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October 1, 2013

Mr. John Heiser
California Energy Commission
1516 Ninth Street, MS-40
Sacramento, CA 95814-5512
john.heiser@energy.ca.gov

Re: Sierra Club's Comments on Air Quality, Water Supply, Alternatives, Public Health, and Nuisance (08-AFC-8A)

Dear Mr. Heiser,

Please find attached Sierra Club's Comments on Air Quality, Water Supply, Alternatives, Public Health, and Nuisance in the above-referenced docket. This document has been e-filed with the Commission, served on parties via the Commission's e-filing system, and filed via email with the DOE.

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

Sincerely,

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AIR QUALITY, WATER SUPPLY, ALTERNATIVES, PUBLIC HEALTH, AND NUISANCE
(PSA Sections 4.1, 4.12, 4.15, 4.8, and 6)

On May 30, 2013, Sierra Club submitted 125 pages of extensive comments on the Preliminary Determination of Compliance ("PDOC") for the Hydrogen Energy California ("HECA") project to the San Joaquin Valley Air Pollution Control District ("SJVAPCD" or "Air District") and the CEC. To date, many of Sierra Club's concerns regarding HECA's impacts on air quality, as well as the concerns of the local community and other interested parties, have not been addressed by either the Air District or the CEC. Presumably due to the timing of the public comment period for the Air District's PDOC and the Preliminary Staff Assessment ("PSA"), which was issued on June 28, 2013, CEC Staff did not address Sierra Club's comments on the PDOC in the PSA.[1]

The Air District received a significant number of substantive written comments from local community members, local, state, and federal agencies, and environmental and community groups, and hundreds of local residents voiced concerns at public meetings. Yet, the Air District issued its Final Determination of Compliance ("FDOC") just a few weeks after close of the comment period with only minor changes stating that "the changes reflected in the FODC [sic] were minor and did not significantly change permitted emissions levels, nor did they affect the basis of the District's decision."[2] The Air District provided largely non-responsive statements in response to Sierra Club's comments on the PDOC.

Below we briefly highlight the unresolved issues raised by Sierra Club in its letter on the PDOC; Sierra Club respectfully requests that CEC Staff review the relevant sections in Sierra Club's comment letter on the PDOC (cross-referenced for ease of review) as well as the additional discussion and address each issue. All comments in this document are relevant to the PSA's *Air Quality* and *Public Health* sections; Comment III.c is relevant for the *Water Supply* section, Comments I and III.c are relevant for the *Alternatives* section, and Comment V is relevant for the *Nuisance* section. Given the number and complexity of issues to be resolved in this section and many others, Sierra

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[1] *See* PSA, Response to Agency and Public Comments, pp. 4.1-110 through 4.1-111 (referencing Sierra Club's EIS scoping comment from July 2012 but not Sierra Club's May 20, 2013 comments on the PDOC); available at: http://docketpublic.energy.ca.gov/PublicDocuments/Delta/Delta/TN%2071444%2006-28-13%20Preliminary%20Staff%20Assessment%20-%20Draft%20Environmental%20Impact%20Statement.pdf.

[2] FDOC, p. 1. The District's response to 600 pages of public comments totals 35 pages. *See* FDOC, Appx. M & N.

Club respectfully requests that Staff prepare a revised Preliminary Staff Assessment ("revised PSA") before issuing a Final Staff Assessment ("FSA").

I. Alternatives Analysis under the Federal Clean Air Act and SJVAPCD Rules 2201 and 2410

Sierra Club commented that the PDOC fails entirely to provide a nonattainment alternatives analysis to satisfy the requirements under the federal Clean Air Act ("CAA" or "the Act"), Section 173(a)(5) and SJVAPCD Rule 2201, Section 4.15.1. Further, the alternatives analysis provided by the Applicant as part of its best available control technology ("BACT") analysis in the Authority to Construct Permit Application ("ATC Application") is deficient under the federal Clean Air Act and SJVAPCD Rules 2410 and 2201 because it fails to consider cleaner fuel alternatives such as natural gas, alternative fuel blends, or biomass.[3]

The Air District acknowledges that the PDOC erroneously includes no discussion of the alternatives analysis required in SJVAPCD Rule 2201, but claims this requirement will be addressed by the CEC as part of its duties under the California Environmental Quality Act ("CEQA").[4] The Air District has sole responsibility for administering the federal Clean Air Act in the San Joaquin Valley Air District. A nonattainment alternatives analysis is a separate and distinct requirement of the federal Clean Air Act. The Act and Air District rules require the Air District to analyze alternatives to the HECA Project and demonstrate that the benefits of the proposed source outweigh "the environmental and social costs" and allow the public an opportunity to review and comment on that analysis.[5] The District cannot pass off its responsibilities under the federal Clean Air Act to the CEC. The Air District's alternatives analysis should have been available for public review and comment as part of the PDOC.

Sierra Club commends CEC Staff for continuing to consider a natural gas-fired combined-cycle power plant with carbon storage and sequestration ("CCS") as well as a biomass boiler as potential alternatives in its *Alternatives* section.[6] However, CEC Staff does not acknowledge the Air District's mandate to conduct a nonattainment alternatives analysis or the District's failure to conduct a proper BACT alternatives analysis. Sierra Club respectfully requests that CEC Staff review Sierra Club's Comments on the PDOC, Section III.

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[3] Sierra Club's Comments on PDOC, p. 6-15; available at: http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/others/2013-05-30_Sierra_Club_Comments_on_PDOC_TN-71051.pdf.

[4] FDOC, Appx. N-27.

[5] Sierra Club's Comments on PDOC, p. 6-11.

[6] PSA, p. 6-9.

II. Emission Reduction Credits

The PSA proposes to offset HECA's emissions with banked emission reduction credits ("ERCs"), *i.e.*, credits for the reduction of emissions that occurred at other facilities at some time in the past.[7]

a) *HECA's VOC ERCs Are Invalid*

Sierra Club takes the position that the lack of attainment plans approved by the U.S. Environmental Protection Agency ("EPA") for achieving attainment with national ambient air quality standards prevents the Air District from relying on ERCs for those pollutants because it cannot assure that allowing new emission increases is consistent with "reasonable further progress" towards attainment.[8] However, even when setting this issue aside, Sierra Club's Comments on the PDOC discussed that HECA's ERCs volatile organic compounds ("VOCs"), which are ozone precursors, are invalid and do not meet the requirements of the Air District's rules and the federal Clean Air Act.[9] Specifically, Sierra Club commented that HECA's VOC ERCs, which are based on the shutdown of a facility *32 years ago in 1981*, are invalid because they were not generated in conformance with applicable rules or the federal Clean Air Act, were erroneously quantified, and were traded in violation of restrictions on their use <u>against express instructions by the EPA</u>.[10] The Air District provided stock responses claiming that the use of ERCs is allowed under District rules and claimed that:[11]

> …, the subject VOC ERCs were determined to meet all applicable requirements for emission reduction credit banking when they were originally issued. Prior to issuance of the ERCs, our preliminary decision was subject to public comment, including comment by the EPA and CARB. The District considered all comments

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[7] PSA, p. 4.1-65 through 4.1-72.

[8] The Air District currently does not have an approved attainment plan for either the 1-hour national ambient air quality standard for ozone or the 2006 24-hour national ambient air quality standard for PM2.5. (*See* Sierra Club's Comments on PDOC, Sections IV.A through IV.C.) The Air District responded that the unapproved attainment plans for the *1-hour ozone* and 2006 24-hour PM2.5 national ambient air quality standard do not affect the continued use of ERCs because the Air District has an attainment plan in place for the *1997 8-hour ozone* national ambient air quality standard and the U.S. Environmental Protection Agency ("EPA") approved all but one minor element of the Air District's state implementation plan for the 1997 PM2.5 national ambient air quality standard.[8] Attainment planning is not one-size-fits-all. To protect public health, EPA has set separate standards for 1-hour and 8-hour ozone concentrations and substantially lowered the 24-hour PM2.5 national ambient air quality standard, which was established in 1997, from 65 $\mu g/m^3$ to 35 $\mu g/m^3$ in 2006. The Air District must plan for attainment for all updated standards and cannot rely on ERCS to approve new pollution sources until those plans are fully approved.

[9] Sierra Club's Comments on PDOC, pp. 20 through 31.

[10] Compare Sierra Club's Comments on PDOC, pp. 23 through 30, with FDOC, Appx. N-18.

[11] FDOC, Appx. N-18 and N-19.

received prior to our decision to issue the ERCs. The subject VOC ERCs are valid for use.[12]

The Air District's response is misleading and does not address Sierra Club's comments. The subject VOC ERCs were banked after close of the public comment period in 1993 with the following restriction on their use to the Frito-Lay facility on Highway 58 (shown for ERC certificate S-0047-1:[13]

EMISSION REDUCTION CREDIT CERTIFICATE S-0047-1

CONDITIONS:

1. **Per Rule 2201 4.2.5.1, these reductions may not be used as offsets for emissions from a major source or major modification. Due to previous agreements regarding these reductions this prohibition does not apply to the use of these reductions as offsets for the Frito-Lay snack food facility located at 22801 Highway 58.**

While it is correct that EPA did not comment on the Air District's preliminary decision for banking these ERCs, they did so <u>precisely because this restriction was included on the ERC certificates</u>.[14] The restriction was later removed from the respective ERC certificates <u>without any comment or explanation</u> by the Air District when the ERCs were traded in 2001.[15] Thus, the Air District's response does not address the issue.

CEC Staff finds in the PSA that the Applicant "has demonstrated, per District requirements and Energy Commission policy, that it owns ERCs in quantities sufficient to offset the project's … VOC … emissions."[16] Sierra Club respectfully requests CEC Staff to reexamine this conclusion in light of the detailed discussion on the validity of HECA's VOC ERCs in Sierra Club's Comments on the PDOC, Sections IV.D through IV.F.5.

b) The Air District's Proposed SOx/PM2.5 Interpollutant Offset Ratio Is Inadequate

Affirming Sierra Club's Comments on the PDOC, CEC Staff also identified that the Air District's proposed use of a 1:1 interpollutant offset ratio for using sulfur oxides ("SOx") ERCs to offset emissions of fine particulate matter ("PM2.5") is problematic because it is not consistent with the Air District's 2012 PM2.5 Plan which relies on a

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12 FDOC, Appx. N-19.

13 *See* Sierra Club's Comments on PDOC, Section IV.F.3, p. 26.

14 *See* Memorandum of Telephone Conversation between Geraldo Rios, EPA, and Lance Ericksen, SJVAPCD, Re: Frito-Lay Banking Project, February 26, 1993. Attached as Exhibit 1.

15 *See* Sierra Club's Comments on PDOC, Section IV.F.3, pp. 26 and 27.

16 PSA, p. 4.1-67.

4.1:1 offset ratio.[17] The 4.1:1 offset ratio was developed by the Air District based on photochemical modeling after EPA rejected the Air District's previous 1:1 offset ratio.[18] Sierra Club urges CEC Staff to require HECA to acquire offsets at the 4.1:1 ratio since this ratio was developed by the Air District itself to bring to bring the air basin into compliance with national ambient air quality standards for PM2.5.[19]

Sierra Club also commented that SOx ERC #C-1058-5 is not accounted for in the Air District's 2008 PM2.5 Plan, which is intended to bring the area into attainment with the annual national ambient air quality standard for PM2.5 of 15 $\mu g/m^3$.[20] The Air District's response entirely ignored Sierra Club's comment.[21] The Air District may not on the one hand rely on the 2008 PM2.5 Plan using a 1:1 SOx to PM2.5 interpollutant offset ratio and on the other hand ignore that SOx ERC #C-1058-5 is not accounted for in this plan.

Sierra Club respectfully requests that CEC Staff review Sierra Club's Comments on the PDOC, Sections IV.H through IV.H.2.

c) Emission Reduction Credits Are Not Adequate Mitigation under CEQA

Putting aside Sierra Club's concerns regarding the illegality of HECA's ERCs, CEC Staff may not rely on 30-year old ERCs to fulfill its obligations under CEQA. As Staff notes in the PSA, "Mitigation required by SJVAPCD is outlined in the District NSR rule and does not necessary reflect the mitigation required by the California Energy Commission under CEQA."[22] Yet CEC Staff puts aside this mandate by relying on ERCs to mitigate air quality impacts[23] and in concluding that "Since the project's direct air quality impacts have been reduced to less than significant, there is no environmental justice issue for air quality."[24]

On a common sense level, it is not logical to assume that ERCs, some of which rely on emission reductions that occurred more than three decades ago, will do anything to counteract contemporary emission increases in a region plagued with serious and ongoing air quality violations. No demonstration of net air quality benefit

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[17] PSA, p. 4.1-70.

