declaration quickly. Local authorities, such as a City Manager or Mayor, should also be allowed to make a declaration that would allow for the release of RTCs from the adjustment account.

Dispersing Credits from the Adjustment Account

It is unclear how access to RTCs would be granted or how competing applicants would be prioritized by SCAQMD to receive RTCs. SCAQMD must further define its role in the process of granting access to the adjustment account if the Cities are to be assured that credits are available not only for the NSR holding demonstration, but also for easy access in case of an emergency.

RTC Management Flexibility

The Cities ask SCAQMD to clarify how the adjustment account would affect the way in which new power producing facilities would manage the remaining RTCs listed in their facility permits, with respect to the Rule 2005 (f) holding requirement. Ideally, provisions to accommodate the holding requirement would also allow facility operators to sell the remaining unused RTCs listed in their permit in advance of compliance year closure. We also ask SCAQMD to give consideration to the same discretionary use of the adjustment account by municipal utilities that is proposed within this letter for the non-tradeable / non-useable holdings.

Thank you for considering these comments. The Cities of Anaheim, Colton and Riverside welcome the opportunity to further discuss SCAQMD's RECLAIM proposal and I am available should you require additional information regarding the Cities' comments.

Sincerely,
SCEC
An affiliate of Montrose Environmental Group, Inc.

Karl A. Lany
Sr. Vice President

cc: Manny Robledo, Electric Operations Manager, Anaheim Public Utilities
Wayne Feragen, Sr. Plant Manager, City of Colton
Reiko Kerr, Assistant General Manager - Power Resources, Riverside Public Utilities
Chuck Casey, Utility Generation Manager, Riverside Public Utilities

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ECO SERVICES OPERATIONS LLC
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August 28, 2015

Via E-mail: jcassmassi@aqmd.gov

Mr. Joe Cassmassi
Planning & Rules Manager
South Coast Air Quality Management District
21865 E. Copley Drive
Diamond Bar, CA 91765-4182

RE: PROPOSED AMENDMENTS TO REGULATION XX: NOx SHAVE FOR RECLAIM SOURCES

Dear Mr. Cassmassi:

Eco Services Operations LLC (Eco Services) is again writing to express its concerns with the South Coast Air Quality Management District's (SCAQMD's) proposed amendments to Regulation XX to implement the latest round of NO_x emissions reduction for RECLAIM sources ("NO_x shave"). Eco Services owns and operates a sulfuric acid regeneration plant located at 20720 South Wilmington Ave in City of Carson (Dominguez Plant). Eco Services provided comments to you by letter dated April 27, 2015 and is attaching a copy of our prior comments for your reference.

As we previously advised, the Dominguez Plant has been an active supporter and participant of the RECLAIM program. In 2010, Eco Services worked cooperatively with the SCAQMD to identify the Best Available Retrofit Control Technology (BARCT) for the control of SOx emissions and installed a caustic scrubber to greatly reduce SOx emissions at a substantial cost. Eco Services is committed to environmental compliance as demonstrated through our implementation of BARCT for SOx.

As the SCAQMD develops amendments to the RECLAIM program for NOx, Eco Services reiterates its commitment to environmental compliance and working cooperatively towards a common sense and practical solution. Eco Services believes that implementation of technically feasible and cost-effective measure is appropriate. Eco Services is amenable to implement any such measures as we have done with SOx emissions. However, based on the SCAQMD's BARCT analysis, there are no technologies that qualify as BARCT for the NOx emissions sources at the Dominguez Plant. Accordingly, Eco Services is left in the unenviable position of having no practical means of complying with RECLAIM other than purchasing additional allowances at a substantial cost.

Eco Services is very concerned with the prospect of having no control over its ability to comply with RECLAIM. Importantly, we have been advised by RECLAIM brokers that the drastic across the board shave being contemplated by the SCAQMD will result in NOx credits being rendered extremely scarce and accordingly, cost prohibitive. In order for a cap-and-trade program to function properly, there must be a reasonable amount of credits available for trading at a reasonable cost. It is our understanding that NOx credits, if available for trading at all, will be exorbitantly priced.

Eco Services simply does not support a program that leaves no reasonable means of complying other than to put us at the mercy of what we believe will be a dysfunctional trading program. Instead, as we have demonstrated with respect to the SOx RECLAIM program, we support revisions to the RECLAIM program that rely on implementation of feasible and cost-effective controls. Sources that can implement BARCT can and should do so as a first step towards additional reductions. We strongly urge the SCAQMD to consider this approach which will result in a reduction of NOx emissions based on cost-effective controls which will not cripple the RECLAIM trading program and leave smaller emitters no real cost-effective option for compliance. If the SCAQMD pursues the across the board shave, it will effectively be imposing cost-effective requirements on the BARCT sources but not considering cost-effectiveness at all for non-BARCT sources. Eco Services believes that is inequitable and inappropriate.

If the SCAQMD does pursue an across the board NOx shave, Eco Services recommends that the changes to RECLAIM include some type of measure to limit the costs of NOx credits in addition to the current $15,000 per ton annualized average cost, particularly for small emitters. An equitable rule should provide the regulated community with a cost-effective means of complying. We request that the SCAQMD somehow provide a ceiling on the financial impact it will have on RECLAIM participants in terms of cost-effectiveness. BARCT sources will be subjected to cost-effective controls. Similarly, the financial impact to non-BARCT sources should also be based on cost-effectiveness.

It is our understanding that Non-Tradable/Non-Useable allocations will be issued to emitters, and that these “safety valve” allocations can be used as compliance instrument when the average cost of annual NOx RTC exceeds $15,000 per ton (or $7.50 per pound). However, we believe that the time for cost averaging should be significantly shortened to prevent the repeat of situation similar to year 2000 when the value of annual NOx RTC went far above the $7.50 per pound threshold. Also, additional safe guards should be considered to prevent non-compliance for non-BARCT sources if the NOx RECLAIM market fails such that no NOx RTCs are available to be purchased.

If you have any questions or need additional details regarding the information contained in this letter, please contact me at (925) 313-8221.

Sincerely,

Anthony Koo
Sr. Environmental Engineer

cc: Philip Fine, Ph.D., Assistant Deputy Executive Officer, pfine@aqmd.gov
Jill Whynot, Assistance Deputy Executive Officer, jwhynot@aqmd.gov
Gary Quinn, P.E., Program Supervisor, gquinn@aqmd.gov
Kevin Orellana, Air Quality Specialist, SCAQMD, korellana@aqmd.gov

Encl.
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ECOSERVICES

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April 27, 2015

Via E-mail: jcassmassi@aqmd.gov

Mr. Joe Cassmassi
Planning & Rules Manager
South Coast Air Quality Management District
21865 E. Copley Drive
Diamond Bar, CA 91765-4182

RE: PROPOSED AMENDMENTS TO REGULATION XX:
NOx SHAVE FOR RECLAIM SOURCES

Dear Mr. Cassmassi:

Eco Services Operations LLC (Eco Services) is writing to express its concerns with the South Coast Air Quality Management District's (SCAQMD's) proposed approach to amending Regulation XX to implement the latest round of reductions in NO_x emissions allowances for RECLAIM sources ("NO_x shave").

Eco Services owns and operates a sulfuric acid regeneration plant (Dominguez Plant) located at 20720 South Wilmington Ave. in City of Carson. The Dominguez Plant's sulfuric acid product is primarily used in petroleum refineries as alkylation catalyst to produce high octane, low vapor pressure, and clean burning gasoline blending stock.

The Dominguez Plant has been an active supporter and participant of the SCAQMD RECLAIM Program. During the 2010 SO_x RECLAIM rulemaking process, Eco Services worked closely and cooperatively with SCAQMD in identifying feasible Best Available Retrofit Control Technology (BARCT) for the Plant. In 2012, the facility became the world's first double absorption sulfuric acid plant to be retrofitted with a caustic scrubber to reduce SO_x emissions. The scrubber has been in operation since November of 2012 and has since been consistently removing approximately 1 ton of SO_x per day from the South Coast Air Basin. These examples serve as a clear indication of Eco Services' commitment to environmental compliance and air quality improvement.

We understand that the SCAQMD is implementing its Air Quality Management Plan (AQMP) and plans to reduce NO_x emissions from its Air Basin. SCAQMD is contemplating on reducing as much as 50% of the currently-available NO_x credit from the Regional Trading Credit (RTC) universe. More importantly, SCAQMD is in the process of evaluating various options on how the reductions will be implemented, including an across-the-board shave approach that would uniformly remove RTCs without consideration of an individual source's operational characteristics or its ability to implement BARCT fundamentally developed for other types of sources.

In 2014, SCAQMD conducted a detailed BARCT study of the major NO_x emitting sources within the South Coast Air Basin. The study did not include the Dominguez Plant because there is no known BARCT available to reduce NO_x emissions at sulfuric acid plants. Furthermore, the study also concluded that the other two natural gas burning sources (the preheater and package boiler) at the Dominguez Plant were not cost-effective for BARCT implementation due to their low usage and NOx emissions.

The Dominguez Plant emits about 0.0685 tons per day of NO_x, which matches its RTC allocations without any surplus. This total represents 0.258% of the entire current NO_x RTC market. Eco Services is concerned that if a 50% across-the-board shave is implemented, it will severely inhibit the Dominguez Plant's ability to comply with the RECLAIM Program. Without a viable BARCT and limited RTC supply, Eco Services is concerned that it will be difficult, if not impossible, for the Dominguez Plant to comply with the post-shave allocation. Assuming that NO_x credits will be available, based on the current credit value of $90 per pound, this translates to an exorbitant minimum of $4,500,000 in compliance costs for the Dominguez Plant.

Eco Services respectfully asks SCAQMD to seriously consider the huge negative impacts to small emitters like the Dominguez Plant, which have no viable options to comply with the proposed NO_x reductions if implemented. Instead, Eco Services urges SCAQMD to consider achieving this round of NO_x reductions by using the sector and subsector approach in lieu of an across-the-board shave. In particular, Eco Services believes that this iteration of the NO_x shave should only be applied to sectors which have viable BARCTs that were identified in the recent BARCT study conducted by the SCAQMD. Applying such an approach, Eco Services respectfully requests that the District remove the Dominguez Plant from the list of facilities subject to this round of the NOx shave.

If you have any questions or need additional details regarding the information contained in this letter, please contact me at (925) 313-8221.

Sincerely,

Anthony Koo
Sr. Environmental Engineer

cc: Elaine C. Chang, D.Ph., Deputy Executive Officer, echang@aqmd.gov
Philip Fine, Ph.D., Assistant Deputy Executive Officer, pfine@aqmd.gov
Jill Whynot, Assistance Deputy Executive Officer, jwhynot@aqmd.gov
Gary Quinn, P.E., Program Supervisor, gquinn@aqmd.gov
Kevin Orellana, Air Quality Specialist, SCAQMD, korellana@aqmd.gov

{B2023836.1}

—7 Joe

CHARLES F. TIMMS, JR.
ATTORNEY AT LAW

445 SOUTH FIGUEROA STREET, 31ST FLOOR
LOS ANGELES, CA 90071-1630

TELEPHONE: 213-489-6868
FACSIMILE: 213-489-6828
EMAIL: cftimms@aol.com

September 17, 2015

<u>BY EMAIL AND U.S. MAIL</u>

Philip M. Fine, Ph.D.
Deputy Executive Officer
South Coast Air Quality Management District
21865 E. Copley Drive
Diamond Bar, CA 91765

Re: Follow-up to Comment Letter on NOx RECLAIM Shave Proposal; Cities of Burbank and Pasadena

Dear Dr. Fine:

On behalf of the City of Burbank, Department of Water and Power ("BWP"), and the City of Pasadena, Water and Power Department ("PWP) (collectively "the Cities"), we are submitting this follow-up letter to our August 21, 2015, comment letter on your staff's draft proposed amendments to Regulation XX, Regional Clean Air Incentives Market ("RECLAIM") ("NOx shave proposal"), published on July 21, 2015.

We have identified some additional rule language that would need to be amended to facilitate our proposal that power plants be provided with quicker access to non-tradable/non-usable NOx RTCs, and/or access to RTCs in the Adjustment Account, if needed to cover annual emissions. This additional language will ensure that the relevant RTCs are only credited to the SIP on a year-by-year basis to the extent they are not needed for power plant compliance purposes. See Attachment 1 to this letter.

In addition, the Cities support the proposal of the Los Angeles Department of Water and Power to expand the emergency provisions in the staff proposal to allow power plants to access RTCs in the Adjustment Account if an energy emergency alert is declared by the relevant electrical "Reliability Coordinator." See Attachment 2 for proposed rule language.

The Cities appreciate your consideration of these additional comments. Please let us know if you have any questions.

Sincerely,

Charles F. Timms, Jr.

cc: Jill Whynot, Assistant Deputy Executive Officer (via email)
Attachments.

ATTACHMENT 1

Proposed Amended Rule 2002(f)(1)(J) shall be amended to read as follows:

"The NOx RTC adjustment factors for compliance years 20019 through 2021 shall not be submitted for inclusion into the State Implementation Plan until the adjustments have been in effect for one full compliance year. The 2022 NOx RTC adjustment factors shall not be submitted for inclusion in the State Implementation Plan until 12-months after the adjustments have been in effect for one full compliance year. <u>At the end of each compliance year reconciliation period from 2022 and each year thereafter, the Power Producing Facility shall surrender unused non-tradable RTCs to the District for inclusion into the State Implementation Plan.</u>"

ATTACHMENT 2

Proposed Amended Rule 2002(f)(5) shall be amended to read as follows:

"During a State of Emergency as declared by the Governor or an Energy Emergency Alert as declared by the Reliability Coordinator, the Executive Officer will allow Power Producing Facilities access to Adjustment Account RTCs for the purpose of compliance with the annual emissions. ~~These available RTCs will be limited to those that are in excess of those specified for use in paragraph (f)(4).~~ The amount and distribution of the RTCs will be determined by the ~~Executive Officer~~ Power Producing Facilities based on the ~~impact that~~ amount of energy they produce during the State of Emergency ~~has on the RECLAIM program~~ or the Energy Emergency Alert."

'Reliability Coordinator' means the entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System as defined in the North American Electric Reliability Corporation Glossary."

SOUTHERN CALIFORNIA
EDISON
An *EDISON INTERNATIONAL*℠ Company

Mr. Joe Cassmassi
Director, Planning and Rules
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

RE: 2015 RECLAIM

Dear Mr. Cassmassi:

Southern California Edison (SCE) appreciates the opportunity to comment on the South Coast Air Quality Management District's (District) proposed reduction of Reclaim Trading Credits (RTCs). Moving the District's air basins into attainment is a step toward improved air quality and improved economic growth by increasing the ability of businesses to operate in this region. The District's proposed reduction in the RTC market should act to drive stationary sources under the RECLAIM program to install Best Available Retrofit Control Technology (BARCT) for control of NOx emissions. SCE recognizes the need to make reductions in NOx in order to assist in the effort to achieve attainment with the National Ambient Air Quality Standards.

The shave should drive sources towards BARCT
The shave, as proposed, would constitute a 53% reduction in the total number of RTCs in the market. 67% would be taken from the refinery sector while 47% would be taken from the non-refinery sector, including electric generation facilities. While this would be better than an outright across-the-board shave, it still would trigger costs for the electric generation sector that would have no commensurate impact on reducing air emissions. The electric generation facilities are already at Best Available Control Technology (BACT) with no existing opportunity to reduce emissions (other than curtailing operation, which is not feasible for electric generation facilities since electric demand will dictate operating times). While there is recognition there will have to be some reduction of RTCs from electric generation facilities, the shave should cause facilities not currently at BARCT to install better controls. With the proposed percentages, the costs will disproportionally impact facilities that are already at BACT and result in a subsidization by those at BACT of facilities not yet utilizing the best controls.

The proposed shave amount on the Electric Generation Facilities in effect caps the amount of fuel we can use
As stated above, SCE's electric generation facilities are already at BACT or BARCT, with no currently feasible opportunity, from a control standpoint, to reduce emissions further. With no advancements in control technology, the only way to further reduce emissions is by curtailing operation (i.e. limiting fuel usage). Thus, if no credits were available for purchase on the open market, which is a possibility given the proposed size of the shave, the only way to stay in compliance would be by reducing fuel usage.

P. O. Box 800
2244 Walnut Grove Ave.
Rosemead, CA 91770

Limiting operations might be an option in other industries where production can be outsourced to different sites, but this is not an option for electric generation facilities, as local demand for electricity dictates when these facilities must operate, as ordered by the California Independent System Operator (CAISO). Existing contracts with the California Public Utilities Commission (CPUC) also require the facility to operate when the grid demands it, meaning that when this equipment will run, is effectively out of SCE's control. In other words, if system demand requires SCE to turn on a unit, the facility must do so. SCE will not violate the air permit conditions. But failure to operate when needed for system demand could result power outages.

It should also be noted that under the California Health & Safety Code for market-based programs [§39616(c)], a program must not result in disproportionate impacts to stationary sources in the program as compared to other permitted stationary sources not in the program. A typical permitted source not in the RECLAIM program is subject to rule-based command and control regulations. Were SCE's facilities not in the RECLAIM program, command and control regulations would require BACT concentration limits with no further limits on operation or fuel use, unless such further limits were agreed to for PTE or CEQA limit purposes. However, because the facilities are in RECLAIM, not only are they subject to BACT, but also to the holding requirement and the potential surrender of RTCs. The result is that if there aren't enough RTCs in the market, this proposed shave would effectively cap fuel use. By setting a concentration limit as well as a fuel use limit, this proposed shave would go beyond command and control regulations.

The amount of the shave could have impacts on grid reliability during emergency situations.

The current proposal contemplates what amounts to a 53% shave in the existing RTC market. While action must be taken to reduce current NOx emissions, this action must not result in a situation where generating facilities are unable to operate during emergency situations. The electric grid is a complex, interrelated system. All components work together to generate and ultimately distribute electric power to end users. If, for example, a major transmission line were to go down, there would be an immediate need for local, dispatchable generation to begin operating. If these facilities don't have sufficient RTCs to operate in these circumstances, the system would be faced with energy resources that could not be operated under SCAQMD rules, which would result in load curtailment. Because of the complexity of the system, there is no bright line that can be drawn. The District must therefore exercise caution and not bring about a market that is incapable of responding to emergency situations.

