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March 23, 2012

VIA FEDERAL EXPRESS

VIA E-MAIL

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Chair
California Energy Commission
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Sacramento, CA 95814-5512

Ms. Carla Peterman
Commissioner
California Energy Commission
1516 Ninth Street
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Re: RPS Proceeding: Docket Numbers 02-REN-1038 and 11-RPS-01
California Energy Commission Proposed Suspension of the RPS Eligibility Guidelines Related to Biomethane

Dear Mr. Weisenmiller, Ms. Peterman and Ms. Douglas:

Thank you for the opportunity to provide comments on the California Energy Commission's Proposed Suspension of the RPS Eligibility Guidelines Related to Biomethane (Docket Numbers 02-REN-1038 and 11-RPS-01) (the "Proposed Suspension"). We represent an informal consortium of companies, including but not limited to Element Markets, LLC and its subsidiaries, with vested interests in the Proposed Suspension. These companies have made investments of various types, with an estimated value in the tens of millions of dollars, in reliance upon the existing RPS Eligibility Guidebook. These investments would be seriously undermined, and in many cases entirely wiped out, by the Proposed Suspension.

With all due respect to the staff of the California Energy Commission ("CEC") which has brought the Proposed Suspension forward, we find the Proposed Suspension seriously flawed from both a legal and policy perspective. From a legal perspective, the Proposed Suspension falls outside the scope of the CEC's jurisdiction, and fails to comport with minimum legal requirements, including the California Administrative Procedures Act and the California Environmental Quality Act. From a policy perspective, the Proposed Suspension strikes a serious blow to the efforts of the state and many other stakeholders to increase California's reliance on renewable energy sources, and undermines the very goals and mandates it purportedly seeks to advance.

Our concerns regarding the Proposed Suspension are set forth in detail below. In light of the serious legal and policy shortcomings of the Proposed Suspension, we urge the CEC to defer any action on this issue until all interested parties, including the state Legislature, have had an opportunity to more carefully evaluate the implications of the Proposed Suspension and develop alternatives that address the concerns and vested interests of all stakeholders.

I. THE PROPOSED SUSPENSION FALLS OUTSIDE THE SCOPE OF THE CEC'S AUTHORITY

The CEC purports to be acting pursuant to authority granted to it by the California Legislature in various sections of the California Public Resources Code and California Public Utilities Code. Section 399.25 of the California Public Utilities Code provides in part:

> The Energy Commission shall do all of the following:
>
> (a) Certify eligible renewable energy resources that it determines meet the criteria described in subdivision (e) of Section 399.12.

California Public Resources Code Section 25747, Subdivision (a) provides:

> The commission shall adopt guidelines governing the funding programs authorized under this chapter, at a publicly noticed meeting offering all interested parties an opportunity to comment. Substantive changes to the guidelines may not be adopted without at least 10 days' written notice to the public. The public notice of meetings required by this subdivision shall not be less than 30 days. Notwithstanding any other provision of law, any guidelines adopted pursuant to this chapter or Section 399.25 of the Public Utilities Code, shall be exempt from the requirements of Chapter 3.5 (commencing with Section 11340) of Part 1 of Division 3 of Title 2 of the Government Code. The Legislature declares that the changes made to this subdivision by the act amending this section during the 2002 portion of the 2001-02 Regular Session are declaratory of, and not a change in existing law.

The CEC staff apparently reads these two provisions as granting the CEC authority to adopt the Proposed Suspension and to avoid the requirements of the California Administrative Procedures Act in so doing. We disagree.

Under Section 399.25 of the Public Utilities Code, the CEC's authority is limited to determining which renewable energy resources "meet the criteria described in subdivision (e) of Section 399.12." Section 399.12(e) of the Public Utilities Code provides:

> (e) "Eligible renewable energy resource" means an electrical generating facility that meets the definition of an a "renewable

> electrical generation facility" in Section 25741 of the Public Resources Code . . . [subject to limitations not relevant here].

Public Resources Code Section 25741(a)(1), in turn, provides:

> (a) "Renewable electrical generation facility" means a facility that meets all of the following criteria:
>
> (1) The facility uses biomass, solar thermal, photovoltaic, wind, geothermal, fuel cells using renewable fuels, small hydroelectric generation of 30 megawatts or less, digester gas, municipal solid waste conversion, landfill gas, ocean wave, ocean thermal, or tidal current, and any additions or enhancements to the facility using that technology.

Thus, the California Legislature very specifically set forth the criteria for eligible renewable energy resources. Biomethane-fueled electricity clearly meets the applicable criteria. Furthermore, eligibility of biomethane-fueled electricity for RPS compliance is no different under SBX1 2 than it was under the previous RPS statute. Put succinctly, Public Resources Code Section 25741(a)(1) provides that a "renewable electrical generation facility" includes a generation facility that uses biomass, digester gas, and landfill gas. A "renewable electrical generation facility" is an "eligible renewable energy resource" under Public Utilities Code Section 399.12(e).

Under the authority granted it by Section 399.25 of the California Public Utilities Code, the CEC is charged with merely applying the criteria established by the Legislature to determine qualifying facilities. Yet, the Proposed Suspension goes well beyond that action and actually re-defines the types of facilities that qualify. This action is contrary to the express provisions of the relevant statutes and the narrowly-tailored role that the Legislature proscribed for the CEC. If the CEC were to adopt the Proposed Suspension, it would be overstepping its authority and substituting its own authority for that of the Legislature. Such an action represents an inappropriate usurpation of the role of the Legislature by an administrative agency of the executive branch.

Article III, section 3 of the California Constitution states: "The powers of state government are legislative, executive, and judicial. Persons charged with the exercise of one power may not exercise either of the others except as permitted by this Constitution."

"The separation of powers doctrine limits the authority of one of the three branches of government to arrogate to itself the core functions of another branch. The courts have long recognized that [the] primary purpose [of the . . . doctrine] is to prevent the combination in the hands of a single person or group of the basic or fundamental powers of government. To serve this purpose, courts have not hesitated to strike down provisions of law that either accrete to a single Branch powers more appropriately diffused among separate Branches or that undermine the authority and independence of one or another coordinate Branch." *Carmel Valley Fire Protection Dist. v. State of California* (2001) 25 Cal. 4th 287, 297 (internal citations omitted).

