Submitted by e-mail to: docket@energy.ca.gov

September 28, 2012

California Energy Commission
Dockets Office, MS-4
Re: Docket No. 12-OIR-1
1516 Ninth Street
Sacramento, CA 95814-5512

In the Matter of:
Rulemaking to Consider Modification of Regulations Establishing a Greenhouse Gases Emission Performance Standard For Baseload Generation of Local Publicly Owned Electric Utilities

Docket No. 12-OIR-1
Rulemaking Workshop

Response of Natural Resources Defense Council and Sierra Club to Energy Commission's Request for Reply Comments

Introduction:

The Natural Resources Defense Council (NRDC) and the Sierra Club submit the following response to the Energy Commission's "Request for Reply Comments" dated August 31, 2012. The Request for Reply Comments first seeks input on the NRDC and Sierra Club's proposal that supporting documentation on all expenditures on non-compliant facilities be provided to the Commission for posting on a publicly available website and sent to interested service lists. Given the statewide importance of limiting continued investment in non-compliant facilities and the minimal burdens associated with forwarding existing documents to the Commission, this reporting requirement is reasonable and necessary to ensure consistent application of SB 1368 and to allow for needed public scrutiny of POU investment decisions.

The Request for Reply Comments also seeks input on the Sierra Club and NRDC recommendation to lower the existing EPS to 825-850 lbs/MWh of CO_2, with a potential higher EPS for smaller facilities. The Request for Reply Comments specifically seeks additional information on: (1) whether the proposed update to the EPS accounts for allowable emissions of NO_x and ammonia slip; (2) whether the proposed EPS would impact the ability of gas plants to operate more flexibly to integrate renewables; and (3) the extent to which existing facilities would be affected by lowering the EPS. Having reviewed these specific concerns, and taking into account that increased ramping may be necessary for integration, we do not believe any adjustments are necessary to the proposed EPS at this time. Our recommended standard is feasible without negative repercussions for utility reliability or customer costs. The Commission should revise the EPS for large base load units and establish a separate limit for smaller units as earlier recommended, consulting with its sister agencies as necessary. To the extent the Commission receives data suggesting an alternative EPS, we welcome the opportunity to respond.

With regard to NOx and ammonia slip, our recommended EPS already employed a 3 percent conversion factor from gross to net emissions. This is sufficient to accommodate the additional energy cost of NOx and ammonia control for new units, especially as there are unit designs that have base emission rates well below our proposed limits. Any NOx/ammonia energy penalty is built into the gross emission rates for existing units and therefore does not merit increasing the proposed EPS.

Our analysis leads us to further conclude that renewable integration concerns also do not warrant upward adjustments to the proposed EPS. First, any energy penalty associated with integrating current levels of renewables is already reflected in gross emission rates for those facilities, which already ramp to accommodate changing power demand. Second, increased use of solar energy that will come with higher levels of renewables may actually lower annual average GHG emission rates from existing (and new) facilities by reducing the need for duct burner operations during peak demand.

Third, the EPS affects all prospective new plants, but only a limited number of existing, relatively new CCNG facilities that became operational after the standard was put in place.[1] As a result a lower standard would affect few current units and mostly impact new facilities, which have significant potential for improvement with new technology. New designs and upgrades from major manufacturers, including GE and Siemens, combine rapid ramp rates, broader operating ranges and greater than 60% efficiency such that renewable integration need not force a tradeoff between flexible operations and overall GHG reduction rates. The Energy Commission can best encourage the continued development of these technologies by lowering the EPS to the recommended range now.

Moreover, since the future impact of integrating renewables is not currently quantified, it is premature for the Commission to attempt to incorporate a numerical adjustment for this factor at this time. Once several years of additional data become available, the Energy Commission could obtain, analyze and make available to all parties representative hour-by-hour emissions from best performing plants that respond to renewable generation to determine the impact, if any, on annual emission rates of integration of natural gas with renewables and modify the EPS if necessary. Since the standard is only enforced upon new long term financial commitment, any operational change outside of the anticipated range to allow for increased renewable integration should not bring about compliance issues before more data is available.

Finally, with regard to the effect of a lower EPS on existing baseload facilities, further investigation of the Colusa plant, a facility that operates above the recommended EPS, suggests that this facility may exceed the proposed EPS due to significant duct burner operation.[2] As the

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[1] SB 1368, Sec. 8341 (d)(1): "All combined-cycle natural gas powerplants that are in operation, or that have an Energy Commission final permit decision to operate as of June 30, 2007, shall be deemed to be in compliance with the greenhouse gases emission performance standard."