Changes to the RATA testing requirements are supported

Thank you for meeting previously with SCE and DWP on this matter and recognizing that there was a legitimate need to change the rule language regarding postponement of RATAs. In the past, SCE has experienced multiple incidents where equipment has failed in the quarter in which a RATA was due, and found that the District's options for RATA postponement were impractical. With no reasonable alternative to postpone testing, and in order to avoid enforcement, the facilities were forced to petition the SCAQMD Hearing Board for variances. SCE believes the proposed language addresses this issue and now provides a legitimate alternative for RATA postponement without variance relief.

While we fully support the option presented, we are requesting an increase of the 14 unit operating day extension to 30 unit operating days. The main concern is with SCE's Pebbly Beach Generating Station on Catalina Island. Due to its remote location, weather related delays of transportation options to the island, and the high work load schedule of our source testing firm, it can be difficult to organize a RATA test in a short timeframe. The testing firm must separately schedule a time to barge its equipment out to the island, and if power demand on the island were high, the engines may need to run as soon as possible when they return to service, which could impact the test protocol This is especially true for the cleaner engines, as they must operate more frequently in order to comply with facility-wide emission limits. If the source testing firm could not schedule a visit to the island and the engines had to operate to support the power demand, 14 operating days might not be enough time to complete an appropriate RATA. As an alternative, if staff is not open to extending the 14 unit operating day window, SCE suggests having an equivalent operating hour limit. This could give the facility more time to schedule a test without increasing the overall operating time of the unit. Whether there are 14 days or 30 days to complete a RATA, a facility has plenty of incentive to complete the RATA as soon as possible so as to minimize the use of missing data procedures. We ask that the District consider this extension. But other than this amendment, we fully support the rule language as presented by the District and we appreciate the work done by staff to address this issue.

SCE Supports the adjustment account for compliance with Rule 2005 Subdivision (f). Existing USEPA interpretation of the NSR requirements hold that a facility in RECLAIM must obtain sufficient RTCs at the beginning of the calendar year to cover the total potential to emit (PTE) for the year notwithstanding that most facilities do not operate at or near their PTE. This results in a substantial procurement of RTCs that are necessarily bought at a time they are most expensive, but if not used are then sold off when they are of little value. Further, there is no environmental benefit created by what is, in effect, an over-procurement of credits. SCE supports the proposal by the District to create an adjustment account that would cover this RTC requirement. It would eliminate the costly procurement of RTCs beyond what is really needed to cover actual emissions and, quite simply, it makes sense. We urge the District to continue to seek EPA concurrence with this proposal.

As stated above. SCE appreciates the opportunity to provide these comments and we can make ourselves available, if needed, to further clarify our positions. We look forward to working with the District on this important issue.

Sincerely,

Thomas Gross

Thomas Gross

GE
Capital

Mark Mellana
General Manager, Inland Empire Energy Center
800 Long Ridge Road
40434260E
Stamford, CT 06927
USA

T 203 326-7355
mark.mellana@ge.com

September 22, 2015

Ref. No. GE/IEEC – 0905

Joe Cassmassi
Rules and Planning Manager, Planning Rule Development, and Area Sources
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

Subject: Inland Empire Energy Center, LLC Request to Change Designation from Investor Category to the Power Plant Category RECLAIM XX Rule Making

Dear Mr. Cassmassi:

Inland Empire Energy Center, LLC (IEEC, LLC), a wholly-owned subsidiary of General Electric (GE), is the permit holder for the Inland Empire Energy Center (IEEC). GE partnered with Calpine in 2005 to bring the H-technology gas turbine to life as a demonstration project at the IEEC. For business reasons that existed at the time, GE purchased all NOx RECLAIM Trading Credits (RTCs) required for the IEEC instead of having them purchased directly by IEEC, LLC. The NOx RTCs were acquired specifically and solely to meet the RECLAIM compliance obligations of IEEC, and have been used for no other purpose throughout the life of the project. GE has no interest in any other RECLAIM facility. The GE RTC account is, and always has been, 100% dedicated to the IEEC (please see attachments for evidence of past account transfers).

The current staff proposal for amending South Coast Air Quality Management District (District) Regulation XX incorrectly categorizes the IEEC RTCs held by GE in the Investor category. As the name suggests, the Investor category includes entities that buy and sell RTCs with the objective of making a profit based on fluctuations in market price. The Investor held RTCs are disassociated from any RECLAIM facility. This is clearly not the situation with respect to the IEEC RTCs held by GE.

We suspect that this error occurred because IEEC, LLC is the permit holder for the IEEC, not GE. However, this legal distinction does not change the fact that the subject RTC account is exclusively associated with the IEEC, and is not an Investor account. Because all of the GE owned NOx RTCs were acquired and are used solely for IEEC compliance purposes, GE's NOx RTC account should be designated as a Power Plant (non-refinery) account for purposes of the allocation "shave" in the proposed amendments to Regulation XX.

Failing to correctly categorize the allocations held by GE for IEEC would result in <u>a double digit multi-million dollar impact on our business</u>. IEEC, LLC and GE could have never known that the means by which they chose to acquire and hold the RTCs for the IEEC could have such serious implications, and we do not believe that the District intends such an unforeseen consequence. We therefore request that the GE RTC account be correctly categorized as a Power Plant (non-refinery) account by changing Table 8 in proposed Rule 2002 from Inland Empire Energy Center, LLC to "General Electric Company, Inland Empire Energy Center, LLC

Thank you for your attention to this matter. If necessary to resolve this matter, we would be happy to meet with you and your team to discuss the details of our request. Please coordinate directly with Alisa Moretto at 951-226-4553.

Sincerely,

Francisco Escobedo for

Mark Mellana
General Manager
Inland Empire Energy Center, LLC

cc: Alisa Moretto
Roy Belden

GE
Energy

Tisha Monaco
Sr. Administrative Assistant

Inland Empire Energy Center
26226 Antelope Road
Romoland, CA 92585
USA

T 951 928 5905
Tisha.monaco@ge.com

March 12, 2009

Ref. No. GE/IEEC – 0308

Ms. Susan Tsai
RECLAIM Administration – RTC Transfers
South Coast Air Quality Management District
21865 E. Copley Dr.
Diamond Bar, CA 1765

RE: Inland Empire Energy Center – Form 2007-1 for Delegation of Authority for RTC Transfers & Credits – ID #129816

Dear Susan,

Per our conversation on Tuesday, March 10, 2009, Attached you will find form 2007-1 filled out to make this change giving Delegation of Authority to Francisco Escobedo & Ken Kohl to make RTC Transfers & Credits under ID #129816.

If you have any questions or needs, please do not hesitate to contact me at 951 928 5905.

Thank you,

Tisha Monaco
Sr. Administrative Assistant

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

Regional Clean Air Incentives Market Trading Account Representative Registration and Certification Form

Form 2007-1

This form is used to identify the authorized account representative(s) for an RTC holder and/or certify the account status for an RTC trader.

Section I - Account Information

Account Name Inland Empire Energy Center, LLC

Account I.D..# 129816
(If known)

Account Street Address
26226 Antelope Rd.
Street # 1

Street # 2

Romoland, CA — 92585
City, State — Zip

Country (if not in the United States)

Mailing Address for Transaction Confirmations
26226 Antelope Rd.
Street # 1, or P.O.Box

Street # 2

Romoland, CA — 92585
City, State — Zip

Country (if not in the United States)

Section II - Designation of Representatives

Name	Title	Signature	Date
Francisco Escobedo	Director, Asset Managment	Francisco Escobedo	3-12-09
Phone # (951) 928 -5941	Fax # (866) 749 - 9109		
Ken Kohl	Owners Engineer	Ken Kohl	3-11-09
Phone # (518) 385 - 4290	Fax # (999) 221 - 3549		
Phone # ( ) -	Fax # ( ) -		

Section III - Certification Status

I certify that the above named entity is (check boxes below that apply):

Yes	No	
☐	☒	a) Domiciled in the State of California[1]
☒	☐	b) A holder of an active RECLAIM Facility Permit
☐	☒	c) A holder of a pending RECLAIM Facility permit application

If any box is checked "Yes", proceed to Section IV and complete. If all boxes are checked "No", complete Section IV and Attachment A – Designation of Agent for Service of Process and Consent to California Jurisdiction Form

[1] Domiciled in the State of California for the purposes of this form shall be deemed: a) for natural individuals - having permanent and primary residence located in the State of California; (b) for a corporation, firm, association, organization, partnership, business trust or other business entity - incorporated or created pursuant to the laws of the State of California, and in good standing according to the Secretary of the State of California, or (c) for any State or local governmental agency, any subdivisions thereof, or any public district - created and existing pursuant to California State, or local governmental laws and regulations.

Section IV - Certification of Owner or Officer

I certify that I am an owner or officer of the account identified and authorize the above parties to act as the company's representatives in the registration of any transactions for RTCs for the Facility identified herein. I am authorized to make this submission on behalf of the persons with an ownership interest for whom this submission is made. I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed on 3/12/09 at 10:00 a.m. — Romoland, CA, USA
Date — *City, State, Country*

Francisco Escobedo — Director, Asset Mgmt. — (951) 928 - 5941 — Francisco Escobedo
Name — *Title* — *Telephone* — *Signature*

This form and SCAQMD's use shall not constitute any acceptance of liability on behalf of SCAQMD for any RTC transaction which may be the result of misrepresentation or error by trading partners or their representatives. This form and SCAQMD's use of it shall not be construed, in any way, to create a fiduciary relationship between it and either the seller or buyer of RTCs or with any other party associated with such transactions.

Submit this form and attachments to:

SCAQMD, RECLAIM Administration - RTC Transfers, P.O. Box 4830, Diamond Bar CA 91765-0830

GE
Energy

Francisco Escobedo
Director, Asset Management

Inland Empire Energy Center
26226 Antelope Road
Menifee, CA 92585
USA

T 951 928 5941
Frank.Escobedo@ge.com

June 10, 2014

Ref. No. GE/IEEC – 0849

Reclaim Administration – RTC Transfer
South Coast Air Quality Management District
21865 Copley Dr.
Diamond Bar, CA 91765-0830

SUBJECT: INLAND EMPIRE ENERGY CENTER (IEEC) – 2014 RTC TRANSFER FROM GE ACCT #700126 TO IEEC ACCT #129816

To Whom It May Concern:

Attached is our completed form 2007-2 for the transfer of internal RTC's from the General Electric account #700126 to the Inland Empire Energy Center account #129816. This internal transfer is for the following single year trades:

- 96,380 lbs of Cycle 1, Coastal zone, RTC's Expiring December 31, 2015 at $0.00/lb/year
- 12,340 lbs of Cycle 2, Coastal zone, RTC's Expiring June 30, 2015 at $0.00/lb/year
- 23,600 lbs of Cycle 1, Inland zone, RTC's Expiring December 31, 2014 at $0.00/lb/year
- 35,000 lbs of Cycle 1, Inland zone, RTC's Expiring December 31, 2015 at $0.00/lb/year
- 82,923 lbs of Cycle 2, Inland zone, RTC's Expiring June 30, 2015 at $0.00/lb/year

Since this is an internal transfer, the price is not applicable and there is no purchase agreement or transaction confirmation required.

If you have any questions or need further information, please don't hesitate to contact me at (951) 928-5941.

Sincerely,

Francisco Escobedo

Francisco Escobedo
Director, Asset Management

Enclosure

cc: Christine Stora - CEC

South Coast Air Quality Management District
Form 2007-2
Regional Clean Air Incentives Market Trading Credits (RTCs) Transaction Registration
AQMD
Submit this form and required documents with Transaction Registration Fee pursuant to Rule 301

Mail To:
SCAQMD, RECLAIM Administration - RTC Transfers
P.O. Box 4830
Diamond Bar, CA 91765-0830

Tel: (909) 396-3119
www.aqmd.gov

Name of Buyer/Transferee Inland Empire Energy Center, LLC   Account I.D. # 129816

Name of Seller/Transferor General Electric Company   Account I.D. # 700126

Pollutant: ⦿ NOx or ○ SOx *(Identify one pollutant only)*   Is this part of a Swap transaction? ○ Yes ⦿ No

Is this form reporting the trade of an Infinite-Year-Block of RTCs? ⦿ No ○ Yes

If "Yes," Total Value of Transaction $ N/A ; Enter N/A in the "Price" column below; Report in this form only those RTCs that are traded as part of a single negotiated price. File separate forms to transfer any other RTCs that were negotiated for a separate price.

(Attach a separate form if more than 8 transfers are being registered)

Terms of RTC Transferred			Original Zone (Coastal or Inland)	Quantity (Pounds/year)	Price‡ ($/Pound)	Use Code (Buyer)	Generation Code (Seller)	Account Source Code (Seller)	Origin of Credits (Seller)	Certificate Serial Number (Seller)
Cycle	From Compliance Year*	To Compliance Year*								
1	12/31/2014	Single Year Trade	Inland	23,600	N/A	01	N/A	B	REGXX	N/A
2	6/30/2015	Single Year Trade	Coasta	12,340	N/A	01	N/A	B	REGXX	N/A
2	6/30/2015	Single Year Trade	Inland	82,923	N/A	01	N/A	B	REGXX	N/A
1	12/31/2015	Single Year Trade	Coasta	96,380	N/A	01	N/A	B	REGXX	N/A
1	12/31/2015	Single Year Trade	Inland	35,000	N/A	01	N/A	B	REGXX	N/A

* In the "From Compliance Year" Column, fill in the expiration date of the first compliance year RTCs. The "To Compliance Year" Column is used to enter (1) single year transaction, (2) perpetual stream transaction, or (3) multiple year transaction of RTCs of same zone, quantity, and price in a single line. For a single year transaction, mark this column "Single Year Trade". For a perpetual stream transaction, mark this column "All Years After". For a multiple year transaction, fill in the expiration date of the last compliance year. Use separate lines for transactions of different RTCs, quantities or prices. Transactions for all inclusive years between these two columns will be registered. **See reverse side for examples.**

Buyer Use Codes *(only one code per transaction)*

01 Increase RTC Allocation account balance to satisfy annual compliance
02 Use under Rule 2005 - New Source Review for RECLAIM
03 Increase RTC certificate account balance without issuance of physical certificate.
04 Increase RTC certificate account balance with issuance of physical certificate
05 Retire RTCs from market without issuance of physical certificate
06 Retire RTCs from market with issuance of physical certificate
07 Facility Acquisition (Change of Ownership)

NOTE: RTCs in Certificate or Printed Certificate Account must be transferred to Allocation Account to be eligible for compliance use.

Seller Generation Codes

01** Process Change
02** Addition of Control Equipment
03** Production Decrease
04** Equipment or Facility Shutdown
06 Facility Acquisition (Change of Ownership)
07 RTCs for Future Compliance Year, cause of generation not yet been determined

*** Selection of this Generation Code must be accompanied by the selection of Account Source Code "A" - Allocation Account.*

Seller Account Source Code *(only one code per transaction)*

A Allocation Account
B*** Certificate Account
C*** Printed Certificate (must list Certificate Serial number and attach certificate to this form)

*** *If this Account Source Code is selected, then select "N/A" from Generation Code field.*

Origin of Credits
State Rule Number from which the credits were originally issued (e.g. Reg XX, R1631, R2506, etc.)

Answer the following Questions:

A. Is this transaction part of a pooled transactions or market?
○ Yes → Attach Form 2007-3 to identify participants (Part A Only)
⦿ No → Go to Question B

B. Is seller an agent, broker, or other intermediary representing the owner of RTC ?
○ Yes → Attach Form 2007-3 to identify Owner of RTC (Part B Only)
⦿ No → Complete this form only

Date when this transaction was agreed upon (trading transaction date): 6/10/2014 → Attach purchase agreement or transaction confirmation

I certify that I am authorized to make this submission on behalf of the affected registered holders of the RTCs listed herein. I certify that the statements are true, accurate, and complete to the best of my knowledge.

Francisco Escobedo
Authorized Representative of Buyer/Transferee *(Print Name)*
Francisco Escobedo   6/10/2014
Signature   Date

Francisco Escobedo
Authorized Representative of Seller/Transferor *(Print Name)*
Francisco Escobedo   6/10/2014
Signature   Date

GE
Energy

Francisco Escobedo
Director, Asset Management

Inland Empire Energy Center
26226 Antelope Road
Menifee, CA 92585
USA

T 951 928 5941
Frank.Escobedo@ge.com

July 21, 2013

Ref. No. GE/IEEC – 0787

Reclaim Administration – RTC Transfer
South Coast Air Quality Management District
21865 Copley Dr.
Diamond Bar, CA 91765-0830

SUBJECT: **INLAND EMPIRE ENERGY CENTER (IEEC) – 2013 RTC TRANSFER FROM GE ACCT #700126 TO IEEC ACCT #129816**

To Whom It May Concern:

Attached is our completed form 2007-2 for the transfer of internal RTC's from the General Electric account #700126 to the Inland Empire Energy Center account #129816. This internal transfer is for the following single year trades:

- 23,380 lbs of Cycle 1, Coastal zone, RTC's Expiring December 31, 2013 at $0.00/lb/year
- 12,340 lbs of Cycle 2, Coastal zone, RTC's Expiring June 30, 2014 at $0.00/lb/year
- 96,380 lbs of Cycle 1, Coastal zone, RTC's Expiring December 31, 2014 at $0.00/lb/year
- 11,400 lbs of Cycle 1, Inland zone, RTC's Expiring December 31, 2014 at $0.00/lb/year
- 82,923 lbs of Cycle 2, Inland zone, RTC's Expiring June 30, 2014 at $0.00/lb/year

Since this is an internal transfer, the price is not applicable and there is no purchase agreement or transaction confirmation required.

If you have any questions or need further information, please don't hesitate to contact me at (951) 928-5941.