The California Supreme Court has stated that "it is well settled that administrative agencies have only the powers conferred on them, either expressly or by implication, by Constitution or statute." *AFL v. Unemployment Ins. Appeals Bd.*, 13 Cal. 4th 1017, 1042 (1996) (internal citations omitted). Agency "actions exceeding those powers are void, and administrative mandate will lie to nullify the void acts." *Id.* (internal citations omitted). Accordingly, ultra vires agency actions can be reversed in administrative mandate proceedings under California Code of Civil Procedure Section 1094.5(b).

II. BECAUSE IT IS ACTING OUTSIDE THE SCOPE OF ITS AUTHORITY, THE CEC CANNOT AVAIL ITSELF OF THE NARROWLY TAILORED EXEMPTION TO THE APA

Since the CEC is acting outside the scope of the authority granted to it by the Legislature in Section 399.25 of the California Public Utilities Code, it cannot avail itself of the exemption from the California Administrative Procedures Act ("APA") set forth in California Public Resources Code Section 25747, Subdivision (a). The APA exemption is limited to actions that fall within the scope of authority provided in Section 399.25. Therefore, assuming that the CEC has the authority to undertake the Proposed Suspension at all, and we do not think it does because in doing so it usurps the Legislature's authority, it must comply with the APA.

As recently articulated in *Bollay v. Office of Administrative Law*, 193 Cal. App. 4th 103, 106-107 (2011) (internal citations omitted): "Unless it is subject to one of the enumerated exceptions, every regulation must be adopted consistent with the procedural requirements of the APA. (Gov. Code, § 11340 et seq.) This requires, among other things, public notice and an opportunity for public comment before the regulation takes effect. (*Morning Star Co. v. State Bd. of Equalization* (2006) 38 Cal.4th 324, 333 (Morning Star).) A regulation that is adopted inconsistent with the APA is an "underground regulation" (Cal. Code Regs., tit. 1, § 250) and may be declared invalid by a court (*Morning Star*, supra, at p. 333; Gov. Code, § 11350)."

The APA defines a "regulation" as a rule or standard of general application. (Gov. Code, § 11342.600.) The state agency rule or standard is a regulation subject to the APA if (1) it applies generally rather than to a specific case and (2) it implements, interprets, or makes specific the law enforced or administered by the state agency imposing the rule or standard.

The Proposed Suspension falls within the definition of "regulation" set forth in the APA, and since the action falls outside the scope of the authority granted to the CEC, and therefore is not covered by the otherwise applicable exemption, the CEC must comply with all of the applicable requirements of the APA in connection with its proposed action. The CEC has failed to do so in connection with the Proposed Suspension, and therefore any action on the Proposed Suspension at this time would constitute a violation of the APA.

III. SUSPENSION WOULD TRIGGER CEQA

Under Public Resources Code § 21080(a), the California Environmental Quality Act ("CEQA") applies to "discretionary projects proposed to be carried out or approved by public agencies," unless they are otherwise exempt. The term "project" refers to an activity subject to CEQA. Title 14, California Code of Regulations ("14 C.C.R.) § 15002(d). A project has two essential elements. First, it is an activity that may cause a direct (or reasonably foreseeable indirect) physical environmental change. Second, it is an activity directly undertaken by a public agency, an activity supported in whole or in part by a public agency, or an activity involving the issuance by a public agency of some form of entitlement, permit, or other authorization. Public Resources Code § 21065; 14 C.C.R. § 15378.[1] The adoption of a rule or regulation can be a project subject to CEQA. *Wildlife Alive v. Chickering (1976) 18 Cal.3d 190, 206*; *Plastic Pipe & Fittings Assn. v. California Building Standards Com. (2004) 124 Cal.App.4th 1390, 1412*.

The Proposed Suspension is the functional equivalent of an adoption of a rule or regulation and triggers CEQA because the Proposed Suspension has a reasonable likelihood to cause direct environmental impacts and has a reasonably foreseeable likelihood of causing indirect changes to the physical environment. The CEC has not demonstrated that a CEQA exemption applies.

First, it is well settled that the agency's adoption of standards, rules or regulations triggers CEQA. *See Wildlife Alive, supra, 18 Cal. 3d 190; Plastic Pipe, supra, (2004) 124 Cal. App. 4th 1390; Dunn-Edwards Corp. v Bay Area Air Quality Mgmt. Dist.* (1992) 9 Cal. App. 4th 644, disapproved on other grounds in *Western States Petroleum Assn. v. Superior Court (1995) 9 Cal.4th 559, 576, footnote 6* (new rules limiting volatile organic compounds in paint held to be "projects"); *Western States Petroleum Ass'n v South Coast Air Quality Mgmt. Dist*. (2006) 136 Cal. App. 4th 1012 (air quality management district's environmental assessment adequately analyzed indirect effects of actions that would have to be taken by oil refineries to comply with new emissions standards).

The mere fact that the standards, rules or regulations may benefit the environment in some way does not exempt the approval from CEQA unless the agency meets its burden to demonstrate that the action is exempt from CEQA. In *Dunn-Edwards*, an air quality management district adopted regulations that required new control measures for the emission of volatile organic compounds (VOC) from paint and other "architectural coatings." *Id., at pp. 649-650*. The plaintiffs presented "evidence that the new regulations require[d] lower quality

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[1] CEQA applies when a public agency proposes to "approve" a project. Public Resources Code § 21080(a); *Save Tara v City of W. Hollywood* (2008) 45 Cal. 4th 116; *RiverWatch v. Olivenhain Mun. Water Dist*. (2009) 170 Cal. App. 4th 1186. The term "approval" refers to a public agency decision that "commits the agency to a definite course of action in regard to a project." 14 C.C.R. § 15352(a). This definition of approval applies to all projects intended to be carried out by any person, which includes actions undertaken by a public agency as well as actions funded or authorized by a public agency. 14 C.C.R. § 15352(a). Approvals subject to CEQA are not limited to public agency authorizations for particular activities, and can include legislative action by a state or local agency. 14 C.C.R. § 15352(a).

products. As a result, more product w[ould] be used, which w[ould] lead to a net increase in VOC emissions." *Id. at p. 658*. The air district took the position that its adoption of the regulations was categorically exempt, citing, among other things, the Class 8 exemption. *Id. at p. 653*. It argued that the regulations "constitute[d] more stringent standards for VOC and [thus] cannot be said to have created an adverse change." *Id. at p. 657*.