[2] Our analysis indicated that Colusa was the only large facility potentially subject to SB 1368 with emissions significantly higher than the recommended range of 825-850 MWh.

Commission should not encourage this extensive use of this inefficient practice in baseload applications, it does not constitute a legitimate basis to revise the proposed EPS upward.

I. The Commission Should Adopt the Recommendation of NRDC and Sierra Club to Establish a New Reporting Requirement for Expenditures at Non-Compliant Facilities

A. Transparent, Timely, and Accessible Information on Potential Expenditures for High-Emission Facilities are Critical to the Public Interest

To date, the CEC has received no information from POUs about ongoing investments at the major non-compliant plants from which California public utilities receive significant energy. Instead, the CEC has relied on POUs to affirmatively raise any potentially barred expenditure or a third party stakeholder to request investigation. The state and the public can no longer afford to rely on POU discretion to disclose information on expenditures at noncompliant facilities. Indeed, it was only after a time consuming Public Records Act process that NRDC and Sierra Club discovered that MSR has already taken initial steps toward authorizing the purchase of federally mandated pollution control equipment at the San Juan Generating Station despite the fact that such an investment clearly triggers SB 1368. While we did not and do not allege that MSR had made binding commitments, we remain very concerned that MSR appears to be taking the first steps toward investments that are not allowed under California law. Such actions underscore the need for greater transparency regarding investments at non-compliant facilities.

While the POUs are instruments of local government subject to the Brown Act and accountable to their local constituents, statewide reporting to the CEC is justified given the larger public interest at stake. Whether California will continue to rely on dirty noncompliant plants that exceed the standard will largely be determined over the next few years. Decisions pertinent to compliance with the statewide EPS will fundamentally affect California's ability to meet the emissions reductions mandate of AB 32 and its longer term greenhouse gas reduction objectives. Given the importance of California's energy mix to a successful transition to a low-carbon future, the CEC and the public should have firsthand knowledge of expenditures that affect California's continued involvement with noncompliant facilities. Reporting by POUs is required in other areas of statewide importance, including emissions reporting for AB 32 compliance, efficiency potential and progress and compliance with the state renewable energy standard, and is equally necessary and appropriate here.

B. Attempting to Follow Investment Decisions at Each POU Governing Board is Unduly Time and Resource Intensive for Stakeholder Groups and Insufficient to Provide a Timely and Complete Picture of Relevant Investment Decisions

POUs oppose a reporting requirement in part because they complain that such a requirement would be time and resource intensive. As an alternative, they suggest that stakeholders interested in these decisions should follow the public meetings of each POU involved in a non-compliant power plant. These meetings take place throughout the state and materials are not always available on the internet. Moreover, the websites of each POU vary drastically, and some have little or no information on expenditure planning regarding these facilities. Stakeholder groups interested in ensuring POU compliance with SB 1368 would potentially have to maintain vigilance on meeting dates, request appropriate documents through the public records act, and travel to each POU meeting of the over one dozen POUs receiving power from noncompliant facilities. As a practical matter, these significant burdens preclude effective monitoring of POU decision-making.

In addition, materials made available through the Brown Act may fail to provide a complete picture of contemplated investments in non-compliant facilities. Some investment decisions may never be taken to governing boards for approval and underlying documentation for other decisions may not be provided in Board agendas and minutes. Requiring POUs to submit information to the Commission on any proposed expenditure on the three non-compliant facilities (San Juan, Navajo and Intermountain Power) for publication on a single website and released to relevant Energy Commission list serves is reasonable and necessary to ensure transparency and compliance with SB 1368.

In contrast to the difficulties in meaningful public review of POU investments through the Brown Act, affirmative reporting by the POUs to the Commission poses minimal burdens. Notably, NRDC and the Sierra Club do not ask the POUs to produce new reports or other documentation of planned expenditures at non-compliant facilities. Rather, we only request that the POUs forward to the Commission and any applicable listserve electronic copies of existing documents relating to expenditures at non-compliant facilities.