[18] Sierra Club's Comments on PDOC, Section IV.H.1, pp. 31 through 33.

[19] *Ibid*.

[20] Sierra Club's Comments on PDOC, Section IV.H.1, p. 32.

[21] Sierra Club's Comments on PDOC, Section IV.H.1, pp. 31 through 33.

[22] PSA, p. 4.1-66.

[23] PSA, p. 4.1-65.

[24] PSA, p. 4.1-73.

has been produced. Instead, this approach prolongs the exposure of residents in the San Joaquin Valley to extraordinarily unhealthy ozone and particulate matter levels. Thus, the use of ERCs is not valid mitigation under CEQA and should be replaced by post-baseline, quantifiable emission reductions that benefit the surrounding community. Sierra Club recommends that CEC Staff evaluate the potential for local mitigation measures to mitigate impacts due to PM2.5 emissions that would occur near the project site.

Sierra Club understands that the CEC has relied on ERCs as valid mitigation under CEQA to "offset" emissions from power plants under its jurisdiction in the past. Sierra Club respectfully requests the CEC to reexamine this issue in light of the specific circumstances of this project where a major new stationary source would emit hundreds of tons of pollutants per year in one of the most polluted airsheds in the country while providing only very little electrical capacity to California grid customers.[25] Sierra Club requests that CEC Staff reevaluate its conclusions regarding HECA's impacts on air quality using a common sense approach rather than relying on accounting acrobatics with ERCs. The CEC is not confined by SJVAPCD's interpretation of the Clean Air Act and must satisfy its responsibilities under CEQA. Sierra Club believes that a revised PSA should find significant impacts on air quality.

III. Best Available Control Technology and Lowest Achievable Emission Rate Are Not Required

Under the federal Clean Air Act, a major new source of air pollution requires emission limits that reflect BACT in attainment areas and lowest achievable emission rate ("LAER"), a generally more stringent level that all but eliminates cost considerations, for nonattainment areas. Under California state law and SJVAPCD Rule 2201, the Air District is required to apply "BACT" for new stationary sources under essentially the same requirements as federal LAER.[26] Sierra Club's Comments on the PDOC discussed that the Air District's BACT/LAER analyses are substantively flawed because they do not address all pollutants subject to Rule 2201 BACT requirements and the BACT determinations for HECA's cooling towers, flares, and fugitive equipment leaks are deficient.[27] The PSA accepts the Air District's BACT determinations mostly without further discussion. Sierra Club respectfully requests CEC Staff to consider the following comments.

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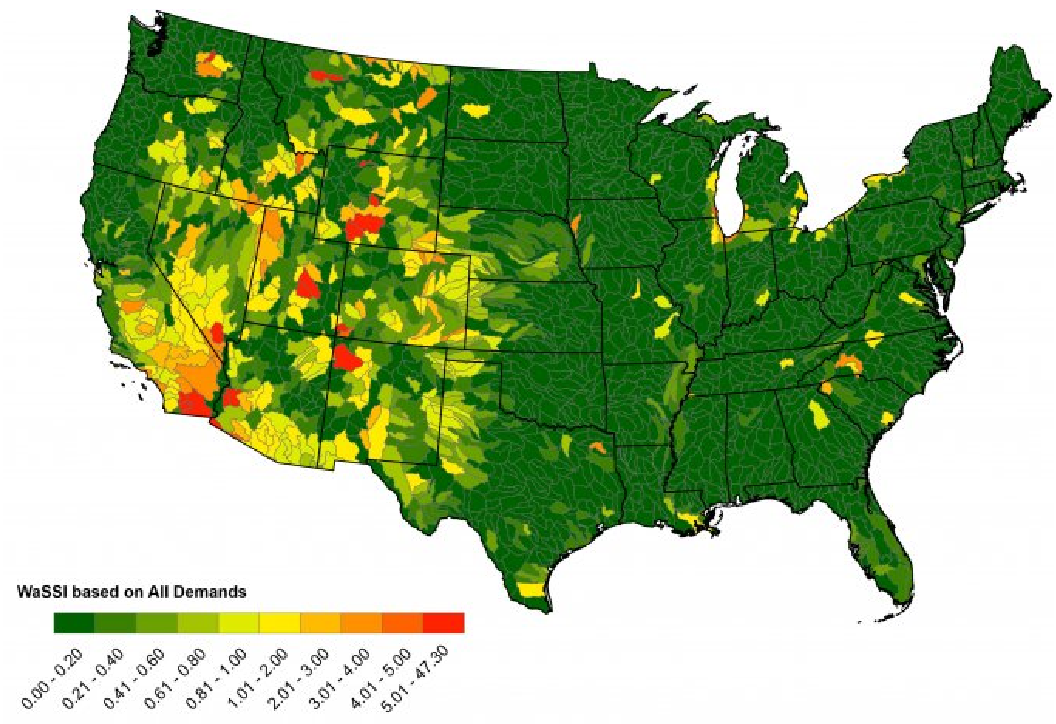
[25] According to the PSA, p. 6-9, HECA's weighted average daily electricity production would be 14.4 MW.

[26] Sierra Club's Comments on PDOC, Section VI, pp. 68 through 96.

[27] *Ibid*.

a) Dry Cooling Is BACT

The watersheds in the San Joaquin Valley are substantially stressed, as illustrated in the map below, and the long-term trend is more acute water stress due to climate change-driven changes in surface flows.[28]



Withdrawal water supply stress index ("WaSSI") in U.S. watersheds
From: University of Colorado press release, Today's Worst Watershed Stresses May Become the New Normal, September 18, 2013; available at http://www.colorado.edu/news/releases/2013/09/18/today%E2%80%99s-worst-watershed-stresses-may-become-new-normal-study-finds

Per the Kern County Water Agency's 2011 Water Supply Report, the average annual overdraft of the Kern groundwater subbasin from 1970 through 2011 is approximately 80,000 acre-feet per year. For this same time period, the report shows that the cumulative overdraft is approximately 3.4 million acre-feet.[29] Only last month, the U.S. Department of Agriculture declared the entire Central Valley and most of

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[28] K. Averyt, J. Meldrum, P. Caldwell, G. Sun, S. McNulty, A. Huber-Lee, and N. Madden, Sectoral Contributions to Surface Water Stress in the Coterminous United States, Environ. Res. Lett. 8, 2013; available at http://iopscience.iop.org/1748-9326/8/3/035046/pdf/1748-9326_8_3_035046.pdf.

[29] Email from Lauren Bauer, Kern County Water Agency, to Chris Romanini, Re: Groundwater Information, September 27, 2013. Attached as Exhibit 2.

California a drought disaster area eligible for federal funding.[30] In this dire situation of increasingly limited water resources, a private company is proposing to use up to 7,500 acre-feet per year of groundwater to produce fertilizer, water that will not be available for farming in the nation's breadbasket. Impacts on the existing water crisis as well as air pollution impacts from particulates emitted with the evaporated cooling water can be reduced by using air cooling, rather than wet cooling, a cost-effective alternative to wet cooling at HECA. Sierra Club agrees with Staff's analysis in the PSA that HECA has failed to adequately evaluate other alternative water supplies.

Sierra Club commends CEC Staff for continuing to consider dry cooling and wet-dry hybrid cooling in the *Alternatives* section,[31] yet, the PSA's *Air Quality* section accepts the Air District's BACT determination for HECA's cooling requirements in the PDOC without further analysis.[32] Sierra Club's Comment on the PDOC noted that the Air District's BACT analysis failed to even mention dry cooling as a potential alternative to the proposed wet cooling towers and provided extensive comment on the feasibility of dry cooling. In response the Air District provided a "screening level" BACT cost-effectiveness analysis for dry cooling in Appendix C of the FDOC. The Air District's analysis is substantially flawed.

First, the Air District recognizes that air-cooling is technologically feasible but eliminates dry cooling based on the results of a cost-effectiveness analysis. As noted above and in Sierra Club's Comments on the PDOC, <u>the Air District's BACT definition does not allow a consideration of costs for control techniques that have been achieved in practice</u>.[33] The Air District notes that "to our knowledge dry cooling has not been achieved in practice at IGCC facilities."[34] This statement is immaterial and ill informed. HECA would operate three cooling towers, one for the gasification block/process units, one for the air separation unit ("ASU"), and one for the combined-cycle power block. While there may currently not be any IGCC facilities that use dry cooling for all components that require cooling, dry cooling has been demonstrated in practice for combined-cycle power blocks, air separation units, and at least some of the process cooling needs. As Sierra Club discussed in its comments on the PDOC, several combined-cycle plants in California operate with dry-cooling and, thus, dry-cooling for the combined-cycle power block is achieved in practice. There is no reason that dry cooling could not be used for the cooling demands of HECA's combined-cycle power

[30] U.S. Department of Agriculture, Disaster and Drought Assistance; http://www.usda.gov/drought .

[31] See, 08-AFC-08A, Table 5.14-5, p. 5.14. (Average annual consumptive water uses for evaporation: 2,679 acre feet/year power block cooling tower + 2,678 acre-feet process block cooling tower + 812 acre-feet/year ASU cooling tower) / (average annual water supply by brackish water from Buena Vista Water Storage District: 7,427 acre-feet/year) = 0.83.

[32] *See* PSA, pp. 4.1-62 through 4.1-65.

[33] *See* SJVAPCD Rule 2201 definition of BACT at 3.10 and Sierra Club Comment VI.

[34] FDOC, Appx. N, p. N-15.

block. In fact, the Texas Clean Energy Project ("TCEP") – which, like HECA, is a proposed coal-gasifying IGCC polygeneration facility manufacturing urea with 90 percent CO_2 capture and sequestration through enhanced oil recovery and was also approved for funding under DoE's Clean Coal Power Initiative ("CCPI") Round 3[35] – is designed to use air cooling for the power block.[36] With respect to cooling requirements for the ASU, one the largest ASU installations in the world, if not the largest, which is operating in Qatar at the Shell Pearl gas-to-liquids IGCC project, uses dry cooling.[37] Very efficient fin-fan air coolers are frequently incorporated by refineries and chemical plants in addition to wet cooling towers[38] and are also available to substitute for similar process cooling water applications at HECA. Thus, dry cooling has been demonstrated in practice for the combined-cycle power block and for the ASU and at least some of HECA's process cooling requirements and must be required as BACT for HECA under California state law and SJVAPCD Rule 2201.

Second, even if dry cooling were eliminated as BACT for HECA, the BACT analysis for wet cooling must evaluate cooling water pre-treatment to reduce the total dissolved solids ("TDS") content in cooling water for the gasification block/process units and combined-cycle power block. Pre-treating cooling water to reduce the TDS content is clearly feasible as it is required for the cooling water that would be used for HECA's ASU.[39] Further, the TCEP has been approved by the DoE with pre-treatment of all process water including cooling water by low pressure membrane filtration followed

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[35] *See* Texas Clean Energy Project (TCEP); http://www.texascleanenergyproject.com/.

[36] Department of Energy, Texas Clean Energy Project Final Environmental Impact Statement (DOE/EIS-0444), August 2011, p. S-35; available at http://www.netl.doe.gov/technologies/coalpower/cctc/EIS/final_eis_texas_clean_energy.html.