The appellate court in *Dunn-Edwards* rejected the air district's exemption claim because it failed to present adequate evidence that there would not be a potential environmental affect: "The only evidence in rebuttal to that presented by plaintiffs is an [air resources board] staff response concluding: [T]he staff disagrees with the assertion that implementation of the [suggested control measures] will result in an emissions increase due to increased thinning, more frequent recoating and increased incidence of job failures. Thus, the staff disagrees with the contention ... that implementation will have adverse environmental impacts. This conclusion is based on the fact there was no supporting data for plaintiffs' claims. Thus, rejection of plaintiffs' claims is predicated on lack of the very information which would be provided by an EIR. Since the staff likewise was unable to produce evidence of no adverse impact, the District cannot say with certainty 'there is no possibility that the activity in question may have a significant effect on the environment.'" *Id. at p. 658* (internal citations omitted).

Courts have recognized that an agency may attempt to skirt CEQA when adopting rulemaking by attempting to rely either on the exemption from CEQA that applies when it is certain an activity will not have a significant environmental impact (14 C.C.R. § 15061(b)(3)), or the categorical exemptions for actions taken to protect natural resources (14 Cal Code Regs §15307) or to protect the environment (14 C.C.R. § 15308). *See California Unions for Reliable Energy v. Mojave Desert Air Quality Mgmt. Dist.* (2009) 178 Cal. App. 4th 1225, 1240. However, an agency's assumption of a CEQA exemption is often incorrect. *See, id.*; *International Longshoremen's & Warehousemen's Union, Local 35 v Board of Supervisors* (1981) 116 CA3d 265 (relaxation of county air pollution rule not exempt under 14 C.C.R. § 15308). Even a regulation that strengthens *some* environmental requirements may not be entitled to an exemption if the new requirements could result in other potentially significant effects. *See Dunn-Edwards, supra*, 9 Cal. App. 4th 644; *City of Arcadia v State Water Resources Control Bd.* (2006) 135 Cal. App. 4th 1392 (regional water quality control board failed to adequately analyze reasonably foreseeable indirect environmental impacts from compliance with new water quality standard designed to eliminate trash discharged from municipal storm drains); *Building Code Action v Energy Resources Conserv. & Dev. Comm'n* (1980) 102 Cal. App. 3d 577 (overturning negative declaration for new energy conservation standards for windows because resulting increase in glass production could have significant air quality impacts).

Second, the Proposed Suspension will likely impact the environment, either directly by increasing GHG emissions and impeding the California Air Resources Board's efforts to achieve the greenhouse gas (GHG) reduction requirements mandated by AB 32,[2] or in a reasonably

[2] *See* discussion in this letter regarding CARB's reliance on the RPS to achieve the mandates required by AB 32.

foreseeable manner, such as by forcing greater reliance on intermittent renewable resources that would have the reasonably foreseeable consequence of decreasing grid stability, increasing in-state fossil fuel needed to stabilize grid capacity and related criteria pollutants, and causing physical changes to the environment associated with developing large-scale solar or wind projects or new transmission infrastructure.[3] The CEC cannot claim the Proposed Suspension will not result in a physical change to the environment without carrying its evidentiary burden that there will not be a direct effect or a reasonable foreseeable effect. *See California Unions for Reliable Energy, supra*, 178 Cal. App. 4th 1225, 1245 (rejecting applicability of categorical exemption because administrative record contained no evidence beyond bare assertions that there would not be an environmental impact).

On point, California's proposed greenhouse gas (GHG) cap and trade program under AB 32 suffered a setback on May 20, 2012 when a San Francisco Superior Court issued a writ of mandate enjoining the California Air Resources Board (CARB) from any further cap and trade rulemaking until CARB satisfied the requirements of CEQA. See *Association of Irritated Residents, et. al v. California Air Resources Board*, No. CPF-09- 509562 (March 18, 2011). CARB completed additional CEQA review to resolve the deficiency.

This recent example demonstrates the judicial recognition of the need to properly complete CEQA in a rulemaking process.[4] In *Plastic Pipe*, the California Building Standards Commission determined that the adoption of regulations allowing the use of cross-linked polyethylene (PEX) pipes required environmental review under CEQA. *124 Cal. App. 4th 1390, 1401*. The Plastic Pipe and Fittings Association (PPFA) challenged this position, but the appellate court agreed with the California Building Standards Commission. *Id. at pp. 1412-1414*. It stated: "PPFA contends the enactment of regulations allowing the use of PEX is not a project because the causal link between the enactment of regulations and a physical change in the environment is too remote. PPFA argues that PEX is only one of several materials available for plumbing uses and that at this time there is no certainty that PEX will be used in any particular work of construction. A project, however, includes an activity that may cause ... a reasonably foreseeable indirect physical change in the environment. Thus, an activity need not cause an immediate environmental impact to be considered a project." *Id. at p. 1413* (internal citations omitted).

With CEQA applying, the CEC is required to prepare an Environmental Impact Report because there is a fair argument that the Proposed Suspension may have a significant effect on

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[3] For a discussion of the environmental benefits of relying upon electricity generated from biogas (and delivered as biomethane) to satisfy RPS see discussion below in this letter. *See also* note 5, *supra*.

[4] The mere fact that the Proposed Suspension may potentially be exempt from rulemaking requirements does not also mean the action is not a rulemaking or regulatory action for purposes of CEQA.

the environment.[5] *No Oil, Inc. v City of Los Angeles* (1974) 13 Cal. 3d 68, 75, 82*; Quail Botanical Gardens Found., Inc. v City of Encinitas* (1994) 29 CA4th 1597, 1602.

In sum, the Proposed Suspension satisfies the definition of a project under CEQA and triggers the need for environmental review because the Proposed Suspension will directly and indirectly affect the physical environment. The CEC has not demonstrated that a CEQA exemption applies. An EIR should be prepared.