Sincerely,

Francisco Escobedo

Francisco Escobedo
Director, Asset Management

Enclosure

cc: Christine Stora - CEC

South Coast Air Quality Management District

Form 2007-2

Regional Clean Air Incentives Market Trading Credits (RTCs) Transaction Registration

Submit this form and required documents with Transaction Registration Fee pursuant to Rule 301

Mail To:
SCAQMD, RECLAIM Administration - RTC Transfers
P.O. Box 4830
Diamond Bar, CA 91765-0830

Tel: (909) 396-3119
www.aqmd.gov

Name of Buyer/Transferee Inland Empire Energy Center, LLC **Account I.D. #** 129816

Name of Seller/Transferor General Electric Company **Account I.D. #** 700126

Pollutant: ⦿ NOx or ○ SOx *(Identify one pollutant only)* **Is this part of a Swap transaction?** ○ Yes ⦿ No

Is this form reporting the trade of an Infinite-Year-Block of RTCs? ⦿ No ○ Yes

If "Yes," Total Value of Transaction $ N/A **; Enter N/A in the "Price" column below; Report in this form only those RTCs that are traded as part of a single negotiated price. File separate forms to transfer any other RTCs that were negotiated for a separate price.**

(Attach a separate form if more than 8 transfers are being registered)

Terms of RTC Transferred			Original Zone (Coastal or Inland)	Quantity (Pounds/year)	Price* ($/Pound)	Use Code (Buyer)	Generation Code (Seller)	Account Source Code (Seller)	Origin of Credits (Seller)	Certificate Serial Number (Seller)
Cycle	From Compliance Year*	To Compliance Year*								
1	12/31/2013	Single Year Trade	Coastal	23380	N/A	01	N/A	B	REGXX	N/A
2	6/30/2014	Single Year Trade	Coastal	12340	N/A	01	N/A	B	REGXX	N/A
2	6/30/2014	Single Year Trade	Inland	82923	N/A	01	N/A	B	REGXX	N/A
1	12/31/2014	Single Year Trade	Coastal	96380	N/A	01	N/A	B	REGXX	N/A
1	12/31/2014	Single Year Trade	Inland	11400	N/A	01	N/A	B	REGXX	N/A

* In the "From Compliance Year" Column, fill in the expiration date of the first compliance year RTCs. The "To Compliance Year" Column is used to enter (1) single year transaction, (2) perpetual stream transaction, or (3) multiple year transaction of RTCs of same zone, quantity, and price in a single line. For a single year transaction, mark this column "Single Year Trade". For a perpetual stream transaction, mark this column "All Years After". For a multiple year transaction, fill in the expiration date of the last compliance year. Use separate lines for transactions of different RTCs, quantities or prices. Transactions for all inclusive years between these two columns will be registered. **See reverse side for examples.**

Buyer Use Codes *(only one code per transaction)*

- 01 Increase RTC Allocation account balance to satisfy annual compliance
- 02 Use under Rule 2005 - New Source Review for RECLAIM
- 03 Increase RTC certificate account balance without issuance of physical certificate.
- 04 Increase RTC certificate account balance with issuance of physical certificate
- 05 Retire RTCs from market without issuance of physical certificate
- 06 Retire RTCs from market with issuance of physical certificate
- 07 Facility Acquisition (Change of Ownership)

NOTE: RTCs in Certificate or Printed Certificate Account must be transferred to Allocation Account to be eligible for compliance use.

Seller Generation Codes

- 01** Process Change
- 02** Addition of Control Equipment
- 03** Production Decrease
- 04** Equipment or Facility Shutdown
- 06 Facility Acquisition (Change of Ownership)
- 07 RTCs for Future Compliance Year, cause of generation not yet been determined

***** Selection of this Generation Code must be accompanied by the selection of Account Source Code "A" - Allocation Account.***

Seller Account Source Code
(only one code per transaction)

- A Allocation Account
- B*** Certificate Account
- C*** Printed Certificate (must list Certificate Serial number and attach certificate to this form)

*** ***If this Account Source Code is selected, then select "N/A" from Generation Code field.***

Origin of Credits
State Rule Number from which the credits were originally issued (e.g. Reg XX, R1631, R2506, etc.)

Answer the following Questions:

A. Is this transaction part of a pooled transactions or market?

○ **Yes → Attach Form 2007-3 to identify participants (Part A Only)**

⦿ **No → Go to Question B**

B. Is seller an agent, broker, or other intermediary representing the owner of RTC ?

○ **Yes → Attach Form 2007-3 to identify Owner of RTC (Part B Only)**

⦿ **No → Complete this form only**

Date when this transaction was agreed upon (trading transaction date): 6/19/2013 **→ Attach purchase agreement or transaction confirmation**

I certify that I am authorized to make this submission on behalf of the affected registered holders of the RTCs listed herein. I certify that the statements are true, accurate, and complete to the best of my knowledge.

Francisco Escobedo
Authorized Representative of Buyer/Transferee *(Print Name)*

Francisco Escobedo
Signature 6/19/2013 **Date**

Francisco Escobedo
Authorized Representative of Seller/Transferor *(Print Name)*

Francisco Escobedo
Signature 6/19/2013 **Date**

Inland Empire Energy Center, LLC
26226 Antelope Rd
Romoland CA 92585

000000001 0000010840 1 1 0684 042 7226

South Coast Air Quality Management
21865 E. Copley Drive
Diamond Bar CA 91765

INVOICE NUMBER	INVOICE AMOUNT	DESCRIPTION
rtc fee 2013	142.17	

CHECK NUMBER	VENDOR NUMBER	DATE	VENDOR NAME	TOTAL AMOUNT
10840	237495101	06/19/13	South Coast Air Quality Management	$142.17

CK0684 v.0.04 09-25-03

00000

64-1278
611

CHECK NO.

Inland Empire Energy Center, LLC
26226 Antelope Rd
Romoland CA 92585

DATE OF CHECK
06/19/13

PAY: **ONE HUNDRED FORTY TWO AND 17/100 DOLLARS**

TO THE ORDER OF SOUTH COAST AIR QUALITY MANAGEMENT
21865 E. COPLEY DRIVE
DIAMOND BAR CA 91765

CHECK AMOUNT
$142.17

Bank of America, N.A.
Atlanta, Dekalb County, GA.

Inland Empire Energy Center, LLC
Authorized Signature

⑈00000

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

BUYER
ID: 129816

RTC Transfer Confirmation

SCAQMD RECLAIM ADMINISTRATION
P.O. BOX 4830, DIAMOND BAR CA 91765-0830

This letter is to confirm that the South Coast Air Quality Management District (AQMD) has received RTC trading information to comply with Rule 2007-Trading Requirements. The following summarizes your company information and the registration information that you and your trading partner specified in Form 2007-2. The transactions have been recorded and the RTC Listing was updated.

Registration No: 12059

Recording Date: 6/26/13
Pollutant: NOX

	TRANSFER FROM:	TRANSFER TO:
Company Name:	GENERAL ELECTRIC COMPANY	INLAND EMPIRE ENERGY CENTER, LLC
Facility ID:	700126	129816
Signing Representative:	Francisco Escobedo	Francisco Escobedo
Mailing Address:	1 RIVER RD SCHENECTADY, NY 12345-	26226 ANTELOPE ROAD MENIFEE, CA 92585-

Terms of RTC Transferred			Original Zone	Quantity (lb/yr)	Unit Price ($/lb)	Use Code	Generation Code	Account Source	Origin of Credits
Cycle	From Compliance Year (*)	To Compliance Year (*)							
1	12/31/2014	Single Year Trade	COASTAL	96,380	0.0000	01	NA	B	REGXX
2	6/30/2014	Single Year Trade	COASTAL	12,340	0.0000	01	NA	B	REGXX
1	12/31/2013	Single Year Trade	COASTAL	23,380	0.0000	01	NA	B	REGXX
1	12/31/2014	Single Year Trade	INLAND	11,400	0.0000	01	NA	B	REGXX
2	6/30/2014	Single Year Trade	INLAND	82,923	0.0000	01	NA	B	REGXX

(*) RTC Expiration Date

Approved By: Jill Whynot
(Signature) JILL WHYNOT
ASSISTANT DEPUTY EXECUTIVE OFFICER
Engineering & Compliance

Code Description :
Use Code (01) : Increase RTC Allocation account balance to satisfy annual compliance
Generation Code (NA) : Not Applicable
Account Source (B) : Certificate

COMMUNITIES FOR A BETTER ENVIRONMENT
EARTHJUSTCE
NATURAL RESOURCES DEFENSE COUNCIL
SIERRA CLUB

July 8, 2015

Philip Fine
Joe Cassmasi
South Coast Air Quality Management District
21865 Copley Dr.
Diamond Bar, CA 91765
pfine@aqmd.gov
jcassmassi@aqmd.gov

Re: Amendments to Regulation XX – NOx RECLAIM

Dear Dr. Fine and Mr. Cassmassi:

On behalf of Communities for a Better Environment, Earthjustice, Natural Resources Defense Council and Sierra Club ("Health Advocates"), we submit these comments on amendments to Regulation XX, which is slated to go to the Governing Board this fall. We are filing these comments based on the presentation that was provided at June 4, 2015 Working Groups Meeting (hereinafter "Staff Presentation"). At the outset, we remind the South Coast Air Quality Management District ("District") of the urgent ozone and particulate matter problems facing the region. Reducing pollution from the sources in the NOx Regional Clean Air Incentives Market ("RECLAIM") program is essential to achieving our air quality goals and attaining ozone and particulate matter standards. The following sections outline our positions on various issues raised at the last Working Group meeting.

I. The Cap Shave for the Program Should be a Minimum of 14.85 Tons Per Day ("tpd"), Not 14 tpd.

We do not agree with the decision to reduce the total shave amount by .85 tpd, from the required 14.85 tpd to 14 tpd. California's Health & Safety Code is abundantly clear that trading programs must "result in an equivalent or greater reduction in emissions at equivalent or less cost compared with current command and control regulations. . . ." Cal. Health & Safety Code § 39616. In reviewing the materials produced through this rulemaking, the Best Available Retrofit Control ("BARCT") assessments show that a BARCT-equivalent program would result in 14.85

tpd fewer emissions. Accordingly, to comply with Health & Safety Code section 39616, the shave for the RECLAIM program must also be at least 14.85 tpd. We also suggest shaving even more from the program given the large size of the "black box" that must be reduced to meet ozone standards.

II. The Implementation Schedule is Weak.

We are deeply concerned that the schedule for implementation for the shave is too protracted. *See* Slide 4 of the Staff Presentation. Given recent difficulties in meeting various air quality standards, including the 1997 and 2006 standards for fine particle pollution ("PM2.5"), it would be prudent to move up some of the latter year reductions. In fact, we suggest amending the schedule to the following to ensure reductions on the front end in time for compliance with standards.

Year	Current Proposal	Health Advocates Proposal
2016	4 tpd	5 tpd
2018	2 tpd	3 tpd
2019	2 tpd	3 tpd
2020	2 tpd	2 tpd
2021	2 tpd	1.85 tpd
2022	2 tpd	0 tpd

We believe our proposed schedule represents an approach more in line with the directive of the California Health & Safety Code than the implementation schedule proposed in Slide 4 of the Staff Presentation.

III. The District Should Not Establish a New Source Review ("NSR") Set Aside.

Health Advocates do not support the implementation of a District-operated set-aside for New Source Review ("NSR") holdings. There is no basis for the District to undertake this task. In fact, this provision exists to ensure the program does not erode air quality progress in the region. We think this is a necessary safeguard, and we have not heard a compelling reason why the District should take on this duty. Industries have complied with this provision for decades, and it makes sense to continue to place this duty on industry.

IV. The California Environmental Quality Act Analysis Should Examine a Command and Control Alternative.

It is important that the Governing Board and the public receive full information on the environmental landscape of this action. In particular, through the California Environmental Quality Act ("CEQA") process, an assessment of a Command and Control alternative will be important to understand how quickly desperately needed reductions could be implemented in the

South Coast under a regulatory program requiring implementation of readily available technologies, many of which have not been installed at the largest NOx emitters in the South Coast. Under the currently proposed approach, clean up would be protracted for many years as the shave is implemented. A Command and Control Alternative would achieve reductions sooner than this compliance schedule.

V. Industry's Critique on Credit Prices Carries No Water.

At the workshop, representatives for NOx emitters suggested that environmental interests were naïve in solely looking at the prices of short term credits in asserting that NOx RECLAIM credits are priced too low. They claimed that environmental interests failed to look at the price of Infinite Year Block ("IYB") credits. Rather than rebut the claims environmentalists have made that the NOx RECLAIM system is broken because credits prices are too low, the IYB credits only help boost the environmentalists claim. Even with the recent doubling of IYB NOx credits in 2014, the value of IYB credits has been excessively low for over a decade. The following chart from the March 5, 2015 Annual NOx RECLAIM report reprinted below confirms this:

Table 2-5
IYB NOx Pricing (Excluding Swaps)

Calendar Year	Total Reported Value ($ millions)	IYB RTC Traded with Price (tons)	Number of IYB Registrati ons With Price	Average Price ($/ton)
1994*	$1.3	85.7	1	$15,623
1995*	$0.0	0	0	N/A
1996*	$0.0	0	0	N/A
1997*	$7.9	404.6	9	$19,602
1998*	$34.1	1,447.6	23	$23,534
1999*	$18.6	438.3	19	$42,437
2000*	$9.1	184.2	15	$49,340
2001*	$34.2	416.9	25	$82,013
2002	$5.5	109.5	31	$50,686
2003	$14.3	388.3	28	$36,797
2004	$12.5	557.0	52	$22,481
2005	$43.1	565.3	71	$76,197
2006	$65.2	432.9	50	$150,665
2007	$45.4	233.5	25	$194,369
2008	$49.7	245.6	27	$202,402
2009	$16.7	134.2	14	$124,576
2010	$14.3	149.0	13	$95,761
2011	$9.1	160.7	29	$56,708
2012	$2.2	46.6	13	$48,146

2013	$12.0	260.9	17	$45,914
2014	$99.7	902.2	49	$110,509

District, Staff Report, 2-24, March 6, 2015, *available at* http://www.aqmd.gov/docs/default-source/Agendas/Governing-Board/2015/2015-mar6-029.pdf?sfvrsn=2.

The claims of industry lobbyists that the IYB credits are appropriately priced are not true. In fact, like the short term credits, these credits are exceptionally low. Even with a more than doubling of the IYB prices in 2014 compared to 2013, these credits are only 18% of the $609,187 cost established by the District pursuant to section 39616(f) of the California Health & Safety Code, which is set to ensure credit prices do not go too high. That the failure of these IYB credits to even approach 1/5 of the District's ceiling for credit costs just bolsters the excessive number of credits in the NOx RECLAIM system. Overall, the evidence conclusively suggests that the credits are not priced correctly to push for pollution reductions at a level commensurate with what command and control would achieve, which is borne out in the District's BARCT assessments.

VI. The Shave Approach Must Ensure Reductions from Refineries and Powerplants.

The evidence presented by the District in this rulemaking indicates that refineries have used the NOx RECLAIM system as a shield from actually installing pollution control equipment like Selective Catalytic Reduction ("SCR"). Given this past behavior, we suggest that the best path forward is that refineries be taken out of the NOx RECLAIM program and be required to install pollution control equipment.

If this cannot happen, we support the shave approach number 4 on slide 2 of the Staff Presentation, which focuses on large emitters like refineries and natural gas powerplants. Absent removing those facilities unwilling to install pollution controls, this methodology appears to be the most sound approach to allocating the shave of those presented at the June 4, 2015 working group meeting.

Overall, we are deeply committed to ensuring stationary sources clean up harmful NOx emissions in the South Coast. As it stands now, the NOx RECLAIM program has failed to spur adoption of available pollution technologies for many large facilities, and has accordingly failed to adequately reduce NOx emissions. In addition, it has continued to allow high NOx emissions in the disproportionately impacted neighborhoods near refineries and powerplants, raising substantial environmental justice issues. Thus it has dramatically displayed one of the major flaws of a trading system.

We therefore support efforts to retool the program, but urge SCAQMD to do so in a way that meets the urgent need of South Coast residents for clean air and clean energy.

Please do not hesitate to contact us if you have questions.

Sincerely,

Adriano L. Martinez

Adrian Martinez
Elizabeth Forsyth
Earthjustice

Bahram Fazeli
Communities for a Better Environment

David Pettit
Natural Resources Defense Council

Evan Gillespie
Sierra Club

From: Arnie.Smith@Fluor.com
Sent: Tuesday, August 11, 2015 2:16 PM
To: Kevin Orellana
Subject: Re: **SAVE THE DATE** SCAQMD NOx RECLAIM Working Group Meeting
Attachments: AACE_CLASSIFICATION_SYSTEM.pdf

Hi Kevin -

I wanted to share with you this document produced by the Association for the Advancement of Cost Estimating (AACE):

This document highlights the deliverables generated in a gated/phased project development and the corresponding estimate detail and accuracy expected. This is followed by **all** major refining and chemical companies when appraising, selecting, and defining projects for internal funding or external financing. **All** of the major EPCs follow process this as well. Fluor and many other EPCs - and the operating companies - have developed proprietary design manuals that address gated process development and we all follow these very rigorously.

So how does this apply to a NOx RECLAIM Program?

For each potential project, a screening level study estimate (Class 5) is developed for each possible solution for a heater's NOx emissions, for example. Screening whether (1) newer/better burners would be a good choice for NOx mitigation, whether (2) improving the refinery fuel gas for lower NOx generation due to heavy hydrocarbon removal or hydrogen removal, whether (3) improved SCR catalysts would be effective, whether (4) new and/or larger SCR systems are required, or whether (5) the heater should be replaced altogether.

The same would apply to FCC regenerator emissions, but from a slightly smaller list of technical choices.

A variation would apply to sulfur plant incinerators with the caveat that the mitigation system cannot interfere with H_2S destruction during an emergency release.

Following a positive outcome of the screening level study, a more detailed look is undertaken to better define the scope and improve the cost estimate. This estimate is usually an equipment factored or Class 4 estimate.

Following a positive outcome of the more detailed study, the refiner would receive internal funding for a Front End Engineering Design effort, which is of sufficient detail and completeness that external financing could be sought or an internal AFE is pursued. The decision to proceed following a FEED effort is serious since it will involve equipment and construction commodity purchased.

With external financing or an internal AFE, the project can now proceed into the detailed design, procurement, and construction effort.

All this takes time:

- Studies take from weeks to several months to complete, depending on the scope of the problem.
- FEEDs tend to take 6 to 12 months, depending on the project complexity and the impacts to offsites and utility systems.
- EPC is usually 18 to 30 months when new equipment is involved and will depend greatly on the project complexity and its impacts on other systems in the refinery.

In between each of the steps is a review and approval period by the client - likely 1 to 3 months, depending on project complexity and the financial analysis required to move forward.

This disciplined decision making approach is driven by refining being a "commodity" business and one that is extremely capital intensive. Shortcuts do not save time or money. An incomplete technology assessment or rushed project development can lead to regretful choices and inadequate mitigation.

At this point, we are probably one to two months away from having finalized NOx RECLAIM rules. Then, we are only another two months from the beginning of the first compliance year. There will be inadequate time for project development with any results in 2016/2017 - even for simpler scopes like burner replacements in existing heaters or catalyst upgrades in existing SCRs. But, new scrubbers or new SCRs would not be able to provide any mitigation benefit until 2018/2019.

The ongoing SOx RECLAIM Program had a gap of 26 months from the end of rule-making to the beginning of compliance - which would allow for some mitigation to be realized in the first compliance year. A three year gap would have insured an even stronger result.