[37] Shell, Pearl GTL; http://www.shell.com/global/aboutshell/major-projects-2/pearl.html; *see* Google view of facility: Linde - Gama Construction site (SPX Cooling Tech) ACC Plant; http://wikimapia.org/7535982/Linde-Gama-Construction-site-SPX-Cooling-Tech-ACC-Plant; *see* photographs of facility at: The Linde Group, Gas to Liquids (GTL): From Natural Gas to Clean Diesel; http://www.the-linde-group.com/en/clean_technology/clean_technology_portfolio/merchant_liquefied_natural_gas_lng/gas_to_liquids/index.html; *see* project diagram at: Gerhard Beysel and Thorsten Schueler, The Linde Group, The Proven Cryogenic Air Separation Process Adapted to the Needs of CCS (IGCC & Oxyfuel), October 6, 2010, p. 16; available at http://www1.icheme.org/gasification2010/pdfs/theprovencryogenicairseparationprocessthostenschueler.pdf; *see* project diagram at: The Linde Group, Cryogenic Air Separation, History and Technological Progress, p. 17; available at http://www.linde-engineering.com/internet.global.lindeengineering.global/de/images/L_2_1_e_10_150dpi20_4353.pdf.

[38] *See*, for example, Hudson Products Corporation, Basics of Air-Cooled Heat Exchangers; http://www.hudsonproducts.com/products/finfan/tech.html.

[39] *See*, for example, HECA Responses to CEC Data Requests Nos. A1 through A123, August 2012, p. A1-3; http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2012-08-22_Applicant_Response_to_CEC_Data_Request_no-A1_through_A123_TN-66876.pdf.

by reverse osmosis.[40] Thus, pretreatment of cooling water is feasible, has been achieved in practice and therefore must be evaluated in a BACT analysis.

Sierra Club respectfully requests CEC Staff to review Sections VI.E through VI.F.1 and Appendix N to Sierra Club's Comments on the PDOC for additional information on feasibility and cost-effectiveness of dry cooling.

It is important that CEC Staff address both air cooled condensers and fin-fan air coolers in the dry cooling or wet-dry hybrid cooling evaluation. Many refineries incorporate fin-fan air coolers for some processes even when wet cooling towers are also used onsite. Powers Engineering conducted a preliminary cost comparison between air cooling and wet towers at the proposed Big West Refinery in Bakersfield in 2007.[41] Sierra Club notes that a simple comparison of the cost of the air cooling systems and cooling towers is not sufficient, as the wet cooling system consists of numerous elements and costs beyond the cooling towers themselves. These include: cost of raw water, construction of raw water pump facility and pipeline, groundwater pump electrical usage, raw water treatment capital and operations and maintenance ("O&M") costs, and cooling tower blowdown treatment capital cost and O&M costs. It is important to assure that all costs for the cooling tower base case include all steps, and the costs associated with each of those steps necessary to get the water to and through the plant. Sierra Club notes that costs for particulate matter ERCs should also be accounted for in a cost-effectiveness analysis for wet cooling towers.

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[40] Department of Energy, Texas Clean Energy Project Final Environmental Impact Statement (DOE/EIS-0444), August 2011; available at http://www.netl.doe.gov/technologies/coalpower/cctc/EIS/final_eis_texas_clean_energy.html. *See* Table S2-2: *Cooling System*: "Two types of cooling systems would be used at the polygen plant: wet and dry cooling. An air-cooled (dry) condenser would be used for the combined-cycle power block. For the chemical process portion of the polygen plant, units requiring cooling to temperatures less than 140 degrees Fahrenheit (60 degrees Celsius) may use wet cooling. Makeup water for the wet cooling tower would be obtained from treated municipal waste water or ground water." *Source Water Treatment System*: "Source water would be delivered to the polygen plant site from one or more of the various waterline options under consideration. If source water from the GCA water option (either WL1 or WL5) were chosen, municipal waste water piped from the city of Midland would receive secondary biological treatment followed by *low pressure membrane filtration* (microfiltration or ultrafiltration) to remove particulate matter at the GCA Odessa South Facility. The source water would then be piped to the polygen plant site where the water would receive *additional treatment using a reverse osmosis system* to remove dissolved solids and other constituents prior to use in the various facility processes. For all other water sources under consideration (Oxy Permian and FSH), *low pressure membrane filtration and additional treatment using reverse osmosis membranes* would both occur at the polygen plant site. After the source water was treated by source water treatment system, it would be used as process water in the various plant processes." *Emphasis* added.

[41] Bill Powers, Powers Engineering, Comments on Proposed Big West Refinery Cooling System, March 27, 2007; *see* Sierra Club's PDOC Comments, Exhibit. N.

Sierra Club looks forward to reviewing in detail the air cooling versus water cooling analysis and urges that Staff will include this analysis in the revised PSA.

b) Flares

HECA proposes to use three steam-assisted elevated flares for both routine flaring and emergency flaring. The minimum "destruction and removal efficiency" ("DRE") of the elevated flare is 98%. Sierra Club's Comments on the PDOC discussed that BACT should require the use of enclosed ground flares and a flare gas recovery system instead of elevated flares.[42] The FDOC does not evaluate this comment and instead merely concludes that a flare gas recovery system is not technologically feasible because the facility will not routinely vent low volume gases and because of unsupported safety concerns.[43] CEC Staff eliminates the enclosed ground flare and flare recovery system alternative because it concludes that this option would not substantially lessen "any significant project-related air quality impacts and for safety reasons."[44] Sierra Club respectfully disagrees and requests CEC Staff to review Sierra Club's Comments on the PDOC, Section VI.G and consider the following.

CEC Staff accept at face value the assertions by the Applicant that the flares will rarely be used because of the exceptional reliability of the gasification process to be used at HECA and that enclosed ground flares are less safe and reliable than elevated flares. Sierra Club has presented the Air District and CEC Staff with the operating history of the one operational facility using the proposed HECA gasification technology, the Nakoso IGCC plant in Japan, which achieved poor availability in its first four years of operation. This means, at least in the case of the Nakoso IGCC, that off-spec gases are being routed to flare(s) on a routine basis. Flaring emissions are likely substantially underestimated by HECA and CEC Staff due to the use of a "best case" process reliability scenario to estimate flaring emissions.

HECA asserts there will be no malfunction flaring at HECA, due to the high reliability of the gasifier technology that will be employed. The amount of annual flaring estimated by the Air District in the PDOC for HECA's three flares is almost trivial: 28 hours for the gasification flare (startup and shutdown only), 40 hours for the sulfur recovery unit ("SRU"), and 40 hours for the Rectisol flare.[45] The assertion that

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[42] Sierra Club's PDOC Comments, pp. 88 through 93.

[43] FDOC, Appx. N-15.

[44] PSA, pp. 6-38 and 6-39.

[45] PDOC, pp. 84 through 86; available at: http://docketpublic.energy.ca.gov/PublicDocuments/Regulatory/08-AFC-8A/2013/FEB/TN%2069525%2002-07-13%20San%20Joaquin%20Valley%20Air%20Pollution%20Control%20District's%20Notice%20of%20Preliminary%20Determination%20of%20Compliance.pdf.

there will be no malfunction flaring is also used as justification for not utilizing a flare gas recovery system, which is an integral component of the Air District's definition of BACT for refinery flares.[46]

The most similar IGCC facility to HECA, Nakoso IGCC in Japan, experienced an availability of 30 percent in Year 1 and 60 percent in Year 2, only marginally better in its first two years of operation than the Tampa (TECO) and Wabash IGCC plant in the U.S., both of which have been operational nearly 20 years.[47] The low availability is due in part to forced outages (aka malfunctions).

Regarding the availability of the Nakoso IGCC plant over time, HECA consultant URS states "Except for a 4.5-month shutdown period following the 2011 earthquake and tsunami, this plant has been operating continuously (except for scheduled maintenance and inspection) on a wide range of coals from around the world (since operation began in 2007) … Cumulative operating hours since commissioning has exceeded 16,100 hours (as of April 2012)."[48] 16,100 hours operating hours from late 2007 through April 2012, excluding 4.5 months for the tsunami outage, is 16,100 hours over approximately four calendar years (35,040 hours). The actual availability of the Nakoso IGCC plant through April 2012 was (16,100 hours)/(35,040 hours) = 0.46 (46 percent). The availability of the Nakoso IGCC plant averaged 45 percent in the first two full years of operation. Thus, the plant averaged 46 percent availability over the first four full years of operation (through April 2012). Nakoso has definitely not been operating continuously. There is no reason based on the operating history at Nakoso to assume that HECA will not have frequent starts and stops due to forced outages.

It is for this reason – the likelihood of substantial periods of malfunction flaring at HECA and subsequent startup flaring following the malfunction shutdown(s) – that the use of an enclosed ground flare, combined with use of either a multi-point ground flare with radiation shields[49], which was proposed as flare BACT for the proposed Big West Refinery in Bakersfield, or a single elevated flare to handle major upsets caused by power outages (for example), should be flare BACT for the facility. This is especially true given that HECA will not be installing flare gas recovery systems. The enclosed

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[46] PDOC, Appx. C, p. C-30.

[47] John Wheeldon, Electric Power Research Institute, IGCC 101, Advanced Coal Gasification Technologies Workshop, Kingsport, 25th & 26th April 2012; available at http://www.gasification.org/uploads/downloads/Workshops/2012/Wheeldon,%20Kingsport.pdf.

[48] HECA's Responses to Sierra Club Data Requests – Nos. 98 through 131, Amended Application for Certification for Hydrogen Energy California (08-AFC-8A) Kern County, California, November 2012, p. 116-1.

[49] For a description, *see*, for example, Zeeco, Multi-Point Ground Flare, 2013; available at http://www.zeeco.com/pdfs/Multi-Point_Ground_Flare.pdf.

ground flare is a necessary component of the flare gas system in light of the failure by HECA to incorporate flare gas recovery system(s) in the plant design.

Enclosed ground flares have been in industrial use for decades, including at the ExxonMobil Refinery in Torrance, California, and have been proposed for the Big West Refinery in Bakersfield, California, and the Pacific Mountain Energy Center IGCC facility in Washington.[50] HECA's consultant, URS Corporation, was part of a team of consultants that identified an enclosed ground flare as BACT for the proposed Pacific Mountain Energy Center IGCC facility in 2006.[51] The estimated carbon monoxide ("CO") destruction efficiency of the enclosed ground flare was 99%; the capacity of the enclosed ground flare for the gasification block is essentially the same as the capacity of the proposed HECA gasification block flare at 4,000 MMBtu/hr.[52]

The purpose of the enclosed ground flare is to effectively combust relatively small amounts of predictable off-specification process gas steams under all wind conditions and with no light pollution. A multipoint ground flare with radiation shield[53] is necessary to combust very large flows to the flare that would occur under emergency conditions, such as a complete loss of power when the facility is at full production.

Further, elevated flare technology is identified in the SJVAPCD refinery flare BACT guideline as having a VOC destruction efficiency of ≥ 98%. HECA is proposing three elevated flares at HECA, with a purported CO and VOC destruction efficiency of 99 percent.[54] However, HECA provided no data to support a CO and VOC destruction efficiency higher than the ≥ 98% assumed in the SJVAPCD BACT guideline for the elevated flare technology.

There is no elevated flare design that has been demonstrated to consistently achieve 98% control under all operating conditions, especially during malfunctions. Many factors reduce flare efficiency in elevated flares. Non-optimal combustion

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[50] *See* Sierra Club's Comments on the PDOC, Section VI.G.1, p. 89.

[51] *See* Energy Northwest, Re: Submittal of Application for Site Certification, Pacific Mountain Energy Center, Kalama, Washington, September 12, 2006; http://www.efsec.wa.gov/PMEC/App/TOC.pdf; ("The Application was prepared jointly by Energy Northwest, URS Corporation, and Geomatrix Consultants.") and HECA's Responses to Sierra Club Data Requests – Nos. 98 through 131, November 2012, p. 121-1; ("The Pacific Mountain Energy Center proposed to install an elevated enclosed flare as part of the gasification block.")

[52] Pacific Mountain Energy Center, EFSEC Application 2006-01, Appendix B Air Quality, B.1 BACT Analysis, Enclosed Ground Flare Emission Rates, Geomatrix Consultants, March 30, 2007; available at http://www.efsec.wa.gov/PMEC/App/PMEC%20Appx%20B.pdf.

[53] *See*, for example, Zeeco, Multi-Point Ground Flare, 2013; available at http://www.zeeco.com/pdfs/Multi-Point_Ground_Flare.pdf.