IV. SUSPENSION WOULD VIOLATE THE DORMANT COMMERCE CLAUSE BY OVERWHELMINGLY BURDENING OUT-OF-STATE BIOGAS RESOURCES

The First Circuit Court of Appeals recently summarized the governing standards of law under the Commerce Clause of the United States Constitution:

> The Commerce Clause prevents states from creating protectionist barriers to interstate trade.... Discrimination under the Commerce Clause means differential treatment of in-state and out-of-state economic interests that benefits the former and burdens the latter, as opposed to state laws that regulate evenhandedly with only incidental effects on interstate commerce.... [A] discriminatory law is virtually per se invalid ... and will survive only if it advances a legitimate local purpose that cannot be adequately served by reasonable non-discriminatory alternatives.... The state bears the burden of showing legitimate local purposes and the lack of non-

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[5] The Proposed Suspension may significantly impact the environment: by increasing GHG emissions associated with landfill methane that would not be captured but for a robust renewable energy market for biomethane (*see* The Importance of Landfill Gas Capture and Utilization in the U.S., Council for Sustainable Use of Resources, Earth Engineering Center, Columbia University, April 6, 2010, available at http://www.seas.columbia.edu/earth/wtert/sofos/Importance_of_LFG_Capture_and_Utilization_in_the_US.pdf), key excerpts attached); or in a reasonably foreseeable manner, such as by forcing greater reliance on intermittent renewable resources that would have the reasonably foreseeable consequence of decreasing grid stability, increasing instate fossil fuel needed to stabilize grid capacity, and causing physical changes to the environment associated with developing large-scale solar or wind projects or new transmission infrastructure (*see id*; *see* U.S. Environmental Protection Agency, Market Opportunities for Biogas Recovery Systems at U.S. Livestock Facilities, Nov. 2011 ("Biogas recovery systems offer substantial economic benefits"); Denholm, P., et al., The Role Of Energy Storage With Renewable Electricity Generation, UNLV, 2010, attached (demonstrating the value of biomethane for load shaping purposes and reduction of the integration cost of intermittent resources); Zaks, David P., et al., Contribution of Anaerobic Digesters to Emissions Mitigation and Electricity Generation Under U.S. Climate Policy, Environmental Science and Technology, 2011, attached; California Energy Commission, 2009 Progress To Plan Bioenergy Action Plan For California, attached; *see note* 3, *supra*).

> discriminatory alternatives, and discriminatory state laws rarely satisfy this exacting standard.[6]

Recently, the United States District Court for the Eastern District of California ruled that the California Air Resource Board's low carbon fuel standard ("LCFS") violated the dormant Commerce Clause, finding that the LCFS inappropriately differentiated between otherwise identical fuels by assigning lower carbon intensity scores based on location. *Rocky Mountain Farmers Union et al. v. Goldstene*, No. 09-2234, 2011 U.S. Dist. LEXIS 149593 (E.D.Cal. Dec. 29, 2011).

Applying *Goldstene* and dormant commerce clause jurisprudence, the Proposed Suspension would result in a discriminatory effect because biogas sellers are largely located outside of California and would find it difficult to enter California's markets if biogas were no longer RPS eligible.[7] Given this discriminatory effect, the CEC must prove that it has a legitimate reason for the suspension and that there are no reasonable alternatives that lack the discriminatory effect. The sweeping and summary nature of the CEC's proposed action raises doubts about whether the CEC could prove that no reasonable alternatives exist. Furthermore, even if the CEC's action is non-discriminatory, it will be struck down if "the burden imposed on [interstate] commerce is clearly excessive in relation to the putative local benefits."[8] The burden on interstate commerce caused by the CEC's suspension would be significant because RPS eligibility is a major factor in the biogas market that would be completely removed, likely crippling the interstate market for biogas. Therefore, the CEC's proposed action would violate the Dormant Commerce Clause by discriminating against out-of-state biogas providers and excessively burdening interstate commerce.

V. THE PROPOSED SUSPENSION IS ARBITRARY AND CAPRICIOUS

An agency action is arbitrary and capricious if it takes a regulatory action that is not supported by substantial evidence in the administrative record. *See Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.* 463 U.S. 29, 43 (1983). In *Burlington Truck Lines, Inc. v. United States*, the Supreme Court rejected the actions of the Interstate Commerce Commission ("ICC")

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6 *Family Winemakers of California v. Jenkins*, 592 F.3d 1, 9 (1st Cir. 2010) (internal citations and quotations omitted) (emphasis added).

7 According to the California Energy Commission, 2009 Progress To Plan Bioenergy Action Plan For California, attached: "Assembly Bill 4037 (Hayden, Chapter 932, Statutes of 1988), effectively precludes using California landfill gas in gas pipelines, although utilities can purchase out-of-state landfill gas without restrictions. See Health and Safety Code, § 25241(a). If a pipeline operator allows the injection of landfill gas into the pipeline, there is a twice monthly measuring requirement. If vinyl chloride is present, both the landfill gas developer and the pipeline operator face a $2,500 penalty per day for each violation. This requirement has resulted in the refusal by instate pipeline operators to accept purchases of landfill gas produced instate for injection into the pipeline. Landfill gas injected into the pipeline from out-of-state sources is not restricted under the code."

8 *Pike v. Bruce Church Inc.*, 397 U.S. 137, 142 (1970).

as arbitrary and capricious.[9] In *Burlington*, the ICC chose one remedy (additional certification) over another (a cease and desist order) in responding to a shipping disruption caused by a labor dispute.[10] In explaining why it rejected the ICC's actions the Court noted:

> There are no findings and no analysis here to justify the choice made, no indication of the basis on which the Commission exercised its expert discretion. We are not prepared to and the Administrative Procedure Act will not permit us to accept such adjudicatory practice.[11]

Furthermore, the *Burlington* Court held that an agency cannot reject the serious arguments of a regulated party without contrary findings of its own, stating that:

> [T]here is not substantial evidence of record upon which to base a finding that a cease and desist order would have been ineffective. There was every indication at the time that a cease and desist order would …[be] effective.[12]

The Court chastised the ICC for failing to make "findings specifically directed to the choice between two vastly different remedies with vastly different consequences," for failing to "articulate any rational connection between the facts found and the choice made," and for not responding to the "serious objections" of the affected party to its chosen remedy.[13] The Court found that these deficiencies resulted in a reversible error.[14]