A three year gap between rule-making and the first compliance year for NOx RECLAIM would have provided a better start for a real NOx reduction.

I am available anytime if you wish to discuss this further.

Thanks and best regards -

Arnie

Arnie Smith | **Fluor** | Executive Director, Process Technology | 3 Polaris Way, Aliso Viejo, CA 92698 | Office: +1 949.349.2231 Mobile: +1 949.322.6985 |
Arnie.Smith@Fluor.com

From: Karl Lany <klany@montrose-env.com>
Sent: Thursday, August 20, 2015 10:58 PM
To: Joe Cassmassi
Cc: Kevin Orellana; Jill Whynot; Gary Quinn
Subject: PAR 2002 RECLAIM and Rule 1146.2 Boilers (Rule 219 exempt)
Attachments: Karl Lany.vcf

Thanks for taking the steps you have to accommodate Rule 219 boiler technology into the proposed RECLAIM amendments. After giving the concept more consideration, I continue to question the proposed requirement that such boilers be subject to testing requirements in order to qualify for RECLAIM reporting factors that reflects certification standards.

Several people at yesterday's meeting raised concerns about the need for, and practicality of, such tests (cost, the presence of certification data, and the way in which certification data supports SIP credit). SCAQMD's position is that certification is for a family of boilers or boiler models, rather than each individual boiler. I understand that concept because of my experience with diesel engine certification programs. There are many parallels that I expect to exist and those parallels lead one to shy away from a testing requirement.

Even though boilers may be certified in groupings, if the boiler program is anything at all like the engine certification program, those groupings are based upon similarity of the equipment, combustion technology and the reasonable expectation that the environmental performance of the lead device truly reflects the environmental performance of the entire family of devices. It seems to me that groups of boilers being certified have very few technological variables. In fact, Rule 1146.2 requires certification based upon each boiler model, which appears to be more restrictive than the engine certification program which includes many different engine ratings and applications in a single family.

As we debate the need for small boiler testing, we should pay close attention to the equity of SCAQMD policy, relative to other certified equipment such as diesel emergency engines that are brought into the RECLAIM program. I recognize I am comparing process units that go through district permitting with Rule 219 permit exempt units, but the comparison is valid because the technology analysis performed by SCAQMD when permitting diesel emergency engines is rather simple.

SCAQMD makes all NSR determinations, including BACT and offset, for certified emergency engines based upon engine certification standards unless the applicant proposes unit-specific certified rates or manufacturer data. SCAQMD does not question the legitimacy of EPA or CARB's certification. Instead SCAQMD makes a very basic determination of the engine certification status and the emission rates to which the engine is certified. SCAQMD then uses the certification status to determine NSR compliance. Then, because Rule 2002 allows, SCAQMD uses the certification standard to determine a RFECLAIM process unit emission factor. The entire SCAQMD program for certified diesel engines rests upon certification standards and excludes any emissions testing. It makes sense that the benefits of certification (exclusion from unnecessary emissions tests) that are extended to process unit diesel engines in RECLAIM would also be extended permit exempt natural gas boilers that arte subjected to a similar certification program.

I sincerely hope that SCAQMD reconsiders its proposed testing requirements for Rule 219 boilers in RECLAIM and instead provides a more practical solution that reflects the legitimacy of its boiler certification program I'm always happy to discuss further at your convenience.

Thanks.

MONTROSE
ENVIRONMENTAL

Karl A. Lany
Senior Vice President
Regulatory Compliance Services
SCEC Air Quality Specialists
an affiliate of Montrose Environmental Group, Inc.
1631 St. Andrew Place, Santa Ana, CA 92705
T: 714.282.8240 | M: 714.376.6531
klany@montrose-env.com
www.montrose-env.com

From: Piantka, George [mailto:George.Piantka@nrg.com]
Sent: Friday, August 14, 2015 4:55 PM
To: Jill Whynot; Joe Cassmassi
Subject: RE: RECLAIM Rulemaking Follow up

Hello Jill and Joe,

I appreciate the time you spent with me last month. I am unclear whether I will be able to make the August 19 RECLAIM Working Group meeting, but nonetheless, we continue to be engaged with the developments of the rulemaking/shave. I have a couple points to consider. I am not considering this formal written comments; just some follow up thoughts. I can give you a call or we can discuss at the August 19 meeting if I can make it.

1. In Rule 2005, will there be proposed language to address annual holding limit requirements for a facility like Walnut Creek. I did not see it, unless I missed it.
2. During our meeting, I may have understated the financial impact to a new facility like Walnut Creek that is different than an existing RECLAIM facility or new plant at an existing RECLAIM facility. In satisfying NSR (unlike a legacy RECLAIM facility), we purchased IYB Cycle 1 and 2 RTCs from the market. Demonstration that we satisfied the RTCs for annual NOx PTE was not only necessary for the Permit to Construct and annual Permit to Operate but also for the financing of the WCEP. We would now represent that the asset has lost the equivalent of 47% of its NOx IYB RTCs at the current rate of say $115/lb-yr and address the means to which we can demonstrate our continued holding and/or access to these RTC for the lenders. While not obvious, the financial implications are different than a facility that has relied on an existing RECLAIM account or the ability to reconcile its emissions for the respective year. It is the difference between losing the unrealized value of IYB RTCs in a legacy RECLAIM account versus the purchase, shave and possible replacement of them at the new market condition (or from the Adjustment Account?) to meet its PTE. This is one of the reasons why we believe WCEP should be exempt from the shave. More food for thought.
3. Any concern about challenges to removal of the annual holding limit requirement by the environmental community?

Thanks for the time. And we can discuss these thoughts soon.

Best Regards,

George Piantka, PE

Sr. Director, Regulatory Environmental Services
NRG Energy, Inc.
5790 Fleet Street, Suite 200
Carlsbad, CA 92008
760.710.2156 office
760.707.6833 mobile
george.piantka@nrg.com

From: Jill Whynot [mailto:JWhynot@aqmd.gov]
Sent: Monday, July 20, 2015 10:28 AM
To: Piantka, George
Cc: Joe Cassmassi
Subject: Re: RECLAIM Rulemaking Follow up

George
kid and I can meet at 8:30 tomorrow morning if that would work for you. Call my number and we can let you know what meeting room.
Jill

Sent from my iPhone

On Jul 19, 2015, at 6:47 PM, Piantka, George <George.Piantka@nrg.com> wrote:

> Hello Jill,
>
> Thanks for discussing the proposed RTC shave and more specifically the Walnut Creek Energy Park site – we have annual holding requirements for new equipment (5 LMS 100 gas turbines) that are BACT. Will you have an opportunity to discuss further on Tuesday July 21. I could come in to the District in the morning, before I have to leave for Santa Barbara for a late afternoon meeting. I will unfortunately miss the July 22 workshop meeting, but will have someone monitor the meeting on NRG's behalf.
>
> George Piantka, PE
> Director, Regulatory Environmental Services
> NRG Energy, Inc.
> 5790 Fleet Street, Suite 200
> Carlsbad, CA 92008
> 760.710.2156 office
> 760.707.6833 mobile
> george.piantka@nrg.com

From: Casey, Chuck <CCasey@riversideca.gov>
Sent: Thursday, September 24, 2015 1:20 PM
To: Kevin Orellana
Cc: Karl Lany; Perez, James M.; Joel Lepoutre; Feragen, Wayne; Manny Robledo; Marnie Dorsz (mdorsz@montrose-env.com); Wright, Jeffrey
Subject: bases for inclusion on Top 90% of RTC Holder list
Attachments: WHEELABRATOR NORWALK ENERGY CO INC 51620.pdf; ALTAGAS POMONA ENERGY INC 176708.pdf; CARSON COGENERATION COMPANY 118406.pdf; CORONA ENERGY PARTNERS, LTD 68042.pdf; HARBOR COGENERATION CO, LLC 156741.pdf; NP COGEN INC 112853.pdf; OLS ENERGY-CHINO 47781.pdf; RegXX Nox shave list July 2015.pdf; SO CAL EDISON CO 4477.pdf; THUMS LONG BEACH 800330.pdf

Kevin,
On behalf of the City of Riverside, City of Anaheim and City of Colton, thank you for your time yesterday regarding an audit of the Preliminary Draft Report – NOx RECLAIM July 21, 2015 Table U.1 "*List of 65 Affected Facilities and Investors.*" The draft report states "*Additionally, all power plants would be included in this option*." (pg 210) but in fact all power plants are NOT included on table U.1.

Attached are the Facilities' "NOx Information" sheets from the AQMD website which appear to hold RTCs and are "power plants" therefore it's a assumed, as per your draft report, would be included on the list but in fact are not. The attachments include power plants such Corona Energy Partners, Wheelabrator Norwalk Energy Co, OLS Energy – CHINO, Carson Cogeneration Company, NP Cogen Inc, Thumbs Long Beach, Harbor Cogeneration Co, and Altagas Pomona Energy inc.

You and I covered a wide range of thoughts yesterday including; ALL power plants are on the list, cogeneration facilities are excluded from the list, "new" power plants are on the list, companies without NSR requirements are excluded, and power plants without any RTCs are not on the list. But in each of these cases I showed how your list contradicts the statement.

For example, you said the list may not include cogeneration facilities even though one of my facilities (facility ID 164204) is on the list and is a cogeneration. Additionally, your familiar with the inclusion of power plants (facility ID 132191 and 132192 for example) with zero RTCs who are on the U.1 list.

In summary, the list as provided in table U.1 needs to be audited with a full explanation of who is included or excluded and the reason for each. The NOx shave percentage adjusted for non-refinery RTC holders' weighted reduction, currently 47%, would require adjustment if the list changes.

Thank you. Please let me know if you have any questions,

Chuck Casey
Utility Generation Manager
Riverside Public Utilities
5901 Payton Ave
Riverside, CA 92504
951.710.5010 direct
909.376.9069 cell
951.710.5040 fax
ccasey@riversideca.gov

Mr. Joe Cassmassi

Los Angeles Department of Water & Power

August 14, 2015

Philip M. Fine, Ph.D., Deputy Executive Officer
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

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Dear Dr. Fine:

Subject: Los Angeles Department of Water & Power's (LADWP) Comments on Proposed Amendments to Regulation XX – Regional Clean Air Incentives Market (RECLAIM) NOx RECLAIM

The LADWP appreciates the opportunity to provide comments on the proposed amendments to Regulation XX – NOx RECLAIM and its accompanying Preliminary Draft Staff Report. LADWP remains committed to working with South Coast Air Quality Management District (SCAQMD) to further develop efficient and effective policies to reduce NOx emissions from RECLAIM facilities in order to meet the federal ozone standards in the South Coast Air Basin.

Serving approximately 1.4 million customers in Los Angeles with a generating capacity of over 7,300 megawatts, LADWP is the largest municipal electric utility in the nation, and the third largest electric utility in California. LADWP is a vertically integrated utility, owning and operating a diverse portfolio of generation, transmission, and distribution assets spanning several states.

All of LADWP's generating units are equipped with Best Available Retrofit Control Technology (BARCT) or Best Available Control Technology (BACT) and have reduced NOx emissions by 90 percent. As part of its modernization efforts, since the 1990s, LADWP has been replacing its existing, less efficient utility boilers in the South Coast Air Basin with new, state-of-the-art combined-cycle and simple cycle turbine systems equipped with selective catalytic reduction technology to minimize NOx emissions. During this modernization process, LADWP's generating facilities have been subject to New Source Review and are equipped with BACT.

LADWP also continues to make unprecedented investments in renewable energy resources, energy efficiency and transportation electrification to improve the

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environment. LADWP is on track to meet 33 percent of its energy sales from renewable energy resources by 2020, has a goal to achieve 15 percent energy savings by 2020, and is continuing to implement programs to support the electrification of the transportation sector to reduce greenhouse gases and criteria pollutants, including NOx, and as a potential solution to absorb over-generation from solar renewable sources.

LADWP's provides comments on SCAQMD's proposed regulatory language and draft preliminary draft staff report below. In addition, LADWP offers a simpler alternate regulatory approach (Pgs. 10 through 14) for the Power Producing Facility sector that is structured to support clean generation and renewable energy while enabling the sector to meet native load and reliably operate.

Comments on the Proposed Amendments to Regulation XX – Regional Clean Air Incentives Market (RECLAIM)

1) Proposed Amended Rule 2002(f) – Annual Allocations for NOx and SOx and Adjustments to RTC Holdings

   a) LADWP is generally supportive of SCAQMD's inclusion of non-tradable RTCs in a Facility Permit Holder's RECLAIM facility account. However, LADWP believes that the current proposed mechanism for accessing the RTCs in a facility's non-tradable account would be costly and inequitably treats Power Producing Facilities that are operating at NOx BARCT levels.

      The proposed rule contains a two-step process before the non-tradable/non-usable RTCs can be converted to tradable/usable RTCs. First, the 12-month rolling average RTC price for all trades (with the exception of transactions at no price or RTC swap transactions) must exceed $15,000 per ton. Second, the SCAQMD Executive Officer would be required to report to the Governing Board at a Board Meeting on the RTC market price. Only upon Board determination that the price threshold of $15,000 per ton was exceeded would the non-tradable RTCs be converted to tradable and usable RTCs. LADWP recommends an alternative approach applicable to Power Producing Facilities such that the non-tradable/non-usable RTCs continue to be deemed non-tradable but *usable* for compliance *without* the price threshold trigger for the following reasons: 18-1

      - All of LADWP's generating facilities have been retrofitted with selective catalytic reduction technology (BARCT/BACT) and have reduced NOx emissions by 90 percent. Thus, LADWP has implemented all feasible NOx controls on-site to control its NOx emissions to the maximum extent feasible.

- As provided in the Los Angeles City Charter, LADWP has the obligation and duty to serve its native load customers. With SCAQMD's proposed 47 percent shave in current RTC holdings, if LADWP were to be short of RTCs, the only compliance option would be to purchase (if available) RTCs at the market price – at whatever that price happens to be. Reducing electricity production at LADWP's Los Angeles basin generating facilities may likely not be an option due to the following operational constraints and needs:
    - Transmission constraints
    - Need for local dispatchable generation to support local renewables
    - Certain minimum amounts of inertia in-basin that are required to import out-of-basin generation
    - "Reliability Must Run" generation that is needed in-basin

18-1 cont

- Although widespread electrification of the transportation sector would result in a *significant net decrease in NOx* emissions in the South Coast Air Basin, there would be a relatively minor increase in NOx emissions at LADWP's generating facilities due to increased electricity demand.
    - SCAQMD, as noted in its 2016 Air Quality Management Plan draft white papers, has stated that there is a need to expand zero-emission technologies in the transportation sector for the South Coast Air Basin to attain the 8-hour ozone standards in 2023 and 2032.
    - The SCAQMD's draft *Residential and Commercial Energy 2016 AQMP* white paper states, "A rough estimate of the NOx emission resulting from upstream power plants providing electricity to the residential and commercial sectors is an additional 1.4 tons per day." This increase in NOx does not include the impacts of electrification of other sectors such as the Goods Movement sector.
    - Having to procure RTCs on the open market to meet native load until the price threshold of $15,000 per ton is reached after investing over

two billion dollars on new advanced gas turbine technology control technology could result in significant additional costs for LADWP.

- These additional costs would likely be, by far, in excess of the proposed $15,000 per ton threshold based on our experience and information in SCAQMD's Annual RECLAIM Report.[1] In particular, RECLAIM RTC prices can be volatile and the market price of RTCs can be significantly high by the time the $15,000 per ton 12-month rolling average price is reached. For example, the average price 1999 NOx RTCs traded in 2000 (1999 cycle 2 RTCs which are valid from July 1, 1999 to June 30, 2000) was $15,369 per ton although 1999 cycle 2 NOx RTCs transacted at significantly higher prices (e.g. $70,000 per ton in the summer of 2000). The average price for NOx RTCs for compliance year 2000 RTCs traded during 2000 increased to $45,609 per ton although there were transactions at the $100,000 per ton level. 18-1 cont.

Thus, the imposition of these incremental costs does not represent an efficient way to achieve the additional NOx reductions needed for meeting the air quality goals in the air basin. In fact, the proposal's process would penalize the Power Producing Facilities which have met NOx BARCT requirements and are making investments in energy efficiency, demand response, energy storage, renewable energy and electric transportation to help meet California's environmental goals as well as help attain the federal ozone standard.

As an alternative to address this concern, LADWP recommends that the non-tradable/non-usable RTCs be deemed non-tradable/usable RTCs such that they are available for Power Producing Facility compliance with NOx RECLAIM. There would be no need for the non-tradable RTCs to be tradable as they would be used strictly for compliance purposes by the affected Power Producing Facility to which the non-tradable RTCs would be allocated. Thus, Power Producing Facilities at BARCT levels would not be subject to the provisions of Rule 2002(f)(D) through (I). To summarize, LADWP would only use the non-tradable RTCs for compliance purposes and allocated tradable RTCs would be used first for compliance and never sold to another electric utility or other entity.

LADWP recommends the addition of the following subparagraph Rule 2002(f)(1)(G) with proposed subparagraphs (G) through (T) renumbered accordingly to (H) to (U):

[1] Annual RECLAIM Audit Report for the 1999 Compliance Year, March 16, 2001

Power Producing Facility Permit Holders listed in Table 8 will obtain tradable/usable NOx RTCs and non-tradable/usable NOx RTCs as listed in subparagraph (f)(1)(C) and shall not be subject to subparagraphs (f)(1)(D) through (F) and (H) through (J). In this subparagraph, a Facility Permit Holder may use its non-tradable/usable NOx RTCs for a compliance year so long as the tradable NOx RTCs were not sold or transferred to another facility not under common ownership during that compliance year. 18-1 cont.

b) Rule 2002(f)(1)(J) states, "The 2022 NOx RTC adjustment factors shall not be submitted for inclusion into the State Implementation Plan until 12-months after the adjustments have been in effect for one full compliance year." For the 2011 compliance year, SCAQMD submitted the non-tradable/non-usable RTCs for 2011 and all years after to the State Implementation Plan such that RECLAIM facility permit holders' non-tradable RTCs were zeroed out for 2011 and all years thereafter. As mentioned previously, LADWP has an obligation to serve its native load customers and anticipates increased electricity demand in the future due to electrification of the transportation sector. Part of serving native load reliably entails having its in-basin generating facilities available to integrate intermittent renewable energy. LADWP recommends that subparagraph (f)(1)(J) not apply to power producing facilities as they are at BARCT levels and SCAQMD's analysis concluded that there is no new BARCT for the power producing facility sector. Recommended language is in underline/strikeout format: 18-2

> ...The 2022 NOx RTC adjustment factors shall not be submitted for inclusion into the State Implementation Plan until 12-months after the adjustments have been in effect for one full compliance year.
> At the end of each compliance year reconciliation period from 2022 and each year thereafter, the power producing facility shall surrender unused non-tradable RTCs to SCAQMD for inclusion into the State Implementation Plan.

c) Proposed Rule 2002(f)(4) and (5) creates an Adjustment Account for Power Producing Facilities for the purpose of complying with the RECLAIM New Source Review requirements in Rule 2005(f) and compliance with annual emissions. The Power Producing Facilities' ability to access RTCs in the Adjustment Account for the purposes of compliance is constrained such that the RTCs would be released only under the following conditions – the Governor declared a State of Emergency and SCAQMD Executive Officer determination on the impact the State of Emergency has on the RECLAIM program. The suggested language 18-3 also states that the available RTCs for Power Producing Facilities to fulfill compliance with RECLAIM would be limited to the RTCs remaining in the Adjustment Account after Power Producing Facilities' New Source Review offset needs are fulfilled. This introduces great uncertainty whether there will be sufficient RTCs in the Adjustment Account.