C. Reporting is Necessary to Ensure Consistent POU Application of SB 1368 to Contemplated Investments and Avoid Improper Investment Expectations

As set forth in the Tentative Conclusions and our comments on the Tentative Conclusions, the Final Statement of Reasons (FSOR) makes clear that pollution control investments required for continued legal operation of a facility are not routine maintenance.[3] The FSOR, in the sections cited by the Tentative Conclusions, also make clear that any expenditure that extends life of a facility by five years or more is disallowed under the EPS.[4] There is no reason whatsoever for a differentiation between expenditures that are required for the legal and physical operation of the facility.

However, MSR's recent filing on its planning for new investment at San Juan suggests that at least some POUs believe they can continue with these expenditures.[5] The Commission should not wait for results of a Public Records Act request from a third party to be potentially

[3] CEC, "Tentative Conclusions And Requests For Additional Information," July 9, 2012, p. 5.
[4] We cited the FSOR's discussion of this issue extensively in our July 27, 2012 Comments, pp. 3-5.
[5] MSR, August 31, 2012 filing, pp. 4-8.

informed of POU decisions on covered procurements. Instead, it should ensure that all relevant materials are made publicly available to ensure a final CEC determination is possible before expectation and momentum build and investments are made for a particular expenditure.

In addition, expenditure decisions often involve discussion with private and public actors outside of California, making early access to information on investment decisions especially critical. For example in their July 27 joint comments SCPPA, MSR and Anaheim refer to their multi-party agreement at San Juan, noting that super majorities are required to allow new major expenditures.[6] The same analysis shows that the California utilities could block investments, particularly if they act as a block under an agreed interpretation of their obligations under the EPS. Thus, consistent application of the EPS by each utility is critical. Early public information will ensure that pending decisions are available for review well before any multi-party decision is made.

II. As Recommended in Earlier Comments, the Commission Should Tighten the EPS to 825-850 lbs/MWh CO_2, With a Separate Standard for Smaller Units

A. The Impact of Allowable Emissions of Ammonia Slip and NOx is Minimal and Already Accounted for in the Recommended EPS

In its August 31, 2012, request for reply comments the Energy Commission expressed its view that the national data base cited in our proposal "does not account for corresponding allowable emission and ammonia slip, which apply only in California" and solicited input on this and other adjustments that might be necessary to reflect California specific conditions. We do not believe that any adjustment to the recommended 825-850 lb range is warranted to address this issue: (1) the decrease in thermal efficiency associated with the use of pollution control devices is reflected in the CAMD emissions data that formed the basis of our proposal; (2) mechanical losses are small and already covered by the application of a 3% increase to gross emission rates provided in the CAMS emissions data; (3) existing highly efficient NGCC can readily meet our proposed limit while achieving NOx and ammonia emission limits as stringent as California limits; (4) dual NOx/ammonia catalysts that reduce ammonia slip without any additional thermal penalty appear to be commercially available; and (5) any adjustment would be very small, in the range of 1-2 lb/MWh, and is therefore well within the 25 lb/MWh range that we have suggested for consideration by the Energy Commission.

The overall energy cost from pollution control devices has two components: (1) the reduced thermal efficiency of the turbine that results from the increased back pressure associated with installing a device in the exhaust stream; and (2) the mechanical load of operating fans, pumps and other auxiliaries.

[6] "Southern California Public Power Authority, MSR Public Power Agency, and City Of Anaheim Response To Tentative Conclusions And Request For Additional Information," July 27, 2012, pp. 9-11.

In our initial proposal we provided the gross emissions data that includes those California units that are contained within the Federal data base. These data reflect the actual, in-service gross emissions performance of these units as that performance is affected by California regulations (including applicable NOx and ammonia slip limitations), weather and usage patterns. The reduced thermal efficiency associated with an increase in back pressure from pollution controls – including any installed SCR and follow on ammonia-reduction catalyst - is reflected in these data.

We have applied a 3 percent factor to the reported gross emissions data to account for the balance of plant electrical needs, including those needed to address pollution control device mechanical loads. This is consistent with information in the literature and in general practice, including estimates of the Energy Commission.[7] We are unaware of any information that would suggest that this factor should be modified because of requirements associated with ammonia slip.