Moreover, the CEC has a heightened duty to explain major changes in policy. In *Entergy Corp. v. Riverkeeper, Inc. (Entergy)*, 129 S. Ct. 1498, 1515 (2009), Justice Breyer questioned whether EPA's sudden break from longstanding agency policy was adequately supported. *Entergy*, 129 S. Ct. 1498, 1515 (2009) (Breyer, J., concurring in part and dissenting in part); (*citing Motor Vehicle Mfrs. Assn. of United States, Inc. v. State Farm Mut. Automobile Ins. Co.*, 463 U.S. 29, 42-43 (1983) ("[A]n agency changing its course by rescinding a rule is obligated to supply a reasoned analysis for the change beyond that which may be required when an agency does not act in the first instance"); *Nat'l Cable & Telecommunications Assn. v. Brand X Internet*, 545 U.S. 967, 981 (2005) ("[I]f the agency adequately explains the reasons for a reversal of policy, 'change is not invalidating . . .'"); *Thomas Jefferson Univ. v. Shalala*, 512 U.S. 504, 524 (1994) (Thomas, J., dissenting) ("[J]udges are properly suspect of sharp departures from past practice that are as unexplained as the [agency's] in this case")).

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9 *See Burlington Truck Lines, Inc. v. United States*, 371 U.S. 156, 165 (1962).

10 *Id.* at 162-63.

11 *Id.* at 167.

12 *Id.* at 169.

13 *Id.* at 168.

14 *See id.* at 174.

The CEC has failed to meet these standards because it has not advanced a rational basis for its sudden break in long-standing agency practice, particularly considering that SBX1-2 does not mandate the Proposed Suspension and, in fact, the express goals of SBX1-2 would be undermined by the Proposed Suspension,[15] and the regulated community has relied on the applicable standards in the ordinary course of business to engage in contractual arrangements to generate electricity and would be significantly harmed by the Proposed Suspension.[16] The CEC has failed to respond in a meaningful way to the insistent submittal of information and data by the regulated community about the harm that would be caused by the Proposed Suspension and the lack of benefits therefrom.[17] Furthermore, as discussed below, the Proposed Suspension is inconsistent with recent past actions of the CEC, including the *2011 Integrated Energy Policy Report* (IEPR), released just last month, which confirmed that bioenergy supports California's energy goals.[18]

Moreover, if the Proposed Suspension is adopted, it would be arbitrary and capricious for the CEC to move forward with its proposal that any filed application that is not fully "complete" will be delayed by a suspension. There is no basis for delaying an application filed in good faith and with reasonable efforts while other applications filed before a suspension are processed. As the CEC is aware, it is extremely difficult for even sophisticated applicants to know with complete certainty that applications are entirely complete despite best efforts and repeated engagement with CEC staff. It would unfair, arbitrary and capricious to reject a good faith, reasonable application on a technicality and therefore subject the application to a delay caused by the suspension.

VI. 10-DAY NOTICE IS NOT SUFFICIENT

The 10-Day notice provided in Public Resources Code Section 25747(a) does not apply to the Proposed Suspension:

> 25747. (a) The commission shall adopt guidelines governing the funding programs authorized under this chapter, at a publicly noticed meeting offering all interested parties an opportunity to comment. Substantive changes **to the guidelines** shall not be adopted without at least 10 days' written notice to the public. The

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15 See discussion of SBX1-2 in this letter.

16 *See* Southern California Public Power Authority, CEC workshop: Use of biomethane delivered via the natural gas pipeline system for California's RPS, September 20, 2011, attached.

17 *See id*.

18 CEC, *2011 IEPR*, at 178 (Feb. 2012), *available at* http://www.energy.ca.gov/2011publications/CEC-100-2011-001/CEC-100-2011-001-CMF.pdf, incorporated by reference because the CEC has access to this information. *See also* CEC, *2011 Bioenergy Action Plan* (March 2011), *available at* http://www.energy.ca.gov/2011publications/CEC-300-2011-001/CEC-300-2011-001-CTF.PDF.

> public notice of meetings required by this subdivision shall not be less than 30 days. Notwithstanding any other law, any guidelines adopted pursuant to this chapter or Section 399.25 of the Public Utilities Code, shall be exempt from the requirements of Chapter 3.5 (commencing with Section 11340) of Part 1 of Division 3 of Title 2 of the Government Code. The Legislature declares that the changes made to this subdivision by the act amending this section during the 2002 portion of the 2001-02 Regular Session are declaratory of, and not a change in existing law. (Emphasis added.)

As shown in the emphasized text, the reference to the guidelines in Public Resources Code Section 25747(a) only applies to "adopt guidelines governing the funding programs authorized under this chapter" and not guidelines adopted pursuant to "Section 399.25 of the Public Utilities Code," which is referenced *later* in the provision. Therefore, the CEC cannot rely on the truncated 10-day notice period and must provide a more appropriate notice period in accordance with due process. *See, generaly, Cranston v. City of Richmond*, 40 Cal. 3d 755, 764 (1985).

The notice provided for the Proposed Suspension because it included a letter from four members of the legislature supportive of the Proposed Suspension[19] while excluding letters from a greater number of legislators that requested the CEC to not move forward with a suspension[20] that were sent before the notice of the Proposed Suspension was provided. Presentation of only a single point of view from a minority number of legislators as a basis for the Proposed Suspension makes the notice facially defective.

VII. BIOMETHANE FACILITIES HELP CALIFORNIA ACHIEVE ITS AGGRESSIVE RPS MANDATES IN A COST-EFFECTIVE MANNER

A. Unlike Intermittent Renewables, Biogas Resources Can Provide Baseload and Peaking Capacities

The CEC should not suspend the RPS eligibility of biogas because it provides a cost-effective, flexible resource that can be deployed to meet baseload and peaking capacity.[21] Other

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[19] *See* letter from Darrell Steinberg, Nancy Skinner, Wesley Chesbro and Steven Bradford, dated February 22, 2012.

[20] *See* attached letter from Mike Gatto and Roger Hernandez, dated March 8, 2012, letter from Ted Lieu, Carol Liu, Tom Berryhill, Jeff Miller, Connie Conway, Roger Hernandez, Katcho Achadjian, Stephen Knight, and Cameron Smyth, dated March 14, 2012, and letter from Kevin De Leon, dated March 9, 2012.