LADWP is subject to mandated and enforceable North American Electric Reliability Corporation (NERC) standards which ensure reliability of the bulk power system in North America. LADWP is concerned with respect to its ability to both comply with the reliability standards and the RECLAIM program using the mechanism as proposed. Compliance with NERC standards requires a Power Producing Facility such as LADWP's power plants to respond quickly, as soon as fifteen minutes. Waiting for the Governor to declare a State of Emergency and for the SCAQMD Executive Officer to determine the impacts RECLAIM has on the emergency jeopardizes LADWP's compliance with NERC standards and its ability to reliably deliver electricity to its customers. 18-3 cont.

NERC Reliability Standard EOP-002-3.1 (Enclosure 1) ensures that Reliability Coordinators and Balancing Authorities such as LADWP are prepared for capacity and energy emergencies. Under this reliability standard, the Reliability Coordinator has the authority to initiate an Energy Emergency Alert, as defined, to mitigate the emergency condition.

There are also instances when LADWP, as a balancing authority, must have its Los Angeles basin generating units available for operation to meet NERC standards; if the units are constrained by the unavailability of RTCs, LADWP may face noncompliance with additional NERC standards. For example, there is operational variability in LADWP's current fleet of renewable resources. By late 2016, LADWP will be subject to as much as a 1000 MW sudden drop in output from renewable resources (e.g. due to cloud cover at solar facilities). In order to comply with NERC Reliability Standard BAL-001-2 (which replaces BAL-001-1 on July 1, 2016), LADWP must respond to this variability by dispatching its local generation facilities. That is, as the renewable production (e.g. wind, solar) suddenly decreases, local generation must be rapidly increased, and vice versa. Starting in July 1, 2016, BAL-001-2 (Enclosure 2) will allow only 30 minutes for LADWP to respond to the renewable variability so its Los Angeles basin generating units will be critical resources planned to be used for compliance with this reliability standard.

Also, if LADWP lost a conventional resource, it would have only fifteen minutes to bring up remaining generation to replace the loss. If generation from LADWP's pumped storage hydroelectric generating facility is unavailable, Los Angeles basin generating units would need to come on-line within this fifteen minute time period.

NERC Reliability Standard FAC-011-2, Requirement 2.2 and LADWP's Transmission Reliability Criteria (Enclosure 3) govern transmission operations with respect to system operating limits. Systems such as LADWP's must demonstrate transient, dynamic and voltage stability, facilities must be in operating within their Facility Ratings and within their thermal, voltage and stability limits such that cascading or uncontrolled separation does not occur. LADWP's local transmission system cannot meet this requirement in the absence of local Los Angeles basin generation. Reliability Must Run local generation is required to be either on-line or available to be quickly put on-line to meet the requirement. The only alternative to increasing or turning on the additional generation to meet this reliability requirement would be to shed customer load if insufficient RTCs are unavailable.

18-3 cont.

LADWP recommends the following language in underline/strikeout format:

> During a State of Emergency as declared by the Governor or Reliability Coordinator, the Executive Officer will allow Power Producing Facilities access to Adjustment Account RTCs for the purpose of compliance with the annual emissions. ~~These available RTCs will be limited to those that are in excess of those specified for use in paragraph (f)(4).~~ The amount and distribution of the RTCs will be determined by the Power Producing Facility ~~Executive Officer~~ based on the impact that the State of Emergency has on compliance with North American Electric Reliability Corporation standards and the RECLAIM program.
>
> "Reliability Coordinator" means the entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System as defined in the North American Electric Reliability Corporation Glossary."

The draft preliminary staff report states that the Adjustment Account RTCs "would be derived from the proposed programmatic 14 tons per day in NOx reductions." In previous NOx RECLAIM working group meetings, SCAQMD stated that Adjustment Account RTCs derived from the 14 tons per day NOx reductions would not be submitted to the State Implementation Plan. LADWP recommends that the preliminary staff report explicitly state that the Adjustment Account RTCs would not be submitted to the State Implementation Plan. 18-3 cont.

2) Table 6 RECLAIM NOx 2021 Ending Emission Factors
LADWP recommends that the description "Gas Turbines" under the Nitrogen Oxide Basic Equipment column be amended to read "Refinery Gas Turbines" to distinguish that the Power Producing Facility gas turbines are not subject to BARCT in this rule amendment process. 18-4

3) Proposed Amended Rule 2012 – Appendix A: Protocol for Monitoring, Reporting and Recordkeeping of Oxides of Nitrogen (NOx) – Attachment C – Quality Assurance and Quality Control Procedures

a) Semi-Annual Assessments
The proposal's 14 unit operating day time window for conducting a RATA in the case where a major source is physically incapable of being operated is insufficient at LADWP generating facilities when a unit is inoperable for an extended period of time. The draft preliminary staff report includes additional information by stating that the "proposed 14 operating day RATA postponement for unforeseen equipment failure would apply separately for each unrelated, independent event." LADWP supports the clarification in the draft staff report and LADWP recommends that this clarification be reflected in the rule language. LADWP offers the following added language to subparagraph B.2.c after clause B.2.c.ii.: 18-5

> The 14 unit operating day RATA postponement for unforeseen equipment failure applies separately for each unrelated, independent event.

Subparagraph B.2.d. - Due Date for RATAs

LADWP appreciates SCAQMD's efforts to consistently treat facilities under contract with the California Independent System Operator (CalISO) as well as electric generating facilities owned and operated by municipalities that have difficulties in meeting RATA deadlines because their equipment does not operate long enough, or not at all, to conduct a RATA in the quarter in which the RATA is due. 18-6

The proposed rule language states that the electric generating facility can postpone the RATA if it was scheduled to be performed during the first 45 days of the calendar quarter in which the assessment is due. This means that if the RATA was scheduled during the second 45 days of the calendar quarter, then the RATA cannot be postponed. The draft preliminary staff report does not provide an explanation as to why the RATA must be scheduled the first 45 days of the calendar quarter. There could be situations where a source tester is not available or a unit has not been capable of operating until the second 45 days of the calendar quarter. Thus, the proposed requirement to schedule the RATA during the first 45 days of the calendar quarter does not resolve the availability issues. In both cases, the facilities would need to schedule the RATA in the second 45 days of the calendar quarter to meet compliance. Therefore, so long as the RATA is performed within the required timeframe, facilities should be able to have flexibility with respect to schedule of a RATA. 18-6 cont.

LADWP recommends the following language changes to Clause B.2.d.i. in underline/strikeout format:

> The semi-annual or annual assessment was scheduled to be performed during ~~the first 45 days of~~ the calendar quarter in which the assessment was due

b) Clauses B.2.c.i. and ii – Proposed requirement to disconnect and flange the fuel feed lines when a unit is physically incapable of operation and maintain operational fuel meters introduces health and safety issues, compromises structural integrity of the pipelines and would be costly at steam generating units scheduled to be replaced.

The proposed language requires that:

i. All fuel lines to the major source are disconnected and either flanges or equivalent sealing devices are placed at both ends of the disconnected lines

ii. The fuel meter(s) for the disconnected fuel feed lines are maintained and operated and associated fuel records showing no fuel flow are maintained on site 18-7

Over the next decade, LADWP's steam generating units will be repowered with a combination of more efficient combined cycle units and quick start combustion turbines. These steam generating units have been constructed such that there are no pipe segments of the fuel lines that could be readily removed. To do so, the lines must be cut at two locations and a removable spool would need to be fabricated at significant costs in order to further prove that a unit is inoperable. Also, this requirement would unnecessarily create a health and safety risk as the fuel lines are insulated with asbestos-containing materials (ACM) at two of LADWP's generating stations. The intact ACM would have to be removed to gain access to the fuel pipelines which would be against the general plant operating and maintenance practice and EPA's recommendation to leave intact ACM alone.

LADWP surveyed all of its generating units that are currently in operation. The survey presented technical difficulties of creating air gaps by cutting into the fuel lines or removing certain piping equipment including valves, strainers, or meters to create the gaps. LADWP has considered alternative methods to pipe cutting and removing equipment such as opening access to the piping and equipment. 18-7 cont.

LADWP recommends the following changes to Clauses B.2.c.i. and ii:

i. All fuel lines to the major source are disconnected <u>or opened</u> and either flanges or equivalent sealing devices are placed at both ends of the disconnected <u>or opened</u> lines

ii. The fuel meter(s) for the disconnected <u>or opened</u> fuel feed lines are maintained and operated and associated fuel records showing no fuel flow are maintained on site

<u>Alternative Regulatory Approach</u>

As discussed above, reducing NOx emissions at in-basin plants may not be feasible due to the fact that the only way to achieve additional reductions from these well-controlled plants is by reducing their generation output. As discussed above, reducing the utilization of in-basin gas-fired generation is not a viable option given the essential role these units play in ensuring a reliable supply of electricity in the basin.

Furthermore, an essential part of the strategy to reduce NOx emission levels in the South Coast Air Basin will be to electrify the transportation sector and other major source categories of NOx emissions. Specifically, the increased electricity generation will result in small increases in NOx emissions by affected electric generating units, but those emission increases will be more than offset by substantial NOx emission reductions achieved by the newly electrified sources. Electrification of even a portion of these sources will result in substantial overall net NOx emission reductions in the SCAB region. 18-8

LADWP has identified a possible regulatory credit mechanism that could be developed to ensure that affected power plant facilities would not be penalized for increased NOx emissions resulting from an increased demand in electricity due to native load needs and increased transportation electrification. Such a crediting mechanism would incentivize the development and implementation of renewable energy and transportation electrification. This approach would be consistent with SCAQMD's position as described in its comment letter to U.S. Environmental Protection Agency (EPA), which states that "It is important that the 111(d) regulation recognizes California's unique situation and does not hinder the introduction of additional renewable energy generation." "The proposed regulation must be structured to support clean generation and renewable energy."[2]

In addition, this proposed regulatory mechanism is consistent with the federal Clean Air Act framework for achieving expeditiously the air quality goals established under the Act. Most importantly, the establishment of a mechanism to enable the achievement of substantial overall net NOx reductions in the South Coast Air Basin region will provide an effective strategy for the SCAQMD to meet its "reasonable further progress" reduction goals for the current 2008 ozone standard as well as any additional NOx reductions that may be necessary for meeting upcoming more stringent ozone standard. 18-8 cont.

The discussion below describes how a similar credit mechanism might be developed to ensure affected electric generating facilities had sufficient RTCs in the event that SCAQMD decides to impose an across-the-board RTC reduction on all affected RECLAIM facilities.

1. <u>Quantify the amount of RTCs needed to support native load and transportation electrification</u>

   The first step of the process would involve each affected electric utility quantifying the amount of NOx RTCs that it would need to cover its projected NOx emissions. The process for calculating each unit's generation level would be based on the amount of electricity that the utility would need to

[2] November 26, 2014 letter to EPA regarding *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units – Proposed Rule*

generate in order to meet its native load, along with the expected electricity demand increase resulting from the transportation electrification. This determination would likely be based on an Integrated Resource Plan (IRP) or similar process for estimating the utility's native load and the expected transportation electrification for the next 10 to 15 years. With respect to transportation electrification, the utility would need to work with the SCAQMD and the California Air Resources Board (CARB) to estimate the level of transportation electrification in the basin in order to determine the resulting increased electricity demand.

Based on this quantification of future electricity demand and NOx emissions (which could be updated on an annual basis), the SCAQMD would allow the affected electric utilities to hold in their accounts sufficient number of NOx RTCs to cover their emissions on a system-wide basis. This amount of each utility's RTCs would not be deducted from its RECLAIM account and consequently remain available for use in meeting its RECLAIM credit-holding requirements.

2. Determine the amount of RTCs used for electrification of major NOx emission source categories 18-8 cont

Each utility sector would quantify the number of RTCs that are actually used to generate electricity for electrification of mobile sources and other major NOx source categories in the South Coast Air Basin region.

In the case of electric vehicles, this quantification would be performed for each compliance year based on a method similar to CARB's Low Carbon Fuel Standard approach. A combination of meter kWh data and estimated kWh data applied to the number of EVs that a utility reports would be used to quantify the emissions due to the increase in electricity demand from electric transportation.

In the case of the other major NOx source categories, the quantification would be performed based on the estimated NOx emission reductions that would occur from mandatory electrification measures established by the CARB and SCAQMD as well as non-mandatory electrification measures and incentives that CARB, SCAQMD and electric utilities may promote.

3. Label unused RTCs designated to cover electrification as non-tradable

The RTCs that an electric utility retains based on the quantification of future electricity demand due to electrification would be put into a utility's account and labeled non-tradable. The non-tradable RTCs could be used for compliance purposes only and allocated tradable RTCs would be used first for compliance. Thus, if a utility has NOx emissions that are lower than expected such that its non-tradable RTCs are unused, the utility would not be able to sell them to entities outside of the utility's system. At the end of the reconciliation period, the utility would surrender unused non-tradable RTCs to SCAQMD for credit toward reducing NOx emissions through the RECLAIM program and meeting attainment of the ozone standard. Enclosed is a more detailed description of this regulatory approach (Enclosure 4).

State Implementation Plan crediting with respect to design of the NOx RECLAIM program to accommodate transportation electrification

18-8 cont.

There are uncertainties with respect to the level of electrification and the level of in-basin generation needed to support future renewables which creates uncertainties as to the number of RTCs that electric generating facilities would need. LADWP believes that SCAQMD has the discretion to develop its NOx RECLAIM program to accommodate such uncertainties without having to determine the exact amount of the NOx reductions upfront for SIP credit purposes. Enclosed for your review is a white paper that outlines the key elements of an emission reduction crediting mechanism that SCAQMD could use to account for and provide the appropriate emission reduction credit to electric utilities for the overall net NOx emission reductions achieved by the electrification of other source categories in order to meet its "reasonable further progress" goals under the Clean Air Act (Enclosure 5). Among other things, the paper presents the key design elements of a crediting mechanism that is modeled after approaches that EPA has developed for promoting energy efficiency and renewable energy measures under the Clean Air Act.

LADWP is ready and willing to work with SCAQMD, CARB, and EPA to explore opportunities in creating an approach to include the benefits of transportation electrification as well as support clean generation and renewable energy. Development of an EPA-recognized SIP crediting mechanism will address the regulatory uncertainty that would otherwise result from this paradigm shift and thereby encourage the implementation of policies to reduce emissions from the transportation and major source categories of emissions through electrification in the South Coast Air Basin and other urban ozone nonattainment areas.

Finally, in the NOx RECLAIM working group meeting on July 9, SCAQMD stated that resolution language would be included in this NOx RECLAIM rulemaking package to address the impacts of transportation electrification on the RECLAIM program. LADWP offers that resolution language to address this issue (Enclosure 6). 18-8 cont.

Again, LADWP appreciates the opportunity to provide comments on the NOx RECLAIM proposed amended rules and draft preliminary staff report. If you have any questions or would like additional information, please contact Ms. Jodean Giese of my staff at (213) 367-0409.

Sincerely,

Mark J. Sedlacek

Mark J. Sedlacek
Director of Environmental Affairs

JG:dms
Enclosures
c: Ms. Jill Whynot, SCAQMD
Mr. Joe Cassmassi, SCAQMD
Ms. Jodean Giese

Standard EOP-002-3.1 — Capacity and Energy Emergencies

A. Introduction

1. **Title:** **Capacity and Energy Emergencies**
2. **Number:** EOP-002-3.1
3. **Purpose:** To ensure Reliability Coordinators and Balancing Authorities are prepared for capacity and energy emergencies.
4. **Applicability**
   - **4.1.** Balancing Authorities.
   - **4.2.** Reliability Coordinators.
   - **4.3.** Load-Serving Entities.
5. **(Proposed) Effective Date:** First day of the first calendar quarter six months following applicable regulatory approval; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter six months following Board of Trustees adoption.

B. Requirements

R1. Each Balancing Authority and Reliability Coordinator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its respective area and shall exercise specific authority to alleviate capacity and energy emergencies.

R2. Each Balancing Authority shall, when required and as appropriate, take one or more actions as described in its capacity and energy emergency plan to reduce risks to the interconnected system.

R3. A Balancing Authority that is experiencing an operating capacity or energy emergency shall communicate its current and future system conditions to its Reliability Coordinator and neighboring Balancing Authorities.

R4. A Balancing Authority anticipating an operating capacity or energy emergency shall perform all actions necessary including bringing on all available generation, postponing equipment maintenance, scheduling interchange purchases in advance, and being prepared to reduce firm load.

R5. A deficient Balancing Authority shall only use the assistance provided by the Interconnection's frequency bias for the time needed to implement corrective actions. The Balancing Authority shall not unilaterally adjust generation in an attempt to return Interconnection frequency to normal beyond that supplied through frequency bias action and Interchange Schedule changes. Such unilateral adjustment may overload transmission facilities.

R6. If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. These remedies include, but are not limited to:

- **R6.1.** Loading all available generating capacity.
- **R6.2.** Deploying all available operating reserve.
- **R6.3.** Interrupting interruptible load and exports.
- **R6.4.** Requesting emergency assistance from other Balancing Authorities.
- **R6.5.** Declaring an Energy Emergency through its Reliability Coordinator; and

R6.6. Reducing load, through procedures such as public appeals, voltage reductions, curtailing interruptible loads and firm loads.