[54] PDOC, Appx. C, p. C-30.

conditions occur, even with well-designed flares. These non-optimal conditions can substantially reduce flare efficiency. The source test data used to establish the minimum elevated flare "destruction and removal efficiency" ("DRE") of 98 percent was conducted under EPA contract with crosswinds at or below 5 miles per hour ("mph").[55] The 98 percent minimum DRE derived from this test data is not applicable to periods when crosswinds exceed 5 mph at the flare tip. In the case of HECA, the flare tip elevation is 300+ feet above ground level. The mean wind speed in Buttonwillow, California at 260 feet (80 meters) above ground level is approximately 9 mph (4 meters/second).[56] At 300 feet above the ground at the proposed plant site, crosswinds will exceed 5 mph most of the time.

The proposed flare manufacturer for HECA, John Zink, has highlighted the problems that can cause low flare efficiency and other flaring problems in elevated flares. John Zink co-authored an article published in *Hydrocarbon Processing* on refinery flares, which states:[57]

> The problem. To the casual observer, it may seem relatively easy to minimize and even eliminate routine flaring from refineries and petrochemical/chemical plants. It appears that these plants are unnecessarily wasting energy and generating pollution. The main challenge is that it can be uneconomical to recover the gases, either for use in the plant or to sell as energy, for a variety of reasons.
>
> The flowrate and composition of the waste gases going to the flare are often highly variable. The unsteady flow (Fig. 2) and variable composition (Table 1) make it difficult to use the waste gases elsewhere in the plant where the energy demand is normally steady. The variable composition makes it difficult to sell, unless a purification system is added to produce a more consistent composition.
>
> The waste gases may have a low heating value, which means that equipment such as burners must be properly designed for the low heating value. The waste gases may be off-spec product that is being flared because it cannot be sold and is not easily reprocessed to produce on-spec product. Off-spec flaring may occur for some time during startup until the product is within specification.

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[55] Marc McDaniel, Engineering-Science, Inc., Flare Efficiency Study, July 1983, EPA-600/2-83-052, p. 19; available at http://www.epa.gov/ttn/chief/ap42/ch13/related/ref_01c13s05_jan1995.pdf. ("Testing of the flares was found to be infeasible when wind velocities exceeded 5 miles per hour. Elevated wind velocities prevented sustained and consistent positioning of the probe in the flare plume.")

[56] National Renewable Energy Laboratory, California 80-Meter Wind Map and Wind Resource Potential (map), October 6, 2010; http://www.windpoweringamerica.gov/wind_resource_maps.asp?stateab=ca. (4 m/s × 3.25 ft/m × 60 seconds/min × 60 min/hr)/5,280 ft/mile = 8.9 mph.)

[57] J. Peterson, Flint Hills Resources and N. Tuttle, H. Cooper and C. Baukal, John Zink Co., LLC, Minimize Facility Flaring, Flares Are Safety Devices that Prevent the Release of Unburned Gases to Atmosphere, June 2007 issue, pp. 111 through 115; available at http://www.johnzink.com/wp-content/uploads/flare_hydro_proc_june_20071.pdf.

> . . . There is growing concern that emissions of VOCs from flares may be much higher than previously thought. One possible reason is that wind effects can reduce flare destruction efficiency. The estimated emissions from flares are often based on measurements made with little or no wind. Accordingly, the emissions may be much higher under windy conditions.
>
> . . . Another very challenging problem is that weather conditions, the waste-gas flowrate, and composition are highly variable and not generally controllable. For example, wind plays a very significant role in the performance of a flare.

Another study cited in the *Hydrocarbon Processing* article identifies wind speed as a major impact on elevated flare efficiency, cites wind tunnel flare efficiencies under 90 percent in certain wind conditions.[58] This reduced efficiency would substantially increase elevated flare emissions compared to emissions using the assumed 98% DRE.

No evidence has been provided by CEC Staff or the Applicant to support the contention that an enclosed ground flare is less safe that an elevated flare. Sierra Club specifically asked in discovery for HECA to provide the safety record of enclosed Ground Flare 65F-8 at the ExxonMobil Torrance Refinery that has been in operation for more than 20 years. The purpose of this request was to provide URS/HECA a concrete opportunity to demonstrate with an actual operating history record that a ground flare at a Southern California refinery was in fact less safe or reliable than elevated flares. HECA declined to do so.[59]

Elevated flares are also a source of light pollution and negative visual impacts. A major advantage of the enclosed ground flare is elimination of the light pollution associated with elevated flares.

c) Fugitive Equipment Leaks

Sierra Club commented that the PDOC's BACT determination for fugitive equipment leaks is deficient because BACT is not required for four of the Project's process streams.[60] The FDOC does not evaluate this comment, and instead merely concludes that the PDOC's BACT determination for fugitive equipment leaks follows guidelines and is appropriate.[61] Sierra Club respectfully requests CEC Staff to review Sierra Club's Comments on the PDOC, Section VI.H.

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[58] P.E.G. Gogolek and A.C.S. Hayden, Performance of Flare Flames in a Crosswind With Nitrogen Dilution, Journal of Canadian Petroleum Technology, August 2004, Volume 43, No. 8, p. 1.

[59] HECA's Response to Sierra Club's Data Requests 98-131, November 2012, p. 122-1.

[60] Sierra Club's Comments on PDOC, pp. 94 through 96.

[61] FDOC, Appx N.-15.

IV. Voluntary Emission Reduction Agreement with Air District

HECA entered into a *Voluntary Emission Reduction Agreement* with the Air District for about $1.2 million to mitigate the additional NOx emissions HECA would generate compared to a natural gas-fired combined-cycle baseload plant.[62] This agreement was not part of the PDOC and was not made available for public comment. For reasons stated below, Sierra Club believes that the *Voluntary Emission Reduction Agreement* does not fulfill its intended objective.

The *Voluntary Emission Reduction Agreement* requires one-time payment of $1.2 million for the excess NOx emissions of 16.7 tons/year HECA would emit compared to a natural gas-fired combined-cycle baseload plant with a similar power output to the grid.[63] The Air District calculates this fee based on a pound NOx per Megawatt-hour rate compared to the proposed Avenal Energy plant as a representative natural gas-fired combined-cycle baseload plant and the current average NOx ERC cost of $67,492 per ton. The Air District's calculation is based on each facility's net annual electricity supply in Megawatt-hours per year and annual NOx emissions in tons per year.[64]

Sierra Club identified several problems with the District's emission estimates resulting in a substantial underestimate of the excess NOx emissions the Air District intends to mitigate with this agreement. Sierra Club requests that CEC Staff considers the following in evaluating whether the proposed *Voluntary Emission Reduction Agreement* would indeed provide the expected air quality benefits and consider whether additional mitigation is required to satisfy CEC's obligation under CEQA.

i) *Problem 1 – Net annual power electricity supply to grid is incorrect metric*: The District's calculations rely on the assumption that HECA would supply about 2.2 million MWh per year of electricity to the grid. This assumption fails to take into account the enormous power demand of the air separation unit which would draw about 0.9 million MWh per year from the grid.[65] As discussed in more detail in Sierra Club's comments on the *Carbon Sequestration and Greenhouse Gas Emissions* section of the PSA, the air separation unit is an integral part of the gasification process and would substantially reduce the net electricity available California grid customers.

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[62] San Joaquin Valley Air Pollution Control District, Hydrogen Energy California Power Plant Project, Mitigation Agreement 20130092 and Voluntary Emission Reduction Agreement 20130026; available at http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/others/2013-04-26_SJVUAPCD_Mitigation_Agreement_TN-70496.pdf.

[63] Voluntary Emission Reduction Agreement, p. 2.

[64] Voluntary Emission Reduction Agreement, Exhibit A.

[65] PSA, Carbon Sequestration and Greenhouse Gas Emissions Table 9, p. 4.3-44.

Because a natural gas-fired combined-cycle plant does not have any comparable equipment that would draw electricity from the grid at similar rates, the ASU's electricity consumption must be included in an apples-to-apples comparison of pollutant emission efficiency for HECA and Avenal Energy. CEC Staff estimated that the net electricity HECA would supply to the grid after accounting for the ASU would amount to about 1.9 million MWh/year.[66]

ii) *Problem 2 – Underestimated annual NOx emissions from HECA*: For annual NOx emissions from the two power plants, the District considers Avenal Energy's two combustion turbines[67] and HECA's combustion turbine generator/heat recovery steam generator and the coal dryer.[68] This is an apples-to-oranges comparison because HECA's IGCC process requires additional equipment that would emit NOx that is not required for a natural gas-fired plant. This equipment includes the tail gas thermal oxidizer with annual NOx emissions of 13.4 tons/year and the gasification flare with annual NOx emissions of 2.5 tons/year.[69] The additional 15.9 tons/year from these units increase HECA's NOx emissions by 13%.[70]

iii) *Problem 3 – Underestimated net annual electricity supplied by Avenal Energy*: The District assumes a net electricity output of about 3.0 million Megawatt-hours per year for Avenal Energy which is substantially lower than the estimate provided in the CEC's Final Staff Assessment of 4.5 million Megawatt-hours per year.[71] Consequently, the pound NOx per Megawatt-hour emission rate estimated by the District for Avenal Energy is almost 50% too high.[72]

As a result of the above identified issues, the Air District's estimate of excess NOx emissions from HECA compared to Avenal Energy on a MWh basis are far too low and describe only a portion of HECA's true impacts.

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[66] PSA, Carbon Sequestration and Greenhouse Gas Emissions Table 9, p. 4.3-44.

[67] Compare Voluntary Emission Reduction Agreement, Exhibit A, p. A-2 (144 tons NOx /year) to Final Staff Assessment for Avenal Energy, Air Quality Table 12, p. 4.1-20 (144 tons NOx /year both combustion turbines); available at http://www.energy.ca.gov/2009publications/CEC-700-2009-001/CEC-700-2009-001-FSA.PDF.

[68] Voluntary Emission Reduction Agreement, Exhibit A, p. A-2.

[69] *See* PSA, Air Quality Table 17, p. 4.1-43.

[70] (123.5 + 15.9) / (123.5) = **1.13**.

[71] Final Staff Assessment for Avenal Energy, Table 2, p. 4.1-78. http://docketpublic.energy.ca.gov/PublicDocuments/Regulatory/Non%20Active%20AFC%27s/08-AFC-1%20Avenal%20Energy/2009/June/TN%2051865%2006-04-09%20Final%20Staff%20Assessment.pdf.

[72] (3,023,388 MW-hr/year) / (4,460,000 MW-hr/year) = **1.48**.

Sierra Club also questions the continued effectiveness of the Air District's emission reduction programs funded by mitigation agreements to create air quality benefits. The agreement assumes that the Air District would use the fee paid by HECA to establish specific programs that create air quality benefits within its jurisdiction.[73] In particular, the Air District intends to establish programs that focus on replacing agricultural equipment, including old tractors and old haul trucks, operating to the extent possible within Kern County or within nearby communities in the San Joaquin Valley.[74] The Air District provides no evaluation of the feasibility of this proposal. Anecdotal evidence appears to indicate that the low-hanging fruit for such programs have already been picked and any future projects will cost increasingly more per ton of NOx reduced. For example, at the September 17-19, 2013 workshop, Mr. Tom Frantz, a local landowner and farmer, stated that his friend obtained $36,000 in funding from the Air District to replace an old tractor and was told that this transaction would result in one third of a ton in NOx reductions. This translates into a cost of $108,000 per ton of NOx reduced, about 1.6 times of what HECA is required to pay under the *Voluntary Emission Reduction Agreement* with the Air District. It appears that the assumption of the average price of NOx ERCs may not be a good indicator of the actuals costs to reduce emissions from agricultural equipment.

Further, it may take years for any mitigation program to take effect and the District has provided no demonstration that there are actually sufficient sources nearby or within Kern County whose emissions could be reduced. Sierra Club suggests that CEC Staff requires the Air District to provide an inventory analysis of older high-emitting agricultural equipment currently being used in the vicinity of HECA and in Kern County and quantify potential NOx reductions that could be achieved by replacing this equipment as well as the costs of subsidizing their replacement.

Finally, Sierra Club inquires whether HECA will be able to pass on the about $8.7 million fees it is obligated to pay under the two mitigation agreements with the Air District to California rate payers.