In addition, other good performing units in the national data base are subject to NOx and ammonia slip limitations that require simultaneous operation of selective catalytic reduction (SCR) NOx controls and techniques to limit ammonia slip. In particular, BACT/LAER decisions for new units have led to NOx/ammonia limits that are as stringent as found in California, without significantly compromising CO_2 emission rates. By way of example, the West County Energy Center in Loxahatchee, FL is subject to limits as stringent as those in California (2 ppm NOx and 5 ppm ammonia)[8] and CAMD data demonstrate that this unit has consistently met the EPS limits we suggest. The BACT analysis prepared by Florida Power and Light [9] for this NGCC plant is based on GE Frame 7FA turbines with a HRSG and includes separate calculations for thermal (efficiency) and mechanical losses that compare an SCR based system and a SCONOx system (which does not use ammonia to reduce NOx emissions). This analysis applies a 0.36 percent penalty to the heat rate associated with the operation of the SCR system and an 80 kW/h (0.03 percent) electrical load for the mechanical losses.[10] It is our understanding that adding an ammonia catalyst after the SCR can be accomplished by addition of a relatively small polishing operation since ammonia reacts readily[11]. Thus, any energy penalty for an ammonia catalyst should be small compared to the penalty for the SCR and, for this reason, the

[7] We have conservatively applied this factor to the capacity of the entire plant, not just the capacity of steam turbine generator.
[8] http://www.dep.state.fl.us/air/emission/construction/westcounty/FPERMIT354.pdf. Apparently, several ozone non-attainment area permitting authorities apply LAER limits that are at least as stringent as California's limits. http://www.epa.gov/eab/disk11/3mountpower.pdf
[9] http://www.dep.state.fl.us/air/emission/construction/westcounty/responseparti.pdf This reference cites to a 1993EPA study to support its applied penalties.
[10] The capacity of the steam turbines is given at 250 MW/h; the overall capacity of the NGCC system is 1250 MW. 80 kW/h represents 0.03 percent of 250 MW/h, far less than the 3 per cent conversion factor applied to the CAMD data.
[11] Chemical Engineering, SCR: New and Improved (July 2010), http://www-static.shell.com/static/cri_catalyst/downloads/business/scr_new_improved.pdf.

Florida BACT analysis did not separately calculate a penalty for the ammonia treatment required of the SCR.

We have conservatively estimated the impact of a 3 inch increase in HRSG backpressure for 17 of the most common NGCC plants using Thermoflow's power plant modeling software, GT Pro and GT Pro Macro. Our analyses assumed a worst case base HRSG backpressure of 19 inches water, corresponding to maximum backpressure during duct burner power augmentation; ambient pressure of 14.7 psia (sea level); 59^{o}F, and 60% relative humidity. These analyses, indicate that an increase in HRSG backpressure of 3 inches water gauge due to SCR plus oxidation catalyst in the HRSG gas path would increase the gross LHV heat rate by 24 to 44 Btu/kWh (0.4 – 0.7 percent).[12] This modeling is consistent with the FP&L BACT analysis and demonstrates that the CO_2 emission increase associated with the energy penalty imposed by operating an SCR and oxidation catalyst would be on the order of 5-6 lb/MWh and that the portion associated with the oxidation catalyst is less than 2 lb/MWh. There is no reason to believe that any polishing that may be required for ammonia control would impose a greater penalty than an oxidation catalyst for CO control. Indeed, the literature points to development of multi-purpose catalysts which would involve no additional penalty.[13] Thus, to the extent that the Energy Commission relies on emissions from California plants, no adjustment is appropriate. Federal emissions data should not be adjusted where the plants at issue employ SCR and have relatively stringent ammonia limits. It may be appropriate to adjust the annual emission rates of other units by 1-2 lb/MWh; however, such adjustments would not warrant a change in the recommended range of 825-850 lb/MWh.

B. Renewable Integration Concerns Do Not Merit Adjustment of the Recommended EPS at This Time

While reducing operating loads below certain thresholds does diminish efficiencies during periods of low load, the impact of such reduced operations on annual GHG emission rates is by no means clear. The deregulation of the U.S. power industry in the 1990s led to construction of 168 GW of underutilized natural gas generating capacity. As a result, even today there is a substantial variation in the capacity factors of existing NGCCs and the list of better performing plants provided with our earlier comment includes units with widely varying operating characteristics, including widely varying annual hours of operation. However, our proposed standard would only affect new plants invested in by CA utilities and a small subset of

[12] Comments of Sierra Club et al on Proposed Rule: Standards of Performance for Greenhouse Gas Emission for New Stationary Sources: Electric Utility Generating Units, dated June 25, 2012, Appendix B http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2011-0660-10798.
[13] Power Engineering, SCR Catalysts: Dual Function Catalyst Promises High NOx Removal with Zero Ammonia Slip for Gas Turbine Applications (Sept. 1, 2011), http://www.power-eng.com/articles/print/volume-105/issue-9/features/scr-catalysts-dual-function-catalyst-promises-high-nosubx-sub-removal-with-zero-ammonia-slip-for-gas-turbine-applications.html

existing NGCC units. In both cases, compliance must be demonstrated for new long term financial commitments.