R7. Once the Balancing Authority has exhausted the steps listed in Requirement 6, or if these steps cannot be completed in sufficient time to resolve the emergency condition, the Balancing Authority shall:

R7.1. Manually shed firm load without delay to return its ACE to zero; and

R7.2. Request the Reliability Coordinator to declare an Energy Emergency Alert in accordance with Attachment 1-EOP-002 "Energy Emergency Alerts."

R8. A Reliability Coordinator that has any Balancing Authority within its Reliability Coordinator area experiencing a potential or actual Energy Emergency shall initiate an Energy Emergency Alert as detailed in Attachment 1-EOP-002 "Energy Emergency Alerts." The Reliability Coordinator shall act to mitigate the emergency condition, including a request for emergency assistance if required.

R9. When a Transmission Service Provider expects to elevate the transmission service priority of an Interchange Transaction from Priority 6 (Network Integration Transmission Service from Non-designated Resources) to Priority 7 (Network Integration Transmission Service from designated Network Resources) as permitted in its transmission tariff:

R9.1. The deficient Load-Serving Entity shall request its Reliability Coordinator to initiate an Energy Emergency Alert in accordance with Attachment 1-EOP-002 "Energy Emergency Alerts."

R9.2. The Reliability Coordinator shall submit the report to NERC for posting on the NERC Website, noting the expected total MW that may have its transmission service priority changed.

R9.3. The Reliability Coordinator shall use EEA 1 to forecast the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7.

R9.4. The Reliability Coordinator shall use EEA 2 to announce the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7.

C. Measures

M1. Each Reliability Coordinator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, job descriptions, signed agreements, authority letter signed by an appropriate officer of the company, or other equivalent evidence that will be used to confirm that it meets Requirement 1.

M2. If a Reliability Coordinator or Balancing Authority implements one or more actions described in its Capacity and Energy Emergency plan, that entity shall have and provide upon request evidence that could include but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, computer printouts or other equivalent evidence that will be used to determine if the actions it took to relieve emergency conditions were in conformance with its Capacity and Energy Emergency Plan. (Requirement 2)

M3. If a Balancing Authority experiences an operating Capacity or Energy Emergency it shall have and provide upon request evidence that could include, but is not limited to operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it met Requirement 3.

M4. The Balancing Authority shall have and provide upon request evidence (such as operator logs, work orders, E-Tags, or other evidence) that it took the actions described in R4 in response to anticipating a capacity or energy emergency.

M5. The Balancing Authority shall have and provide upon request evidence (such as operator logs, dispatch instructions, or other evidence) that it only used the assistance provided by the Interconnection frequency bias for the time needed to implement corrective actions and did not attempt to return Interconnection frequency to normal through unilateral adjustment of generation beyond that supplied through the frequency bias action and Interchange Schedule changes. (Requirement 5)

M6. The Balancing Authority shall have and provide upon request evidence (such as operator logs, dispatch instructions, or other evidence) that it took actions such as those listed in R6 to comply with CPS and DCS.

M7. The Balancing Authority shall have and provide upon request evidence (such as operator logs, voice recordings, or other evidence) that it took the actions listed in R7 when unable to resolve an emergency condition.

M8. If a Reliability Coordinator has any Balancing Authority within its Reliability Coordinator Area that has notified the Reliability Coordinator of a potential or actual Energy Emergency, the Reliability Coordinator involved in the event shall have and provide upon request evidence that could include, but is not limited to operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence to determine if it initiated an Energy Emergency Alert as specified in Requirement 8 and as detailed in Attachment 1-EOP-002 "Energy Emergency Alerts."

M9. If a Transmission Service Provider expects to elevate the transmission service priority of an Interchange Transaction from Priority 6 (Network Integration Transmission Service from Non-designated Resources) to Priority 7 (Network Integration Transmission Service from designated Network Resources), the Reliability Coordinator involved in the event shall have and provide upon request evidence that could include, but is not limited to, NERC reports, EEA reports, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if that Reliability Coordinator met Requirements 9.2, 9.3 and 9.4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Compliance Monitoring Period and Reset Timeframe

Not Applicable.

1.3. Compliance Monitoring and Enforcement Process

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

For Measure 1, each Reliability Coordinator and Balancing Authority shall keep The current in-force documents.

For Measure 2, 8 and 9 the Reliability Coordinator shall keep 90 days of historical data.

For Measure 3, 4, 5, 6, and 7 the Balancing Authority shall keep 90 days of historical data.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor.

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.5. Additional Compliance Information

None.

E. Regional Differences

None identified.

Version History

Version	[illegible]	[illegible]	[illegible]
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	September 19, 2006	Changes R7. to refer to “Requirement 6” instead of “Requirement 7”	Errata
2	November 1, 2006	Adopted by Board of Trustees	Revised
2	November 1, 2006	Corrected numbering in Section A.4. “Applicability.”	Errata
2	October 1, 2007	Added to Section 1 inadvertently omitted “4.3. Load-Serving Entities	Errata
2.1	October 29, 2008	BOT adopted errata changes; updated version number to “2.1”	Errata
2.1	May 13, 2009	FERC Approved	Revised
3	June 4, 2010	Modified to address Order No. 693 Directives contained in paragraphs 582.	Revised.
3	August 5, 2010	Adopted by NERC Board of Trustees	New
3.1	March 8, 2012	Errata adopted by Standards Committee; (Updated title of Attachment 1 and changed	Errata

		references to Attachment 1 throughout Standard from "Attachment 1-EOP-002-0 Energy Emergency Alert Levels" to "Attachment 1-EOP-002 Energy Emergency Alerts". Removed parenthetical in Requirement R9 referencing a retired Attachment in IRO-006)	
3.1	September 13, 2012	FERC Approved	Errata

Attachment 1-EOP-002
Energy Emergency Alerts

Introduction
This Attachment provides the procedures by which a Load Serving Entity can obtain capacity and energy when it has exhausted all other options and can no longer provide its customers' expected energy requirements. NERC defines this situation as an "Energy Emergency." NERC assumes that a capacity deficiency will manifest itself as an energy emergency.

The Energy Emergency Alert Procedure is initiated by the Load Serving Entity's Reliability Coordinator, who declares various Energy Emergency Alert levels as defined in Section B, "Energy Emergency Alert Levels," to provide assistance to the Load Serving Entity.

The Load Serving Entity who requests this assistance is referred to as an "Energy Deficient Entity."

NERC recognizes that Transmission Providers are subject to obligations under FERC-approved tariffs and other agreements, and nothing in these procedures should be interpreted as changing those obligations.

A. General Requirements

1. **Initiation by Reliability Coordinator.** An Energy Emergency Alert may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of a Balancing Authority, or 3) upon the request of a Load Serving Entity.

    1.1. Situations for initiating alert. An Energy Emergency Alert may be initiated for the following reasons:

    - When the Load Serving Entity is, or expects to be, unable to provide its customers' energy requirements, and has been unsuccessful in locating other systems with available resources from which to purchase, or
    - The Load Serving Entity cannot schedule the resources due to, for example, Available Transfer Capability (ATC) limitations or transmission loading relief limitations.

2. **Notification.** A Reliability Coordinator who declares an Energy Emergency Alert shall notify all Balancing Authorities and Transmission Providers in its Reliability Area. The Reliability Coordinator shall also notify all other Reliability Coordinators of the situation via the Reliability Coordinator Information System (RCIS). Additionally, conference calls between Reliability Coordinators shall be held as necessary to communicate system conditions. The Reliability Coordinator shall also notify the other Reliability Coordinators when the alert has ended.

B. Energy Emergency Alert Levels

Introduction
To ensure that all Reliability Coordinators clearly understand potential and actual energy emergencies in the Interconnection, NERC has established three levels of Energy Emergency Alerts. The Reliability Coordinators will use these terms when explaining energy emergencies to each other. An Energy Emergency Alert is an emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC reliability standards or power supply contracts.

The Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.

1. **Alert 1 — All available resources in use.**

Circumstances:

- Balancing Authority, Reserve Sharing Group, or Load Serving Entity foresees or is experiencing conditions where all available resources are committed to meet firm load, firm transactions, and reserve commitments, and is concerned about sustaining its required Operating Reserves, and

- Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

2. **Alert 2 — Load management procedures in effect.**

Circumstances:

- Balancing Authority, Reserve Sharing Group, or Load Serving Entity is no longer able to provide its customers' expected energy requirements, and is designated an Energy Deficient Entity.
- Energy Deficient Entity foresees or has implemented procedures up to, but excluding, interruption of firm load commitments. When time permits, these procedures may include, but are not limited to:
    - Public appeals to reduce demand.
    - Voltage reduction.
    - Interruption of non-firm end use loads in accordance with applicable contracts[1].
    - Demand-side management.
    - Utility load conservation measures.

During Alert 2, Reliability Coordinators, Balancing Authorities, and Energy Deficient Entities have the following responsibilities:

2.1 Notifying other Balancing Authorities and market participants. The Energy Deficient Entity shall communicate its needs to other Balancing Authorities and market participants. Upon request from the Energy Deficient Entity, the respective Reliability Coordinator shall post the declaration of the alert level along with the name of the Energy Deficient Entity and, if applicable, its Balancing Authority on the NERC website.

2.2 Declaration period. The Energy Deficient Entity shall update its Reliability Coordinator of the situation at a minimum of every hour until the Alert 2 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the NERC website as changes occur and pass this information on to the affected Reliability Coordinators, Balancing Authority, and Transmission Providers.

2.3 Sharing information on resource availability. A Balancing Authority and market participants with available resources shall immediately contact the Energy Deficient Entity. This should include the possibility of selling non-firm (recallable) energy out of available Operating Reserves. The Energy Deficient Entity shall notify the Reliability Coordinators of the results.

2.4 Evaluating and mitigating transmission limitations. The Reliability Coordinators shall review all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) and transmission loading relief procedures in effect that may limit the Energy Deficient Entity's scheduling capabilities. Where appropriate, the Reliability Coordinators shall inform

[1] For emergency, not economic, reasons.

the Transmission Providers under their purview of the pending Energy Emergency and request that they increase their ATC by actions such as restoring transmission elements that are out of service, reconfiguring their transmission system, adjusting phase angle regulator tap positions, implementing emergency operating procedures, and reviewing generation redispatch options.

2.4.1 Notification of ATC adjustments. Resulting increases in ATCs shall be simultaneously communicated to the Energy Deficient Entity and the market via posting on the appropriate OASIS websites by the Transmission Providers.

2.4.2 Availability of generation redispatch options. Available generation redispatch options shall be immediately communicated to the Energy Deficient Entity by its Reliability Coordinator.

2.4.3 Evaluating impact of current transmission loading relief events. The Reliability Coordinators shall evaluate the impact of any current transmission loading relief events on the ability to supply emergency assistance to the Energy Deficient Entity. This evaluation shall include analysis of system reliability and involve close communication among Reliability Coordinators and the Energy Deficient Entity.

2.4.4 Initiating inquiries on reevaluating SOLs and IROLs. The Reliability Coordinators shall consult with the Balancing Authorities and Transmission Providers in their Reliability Areas about the possibility of reevaluating and revising SOLs or IROLs.

2.5 Coordination of emergency responses. The Reliability Coordinator shall communicate and coordinate the implementation of emergency operating responses.

2.6 Energy Deficient Entity actions. Before declaring an Alert 3, the Energy Deficient Entity must make use of all available resources. This includes but is not limited to:

2.6.1 All available generation units are on line. All generation capable of being on line in the time frame of the emergency is on line including quick-start and peaking units, regardless of cost.

2.6.2 Purchases made regardless of cost. All firm and non-firm purchases have been made, regardless of cost.

2.6.3 Non-firm sales recalled and contractually interruptible loads and demand-side management curtailed. All non-firm sales have been recalled, contractually interruptible retail loads curtailed, and demand-side management activated within provisions of the agreements.

2.6.4 Operating Reserves. Operating reserves are being utilized such that the Energy Deficient Entity is carrying reserves below the required minimum or has initiated emergency assistance through its operating reserve sharing program.

3. Alert 3 — Firm load interruption imminent or in progress.

Circumstances:

- Balancing Authority or Load Serving Entity foresees or has implemented firm load obligation interruption. The available energy to the Energy Deficient Entity, as determined from Alert 2, is only accessible with actions taken to increase transmission transfer capabilities.

3.1 Continue actions from Alert 2. The Reliability Coordinators and the Energy Deficient Entity shall continue to take all actions initiated during Alert 2. If the emergency has not already been posted on the NERC website (see paragraph 2.1), the respective Reliability Coordinators will, at this time, post on the website information concerning the emergency.

3.2 Declaration Period. The Energy Deficient Entity shall update its Reliability Coordinator of the situation at a minimum of every hour until the Alert 3 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the NERC website as changes occur and pass this information on to the affected Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Providers.

3.3 Use of Transmission short-time limits. The Reliability Coordinators shall request the appropriate Transmission Providers within their Reliability Area to utilize available short-time transmission limits or other emergency operating procedures in order to increase transfer capabilities into the Energy Deficient Entity.

3.4 Reevaluating and revising SOLs and IROLs. The Reliability Coordinator of the Energy Deficient Entity shall evaluate the risks of revising SOLs and IROLs on the reliability of the overall transmission system. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Balancing Authority or Transmission Operator whose equipment would be affected. The resulting increases in transfer capabilities shall only be made available to the Energy Deficient Entity who has requested an Energy Emergency Alert 3 condition. SOLs and IROLs shall only be revised as long as an Alert 3 condition exists or as allowed by the Balancing Authority or Transmission Operator whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:

3.4.1 Energy Deficient Entity obligations. The deficient Balancing Authority or Load Serving Entity must agree that, upon notification from its Reliability Coordinator of the situation, it will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include load shedding.

3.4.2 Mitigation of cascading failures. The Reliability Coordinator shall use its best efforts to ensure that revising SOLs or IROLs would not result in any cascading failures within the Interconnection.

3.5 Returning to pre-emergency Operating Security Limits. Whenever energy is made available to an Energy Deficient Entity such that the transmission systems can be returned to their pre-emergency SOLs or IROLs, the Energy Deficient Entity shall notify its respective Reliability Coordinator and downgrade the alert.

3.5.1 Notification of other parties. Upon notification from the Energy Deficient Entity that an alert has been downgraded, the Reliability Coordinator shall notify the affected Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Providers that their systems can be returned to their normal limits.

3.6 Reporting. Any time an Alert 3 is declared, the Energy Deficient Entity shall submit the report enclosed in this Attachment to its respective Reliability Coordinator within two business days of downgrading or termination of the alert. Upon receiving the report, the Reliability Coordinator shall review it for completeness and immediately forward it to the NERC staff for posting on the NERC website. The Reliability Coordinator shall present this report to the Reliability Coordinator Working Group at its next scheduled meeting.

4. Alert 0 - Termination. When the Energy Deficient Entity believes it will be able to supply its customers' energy requirements, it shall request of its Reliability Coordinator that the EEA be terminated.

4.1. Notification. The Reliability Coordinator shall notify all other Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator shall also notify the affected Balancing Authorities and Transmission Operators. The Alert 0 shall also be posted on the NERC website if the original alert was so posted.

C. Energy Emergency Alert 3 Report

A Deficient Balancing Authority or Load Serving Entity declaring an Energy Emergency Alert 3 must complete the following report. Upon completion of this report, it is to be sent to the Reliability Coordinator for review within two business days of the incident.

Requesting Balancing Authority:

Entity experiencing energy deficiency (if different from Balancing Authority):

Date/Time Implemented:

Date/Time Released:

Declared Deficiency Amount (MW):

Total energy supplied by other Balancing Authority during the Alert 3 period:

Conditions that precipitated call for "Energy Deficiency Alert 3":

If "Energy Deficiency Alert 3" had not been called, would firm load be cut? If no, explain:

Explain what action was taken in each step to avoid calling for "Energy Deficiency Alert 3":

1. **All generation capable of being on line in the time frame of the energy deficiency was on line (including quick start and peaking units) without regard to cost.**

2. **All firm and nonfirm purchases were made regardless of cost.**

3. **All nonfirm sales were recalled within provisions of the sale agreement.**

4. **Interruptible load was curtailed where either advance notice restrictions were met or the interruptible load was considered part of spinning reserve.**

5. **Available load reduction programs were exercised (public appeals, voltage reductions, etc.).**

6. **Operating Reserves being utilized.**

Comments:

Reported By: **Organization:**

Title:

A. Introduction

1. **Title:** **Real Power Balancing Control Performance**
2. **Number:** **BAL-001-2**
3. **Purpose:** To control Interconnection frequency within defined limits.
4. **Applicability:**

4.1. Balancing Authority

4.1.1 A Balancing Authority receiving Overlap Regulation Service is not subject to Control Performance Standard 1 (CPS1) or Balancing Authority ACE Limit (BAAL) compliance evaluation.

4.1.2 A Balancing Authority that is a member of a Regulation Reserve Sharing Group is the Responsible Entity only in periods during which the Balancing Authority is not in active status under the applicable agreement or the governing rules for the Regulation Reserve Sharing Group.

4.2. Regulation Reserve Sharing Group

5. **(Proposed) Effective Date:**

5.1. First day of the first calendar quarter that is twelve months beyond the date that this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective the first day of the first calendar quarter that is twelve months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

B. Requirements

R1. The Responsible Entity shall operate such that the Control Performance Standard 1 (CPS1), calculated in accordance with Attachment 1, is greater than or equal to 100 percent for the applicable Interconnection in which it operates for each preceding 12 consecutive calendar month period, evaluated monthly. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

R2. Each Balancing Authority shall operate such that its clock-minute average of Reporting ACE does not exceed its clock-minute Balancing Authority ACE Limit (BAAL) for more than 30 consecutive clock-minutes, calculated in accordance with Attachment 2, for the applicable Interconnection in which the Balancing Authority operates.*[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

C. Measures

M1. The Responsible Entity shall provide evidence, upon request, such as dated calculation output from spreadsheets, system logs, software programs, or other evidence (either in hard copy or electronic format) to demonstrate compliance with Requirement R1.

M2. Each Balancing Authority shall provide evidence, upon request, such as dated calculation output from spreadsheets, system logs, software programs, or other evidence (either in hard copy or electronic format) to demonstrate compliance with Requirement R2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The Responsible Entity shall retain data or evidence to show compliance for the current year, plus three previous calendar years unless, directed by its Compliance Enforcement Authority, to retain specific evidence for a longer period of time as part of an investigation. Data required for the calculation of Regulation Reserve Sharing Group Reporting Ace, or Reporting ACE, CPS1, and BAAL shall be retained in digital format at the same scan rate at which the Reporting ACE is calculated for the current year, plus three previous calendar years.