V. Mitigation for Fugitive Coal Dust Emissions from Rail Cars

Fugitive dust and pieces of coal falling from railcars is a major concern. Publicly available testimony from coal companies quantifies the loss from each rail car at between 250 and 700 pounds of coal and coal dust on each trip for an average loss of 500 pounds of coal lost from each car per trip.[75] CEC staff addresses these concerns with

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[73] Voluntary Emission Reduction Agreement, p. 2.

[74] *Ibid*.

[75] Sierra Club's Comments on PDOC, p. 122 (citing Hearing Transcript and Recording, July 29, 2010, Arkansas Electric Cooperative Association – Petition for Declaratory Order, Surface Transportation

Condition of Certification AQ-SC10 which requires a) the use a surface stabilizing compound (surfactant or water), railcars with adequate freeboard or other mitigation design features or combination thereof; b) that no coal and produced product of any size are released in visible quantities alongside the rail spur from the main rail line to the project site; and c) that no visible product coal dust is emitted at the project site or along the rail spur. The condition requires the Applicant to inspect the rail spur on a monthly basis or if complaints are received. The condition eliminates the requirement for this measure if fully enclosed railcars are used for coal or produced product transport.[76]

Sierra Club requests that CEC modify this condition to require the use of closed railcars since neither surfactants nor water would adequately control dust or coal spillage from the rail cars, as discussed below. Further, Sierra Club notes that railcars also lose coal from the bottom hopper, not just from the top, and dust suppressants have no effect on the chunks of coal that are spilled from the top or bottom of the rail cars.[77] Sierra Club further requests that CEC Staff require regular inspections of the rail spur regardless of what type of railcars are used by the Applicant because inspection is the only means to ensure compliance.

While surfactants have been demonstrated to achieve some control of dust from stationary coal piles, the effectiveness of surfactants, applied on loaded coal at the mine, over long distances is questionable and claimed control efficiencies have been criticized as being based on "junk science".[78] There is some evidence that indicates that

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Board, Docket No. FD 35305, tape 1 at Transcript (Tr.) at 102:9-103:7, 37:07, 1h:42; Tr. at 42:5-13, 102:9-103:7 (BNSF Testimony)).

[76] PSA, p. 4.1-130.

[77] *See* Sierra Club Comments on PDOC, pp. 122 through 123.

[78] Before the Surface Transportation Board, Reasonableness of BNSF Railway Company Coal Dust Mitigation Tariff Provisions, Finance Docket No. 35557, Opening Evidence and Argument of Western Coal Traffic League, American Public Power Association, Edison Electric Institute and National Rural Electric Cooperative Association, October 1, 2012 ("STB Brief"), PDF p. 18 ("Coal Shippers demonstrated in Dust I that the coal dust mitigation standards in the Original Coal Dust Tariff [the 85% relied on by ODEQ] were predicated on junk science..."). *See* also Arkansas Electric Cooperative Corporation's Reply Evidence and Argument, PDF p. 3 ("BNSF created the appearance that toppers are highly effective by simply excluding from testing the real world conditions where they are not effective."), PDF p. 4 ("BNSF's claim that toppers remain intact until they reach their final destination is refuted by [REDACTED] toppers cannot achieve the promised reductions in fugitive coal deposition between the mine and the power plants."), PDF p. 9 ("… the profile established at the mine and the coating of the topper on the coal are likely to degrade during the course of the rail journey from the mine. This is particularly true where excessive stresses are placed on the coal load as a result of the railroad's operations (*e.g.*, excessive speed, slack action, etc.,) and/or the state and condition of the track (*e.g.*, modulus changes, worn switches, etc.). Shippers have no control over these factors, which may materially alter the load profile and/or the integrity of the topper that have been applied."), PDF p. 14 ("The safe harbor toppers put a thin chemical coating over the top of the coal, which is supposed to "keep [] the wind from blowing coal dust out of a coal car or off the top of a coal stockpile."[] that may work

surfactants/topping agents may even increase coal loss due to "saltation".
A declaration by Dr. Mark Viz in a case before the Surface Transportation Board ("STB") noted as follows: [79]

> e. I also note at the outset that many if not all of the dust suppressants were designed for use in dust mitigation from static coal stockpiles at coal-burning power plants or similar facilities. In this regard these products are generally recognized to work when applied to a large pile of coal ***that is stationary***, but there are still many aspects of their performance ***in moving railcars*** that have not yet been verified. I have observed from my own field work that crusting agents and other topper sprays essentially break apart when a railcar gets shaken or bumped going over the track. Frequently other events can also occur to either upset the efficacy of the topper agent or in certain cases to make the fugitive loss even worse by a process known as "saltation," i.e., the greater entrainment of particles in a moving air stream as a result of released particles impacting the surface and therefore releasing yet greater amounts of dust. The performance of suppressants during precipitation events and long exposure to wind and solar radiation are also not that well-understood.

Topping agents have a limited useful lifetime as they breakdown by ultraviolet radiation and microbes; abrasion and loss from wind erosion and motion of the train; washout by rain; and degradation of the coal itself.[80] One proposed topping agent, for example, DustBind, is mostly alcohol, which is highly volatile. As noted by Dr. Viz, topping agents have been mainly studied only on stationary coal piles, not on moving

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well enough on a stationary pile of coal, but coal cars move. Coal leaves a rail car not only because of wind, but also because of vibrations, impacts, and other forces caused by the movement of the train over the track… Moreover, these same forces can cause the thin chemical coating on top of the coal in the car to break apart so that it is no longer effective even to prevent wind-blown coal dust."), PDF p. 15 ("BNSF's claim that chemical toppers are a silver bullet to prevent deposition of fugitive coal is a fantasy."); available at: http://www.stb.dot.gov/filings/all.nsf/d6ef3e0bc7fe3c6085256fe1004f61cb/dbf283ade01f06db85257a8b004d420f/$FILE/233093.PDF.

[79] Verified Statement of Mark J. Viz, Ph.D., P.E., on behalf of Western Coal Traffic League, American Public Power Association, Edison Electric Institute and National Rural Electric Cooperative Association, in support of Opening Brief Dust II, Surface Transportation Board, Docket No. 35557, October 1, 2012, p. 3.

[80] *See*, for example, Kotchenruther EPA Region 10, Fugitive Dust from Coal Trains: Factors Effecting [sic] Emissions & Estimating PM2.5, 2013; available at: http://lar.wsu.edu/nw-airquest/docs/201306_meeting/20130606_Kotchenruther_coal_trains.pdf. ("Effectiveness of controls may wear off throughout journey, leading to more dust later in the journey.").

trains.[81] Further, evidence presented in proceedings before the Surface Transportation Board suggests that all or most of the topping agent or surfactant is lost during transit.[82]

Further, surfactants contain a myriad of unknown chemicals that have not yet been adequately studied which could cause a number of potential harms, including: danger to human health during and after application; surface, groundwater and soil contamination; air pollution; and impacts on native flora and fauna populations.[83]

Using covered rail cars would have the added benefit of potentially reducing round-trip fuel use by about 9 percent. Attached for the CEC's reference is a DoE-sponsored study regarding the potential fuel savings achieved by reducing the aerodynamic drag of rail cars by using covers.[84]

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[81] *See* Western Coal Transportation League brief, p. 19. Viz verified statement at p. 3.

[82] Verified statement of Michael Nelson, a coal transportation analyst provided in support of *Arkansas Electric Cooperative Ass'n* reply brief, Dust II Proceeding, Surface Transportation Board, Docket. No. FD 35557 , November 15, 2012. "Ultimately, the evidence shows that BNSF's claim that the toppers normally are intact at the destination point is unsupported, incorrect, and entitled to no weight." Further, utilities have noticed that topping agents do not make it through the trip. "Corroboration of the seriousness of enroute topper failure has been provided by coal users who have movements currently receiving treatment with safe harbor toppers. Such users have noticed that the toppers they pay for frequently don't make it all the way to the plant." Nelson, *id.* at 7; available at: http://www.stb.dot.gov/filings/all.nsf/d6ef3e0bc7fe3c6085256fe1004f61cb/3ce0771991fbe5ee85257ab8004f5d75/$FILE/233355.pdf.

[83] Dr. Thomas Piechota, Eds., et al., Potential Environmental Impacts of Dust Suppressants: "Avoiding Another Times Beach," An Expert Panel Summary, Las Vegas, Nevada (May 30-31, 2002) at Section 3, http://www.epa.gov/esd/cmb/pdf/dust.pdf.

[84] Bruce Storms, NASA Ames Research Center, Kambiz Salari, Lawrence Livermore National Laboratory And Alex Babb, University of California Los Angeles, Fuel Savings & Aerodynamic Drag Reduction from Rail Car Covers. ("The median wind-averaged drag reduction for all four [tested] cover designs was 43% which would result in a round-trip fuel savings of approximately 9%"). Attached as Exhibit 3.

Exhibit 1

TELEPHONE CONVERSATION

Date: 2/26/93
Time: 2:00

With: Geraldo Rios Title:

Company : EPA Phone: (415) 744-1257

APCD Representative: Lance Ericksen Title

Subject of Conversation: Frito-Lay Banking Project

Summary of Conversation:

LE: will you comment on the frito-Lay banking project

GR: Is this the project EPA previously agreed to use as offsets only by frito-lay

LE: Yes The ERC banking certificate will be limited to use by frito-lay at their highway 58 site or by other non-major sources.

GR. With these limitations I probably won't comment

LE we will need to proceed with issuance. I'll send you a copy of the draft ERC document.

GR OK

TELEPHONE CONVERSATION

Date: 2/25/93
Time: 11:15

With: Narci
Title:
Company : CARB
Phone: (916) 327-5611
APCD Representative: Lance Ericksen
Title
Subject of Conversation: Comments on Frito-Lay Banking
Summary of Conversation:

LE: Will you be commenting on the Frito-Lay Project 600026 920416

N: There will be no comments from CARB

EMISSION REDUCTION CREDIT CERTIFICATE S-0001-6

CONDITIONS:

1. **Any new or modified combustion device otherwise permit exempt heating crude oil at Ant Hill shall obtain Authority to Construct prior to installation or modification. (Rules 2201 and 230.1)**

2. **Per Rule 2201 4.2.5.1, these reduction credits may not be used as offsets for emissions from a major source or major modification.**

Exhibit 2

SIERRA CLUB FOUNDED 1892

Andrea Issod <andrea.issod@sierraclub.org>

Groundwater Information

chris ROMANINI <romaninichris2@gmail.com> Sat, Sep 28, 2013 at 11:10 AM
To: Andrea Issod <andrea.issod@sierraclub.org>, Beau Antongiovanni <blwillow@netzero.com>, Tom Frantz <tom.frantz49@gmail.com>

A response from Kern Water Agency stating overdraft in Kern.

Begin forwarded message:

From: "Bauer, Lauren" <lbauer@kcwa.com>
Subject: Groundwater Information
Date: September 27, 2013 3:06:21 PM PDT
To: Chris Romanini <romaninichris2@gmail.com>
Cc: "Varga, Jeanne" <jvarga@kcwa.com>

Chris,

Per our conversation yesterday morning, the Kern County Water Agency (Agency) produces an annual water supply report that includes an inventory of water supplies and demands relative to the Valley floor. Agency staff uses these data to calculate a hydrologic balance for the region, including the Kern groundwater subbasin. Per the Agency's 2011 Water Supply Report (Report), the average annual overdraft of the Kern subbasin from 1970 through 2011 is approximately 80,000 acre-feet per year. For this same time period, the Report shows that the cumulative overdraft is approximately 3.4 million acre-feet. As I explained on the phone, in wet years typically more water is recharged into the groundwater basin than is recovered and vise versa in dry years. To illustrate this, attached is Figure 18 of the Report that shows annual water supplies and demand. As illustrated on the graph, when surface water supplies are insufficient to meet demands, water is recovered from the groundwater basin.

Additionally, please find attached the following documents:

1. DWR's 2003 groundwater bulletin (Bulletin 118) Chapter 7 for the Tulare Lake Region – this document includes general information on the groundwater subbasins in the Tulare Lake Hydrologic Region.

2. DWR's Bulletin 118 Kern basin section (updated in 2006) – this document includes information specific to the Kern subbasin.

If you have any questions, please let me know.