[21] Patrick Sullivan, *The Importance of Landfill Gas Capture and Utilization in the U.S.* at 28 (Apr. 6, 2010), *available at* http://www.seas.columbia.edu/earth/wtert/sofos/Importance_of_LFG_Capture_and_Utilization_in_the_US.pdf.

renewable technologies like solar and wind power only assist the grid when the sun is shining or the wind is blowing. In contrast with these intermittent renewable resources, biogas can be stored until it is needed. This allows biogas to be dispatched when other resources are unavailable as part of a locally-tailored, integrated energy solution. The ability to use biogas to provide baseload and peaking capacity provides increased stability to electricity grids that other renewable resources cannot offer. Biogas also increases the diversity of fuel resources, a key goal of the RPS program, making the market for renewables more competitive.[22] Biogas provides a reliable supply of renewable power that brings security to the energy grid in a way other renewable resources cannot.

B. Biogas Can Be Delivered Using Existing Infrastructure

Unlike other renewable resources, biogas can be transported into California using the existing natural gas pipeline system.[23] Use of the pipeline system brings several benefits. First, without the need for costly new infrastructure development, biogas has the potential to become a significant renewable resource with fewer added costs to pass on to consumers. Second, the existing transportation framework allows biogas to be implemented more quickly than resources like wind and solar, which can encounter more lengthy development issues. Third, transportation of biogas in the natural gas pipelines displaces fossil fuels that otherwise would have been burned, ultimately leading to lower greenhouse gas emissions. Finally, in order to use the natural gas pipeline system, the transported biogas must be processed into pipeline quality gas, reducing the likelihood of criteria pollutants being released through flaring. When compared to other renewable resources, the transportation advantages of biogas make it an efficient, low-cost renewable resource.

C. Reliance on Biogas Allows Facilities To Be Less Reliant on Fossil Fuel Generation For Backup Capacity

Biogas is also an efficient renewable resource because it can replace fossil fuels as a backup resource.[24] Rather than filling the gaps left by intermittent renewable resources with fossil fuels, biogas can be used to fulfill this demand with a cleaner, renewable fuel source. At least two major benefits can result from this substitution. First, instead of flaring the biogas or allowing it to escape into the atmosphere, it will be processed into pipeline quality gas for use at a power plant and serve a meaningful role in meeting demand. Second, substituting natural gas for cleaner biogas lowers the greenhouse gas emissions that would have resulted from burning

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22 Cal. Pub. Res. Code § 25740.5(c).

23 Sullivan, *The Importance of Landfill Gas Capture* at 27; Eastern Research Group, Inc., *Protocol for Quantifying and Reporting the Performance of Anaerobic Digestion Systems for Livestock Manures* at 12 (March 2011), *available at* http://www.epa.gov/agstar/documents/protocol.pdf (prepared for the EPA's AgSTAR program).

24 Eastern Research Group, Inc., *Protocol for Quantifying and Reporting the Performance of Anaerobic Digestion Systems for Livestock Manures* at 14.

fossil fuels.[25] Given these benefits, biogas is a key component in California's attempts to reduce its reliance on fossil fuels and meet RPS goals.

D. The Proposed Suspension Would Impact In-State Biogas Resources, Increase Pollutant Emission, and Impair In-state Jobs

The Proposed Suspension would adversely impact the current and long-term viability of existing and planned out-of-state and in-state biogas projects. Disrupting in-state projects would impair instate jobs and could increase in-state GHG emissions and criteria pollutant emissions. The Proposed Suspension would directly contradict the express goals of SBX1-2, as described below, by decreasing in-state job growth, increasing emissions, and reducing the state's ability to achieve mandates under the RPS and AB 32.

VIII. EXISTING PROCEDURES ADEQUATELY ADDRESS CONCERNS RELATED TO BIOMETHANE TRACKING AND MONITORING

The CEC should not impose increased requirements on tracking biomethane. The current procedures used to monitor biomethane are sufficient to ensure that biomethane resources are eligible for RPS purposes. Several types of documentation are already required that the CEC can use to confirm RPS requirements are being met. For example, current documentation includes supply information, transportation and storage invoices, and schedules for pipeline transportation and storage. This paper trail provides the information needed to verify the nature and amount of biomethane resources as they travel from the provider to the generating facility. The CEC can use these documents to audit biomethane contracts as needed and ensure that the renewable benefits of biomethane are only being counted once for RPS purposes.

Moreover, the current requirements sensibly conform to standard practices in the natural gas industry. The system already tracks the volume of biogas inserted into the pipeline and the volume eventually delivered to the power plant. This is consistent with the typical practice in the natural gas pipeline system to transport gas using displacement, or backhaul, and should not be altered for biogas. Attempting to track specific amounts of biomethane would be inefficient and unnecessary. Instead, the current system's common sense approach acknowledges the reality that biomethane mingles with natural gas in the pipeline. This reality should not be ignored by imposing additional tracking requirements. Similarly, the precise path taken by biogas after entering the pipeline should not be the focus of these requirements because any insertion of biogas necessarily displaces fossil fuels that otherwise would have been used. The current requirements also include the Federal Energy Regulatory Commission's (FERC) pipeline rules for system imbalances, and it would be unreasonable for the CEC to impose more stringent requirements on biogas. Finally, the California Air Resources Board's greenhouse gas reporting system provides another possible data source for confirming RPS compliance. Therefore, given its reliance on a system that works for the natural gas industry, the current system is an efficient

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[25] CPUC, *Annual Report 2008* at 33 (2008), *available at* http://www.cpuc.ca.gov/NR/rdonlyres/F7CE31C1-64AF-4656-8646-57E2D52264E2/0/CPUC2008AnnualReport.pdf; Sullivan, *The Importance of Landfill Gas Capture* at 23.

and practical way to track biogas throughout its transportation, storage, and use. No further action is needed by the CEC.

The current reporting system is also part of a stable regulatory foundation on which stakeholders in the biogas market have relied. Altering these procedures as part of any suspension could introduce regulatory uncertainty, raise transaction costs, and damage the market for biogas. Any changes to tracking requirements would not only be unnecessary, they would also impair the use of a needed renewable resource into California, limiting the state's ability to meet its RPS goals.