If a Responsible Entity is found noncompliant, it shall keep information related to the noncompliance until found compliant, or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all subsequent requested and submitted records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The CPS 1 value of the Responsible Entity, for the preceding 12 consecutive calendar month period, is less than 100 percent but greater than or equal to 95 percent for the applicable Interconnection.	The CPS 1 value of the Responsible Entity, for the preceding 12 consecutive calendar month period, is less than 95 percent, but greater than or equal to 90 percent for the applicable Interconnection.	The CPS 1 value of the Responsible Entity, for the preceding 12 consecutive calendar month period, is less than 90 percent, but greater than or equal to 85 percent for the applicable Interconnection.	The CPS 1 value of the Responsible Entity, for the preceding 12 consecutive calendar month period, is less than 85 percent for the applicable Interconnection.
R2	The Balancing Authority exceeded its clock-minute BAAL for more than 30 consecutive clock minutes but for 45 consecutive clock-minutes or less for the applicable Interconnection.	The Balancing Authority exceeded its clock-minute BAAL for greater than 45 consecutive clock minutes but for 60 consecutive clock-minutes or less for the applicable Interconnection.	The Balancing Authority exceeded its clock-minute BAAL for greater than 60 consecutive clock minutes but for 75 consecutive clock-minutes or less for the applicable Interconnection.	The Balancing Authority exceeded its clock-minute BAAL for greater than 75 consecutive clock-minutes for the applicable Interconnection.

E. Regional Variances

None.

F. Associated Documents

BAL-001-2, Real Power Balancing Control Performance Standard Background Document

Version History

[illegible]	[illegible]	[illegible]	[illegible]
0	February 8, 2005	BOT Approval	New
0	April 1, 2005	Effective Implementation Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	July 24, 2007	Corrected R3 to reference M1 and M2 instead of R1 and R2	Errata
0a	December 19, 2007	Added Appendix 2 – Interpretation of R1 approved by BOT on October 23, 2007	Revised
0a	January 16, 2008	In Section A.2., Added "a" to end of standard number In Section F, corrected automatic numbering from "2" to "1" and removed "approved" and added parenthesis to "(October 23, 2007)"	Errata
0	January 23, 2008	Reversed errata change from July 24, 2007	Errata
0.1a	October 29, 2008	Board approved errata changes; updated version number to "0.1a"	Errata
0.1a	May 13, 2009	Approved by FERC	
1		Inclusion of BAAL and WECC Variance and exclusion of CPS2	Revision
1	December 19, 2012	Adopted by NERC Board of Trustees	
2	August 15, 2013	Adopted by the NERC Board of Trustees	
2	April 16, 2015	FERC Order issued approving BAL-001-2	

Attachment 1
Equations Supporting Requirement R1 and Measure M1

CPS1 is calculated as follows:

$$CPS1 = (2 - CF) * 100\%$$

The frequency-related compliance factor (CF), is a ratio of the accumulating clock-minute compliance parameters for the most recent preceding 12 consecutive calendar months, divided by the square of the target frequency bound:

$$CF = \frac{CF_{12\text{-month}}}{(\varepsilon 1_I)^2}$$

Where $\varepsilon 1_I$ is the constant derived from a targeted frequency bound for each Interconnection as follows:

- Eastern Interconnection $\varepsilon 1_I = 0.018$ Hz
- Western Interconnection $\varepsilon 1_I = 0.0228$ Hz
- ERCOT Interconnection $\varepsilon 1_I = 0.030$ Hz
- Quebec Interconnection $\varepsilon 1_I = 0.021$ Hz

The rating index $CF_{12\text{-month}}$ is derived from the most recent preceding 12 consecutive calendar months of data. The accumulating clock-minute compliance parameters are derived from the one-minute averages of Reporting ACE, Frequency Error, and Frequency Bias Settings.
A clock-minute average is the average of the reporting Balancing Authority's valid measured variable (i.e., for Reporting ACE (RACE) and for Frequency Error) for each sampling cycle during a given clock-minute.

$$\left(\frac{RACE}{-10B}\right)_{\text{clock-minute}} = \frac{\left(\frac{\sum RACE_{\text{sampling cycles in clock-minute}}}{n_{\text{sampling cycles in clock-minute}}}\right)}{-10B}$$

And,

$$\Delta F_{\text{clock-minute}} = \frac{\sum \Delta F_{\text{sampling cycles in clock-minute}}}{n_{\text{sampling cycles in clock-minute}}}$$

The Balancing Authority's clock-minute compliance factor ($CF_{\text{clock-minute}}$) calculation is:

$$CF_{\text{clock-minute}} = \left[\left(\frac{RACE}{-10B}\right)_{\text{clock-minute}} * \Delta F_{\text{clock-minute}}\right]$$

Normally, 60 clock-minute averages of the reporting Balancing Authority's Reporting ACE and Frequency Error will be used to compute the hourly average compliance factor ($CF_{\text{clock-hour}}$).

$$CF_{\text{clock-hour}} = \frac{\sum CF_{\text{clock-minute}}}{n_{\text{clock-minute samples in hour}}}$$

The reporting Balancing Authority shall be able to recalculate and store each of the respective clock-hour averages ($CF_{\text{clock-hour average-month}}$) and the data samples for each 24-hour period (one for each clock-hour; i.e., hour ending (HE) 0100, HE 0200, ..., HE 2400). To calculate the monthly compliance factor (CF_{month}):

$$CF_{\text{clock-hour average-month}} = \frac{\sum_{\text{days-in-month}}[(CF_{\text{clock-hour}})(n_{\text{one-minute samples in clock-hour}})]}{\sum_{\text{days-in month}}[n_{\text{one-minute samples in clock-hour}}]}$$

$$CF_{\text{month}} = \frac{\sum_{\text{hours-in-day}}[(CF_{\text{clock-hour average-month}})(n_{\text{one-minute samples in clock-hour averages}})]}{\sum_{\text{hours-in day}}[n_{\text{one-minute samples in clock-hour averages}}]}$$

To calculate the 12-month compliance factor ($CF_{\text{12 month}}$):

$$CF_{\text{12-month}} = \frac{\sum_{i=1}^{12}(CF_{\text{month-i}})(n_{(\text{one-minute samples in month})-i})]}{\sum_{i=1}^{12}[n_{(\text{one-minute samples in month})-i}]}$$

To ensure that the average Reporting ACE and Frequency Error calculated for any one-minute interval is representative of that time interval, it is necessary that at least 50 percent of both the Reporting ACE and Frequency Error sample data during the one-minute interval is valid. If the recording of Reporting ACE or Frequency Error is interrupted such that less than 50 percent of the one-minute sample period data is available or valid, then that one-minute interval is excluded from the CPS1 calculation.

A Balancing Authority providing Overlap Regulation Service to another Balancing Authority calculates its CPS1 performance after combining its Reporting ACE and Frequency Bias

Settings with the Reporting ACE and Frequency Bias Settings of the Balancing Authority receiving the Regulation Service.

Attachment 2

Equations Supporting Requirement R2 and Measure M2

When actual frequency is equal to Scheduled Frequency, $BAAL_{High}$ and $BAAL_{Low}$ do not apply.

When actual frequency is less than Scheduled Frequency, $BAAL_{High}$ does not apply, and $BAAL_{Low}$ is calculated as:

$$BAAL_{Low} = \left(-10B_i \times \left(FTL_{Low} - F_S\right)\right) \times \frac{\left(FTL_{Low} - F_S\right)}{\left(F_A - F_S\right)}$$

When actual frequency is greater than Scheduled Frequency, $BAAL_{Low}$ does not apply and the $BAAL_{High}$ is calculated as:

$$BAAL_{High} = \left(-10B_i \times \left(FTL_{High} - F_S\right)\right) \times \frac{\left(FTL_{High} - F_S\right)}{\left(F_A - F_S\right)}$$

Where:

$\mathbf{BAAL_{Low}}$ is the Low Balancing Authority ACE Limit (MW)

$\mathbf{BAAL_{High}}$ is the High Balancing Authority ACE Limit (MW)

10 is a constant to convert the Frequency Bias Setting from MW/0.1 Hz to MW/Hz

$\boldsymbol{B_i}$ is the Frequency Bias Setting for a Balancing Authority (expressed as MW/0.1 Hz)

$\boldsymbol{F_A}$ is the measured frequency in Hz.

F_S is the scheduled frequency in Hz.

$\boldsymbol{FTL_{Low}}$ is the Low Frequency Trigger Limit (calculated as $F_S - 3\varepsilon 1_I$ Hz)

$\boldsymbol{FTL_{High}}$ is the High Frequency Trigger Limit (calculated as $F_S + 3\varepsilon 1_I$ Hz)

Where $\varepsilon 1_I$ is the constant derived from a targeted frequency bound for each Interconnection as follows:

- Eastern Interconnection $\varepsilon 1_I = 0.018$ Hz
- Western Interconnection $\varepsilon 1_I = 0.0228$ Hz
- ERCOT Interconnection $\varepsilon 1_I = 0.030$ Hz
- Quebec Interconnection $\varepsilon 1_I = 0.021$ Hz

To ensure that the average actual frequency calculated for any one-minute interval is representative of that time interval, it is necessary that at least 50% of the actual frequency sample data during that one-minute interval is valid. If the recording of actual frequency is interrupted such that less than 50 percent of the one-minute sample period data is available or valid, then that one-minute interval is excluded from the BAAL calculation and the 30-minute clock would be reset to zero.

A Balancing Authority providing Overlap Regulation Service to another Balancing Authority calculates its BAAL performance after combining its Frequency Bias Setting with the Frequency Bias Setting of the Balancing Authority receiving Overlap Regulation Service.

A. Introduction

1. **Title:** **System Operating Limits Methodology for the Operations Horizon**

2. **Number:** FAC-011-2

3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability**

   4.1. Reliability Coordinator

5. **Effective Date:** April 29, 2009

B. Requirements

R1. The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall:

R1.1. Be applicable for developing SOLs used in the operations horizon.

R1.2. State that SOLs shall not exceed associated Facility Ratings.

R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.

R2. The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:

R2.1. In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.

R2.2. Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

R2.2.1. Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.

R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.

R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

R2.3. In determining the system's response to a single Contingency, the following shall be acceptable:

R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

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[1] The Contingencies identified in FAC-011 R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

R2.3.2. Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or (b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies

R2.3.3. System reconfiguration through manual or automatic control or protection actions.

R2.4. To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.

R3. The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:

R3.1. Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)

R3.2. Selection of applicable Contingencies

R3.3. A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with FAC-014 Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions.

R3.3.1. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.

R3.4. Level of detail of system models used to determine SOLs.

R3.5. Allowed uses of Special Protection Systems or Remedial Action Plans.

R3.6. Anticipated transmission system configuration, generation dispatch and Load level

R3.7. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.

R4. The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following:

R4.1. Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.

R4.2. Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area.

R4.3. Each Transmission Operator that operates in the Reliability Coordinator Area.

R5. If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Reliability Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why. (Retirement approved by FERC effective January 21, 2014.)

C. Measures

M1. The Reliability Coordinator's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.

M2. The Reliability Coordinator shall have evidence it issued its SOL Methodology, and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

M3. If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Reliability Coordinator that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5. (Retirement approved by FERC effective January 21, 2014.)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Reliability Coordinator shall self-certify its compliance to the Compliance Monitor at least once every three years. New Reliability Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

1.3. Data Retention

The Reliability Coordinator shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology ~~and shall keep all documented comments on its SOL Methodology and associated responses for three years~~. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant. (Deleted text retired-Retirement approved by FERC effective January 21, 2014.)

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Reliability Coordinator shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology.

1.4.2 Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses. (Retirement approved by FERC effective January 21, 2014.)

1.4.3 Superseded portions of its SOL Methodology that had been made within the past 12 months.

1.4.4 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

2. Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions exists:

2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

2.1.2 No evidence of responses to a recipient's comments on the SOL Methodology (Retirement approved by FERC effective January 21, 2014.)

2.2. Level 2: The SOL Methodology did not include a requirement to address all of the elements in R3.1, R3.2, R3.4 through R3.7 and E1.

2.3. Level 3: There shall be a level three non-compliance if any of the following conditions exists:

2.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.

2.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.

2.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.1, R3.2, R3.4 through R3.7.

2.4. Level 4: The SOL Methodology was not issued to all required entities in accordance with R4.

3. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	Not applicable.	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.2	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.3.	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.1. OR The Reliability Coordinator has no documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area.
R2	The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance following single contingencies, but does not require that SOLs are set to meet BES performance in the pre-contingency state. (R2.1)	Not applicable.	The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state, but does not require that SOLs are set to meet BES performance following single contingencies. (R2.2 – R2.4)	The Reliability Coordinator's SOL Methodology does not require that SOLs are set to meet BES performance in the pre-contingency state and does not require that SOLs are set to meet BES performance following single contingencies. (R2.1 through R2.4)
R3	The Reliability Coordinator's SOL Methodology includes a description for all but one of the following: R3.1 through R3.7.	The Reliability Coordinator's SOL Methodology includes a description for all but two of the following: R3.1 through R3.7.	The Reliability Coordinator's SOL Methodology includes a description for all but three of the following: R3.1 through R3.7.	The Reliability Coordinator's SOL Methodology is missing a description of four or more of the following: R3.1 through R3.7.
R3.6	N/A	N/A	N/A	N/A
R4	The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to one of the required entities specified in R4.1, R4.2, and R4.3.	The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to two of the required entities specified in R4.1, R4.2, and R4.3.	The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to three of the required entities specified in R4.1, R4.2, and R4.3.	The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to four or more of the required entities specified in R4.1, R4.2, and R4.3

Requirement	Lower	Moderate	High	Severe
	OR For a change in methodology, the changed methodology was provided to one or more of the required entities before the effectiveness of the change, but was provided to all the required entities no more than 10 calendar days after the effectiveness of the change.	OR For a change in methodology, the changed methodology was provided to one or more of the required entities more than 10 calendar days after the effectiveness of the change, but less than or equal to 20 days after the effectiveness of the change.	OR For a change in methodology, the changed methodology was provided to one or more of required entities more than 20 calendar days after the effectiveness of the change, but less than or equal to30 days after the effectiveness of the change.	OR For a change in methodology, the changed methodology was provided to one or more of the required entities more than30 calendar days after the effectiveness of the change.
R5 (Retirement approved by FERC effective January 21, 2014.)	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days. OR The Reliability Coordinator's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or longer. OR The Reliability Coordinator's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.

Regional Differences

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:

   1.1. As governed by the requirements of R3.3, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:

   1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.

   1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7

   1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.

   1.1.4 The failure of a circuit breaker associated with a Special Protection System to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.

   1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.

   1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-011.

   1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.

   1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:

   1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.

   1.2.2 Cascading does not occur.

   1.2.3 Uncontrolled separation of the system does not occur.

   1.2.4 The system demonstrates transient, dynamic and voltage stability.

   1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

   1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.

1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:

1.3.1 Cascading does not occur.

1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
2		Changed the effective date to October 1, 2008 Changed "Cascading Outage" to "Cascading" Replaced Levels of Non-compliance with Violation Severity Levels Corrected footnote 1 to reference FAC-011 rather than FAC-010	Revised
2	June 24, 2008	Adopted by Board of Trustees: FERC Order 705	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update
2	February 7, 2013	R5 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	
2	November 21, 2013	R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	
2	February 24, 2014	Updated VSLs based on June 24, 2013 approval.	

AUGUST 18, 2015

Framework for NO_x RTC Allocations

This paper provides an informal outline of a possible framework for the allocation of NO_x RTCs to the electric generating units (EGUs) under the RECLAIM program. The objective of this proposed framework is to establish an effective regulatory approach for AQMD to meet its ozone reasonable further progress goals for reducing NO_x emissions under the Clean Air Act. The NO_x emissions for EGUs represent a very small share (less than 3 tons per day during 2011-2013) of the total NO_x emissions in the region (about 550 tons per day estimated for 2016). Part of the strategy to reduce NO_x levels in the region is to electrify sources that are currently burning fossil fuels. Specifically, the increased electricity generation will result in small increases in NO_x at EGU, but those emissions will be more than offset by substantial NO_x emission reductions at the newly electrified sources. Several of those source categories provide large opportunities to reduce overall NO_x emissions: off road equipment, locomotives, ships and commercial boats, and passenger vehicles, SUVs and light duty trucks. Electrification of even portion of these sources will result in substantial overall NO_x reductions. The AQMD's forecasts indicate NO_x reductions in excess of 200 tons per day from forecast 2023 levels are required to keep the region on track for attainment of the current 2008 ozone standard. Notably, electrification of sources that currently burn fossil fuels also increases efficiency so it will be an important tool in achieving the ozone NAAQS as well as the California's CO_2 emission goals under federal and state regulatory programs.

As reflected in the matrix below, the proposed approach would establish the following three "building blocks" for the allocation of NO_x RTCs to affected EGUs: (1) Tradable RTCs allocated to serve native load (forecast demand absent additional electrification programs); (2) Non-tradable RTCs allocated to cover increased generation resulting from mandatory electrification measures established by the ARB or AQMD; and (3) Non-tradable RTCs allocated to cover increased generation resulting from non-mandatory electrification measures and incentives that the ARB, AQMD or electric utilities may promote. Under the proposed approach, RTCs allocated under building block 1 cannot be reduced under any circumstances given that they need to cover native load, while RTCs allocated under building blocks 2 and 3 can be adjusted to reflect the actual amount of increased demand that results from electrification measures actually implemented.

There are several ways that the AQMD could incorporate the non-mandatory electrification measures and incentives into its SIP and receive NO_x emission reduction credit for meeting its ozone reasonable further progress goals under the Clean Air Act. One such approach is the "state measure" approach[1] that EPA has established for a state to meet its applicable CO_2 emission rate target under the Clean Power Plan. In so doing, EPA states that the state plan would include an enforceable commitment by the state itself to implement state-enforceable (but not federally enforceable) measures that would achieve specified portion of the required emission performance level on behalf of affected EGUs. The key difference between the traditional federal-state regulatory approach and EPA's "state measures" approach is that instead of private entities, such as affected EGUs, being responsible for obtaining specific emission reductions, the state adopts a plan that makes itself responsible for ensuring the implementation of the particular state measures in order to meet its federal emission reduction obligations. A similar regulatory approach could be implemented by the AQMD in order to meet its ozone reasonable further progress goals for reducing NO_x emissions under the Clean Air Act.