Thank you,
Lauren

Lauren Bauer
Water Resources Planner
Kern County Water Agency
Office: (661) 634-1411
Fax: (661) 634-1438
lbauer@kcwa.com

3 attachments

bulletin118_7-tl.pdf
949K

5-22.14.pdf
48K

KCWA_2011WSR_Figure18_1970_2011.pdf
88K

San Joaquin Valley Groundwater Basin
Kern County Subbasin

- Groundwater Basin Number: 5-22.14
- County: Kern
- Surface Area: 1,945,000 acres (3,040 square miles)

Basin Boundaries & Hydrology

The San Joaquin Valley is surrounded on the west by the Coast Ranges, on the south by the San Emigdio and Tehachapi Mountains, on the east by the Sierra Nevada and on the north by the Sacramento-San Joaquin Delta and Sacramento Valley. The northern portion of the San Joaquin Valley drains toward the Delta by the San Joaquin River and its tributaries, the Fresno, Merced, Tuolumne, and Stanislaus Rivers. The southern portion of the valley is internally drained by the Kings, Kaweah, Tule, and Kern Rivers that flow into the Tulare drainage basin including the beds of the former Tulare, Buena Vista, and Kern Lakes.

The Kern County Groundwater subbasin is bounded on the north by the Kern County line and the Tule Groundwater subbasin, on the east and southeast by granitic bedrock of the Sierra Nevada foothills and Tehachapi mountains, and on the southwest and west by the marine sediments of the San Emigdio Mountains and Coast Ranges. Principal rivers and streams include Kern River and Poso Creek. Active faults include the Edison, Pond-Poso, and White Wolf faults. Average precipitation values range from 5 in. at the subbasin interior to 9 to 13 in. at the subbasin margins to the east, south, and west.

Hydrogeologic Information

The San Joaquin Valley represents the southern portion of the Great Central Valley of California. The San Joaquin Valley is a structural trough up to 200 miles long and 70 miles wide filled with up to 32,000 feet of marine and continental sediments deposited during periodic inundation by the Pacific Ocean and by erosion of the surrounding mountains, respectively. Continental deposits shed from the surrounding mountains form an alluvial wedge that thickens from the valley margins toward the axis of the structural trough. This depositional axis is below to slightly west of the series of rivers, lakes, sloughs, and marshes that mark the current and historic axis of surface drainage in the San Joaquin Valley.

Water Bearing Formations

Sediments that comprise the shallow to intermediate depth water-bearing deposits in the groundwater subbasin are primarily continental deposits of Tertiary and Quaternary age. From oldest to youngest the deposits include the Olcese and Santa Margarita Formations; the Tulare Formation (western subbasin) and its eastern subbasin equivalent, the Kern River Formation; older alluvium/stream deposits; and younger alluvium and coeval flood basin deposits. Specific yield values for the unconfined aquifer (Tulare and Kern River Formations and overlying alluvium) were compiled from two sources. The DWR's San Joaquin District office estimates (unpublished) ranges from 5.3 to 19.6 percent and averages 11.8 percent for the interval from surface to

300 feet below grade. The DWR (1977) groundwater model of Kern County lists the range as 8.0 to 19.5 percent with an average value of 12.4 percent representing an interval thickness of 175 to 2,900 feet and averaging approximately 600 feet. The greatest thickness of unconfined aquifer occurs along the eastern subbasin margin. The highest specific yield values are associated with sediments of the Kern River Fan west of Bakersfield.

Olcese and Santa Margarita Formations
The origin of these Miocene-age deposits varies from continental to marine from east to west across the subbasin (Bartow and McDougall 1984). The Olcese and Santa Margarita Formations are current or potential sources of drinking water only in the northeastern portion of the subbasin where they occur as confined aquifers. The Olcese Formation is primarily sand, ranging in thickness from 100 to 450 feet. The Santa Margarita Formation is from 200 to 600 feet thick and consists of coarse sand (Hilton and others 1963).

Tulare and Kern River Formations
These units are both Plio-Pleistocene age and represent a west/east facies change across the subbasin. The Tulare Formation (western subbasin) contains up to 2,200 feet of interbedded, oxidized to reduced sands; gypsiferous clays and gravels derived predominantly from Coast Range sources. The formation includes the Corcoran Clay Member, which is present in the subsurface from the Kern River Outlet Channel on the west through the central and much of the eastern subbasin at depths of 300 to 650 feet (Croft 1972), groundwater beneath the Corcoran Clay is confined. The Kern River Formation includes from 500 to 2,000 feet of poorly sorted, lenticular deposits of clay, silt, sand, and gravel derived from the Sierra Nevada. Both units are moderately to highly permeable and yield moderate to large quantities of water to wells (Hilton and others 1963).

Older Alluvium/Stream and Terrace Deposits
This unit is composed of up to 250 feet of Pleistocene-age lenticular deposits of clay, silt, sand, and gravel that are loosely consolidated to cemented and are exposed mainly at the subbasin margins. The unit is moderately to highly permeable and yields large quantities of water to wells (Hilton and others 1963; Wood and Davis 1959; Wood and Dale 1964). This sedimentary unit is often indistinguishable from the Tulare and Kern Formations below and together with these underlying formations, forms the principal aquifer body in the Kern County Groundwater subbasin.

Younger Alluvium/Flood Basin Deposits
This Holocene-age unit varies in character and thickness about the subbasin. At the eastern and southern subbasin margins the unit is composed of up to 150 feet of interstratified and discontinuous beds of clay, silt, sand, and gravel. In the southwestern subbasin it is finer grained and less permeable as it grades into fine-grained flood basin deposits underlying the historic beds of Buena Vista and Kern Lakes in the southern subbasin (Hilton and others 1963; Wood and Dale 1964). The flood basin deposits consist of silt, silty clay, sandy clay, and clay interbedded with poorly permeable sand layers. These flood basin deposits are difficult to distinguish from underlying fine-grained older alluvium and the total thickness of both units may be as much as 1,000 feet (Wood and Dale 1964).

Restrictive Structures

Faults that affect groundwater movement include the Edison, Pond-Poso, and White Wolf faults. Other barriers to groundwater movement include folds such as Elk Hills and Buena Vista Hills, angular unconformities, and contacts with crystalline and consolidated sedimentary rocks at the subbasin margins (DWR 1977). The Corcoran Clay significantly impedes vertical groundwater movement where present.

Recharge Areas

Natural recharge is primarily from stream seepage along the eastern subbasin and the Kern River; recharge of applied irrigation water, however, is the largest contributor (DWR 1995).

Groundwater Level Trends

The average subbasin water level is essentially unchanged from 1970 to 2000, after experiencing cumulative changes of approximately -15 feet through 1978, a 15-foot increase through 1988, and an 8-foot decrease through 1997. However, net water level changes in different portions of the subbasin were quite variable through the period 1970-2000. These changes ranged from increases of over 30 feet at the southeast valley margin and in the Lost Hills/Buttonwillow areas to decreases of over 25 and 50 feet in the Bakersfield area and McFarland/Shafter areas, respectively. The above information is a summary of unpublished DWR water level data.

Groundwater Storage

Kern County Water Agency estimates the total water in storage to be 40,000,000 af and dewatered aquifer storage to be 10,000,000 af (Fryer 2002). It appears that these calculations consider areas of the subbasin which are known to overlay useable groundwater, which they report to be about 1,000,000 acres.

Additional Information

Between 1926 and 1970, groundwater extraction has resulted in more than 8 feet of subsidence in the north-central portion of the subbasin, and approximately 9 feet in the south-central area (Ireland and others 1984).

Water banking was initiated in the subbasin in 1978, and as of 2000, seven projects contain over 3 million af (MAF) of banked water in a combined potential storage volume of 3.9 MAF (KCWA 2001). Approximately two-thirds of this storage is in the Kern River Fan area west of Bakersfield; the remainder is in the Arvin-Edison WSD in the southeastern subbasin or in the Semitropic WSD in the northwestern subbasin.

Groundwater Budget (Type A)

The budget presented below is based on data collected as part of DWR's Bulletin 160 preparation. The basis for calculations include a 1990 normalized year and land and water use data, with subsequent analysis by a DWR water budget spreadsheet to estimate overall applied water demands, agricultural groundwater pumpage, urban pumping demand, and other extraction data. As no data for subsurface inflow or outflow exists in Bulletin 160 data, these values were obtained from a 1977 groundwater model developed by DWR and the Kern County Water Agency (DWR 1977). Inflows to the subbasin include natural recharge of 150,000 af per year, artificial recharge of 308,000 af per year, applied water recharge 843,000 af per year, and a 1958-1966 average estimated subsurface inflow of 233,000 af per year (DWR 1977), for a total subbasin inflow of 1,534,000 af per year. Subbasin outflows are urban extraction of 154,000 af per year, agricultural extraction of 1,160,000 af per year, other extractions (oil industry related) of 86,333, and subsurface outflow was considered minimal, for a total subbasin outflow of 1,400,300 af per year. In addition to the above budget, KCWA has prepared a detailed long-term water balance from 1970 to 1998 which shows an average change in storage of minus 325,000 af per year (Fryer 2002). This analysis does not consider subsurface inflow.

Groundwater Quality

Characterization. The eastern subbasin contains primarily calcium bicarbonate waters in the shallow zones, increasing in sodium with depth. Bicarbonate is replaced by sulfate and lesser chloride in an east to west trend across the subbasin. West side waters are primarily sodium sulfate to calcium-sodium sulfate type (Hilton and others 1963; Wood ands Dale 1964; Wood and Davis 1959; Dale and others, 1966). The average TDS of groundwater is 400-450 mg/L with a range of 150 – 5,000 mg/L (KCWA 1995).

Impairments. Shallow groundwater presents problems for agriculture in the western portion of the basin. High TDS, sodium chloride, and sulfate are associated with the axial trough of the subbasin. Elevated arsenic concentrations exist in some areas associated with lakebed deposits. Nitrate, DBCP, and EDB concentrations exceed MCLs in various areas of the basin. Specific data for municipal production wells are available in the DHS water quality data base.

Water Quality in Public Supply Wells

Constituent Group[1]	Number of wells sampled[2]	Number of wells with a concentration above an MCL[3]
Inorganics – Primary	444	18
Radiological	372	15
Nitrates	475	38
Pesticides	436	23
VOCs and SVOCs	409	19
Inorganics – Secondary	444	60

[1] A description of each member in the constituent groups and a generalized discussion of the relevance of these groups are included in *California's Groundwater – Bulletin 118* by DWR (2003).
[2] Represents distinct number of wells sampled as required under DHS Title 22 program from 1994 through 2000.
[3] Each well reported with a concentration above an MCL was confirmed with a second detection above an MCL. This information is intended as an indicator of the types of activities that cause contamination in a given basin. It represents the water quality at the sample location. It does not indicate the water quality delivered to the consumer. More detailed drinking water quality information can be obtained from the local water purveyor and its annual Consumer Confidence Report.

Well Characteristics

	Well yields (gal/min)	
Municipal/Irrigation	Range: 200-4,000	Average: 1,200-1,500 (KCWA 1995)
	Total depths (ft)	
Domestic	Range: Not determined	Average: Not determined
Municipal/Irrigation	Range: 150-1,200	Average: 300-600 (KCWA 1995)

Active Monitoring Data

Agency	Parameter	Number of wells /measurement frequency
DWR (incl. Cooperators)	Groundwater levels	1,487 Semi-annually
Arvin Edison WSD	Quality	50-75 Annually
Arvin Edison WSD	Levels	250-300 Biennially
Cawelo WD	Quality	45 Annually
Kern Delta WD	Quality (EC, TDS, pH)	17 Infrequently
Kern Delta WD	Levels	115 Semi-annually
West Kern WD	Levels	5 Monthly
West Kern WD	Gen. mineral, organic chemicals, and radiological.	5 Every 3 years
Wheeler Ridge-Maricopa WSD	Quality (Irregular) Title 22	12 Annually 17 During Drought Years
Wheeler Ridge-Maricopa WSD	Levels	88-110 Annually
Buena Vista WSD	Quality (EC, TDS)	25 Quarterly 94 Biennially
Buena Vista WSD	Levels	76 Quarterly
Semitropic WSD	Levels	300 Annually
Department of Health Services and cooperators	Title 22 water quality	476 Varies

Basin Management

Groundwater management:	Recharge and in-lieu programs are operated by various water districts, the City of Bakersfield, and Kern County Water Agency (see Comments below). Buena Vista WSD is currently drafting an AB 255 Management Plan. Shafter-Wasco ID implemented an AB 255 management plan in June 1993. West Kern Water District adopted a groundwater management plan. Kern Delta WD adopted a plan on October 15, 1996. Rosedale-Rio Bravo WSD's AB 3030 plan was adopted on March 11, 1997. Arvin-Edison WSD adopted a plan. Cawelo WD adopted an AB 3030 management plan in 1994. While Wheeler Ridge-Maricopa WSD has not formally adopted an AB 255 or AB 3030 plan, it has implemented the groundwater management plan contained in its Project Report. Semitropic Water Storage District adopted a groundwater management plan in September 2003.
Water agencies	
Public	Kern County Water Agency, City of Bakersfield, and numerous water districts and small Community Services Districts.
Private	California Water Service Co., McFarland Mutual Water Company, Stockdale Mutual Water Company, and numerous small community water groups.
Water Projects	Kern Fan Banking Unit; Arvin-Edison Banking Project; Semitropic Banking Project; Cross Valley Canal; Friant-Kern Canal.