In response to the Energy Commission's request for reply comments we have reviewed the year-over-year emissions from individual units to attempt to ascertain if the difference in annual emission rates at individual facilities was associated with differences in annual operating hours. The annual emissions data do not demonstrate a consistent pattern. The following Tables set out year-over-year emission rates and operating hours for three units at two California plants. For Inland Energy Center Unit 2, the emission rates are identical for 2011 with an average of 329.80 hours of operation as they are for the first quarter of 2012, where the utilization (614.65) is almost twice as great. For Inland Energy Center Unit 1, the period with the highest utilization rate has the second highest emission rate.

Unit	Year (no of months)	Avg. Monthly Hours of Operation	CO2 rate (gross)
Inland Energy Center #2	2010 (9)	497.60	811.12
Inland Energy Center #2	2011 (12)	329.80	784.34
Inland Energy Center #2	2012 (3)	614.85	784.58
Inland Energy Center #1	2009 (12)	516.56	871.81
Inland Energy Center #1	2010 (12)	548.49	761.13
Inland Energy Center #1	2011 (12)	553.37	767.54
Inland Energy Center #1	2012 (3)	648.79	780.21

Walnut Energy Center's data show widely varying operations – from 416 to 713 hours per month, but relatively consistent emission rates.[14]

Unit	Year (no of months)	Avg. Monthly Hours of Operation	CO2 rate (gross)
Walnut Energy Center	2006 (12)	415.89	958.24
Walnut Energy Center	2007 (12)	562.99	947.23
Walnut Energy Center	2008 (12)	632.78	940.48
Walnut Energy Center	2009 (3)	622.71	939.02
Walnut Energy Center	2010 (12)	599.29	934.53
Walnut Energy Center	2011 (12)	497.05	945.43
Walnut Energy Center	2012 (3)	712.50	933.14

A review of hourly emission data may identify the operating characteristics that significantly impact annual emission rates. In the absence of such data, we have reported the highest annual emissions for each unit in our Federal data analysis and what we believe are

[14] Walnut Energy Center is an older, small unit that would not be subject to the EPS. This data is only intended to show the effect of operating hours on emissions rates.

"representative" emissions for California units in our submission to the Energy Commission. These data represent reasonable worst case emissions based on today's operations.

EPA currently estimates that current part load operation of NGCC units imposes a 5 percent GHG emission penalty over ISO design conditions. If future additional generation by intermittent renewable sources increased the part load penalty by 20 percent, the result would be a one percent (8 lb/MWh) increase in annual GHG emission rates. As we discuss below, greater penetration of renewables (especially solar power) in California markets may lead to a reduction in emissions associated with supplemental (duct) firing during peak periods and offset or eliminate the increase from added cycling operations. In addition, the growth in energy demand over the next decade may lead to an overall increase in the utilization rates of NGCC units, even as cycling increases to accommodate increases in renewable generation. We do not believe it is possible to predict to this degree of precision, the impact of renewables on the annual CO_2 emission rates of such units.

Further, providing more lenient GHG base load emission rates to accommodate part load operations is not the best way to facilitate the integration of renewables in California. New designs and upgrades are now offered by major manufacturers, including GE and Siemens that are specifically designed to integrate with renewable energy sources.[15] These products combine rapid ramp rates, broad operating ranges, and greater than 60 percent efficiency.[16] The design features that facilitate integration of renewables do not force a tradeoff between flexible operations and overall GHG emission rates, but generally involve some additional upfront costs. A number of these features are available as retrofits to existing units. We recommend that any action taken by the Energy Commission be designed to encourage these and other technical advances in gas-fired technologies that are intended to facilitate the integration of renewables in California's energy grid while optimizing energy efficiency of the NGCC units.