Finally, it should be noted that EPA has suggested that a "state measure" approach should include a number of key measures in order to guarantee the achievement of the targeted emissions reductions. In particular, it may be necessary for a state to support its state measures with clear initial demonstrations that the required reductions will be achieved, regular reporting during the compliance period, and clear contingency and federally enforceable backstop measures if the expected emission reductions are not achieved by the state. In the case of the non-mandatory electrification measures, AQMD may need to include backstop provisions that automatically place a federally enforceable control measures on NO_x sources in the region to secure any reductions that the state plan commitments do not deliver. The AQMD would choose the appropriate backup reduction measures. However those federally enforceable measures should most likely apply to sources other than power plants given that EGUs are regulated to the maximum extent feasible under AQMD's plan (*i.e.*, EGUs are operating to meet native load or supply electricity for electrification measures that are achieving a net NO_x reduction.)

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[1] Another approach not discussed in this paper to provide SIP credit for non-mandatory electrification measures based on the guidance that EPA has developed for how states can earn SIP credit for state implementation of energy efficiency and renewable energy measures under its SIPs.

	RTC Allocation	Types of Credits	SIP Implications
Building Block 1	RTCs are allocated at sufficient levels to cover NO_x emissions from affected EGUs that operate at levels necessary to serve electricity demand within the South Coast Air Basin. RTC allocations are based on stringent NO_x BARCT emission rates set for highly efficient gas-fired generation. RTC allocations are based on utilization levels that are necessary for affected EGUs to meet forecast demand absent additional electrification programs. RTC allocation is sufficient to cover NO_x emissions attributable for startups and shutdowns.	The RTCs are tradable. The RTCs cannot be reduced given that they are essential for EGUs meeting electricity demand and doing so at the lowest feasible NO_x emission rate.	Since BARCT is imposed on all affected EGUs, they are already well-controlled sources that are doing their share to meet RFP goals for reducing NO_x emissions in the South Coast Air Basin.
Building Block 2	An incremental allocation of RTCs is allocated to cover NO_x emissions attributable to incremental electricity demand (beyond Building Block 1) for the implementation of mandatory electrification measures under the state implementation plan.	The RTCs are non-tradable. The number of RTCs can be adjusted to reflect the actual amounts of increased electricity demand attributable to the mandatory electrification	Federally enforceable SIP measure Because the NO_x reductions result from mandatory electrification measures, incremental RTCs to EGUs will not result in a net NO_x emission increase. Furthermore,

	RTC Allocation	Types of Credits	SIP Implications
	For example, an incremental allocation of RTCs could be allocated for the increased generation attributable to mandatory requirements to electrify additional operations at the Port of Los Angeles, LAX, or other significant sources of NO_x emissions.	measures. This incremental allocation of RTC will result in a net reduction in NO_x emissions in the South Coast Air Basin due to offsetting NO_x emission reductions achieved from the mandatory electrification measures.	there is no question on whether there will be a net NO_x reduction, but rather only a question on how many reductions will be achieved (dependent on the source converting to electricity).
Building Block 3	An additional allocation of RTCs is allocated to cover NO_x emissions attributable to incremental electricity demand (beyond Building Blocks 1 and 2) that result from non-mandatory (voluntary) electrification measures. For example, there are many possible policies, incentives, and other measures that the State, City, AQMD, or electric utilities may undertake to encourage the electrification of the transportation or other NO_x emitting sectors. To the extent that these efforts result in the electrification, then there will be a net NO_x emission	The RTCs are non-tradable. The number of RTCs can be adjusted to reflect the electricity demand attributable to the mandatory electrification measures	There are several possible ways to reflect the non-mandatory electrification measures in the SIP. One possible way is to follow the "state measure" approach proposed by EPA in the Clean Power Plan. Under this approach, the AQMD or the State would make a commitment to achieve a specific amount of NO_x reductions through the implementation of voluntary measures referenced in the SIP. Although further EPA guidance is needed, it is likely that AQMD will need to provide enforceable

	RTC Allocation	Types of Credits	SIP Implications
	reduction even though NO_x emissions from affected EGUs will slightly increase.		regulatory backstop measures that would be activated in the event that the NO_x reductions are not achieved. However, the backstop provisions would apply to sources other than power plants given that EGUs are regulated to the maximum extent feasible (i.e., EGUs are operating to meet native load or supply electricity for electrification measures that are achieving a net NO_x reduction.) Another possible way to include non-mandatory measures in the SIP is through existing EPA policy guidance that allows the use of energy efficiency measures and renewable energy generation to achieve emissions reductions under certain situations.

AUGUST 18, 2015

SIP CREDITING MECHANISM TO PROVIDE CREDIT FOR REDUCTIONS ACHIEVED THROUGH ELECTRIFICATION

OUTLINE OF KEY ELEMENTS

The objective of this white paper is to outline the key elements of an emission reduction crediting mechanism that state or local regulatory authorities, such as the South Coast Air Quality Management District (AQMD or District), can use to account for and provide the appropriate emission reduction credit to electric utilities for the overall net NO_x emission reductions achieved by the electrification of other source categories under their state implementation plan (SIP). The paper begins with a brief discussion on the need for the Environmental Protection Agency (EPA) to establish such a SIP crediting mechanism and then presents the key design elements of a crediting mechanism that is modeled after approaches that EPA has developed for promoting energy efficiency and renewable energy measures under the Clean Air Act (CAA).

Need for SIP Crediting Mechanism

The attainment and maintenance of the current 2008 national ambient air quality standard for ozone will require substantial NO_x emission reductions from the largest source categories of NO_x emissions in the South Coast Air Basin (SCAB). As a result, AQMD is examining various NO_x emission reduction strategies, including a substantial reduction in the NO_x RTC holdings for all affected RECLAIM facilities, in order to meet its "reasonable further progress" (RFP) goals for reducing NO_x emissions under the CAA. This need for NO_x emission reductions in the SCAB will only increase when EPA adopts (as expected) final rules to tighten the current ozone standard in October 2015.

According to the District, an essential part of the strategy to reduce NO_x emission levels in the SCAB region will be to electrify the transportation sector and other major source categories of NO_x emissions. Specifically, the increased electricity generation will result in small increases in NO_x emissions by affected electric generating units (EGUs), but those emission increases will be more than offset by substantial NO_x emission reductions achieved by the newly electrified sources. Electrification of even portion of these sources will result in substantial overall net NO_x emission reductions in the SCAB region.

One key implementation issue relates to how the AQMD can account for and provide appropriate emission reduction credit to electric utilities for the net NO_x emission reductions achieved by the electrification of other source categories under the District's ozone attainment SIP. At present, there does not exist an EPA-recognized SIP crediting mechanism for electrification that the District could use for meeting its ozone RFP reduction obligations under the CAA. Without such a crediting mechanism, it is difficult for the AQMD to allocate in advance an additional amount of NO_x RTCs to affected EGUs – even though this increased RTC allocation is necessary for the electrification of the other major sources that will achieve an overall net NO_x reduction within the SCAB region.

The establishment of such a SIP crediting mechanism for electrification is needed not only for the SCAB region, but other major urban areas with significant ozone nonattainment problems for which electrification of major NO_x source categories will likely become an important ozone attainment strategy. Furthermore, the need for such a SIP crediting mechanism is particularly important given that many of the measures for promoting electrification may be non-mandatory policies and incentives that are not federally enforceable under the CAA. The use of non-mandatory policies and incentives in SIP attainment strategies is major shift in the typical CAA regulatory paradigm of states developing SIP control strategies that impose federally enforceable emissions reduction requirements on affected emission sources. The establishment of EPA-recognized SIP crediting mechanism will therefore address the regulatory uncertainty that would otherwise result from this paradigm shift and thereby encourage the implementation of policies to reduce emissions from the transportation and major source categories of emissions through electrification in the SCAB and other urban ozone nonattainment areas.

Key Design Elements of SIP Crediting Mechanism

The purpose of this paper is to identify the key design elements of a SIP crediting mechanism that state or local regulatory authorities, such as AQMD, can use to account for and provide appropriate emission reduction credit to electric utilities for emission reductions achieved by the electrification of other source categories with the same region under their SIP attainment strategies. This proposed SIP crediting mechanism is based on similar approaches that EPA has developed for incorporating energy efficiency and renewable energy strategies into SIP attainment strategies under CAA section 110[1] and state plans for meeting its applicable CO_2 emission reduction targets under CAA section 111(d).[2]

[1] *See* Guidance by EPA Office of Air Quality Planning and Standards, entitled: *Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans* (July 2012) (hereinafter referred to as "*EPA Roadmap*").

[2] *See* Proposed Clean Power Plan, 79 Fed. Reg. at 34,902.

As a general matter, EPA has interpreted the CAA to require that four criteria must be satisfied in order for an emission control measure to generate creditable emission reductions that can be used for meeting its RFP goals in the SIP attainment strategy. These criteria are that the emission reductions are: quantifiable, permanent, surplus, and enforceable. The discussion below presents the design elements of a SIP crediting mechanism that would satisfy each of these criteria.

Quantifiable. In order for a policy or measure to be quantifiable, the state or local regulatory authority must quantify the overall net emission reductions that would result from the implementation of the policy or measure for electrification. This analysis would require a quantification of the NO_x emission reductions that are projected to occur as a result of the electrification of existing sources of NO_x emissions in the nonattainment area. One challenge would be the quantification of NO_x emission reductions resulting from the implementation of non-mandatory policies and incentives to encourage electrification. In addition, the analysis should include a quantification of projected NO_x emission increases that would likely occur due to the increased generation of electricity by EGUs located in the nonattainment area. EPA guidance should be developed on each of these steps of analysis in order to ensure consistency among states on how to quantify the overall net reductions that result from electrification policies and measures.

Permanent. The state or local regulatory authority must show that the emission reductions from the electrification policies and measures will not be temporary, but will continue through the future attainment date. To that end, the regulatory authority should develop policies and measures that reflect long-term commitments for electrification and include in its SIP control plan a demonstration on why these commitments will yield extended emissions reductions that satisfy the criterion for permanency.

Surplus. The electrification policies and measures must not be otherwise required under the CAA.[3] To meet this criterion, the state or local regulatory authority would need to demonstrate in its SIP submission that these policies and measures are additional to the control measures included in the baseline emissions projections for the SIP attainment strategy so that there will be no double counting of emission reductions. One element of this demonstration should include a certification that the regulatory authority has reviewed the electrification control strategies and confirms that these strategies are not being used to claim emission reduction credits in any of control strategies included in the SIP attainment strategy, as well as a description of specific

[3] Section 173 (c)(2) of the CAA (providing that "Emission reductions otherwise required by this chapter shall not be creditable as emissions reductions for purposes of any such offset requirement").

steps that the regulatory authority is taking to ensure that there is no double counting of emission reductions.

Enforceable. There would be two pathways from demonstrating compliance with this criterion. The first, and most straightforward, pathway would be the adoption of mandatory control measures that would directly or indirectly require the electrification of the affected sources of NO_x emissions in the nonattainment area. Such mandatory measures would be federally enforceable against specific entities which must be able to verify compliance with the specific control requirements and be subject to enforcement for the failure to comply with those requirements, including civil penalties and corrective action.

The second pathway would be the adoption of non-mandatory policies and incentives for encouraging electrification. Under this alternative approach, the regulatory authority would have the option of meeting the criterion for enforceability through the adoption of an enforceable commitment requiring the regulatory authority to evaluate the effectiveness of the non-mandatory electrification policies or incentives and, if these measures do not achieve the projected emission reductions, to remedy any SIP reduction shortfall. This remedy may involve the implementation of contingency control measures to achieve the necessary emission reductions or demonstrating that the emission reductions are not needed to achieve the RFP reduction requirements for attaining the ozone standard.

Such an approach, as noted above, is modeled after the federal guidance that EPA has developed for incorporating energy efficiency and renewable energy strategies into SIP attainment strategies under CAA section 110.[4] Importantly, the EPA guidance describes four possible implementation pathways for incorporating energy efficiency and renewable energy policies and programs into SIP control strategies. One such pathway involves the adoption of non-mandatory policies and programs to encourage the use of energy efficiency and renewable energy.[5] To meet the enforceability criterion, the state or regulatory authority must make an enforceable commitment to:

- Implement those parts of the policies or measures for which the agency are responsible;
- Monitor, evaluate, and report at least every three years on progress toward emission reductions; and

[4] *See EPA Roadmap*. Notably, this guidance draws from previously issued EPA guidance documents that seek to encourage states to incorporate energy efficiency and renewable energy measures into their SIP control strategies.

[5] *See EPA Roadmap* at pages 9 and 30-32.

- Remedy any SIP credit shortfall if the policies or measures do not meet the projected emission reductions.[6]

In addition, this approach for meeting the enforceability criterion is consistent with the "state measure" approach that EPA has proposed for a state to meet its applicable CO_2 emission rate target under the Clean Power Plan. In this case, EPA has proposed to allow a state to achieve a portion of its CO_2 emission reduction obligation through enforceable requirements to increase renewable energy, energy efficiency, and perhaps other control methods that do not apply directly to EGUs. In so doing, EPA states that the state plan would include an enforceable commitment by the state itself to implement state-enforceable (but not federally enforceable) measures that would achieve specified portion of the required emission performance level on behalf of affected EGUs. The key difference between the traditional federal-state regulatory approach and EPA's proposed state measure approach is that instead of private entities, such as affected EGUs, being responsible for obtaining specific emission reductions, the state adopts a plan that makes itself responsible for ensuring the implementation of the particular measures in order to meet its federal emission reduction obligations.

[6] *See EPA Roadmap* at page 37.

RESOLUTION NO. 15-XXX

A Resolution of the South Coast Air Quality Management District Board Recognizing the Need to Increase the NO_x RTCs Allocations for Affected Electric Generating Units in order to Achieve National Ambient Air Quality Standards

WHEREAS, the attainment and maintenance of the national ambient air quality standards for ozone will require substantial NO_x emission reductions from the largest source categories of NO_x emissions in the South Coast Air Basin (SCAB).

WHEREAS, the largest source categories of NO_x emissions in the SCAB include off road equipment (43 tons per day), locomotives (22 tons per day), ships and commercial boats (41 tons per day), and passenger vehicles, sport utility vehicles, and light duty trucks (24 tons per day);

WHEREAS, the District is currently examining possible regulatory strategies for achieving NO_x reductions from these and other source categories through the electrification of combustion sources;

WHEREAS, the regulatory strategies under consideration include both mandatory and voluntary measures for electrification of combustion sources that would be incorporated into the state implementation plan and achieve substantial NO_x emission reductions that are required for meeting the obligations of the South Coast Air Quality Management District under the federal Clean Air Act; and

WHEREAS, the electrification of these other source categories will require substantial increases in electricity generation from affected electric generating units (EGUs) within the SCAB and that such increases in electricity generation will result in a corresponding increase in NO_x emissions from affected EGUs.

THEREFORE, BE IT RESOLVED that the Board of the South Coast Air Quality Management District commits to provide in the future an additional allocation of NO_x RECLAIM Trading Credits (RTCs) to affected EGUs in order to cover the additional NO_x emissions attributable to such increased electricity generation.

BE IT FURTHER RESOLVED that this future increased allocation of NO_x RTCs to affected EGUs does not constitute a change to the New Source Review regulations that is prohibited under the provisions of Senate Bill 288, entitled *The Protect California Air Act of 2003* and codified at Health and Safety Code §§ 42500-42507, but rather is fully consistent with the goals and protections afforded under Senate Bill 288 given that—

- any additional NO_x emissions from affected EGUs in the SCAB would be offset by a significantly greater reduction in NO_x emissions from other sources within SCAB for an overall net air quality improvement; and

- affected EGUs have already installed the most stringent NO_x control technologies currently available and, consequently, that the NO_x emissions from such EGUs comprise only a very small share (less than 3 tons per day during 2011-2013) of the total NO_x emissions in the SCAB (about 550 tons per day estimated in 2016).

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Subject: Proposed Amendments to Regulation XX – NOx Reclaim

This letter includes Shell Energy's comments to the proposed amendments to Regulation XX – NOx RECLAIM. Shell Energy and Wildflower Energy are parties to an Energy Conversion Agreement dated July 26, 2004 (the "ECA"). Under the ECA, Shell Energy has the right to direct that fuel be converted into energy by the Indigo Generated Units that are located in SCAQMD territory.

After analyzing the Draft Rule Language released on July 22, 2015 and participating in the public workshop about this topic we would like to submit the following comments for your consideration:

- The Indigo Facility was built in response to the California Energy crisis in 2001. Indigo was constructed with BACT - best available control technology – including a CO catalyst and SCR to limit NOx to 5 ppm. It operates at a very low capacity factor as this technology is only needed during periods of high demand on the grid, although the SCAQMD permit requirements obligate the facility to hold offsets for significantly greater operational hours. Typically, SCAQMD considers the cost effectiveness of emission reductions, and will evaluate a cost benefit analysis. To meet the proposed requirements in Rule XX, the facility would need to make significant modifications to the SCR, CO catalyst and to the exhaust modules housing the catalyst, far exceeding typical cost benefit ratios. The alternate emissions reduction choice would be to replace the combustor on the gas turbine, also cost prohibitive. There is no further cost effective NOx reduction technology for this facility. The only way that such Facilities can comply with the current proposed rule is to purchase additional NOx RTCs. This represents a significant expense for generating facilities especially considering the current market conditions in California, including the recent decommissioning of San Onofre Nuclear Generating Station. We request that SCAQMD consider that peaking generation facilities with lower capacity factor built to BACT should not be obligated under the proposed rule to make further emissions reductions, and allow the emissions offsets previously procured for the unit to meet current and future SCAQMD requirements. 1C1-1

- Rule 2002 Section PAR 2002(f)(1)(B) and (C) state that the Executive Officer will adjust NOx RTC holdings, as of (Date of Amendment) for compliance years 2016 and thereafter by multiplying the amount of RTC holdings as of March 20, 2015 by adjustment factors for the relevant compliance year. Setting the Amendment Date after it had passed is equivalent to retroactive ratemaking and could have unintended economic consequences. We believe that the Date of Amendment should be set closer to or upon the actual date when the final Rule is published. Additionally, it is not clear how the March 20, 2015 date was established and does not address how NOx RTCs that were transferred between March 20, 2015 and the date of the implementation of the Proposed Rule will be treated. We request the SCAQMD act prospectively; the NOx RTC holdings should be the quantity as of the date of the implementation of the Proposed Rule. 19-2

- Additional information and clarification is needed regarding the Proposed Adjustment Account for Generators PAR 2000 (f) (4). 19-3

We appreciate your consideration of the comments above and look forward to continuing this conversation. Please don't hesitate to contact me at (858) 526-2103 if you would like to discuss our comments.

Yours truly,

Manuel Rolin for Michael D. Evans

Michael D. Evans
Regulatory Manager

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