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Errata

Updated groundwater management information and added hotlinks to applicable websites. (1/20/06)

Tulare Lake Hydrologic Region

Figure 37 Tulare Lake Hydrologic Region

Basins and Subbasins of Tulare Lake Hydrologic Region

Basin/subbasin	Basin name
5-22	San Joaquin Valley
5-22.08	Kings
5-22.09	Westside
5-22.10	Pleasant Valley
5-22.11	Kaweah
5-22.12	Tulare Lake
5-22.13	Tule
5-22.14	Kern County
5-23	Panoche Valley
5-25	Kern River Valley
5-26	Walker Basin Creek Valley
5-27	Cummings Valley
5-28	Tehachapi Valley West
5-29	Castaic Lake Valley
5-71	Vallecitos Creek Valley
5-80	Brite Valley
5-82	Cuddy Canyon Valley
5-83	Cuddy Ranch Area
5-84	Cuddy Valley
5-85	Mil Potrero Area

Description of the Region

The Tulare Lake HR covers approximately 10.9 million acres (17,000 square miles) and includes all of Kings and Tulare counties and most of Fresno and Kern counties (Figure 37). The region corresponds to approximately the southern one-third of RWQCB 5. Significant geographic features include the southern half of the San Joaquin Valley, the Temblor Range to the west, the Tehachapi Mountains to the south, and the southern Sierra Nevada to the east. The region is home to more than 1.7 million people as of 1995 (DWR, 1998). Major population centers include Fresno, Bakersfield, and Visalia. The cities of Fresno and Visalia are entirely dependent on groundwater for their supply, with Fresno being the second largest city in the United States reliant solely on groundwater.

Groundwater Development

The region has 12 distinct groundwater basins and 7 subbasins of the San Joaquin Valley Groundwater Basin, which crosses north into the San Joaquin River HR. These basins underlie approximately 5.33 million acres (8,330 square miles) or 49 percent of the entire HR area.

Groundwater has historically been important to both urban and agricultural uses, accounting for 41 percent of the region's total annual supply and 35 percent of all groundwater use in the State. Groundwater use in the region represents about 10 percent of the State's overall supply for agricultural and urban uses (DWR 1998).

The aquifers are generally quite thick in the San Joaquin Valley subbasins with groundwater wells commonly exceeding 1,000 feet in depth. The maximum thickness of freshwater-bearing deposits (4,400 feet) occurs at the southern end of the San Joaquin Valley. Typical well yields in the San Joaquin Valley range from 300 gpm to 2,000 gpm with yields of 4,000 gpm possible. The smaller basins in the mountains surrounding the San Joaquin Valley have thinner aquifers and generally lower well yields averaging less than 500 gpm.

The cities of Fresno, Bakersfield, and Visalia have groundwater recharge programs to ensure that groundwater will continue to be a viable water supply in the future. Extensive groundwater recharge programs are also in place in the south valley where water districts have recharged several million acre-feet for future use and transfer through water banking programs.

The extensive use of groundwater in the San Joaquin Valley has historically caused subsidence of the land surface primarily along the west side and south end of the valley.

Groundwater Quality

In general, groundwater quality throughout the region is suitable for most urban and agricultural uses with only local impairments. The primary constituents of concern are high TDS, nitrate, arsenic, and organic compounds.

The areas of high TDS content are primarily along the west side of the San Joaquin Valley and in the trough of the valley. High TDS content of west-side water is due to recharge of stream flow originating from marine sediments in the Coast Range. High TDS content in the trough of the valley is the result of concentration of salts because of evaporation and poor drainage. In the central and west-side portions of the valley, where the Corcoran Clay confining layer exists, water quality is generally better beneath the clay than above it. Nitrates may occur naturally or as a result of disposal of human and animal waste products and fertilizer. Areas of high nitrate concentrations are known to exist near the town of Shafter and other isolated areas in the San Joaquin Valley. High levels of arsenic occur locally and appear to be associated with lakebed areas. Elevated arsenic levels have been reported in the Tulare Lake, Kern Lake and Buena Vista Lake bed areas. Organic contaminants can be broken into two categories, agricultural and industrial. Agricultural pesticides and herbicides have been detected throughout the valley, but primarily along the east side where soil permeability is higher and depth to groundwater is shallower. The most notable agricultural contaminant is DBCP, a now-banned soil fumigant and known carcinogen once used extensively on grapes. Industrial organic contaminants include TCE, DCE, and other solvents. They are found in groundwater near airports, industrial areas, and landfills.

Water Quality in Public Supply Wells

From 1994 through 2000, 1,476 public supply water wells were sampled in 14 of the 19 groundwater basins and subbasins in the Tulare Lake HR. Evaluation of analyzed samples shows that 1,049 of the wells, or 71 percent, met the state primary MCLs for drinking water. Four-hundred-twenty-seven wells, or 29 percent, exceeded one or more MCL. Figure 38 shows the percentages of each contaminant group that exceeded MCLs in the 427 wells.

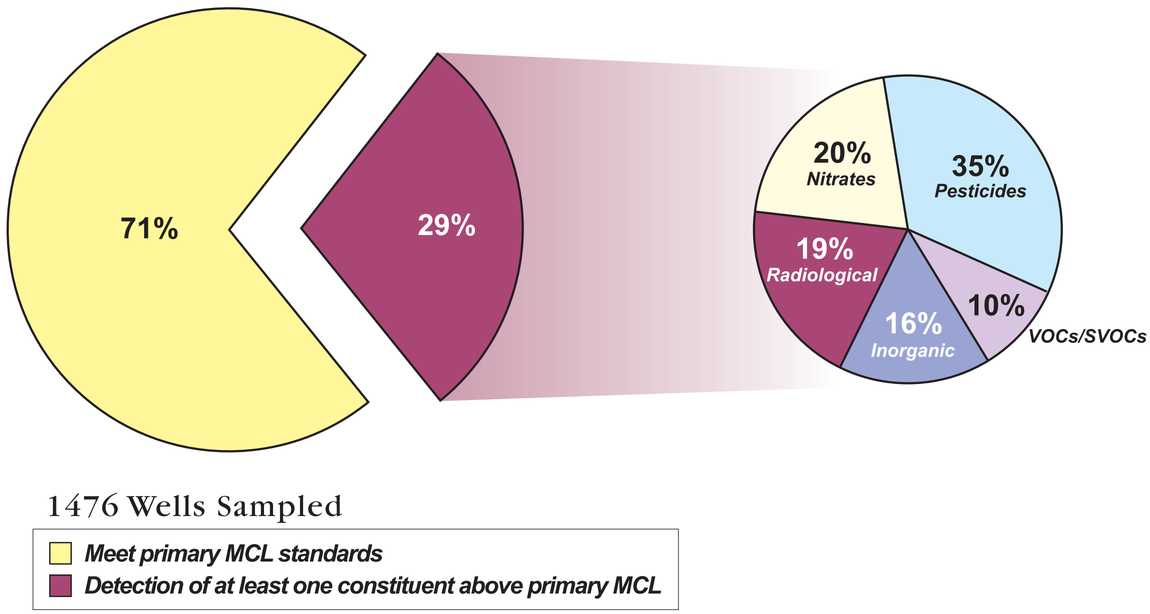


Figure 38 MCL exceedances by contaminant group in public supply wells in the Tulare Lake Hydrologic Region

Table 31 lists the three most frequently occurring contaminants in each of the six contaminant groups and shows the number of wells in the HR that exceeded the MCL for those contaminants.

Table 31 Most frequently occurring contaminants by contaminant group in the Tulare Lake Hydrologic Region

Contaminant group	Contaminant - # of wells	Contaminant - # of wells	Contaminant - # of wells
Inorganics - Primary	Fluoride – 32	Arsenic – 16	Aluminum – 13
Inorganics - Secondary	Iron – 155	Manganese – 82	TDS – 9
Radiological	Gross Alpha – 74	Uranium – 24	Radium 228 – 8
Nitrates	Nitrate(as NO_3) – 83	Nitrate + Nitrite – 14	Nitrite(as N) – 3
Pesticides	DBCP – 130	EDB – 24	Di(2-Ethylhexyl)phthalate – 7
VOCs/SVOCs	TCE – 17	PCE – 16	Benzene – 6 MTBE – 6

DBCP = Dibromochloropropane
EDB = Ethylenedibromide
TCE = Trichloroethylene
PCE = Tetrachloroehylene
VOC = Volatile organic compound
SVOC = Semivolatile organic compound

Changes from Bulletin 118-80

There are no newly defined basins since Bulletin 118-80. However, the subbasins of the San Joaquin Valley, which were delineated as part of the 118-80 update, are given their first numeric designation in this report (Table 32).

Table 32 Modifications since Bulletin 118-80 of groundwater basins and subbasins in Tulare Lake Hydrologic Region