IX. SBX1-2 DOES NOT SUPPORT SUSPENSION

A. SBX1-2 Does Not Mandate or Even Support Suspension

SBX1-2 revises California Public Utilities Code Section 399.11 to state the Legislature's intent to increase the amount of electricity generated from eligible renewable energy resources to 33% by the end of 2020. SBX1-2 does not establish any preferences, but does amend the language in Section 399.11 to better describe the benefits provided by achieving the revised renewables portfolio standard. Instead of listing the benefits in sentence format as was the case in former sections (b) and (c), SBX1-2 amended those sections and revised section (b) to specifically enumerate them. SBX1-2 revised the statute's terminology, not the intent. For example, prior to the amendments provided for in SBX1-2, Section 399.11 stated that "[i]ncreasing California's reliance on eligible renewable energy resources may promote stable electricity prices, protect public health, improve environmental quality, stimulate sustainable economic development, create new employment opportunities, and reduce reliance on imported fuels" and "[t]he development of eligible renewable energy resources and the delivery of the electricity generated by those resources to customers in California may ameliorate air quality problems throughout the state and improve public health by reducing the burning of fossil fuels and the associated environmental impacts and by reducing in-state fossil fuel consumption." (399.11 (b) and (c).

Section 399.11, as amended by SBX1-2, now states that "[a]chieving the renewables portfolio standard through the procurement of various electricity products from eligible renewable energy resources is intended to provide unique benefits to California, including all of the following, each of which independently justifies the program...[d]isplacing fossil fuel consumption within the state..[r]educing air pollution in the state...[m]eeting the state's climate change goals by reducing emissions of greenhouse gases associated with electrical generation" along with six other enumerated benefits.

The legislative history of SBX1-2 confirms that no new preferences were established, and each analysis notes essentially the same goals. The March 14, 2011 Assembly Committee on Appropriations analysis notes the bill's "author proposes to codify the 33% RPS goal to increase the amount of electricity procured from renewable generation sources to achieve various [pre-existing, and newly enumerated and defined] goals: improved air quality, reduced greenhouse gas emissions, diversification of energy sources, energy independence, and encouraging innovation and investment in green energy technologies." This analysis also notes

that the bill's author "contends the requirements of this bill...will lead to an increase in renewable energy resources available to the state's electricity users...[and] further contends this increase in renewable energy supply will likely reduce the cost of renewable energy relative to conventionally produce energy, as well as provide the other economic and social benefits mentioned above."

In no way does any of the legislative history of SBX1-2 indicate an intent to eliminate a viable source of renewable energy from the RPS program or suspend specific provisions relating to biomethane. In fact, the author's specific intent is to increase renewable energy resources available to the state's electricity users. The plain language of SBX1-2, as well as the available legislative history regarding the author's and Legislature's intent to increase the amount of electricity generated from eligible renewable energy resources from 20% by the end of 2010 to 33% by the end of 2020, is in no way intended to forbid the utilization of natural gas or existing natural gas infrastructure to deliver biomethane which will help meet the intent and goals of the RPS program and SBX1-2 to the state's electricity producers. If biomethane is imported into the state (the vast majority of natural gas is also imported into the state[26]), the biomethane displaces natural gas that would be used in California.

B. Suspension Would Be Inconsistent With SBX1-2

The Proposed Suspension is directly inconsistent with the new statutory goals added by SBX1-2. To illustrate the changes with the new statute, we provide the following excerpt of Section 399.11 of the Public Utilities Code with the prior version of similar text in brackets:

> (b) Achieving the renewables portfolio standard through the procurement of various electricity products from eligible renewable energy resources is intended to provide unique benefits to California, including all of the following, each of which independently justifies the program:
>
> (1) Displacing fossil fuel consumption within the state. [PRIOR: reducing in-state fossil fuel consumption]
>
> (2) Adding new electrical generating facilities in the transmission network within the Western Electricity Coordinating Council service area.
>
> (3) Reducing air pollution in the state. [PRIOR: ameliorate air quality problems throughout the state]

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26 According the California Integrated Policy Report, page 131, 87% of natural gas is imported into California, available at:http://www.energy.ca.gov/2009publications/CEC-100-2009-003/CEC-100-2009-003-CMF.PDF

(4) Meeting the state's climate change goals by reducing emissions of greenhouse gases associated with electrical generation.

(5) Promoting stable retail rates for electric service. [PRIOR: promote stable electricity prices]

(6) Meeting the state's need for a diversified and balanced energy generation portfolio.

(7) Assistance with meeting the state's resource adequacy requirements.

(8) Contributing to the safe and reliable operation of the electrical grid, including providing predictable electrical supply, voltage support, lower line losses, and congestion relief.

(9) Implementing the state's transmission and land use planning activities related to development of eligible renewable energy resources

RPS generation via combustion of biogas that has been injected into the existing natural gas pipeline system as biomethane advances the prior and *new* goals in SBX1-2. Biomethane advances each state goal, but particularly (b) (4), (5), (6), (7) and (8) as much, or more than, other intermittent renewable resources, such as wind and solar that would also require significant infrastructure upgrades to develop.[27] Thus, counter to the CEC's suggestion, SBX1-2 does not mandate the Proposed Suspension, and, in fact, counters any attempts to limit the use of biomethane.

X. SUSPENSION IS INCONSISTENT WITH THE CEC'S INTEGRATED ENERGY POLICY REPORT (IEPR) AND STATE POLICY

Biogas has been recognized as an important part of realizing California's clean energy objectives. The California Energy Commission's (CEC) *2011 Integrated Energy Policy Report* (IEPR), released just last month, confirmed that bioenergy supports California's energy goals.[28]

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[27] For example, the California Public Utilities Commission (CPUC) has estimated that a 33 percent by 2020 RPS will require almost a tripling of current renewable generation from 27 terawatt hours in 2009 to 75 terawatt hours in 2020, potentially necessitating $115 billion in new infrastructure investment including at least seven new major transmission lines at a cost of $12 billion because many large scale solar and wind projects would be developed in areas without existing transmission capacity. *See* California Public Utilities Commission, 33 Percent Renewables Portfolio Standard Implementation Analysis Preliminary Results at 1-4 (June 2009), attached.