We believe that the Energy Commission can best encourage the continued development of these technologies by lowering the EPS to the recommended range now. Given the structure of the EPS, taking action now will provide specific direction that will enable operators of affected units to plan for the future and integrate these new technologies into their operations. The Commission should not take any further steps to exempt "integration" emissions at this time as exempting such emissions would serve to discourage the adoption of these new technologies in the market. Instead, the Commission should establish a structured program to monitor the ongoing integration of renewables and be prepared to act. The lead time associated with

[15] See, Ecomagination, Tower of Power: The World's First Wind-Solar-Natural Gas Plant (Sept. 28, 2011), http://www.ecomagination.com/showcase/tower-of-power-the-worlds-first-wind-solar-natural-gas-plant; see also Matthew Wald, Adapting Gas-Fired Power to a Greener Grid, N.Y. TIMES (Sept. 26, 2012), http://green.blogs.nytimes.com/2012/09/26/adapting-gas-fired-power-to-a-greener-grid/?smid=tw-share

[16] See, GE Energy, FlexEfficiency* 50 Combined Cycle Power Plant, http://www.ge-energy.com/products_and_services/products/gas_turbines_heavy_duty/flexefficiency_50_combined_cycle_power_plant.jsp; http://www.ge-energy.com/products_and_services/

providing relief for specific issues is far less than that needed by operators to reduce emissions. An exemption for certain "integration emissions", for example, could be adopted at a later date in a matter of a few months if an emergent need arises and the Energy Commission has obtained the information needed to define the specific issue and a resolution. Such an exemption could then have an immediate effective date and provide any necessary relief in a timely fashion.

C. Evaluation of Changed Operation for Renewable Integration Should Also Include a Potential Revision of the Current Definition of "Baseload Facility"

The change in load patterns that occurs with increased market penetration of renewables and new developments in flexible base load generating technology may well require reconsideration of what is meant by base load generation. The increase in market penetration by renewable resources and resulting decline in gas generation may render the current 60% threshold obsolete. As wind, solar and other renewable production increases, NGCC units that would normally be considered "base load" may be idled or reduced to minimum loads for several hours daily during some periods. Under these circumstances, the notion of load-following units may also be obsolete and it may be easier to define peaking units that are not covered by the EPS rule rather than base load units that are covered. A likely first step would be to reduce the 60% or replace the capacity factor test in favor of a definition of base load units that incorporate the notion that such units are designed and intended to provide base load (i.e. non-peaking) electrical needs of the system at such times when renewables are not available.

D. Applicability of EPS to Existing Operations

1. Duct Burner Operation

We have also examined the small group of existing natural gas fired power plants that fall under SB 1368 that may have emissions higher than the recommended EPS. Our earlier submission reported net annual GHG emissions as high as 960 lb/MWh for the Colusa Generating Station. In response to the Commission's request we attempted to understand why the emissions from this plant are so high. The Colusa plant consists of GE 7FA turbines in a 2x1 arrangement with an HRSG and an SCR. The relevant emission limits are fairly standard for California (and elsewhere).[17] This configuration is listed in the GTW Handbook as having a net plant efficiency of 58.5 percent (not including the effect of the SCR). This plant should ordinarily be able to meet our proposed standard. First quarter 2012 emissions are below 825 lb/MWh and the unit is described as "heavily-duct fired."[18] That description and the 2012 emissions data suggest that the plant's emissions significantly increase during the warm months as a result of substantial duct burner operation.

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[17] The NOx limit is 2 ppm, while the ammonia limit is 5ppm.

[18] Energy-Tech, Hoc Phung et al., ASME: Comparison Between Air Blows and Gas Blows for Cleaning Power Plant Fuel Gas Piping Systems (Apr. 2012), http://www.energy-tech.com/article.cfm?id=32237.

Supplemental firing operations (also known as duct firing) may have a heat rate of 9500 btu/kWh[19] compared to 7000 btu/kWh or less for a NGCC unit without supplemental firing. Accordingly, duct firing GHG emission rates may be more than 35 percent higher than NGCC rates. Duct firing is used to increase the output of NGCC units to accommodate periods of high load and the overall impact of the use of this technique on annual emissions depends on the capacity of the supplemental firing apparatus and the extent to which it is used. The GHG limits established by the Energy Commission should not encourage extensive use of duct firing in base load applications. For this reason, the Energy Commission should not increase the applicable EPS to accommodate units that extensively employ supplemental firing. When added generation is routinely needed throughout the year, such generation should be provided[20] by renewables to the extent that they are available, and added high efficiency NGCC capacity where renewables are not feasible. The First Quarter 2012 emissions data suggests that, without extensive supplemental firing, the Colusa plant could meet the recommended EPS. Thus, imposition of the recommended EPS would not necessarily preclude compliance by the Colusa plant, but may limit the extent of supplemental firing at the facility.