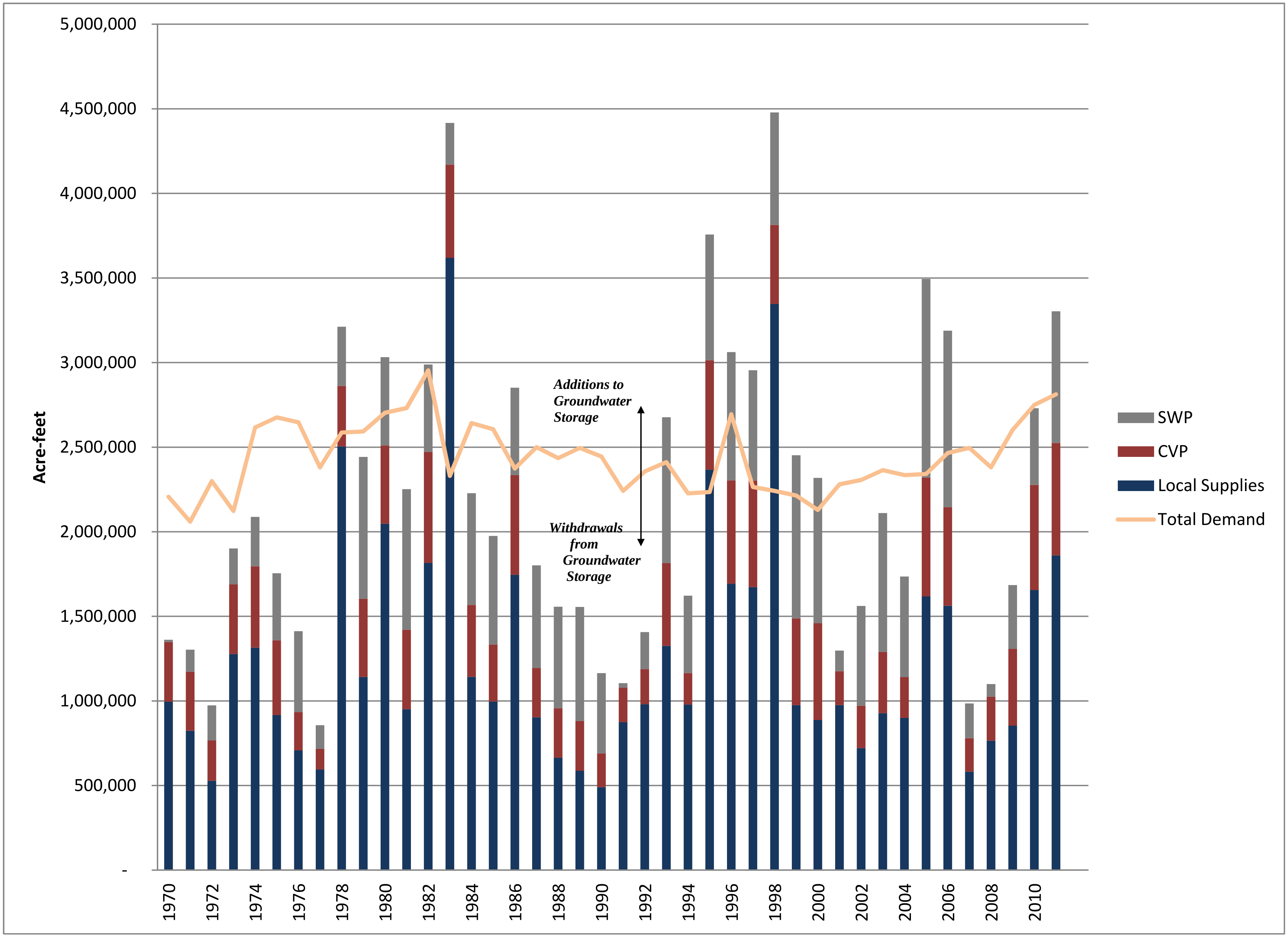
Subbasin name	New number	Old number
Kings	5-22.08	5-22
Westside	5-22.09	5-22
Pleasant Valley	5-22.10	5-22
Kaweah	5-22.11	5-22
Tulare Lake	5-22.12	5-22
Tule	5-22.13	5-22
Kern County	5-22.14	5-22
Squaw Valley	deleted	5-24
Cedar Grove Area	deleted	5-72
Three Rivers Area	deleted	5-73
Springville Area	deleted	5-74
Templeton Mountain Area	deleted	5-75
Manache Meadow Area	deleted	5-76
Sacator Canyon Valley	deleted	5-77
Rockhouse Meadows Valley	deleted	5-78
Inns Valley	deleted	5-79
Bear Valley	deleted	5-81

Several basins have been deleted from the Bulletin 118-80 report. In Squaw Valley (5-24) all 118 wells are completed in hard rock. Cedar Grove Area (5-72) is a narrow river valley in Kings Canyon National Park with no wells. Three Rivers Area (5-73) has a thin alluvial terrace deposit but 128 of 130 wells are completed in hard rock. Springville Area (5-74) is this strip of alluvium adjacent to Tule River and all wells are completed in hard rock. Templeton Mountain Area (5-75), Manache Meadow Area (5-76), and Sacator Canyon Valley (5-77) are all at the crest of mountains with no wells. Rockhouse Meadows Valley (5-78) is in wilderness with no wells. Inns Valley (5-79) and Bear Valley (5-81) both have all wells completed in hard rock.

Table 33 Tulare Lake Hydrologic Region groundwater data

Basin/Subbasin	Basin Name	Area (acres)	Groundwater Budget Type	Well Yields (gpm)		Types of Monitoring			TDS (mg/L)	
				Maximum	Average	Levels	Quality	Title 22	Average	Range
5-22	SAN JOAQUIN VALLEY									
5-22.08	KINGS	976,000	C	3,000	500-1,500	909	-	722	200-700	40-2000
5-22.09	WESTSIDE	640,000	C	2,000	1,100	960	-	50	520	220-35,000
5-22.10	PLEASANT VALLEY	146,000	B	3,300	-	151	-	2	1,500	1000-3000
5-22.11	KAWEAH	446,000	B	2,500	1,000-2,000	568	-	270	189	35-580
5-22.12	TULARE LAKE	524,000	B	3,000	300-1,000	241	-	86	200-600	200-40,000
5-22.13	TULE	467,000	B	3,000	-	459	-	150	256	200-30,000
5-22.14	KERN COUNTY	1,950,000	A	4,000	1,200-1,500	2,258	249	476	400-450	150-5000
5-23	PANOCHE VALLEY	33,100	C	-	-	48	-	-	1,300	394-3530
5-25	KERN RIVER VALLEY	74,000	C	3,650	350	-	-	92	378	253-480
5-26	WALKER BASIN CREEK VALLEY	7,670	C	650	-	-	-	1	-	-
5-27	CUMMINGS VALLEY	10,000	A	150	56	51	-	15	344	-
5-28	TEHACHAPI VALLEY WEST	14,800	A	1,500	454	64	-	19	315	280-365
5-29	CASTAC LAKE VALLEY	3,600	C	400	375	-	-	3	583	570-605
5-71	VALLECITOS CREEK VALLEY	15,100	C	-	-	-	-	0	-	-
5-80	BRITE VALLEY	3,170	A	500	50	-	-	-	-	-
5-82	CUDDY CANYON VALLEY	3,300	C	500	400	-	-	3	693	695
5-83	CUDDY RANCH AREA	4,200	C	300	180	-	-	4	550	480-645
5-84	CUDDY VALLEY	3,500	A	160	135	3	-	3	407	325-645
5-85	MIL POTRERO AREA	2,300	C	3,200	240	7	-	7	460	372-657

gpm - gallons per minute
mg/L - milligram per liter
TDS -total dissolved solids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2002
2004
2006
2008
2010
Additions to Groundwater Storage
Withdrawals from Groundwater Storage
SWP
CVP
Local Supplies
Total Demand

Exhibit 3

FUEL SAVINGS & AERODYNAMIC DRAG REDUCTION FROM RAIL CAR COVERS

Bruce Storms, NASA Ames Research Center
Kambiz Salari, Lawrence Livermore National Laboratory
Alex Babb, University of California Los Angeles

ABSTRACT

The potential for energy savings by reducing the aerodynamic drag of rail cars is significant. A previous study of aerodynamic drag of coal cars suggests that a 25% reduction in drag of empty cars would correspond to a 5% fuel savings for a round trip [1]. Rail statistics for the United States [2] report that approximately 5.7 billion liters of diesel fuel were consumed for coal transportation in 2002, so a 5% fuel savings would total 284 million liters. This corresponds to 2% of Class I railroad fuel consumption nationwide. As part of a DOE-sponsored study, the aerodynamic drag of scale rail cars was measured in a wind tunnel. The goal of the study was to measure the drag reduction of various rail-car cover designs. The cover designs tested yielded an average drag reduction of 43% relative to empty cars corresponding to an estimated round-trip fuel savings of 9%.

APPROACH

The measurements were made in the NASA-Ames 15- by 15-Inch Low-Speed Wind Tunnel. Five 1:87-scale hopper-type rail cars were mounted on a scale train track (Fig. 1) with the middle car connected to the upwind car by a 9-N load cell and disconnected from the downwind car. All cars except the middle car were affixed to the track to prevent motion. In terms of full-scale values, the cars measure approximately 3 m wide, 3.4 m high, and 14.6 m long with a gap between cars of 1.7 m.

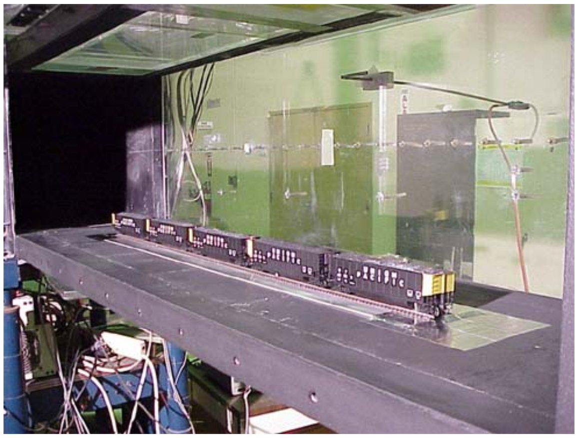

Figure 1. Five coal cars mounted in wind-tunnel

This configuration was tested at a free-stream velocity of 65 m/s with and without simulated coal in all cars. This relatively high tunnel speed was chosen to maximize the measured drag and minimize measurement uncertainty. Due to the nature of sharp-edged bluff-body flow fields, the differences in model scale and speed are not expected to significantly affect the experimental results. Previous larger-scale results [3] compare favorably with the current study and validate the small-scale methodology.

Several cover designs were applied to all five cars and the resulting drag on the middle car was measured for each configuration. In addition to the flat cover (flush with the top of the rail car), three domed cover designs were tested with differing heights and/or end geometries. The 50-deg and vertical end configurations (Fig. 2-3) had a dome height of 1 m, while an addition 50-deg end configuration was tested with a height of 0.5 m. The five-car combination was tested at yaw angles from zero to 10 deg to determine the effects of crosswind.

Figure 2: 50-deg end domed cover

Figure 3: Vertical end domed cover

EXPERIMENTAL RESULTS

In rail-car analysis, the aerodynamic resistance is the force opposite the direction of travel and is identical to the axial force measured by the load cell in this experiment. The drag coefficient (C_D) for each configuration was calculated by dividing the axial force by the dynamic pressure ($1/2\rho V^2$, where ρ is air density and V is train velocity) and the cross-sectional area of the empty model rail car.

For each configuration, measurements were made in 2-deg increments for yaw angles from zero to 10 deg. Using the variation of drag with yaw angle, wind-averaged drag coefficients were computed using the SAE Recommended Practice [4]. This practice assumes that the mean wind speed in the United States of 11 kph has an equal probability of approaching the vehicle from any direction. This mean wind speed and the vehicle velocity were used to calculate a weighted average of the drag coefficient at various yaw angles. The values for wind-averaged drag reduction reported in this paper were computed for a speed of 65 kph.

The effects of the rail-car covers and the simulated coal loading are presented in Fig. 4. Relative to the empty rail car, the full coal car indicated significantly less drag ranging from 29% to over 41% for yaw angles of zero to 10 deg, respectively. The rail car covers reduced the aerodynamic drag even relative to the full car configuration. The measurement accuracy and repeatability resulted in error bars that increase with yaw angle as shown on the empty-car drag curve. Since the differences between the cover data is of the same order as that of the error bars, it is difficult to make any meaningful distinction between the cover designs except that the flat covers generate marginally higher drag at yaw angles below 8 deg. The median wind-averaged drag reduction for all four cover designs was 43% which would result in a round-trip fuel savings of approximately 9% based on the prediction of Ref. 1.

SUMMARY

Using the coal transportation statistics [2], the estimate fuel savings [1], and a diesel fuel cost of R10/L (for ease of scaling), estimates of the cost savings per tonne and carload were calculated and are listed in Table 1. Since these estimates include numerous assumptions and uncertainties, it is recommended that the fuel savings be verified by full-scale trials. At the date of publication, fuel savings measurements were underway by railroad operators in the United States. Preliminary results are said to be "better than expected".

Table 1: Estimated cost savings (based on R10/L) for rail transportation of coal

Per tonne	R8.16
Per carload	R819

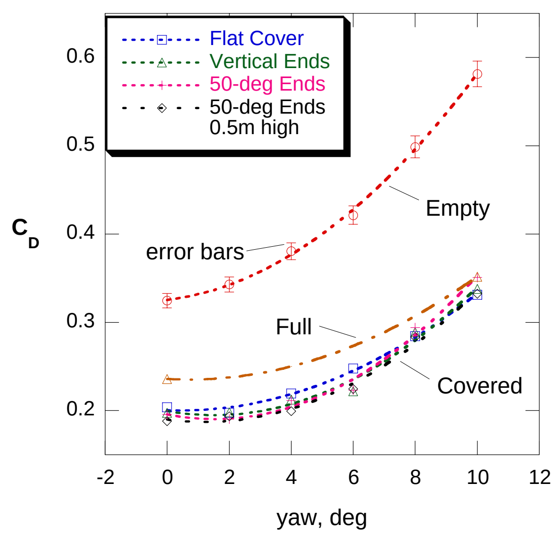

Figure 4: Drag coefficient vs. yaw angle of rail cars with and without covers

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