2. Dry Cooling

Use of dry cooling also does not warrant raising the EPS above the recommended 825-850 MWh. Under Section 316(b) of the Clean Water Act, EPA is required to set requirements applicable to the location, design, construction, and capacity of cooling water intake structures at existing facilities based on the best technology available to minimize the adverse environmental impact associated with the use of these structures. In the course of establishing such standards, EPA prepared a study that, *inter alia*, examined the energy losses associated with dry and wet cooling technologies at combined cycle natural gas power generating plants.[21] EPA's study differentiated between the adverse impact on thermal efficiency and the electrical load required to drive fans and pumps. It concluded that the adverse effect on thermal efficiency was 0.90 percent for dry cooling systems and 0.11 percent for once through (wet) cooling systems in the West. The 0.79 percent difference amounts to 6.5 lb/MWh. It should be noted that this energy penalty is embedded in the CAMD gross emissions for the unit. Therefore, no further adjustment is needed for existing California units that have dry cooling towers. Further, the issue is not unique to California as other units in other states have dry condenser cooling and the energy penalty is larger for such units other regions of the country (especially the south). When comparing the performance of dry-cooled California units with wet-cooled units in California and elsewhere, it may be appropriate to increase representative emissions of existing wet cooled

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[19] Northwest Planning Council, New Resource Characterization for the Fifth Power Plan, Natural Gas Combined-Cycle Gas Turbine Power Plants (Aug. 8, 2002), http://www.westgov.org/wieb/electric/Transmission%20Protocol/SSG-WI/pnw_5pp_02.pdf.

[20] Or avoided through the use of demand side management and energy efficiency programs.

[21] See, USEPA, Office of Science and Technology, *Economic and Benefits Analysis for the Proposed Section 316(b) Phase II Existing Facilites Rule*, (2002), Table B1-1.

NGCC by up to 6.5 lb/MWh. However, the possibility of the need for such adjustments was anticipated in our earlier recommendation of a range of 825-850 lb/MWh rather than a specific limit, consequently, this factor does not warrant a change in the recommended range.

In addition, EPA's study estimated that the adverse mechanical load impact is 0.82 percent for dry cooling and 0.26 percent for wet cooling of NGCC. Each of these figures is well within the 3 percent increase that we have used to convert from gross to net emissions. Accordingly, no further adjustment is warranted for this issue.

III. Full Compliance with the Emissions Performance Standard is Required to Realize California's Greenhouse Gas Reduction Targets

In it July 9th Tentative Conclusions, the CEC rightfully rejected POU arguments that operation of the cap and trade program under AB 32 terminates the EPS. At the Commission noted, the AB 32 cap and trade program does not establish a cap enforceable against POUs, but rather a statewide cap under which POUs could conceivable make no emissions reductions. Sierra Club and NRDC support this conclusion. The EPS is a critical backstop to prevent new investment in the dirtiest power plants. The EPS was intended to make California utilities "internalize the significant and underrecognized cost of emissions … and to reduce California's exposure to costs associated with future federal regulation of these emissions"[22] Indeed, the structure of the cap, along with significant free allocation of emissions permits, underscores the need for the EPS bar on new long term investment in high-emissions facilities. California publicly owned utilities will receive significant free allocation of pollution permits to cover their emissions under the AB 32 Cap and Trade program- in some cases their allocation even increases over time, despite the declining overall cap.[23] As noted in the Tentative Conclusions, even if the free allocation does not cover all emissions, POUs are free to purchase further emissions permits. Finally, The AB 32 Cap and Trade program only extends until 2020 and power plant investments are frequently made to last decades. Without full compliance with the EPS, the state would lose the critical protection from backsliding investments in dirty power plants.

Thank you for your consideration of these comments.

Respectfully Submitted,

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[22] SB 1368 (2006) Sec. I (g).

[23] CARB "Staff Proposal for Allocating Allowances to the Electric Sector," July 2011, pp 7-10, available at http://www.arb.ca.gov/regact/2010/capandtrade10/candtappa2.pdf.

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