[28] CEC, *2011 IEPR*, at 178 (Feb. 2012), *available at* http://www.energy.ca.gov/2011publications/CEC-100-2011-001/CEC-100-2011-001-CMF.pdf, incorporated by reference because the CEC has access to this information. *See*

Namely, bioenergy was touted as an RPS-eligible resource that is more reliable than intermittent renewable resources like solar and wind.[29] The benefits of biogas have long been recognized. As noted in the IEPR, the CEC has supported the use of biogas "to help achieve the state's clean energy goals" for years, including in its first *Bioenergy Action Plan for California* in 2006.[30] The CEC also recognized that biogas' role in meeting California's renewable energy goals could increase in the coming years, identifying it as a suitable renewable substitute for natural gas in certain sectors.[31] Therefore, California has a history of supporting biogas and believes in its growing potential as a renewable resource.

XI. SUSPENSION WOULD IMPAIR ACHIEVEMENT OF GHG REDUCTION GOALS UNDER AB 32

As acknowledged in the Notice to Consider Suspension of the RPS Eligibility Guidelines Related to Biomethane ("Notice"), "SBX1-2 does establish a preference for electricity generation that provides more environmental benefits to the state by … helping the state meet its climate change goals by reducing emissions of greenhouse gases (GHG) associated with electrical generation." Notice at 3. Indeed, Public Utilities Code Section 399.11, as amended by SBX1-2, provides: "Achieving the renewables portfolio standard through the procurement of various electricity products from eligible renewable energy resources is intended to provide unique benefits to California, including all of the following, each of which independently justifies the program: ... (4) Meeting the state's climate change goals by reducing emissions of greenhouse gases associated with electrical generation…." Notably, SBX1-2 added enumerated benefit (4), which was not present in the pre-amended version of Public Utilities Code Section 399.11. This addition underscores the importance of the RPS to meeting the mandates set forth in AB 32.

The Proposed Suspension would imperil California's ability to satisfy the mandates of AB 32 in at least two ways. First, ARB's Climate Change Scoping Plan ("Scoping Plan"), which charts the State's course to return to 1990 levels of GHG emissions by 2020, heavily relies on achievement of the 33% RPS. *See* ARB, Scoping Plan at 44-46 (available at http://www.arb.ca.gov/cc/scopingplan/document/adopted_scoping_plan.pdf), attached. Indeed, the Scoping Plan originally anticipated a 21.3 MMTCO2e reduction by 2020 due to the RPS. *Id.* The recent updates to the ARB's GHG Inventories and projections indicates that the State is now evenly more heavily reliant on the RPS, as the anticipated reductions have grown to 23.4 MMTCO2e by 2020. *See* ARB, Final Supplement to the AB 32 Scoping Plan Functional Equivalent Document, Table 2.3-1 (available at http://www.arb.ca.gov/cc/scopingplan/document/final_supplement_to_sp_fed.pdf). As discussed elsewhere in this comment letter, the disruption of the biomethane market(s) caused by the

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also CEC, *2011 Bioenergy Action Plan* (March 2011), *available at* http://www.energy.ca.gov/2011publications/CEC-300-2011-001/CEC-300-2011-001-CTF.PDF.

29 *Id.*

30 *Id.* at 27 (citing CEC, *Bioenergy Action Plan for California* (July 2006), *available at* http://www.energy.ca.gov/2006publications/CEC-600-2006-010/CEC-600-2006-010.PDF).

31 *Id.* at 86.

proposed suspension will make it more difficult for utilities to achieve the RPS by eliminating a critical option – namely, the procurement of new or expanded biomethane-fired generation resources.

Second, the Scoping Plan heavily relies on ARB's Cap-and-Trade Program to achieve AB 32's mandates. *Id.* at 30-38. The Cap-and-Trade Program provides an important, enforceable backstop to ensure the necessary reductions from the capped sectors actually occur. *See* Scoping Plan, Appendix C – Sector Overviews and Emission Reduction Strategies, at C-13. ARB's regulations implementing the Cap-and-Trade Program acknowledge that the combustion of biogas does not create a Compliance Obligation for Covered Entities. 17 CCR §§ 95852.1, 95852.1.1, 95852.2(a)(8). Thus, the Cap-and-Trade Program is premised in part on a properly functioning biomethane market. Those Covered Entities involved in electricity generation (*e.g.*, Electrical Distribution Utilities, Electricity Importers, Electricity Generating Facilities) have been relying on this recognition of the beneficial environmental attributes of biomethane to plan their compliance with the Cap-and-Trade Program. In light of the Proposed Suspension, the development and procurement of biomethane-fueled electricity generation will be adversely impacted and it will be harder and more expensive for Covered Entities to achieve cap-and-trade compliance. This will result in an increased economic burden on ratepayers. Moreover, the Proposed Suspension is inconsistent with ARB's reasoned and careful resolution of the issues surrounding biomethane contracts and delivery, as set forth in the aforementioned regulations. Further, the Proposed Suspension has the potential to disrupt the Compliance Instrument markets. The first quarterly auction of GHG Allowances will be held in August 2012. Futures of Allowances and Offset already are trading. If the CEC were to suspend the biomethane rules, it could call into question both what a Covered Entity's Compliance Obligation is today and what it will be in the future, with concomitant impacts on Covered Entities' auction bidding and, ultimately, on Compliance Instrument pricing.

XII. CONCLUSION

Based on the foregoing, we firmly believe that the Proposed Suspension is contrary to both applicable law and various policy objectives of the State. We, therefore, urge the CEC to defer any action on this issue until all interested parties, including the state Legislature, have had an opportunity to more carefully evaluate the implications of the Proposed Suspension and develop alternatives that address the concerns and vested interests of all stakeholders. We and our clients stand ready to participate in further dialogue regarding this issue.

Very truly yours,

/s/ Michael Carroll

Michael J. Carroll
of LATHAM & WATKINS LLP

Enclosures

ATTACHMENT

THE IMPORTANCE OF LANDFILL GAS CAPTURE AND UTILIZATION IN THE U.S.

PATRICK SULLIVAN, SENIOR VICE PRESIDENT, SCS ENGINEERS

&

EEC RESEARCH ASSOCIATE

APRIL 6, 2010

SUR Council for Sustainable Use of Resources

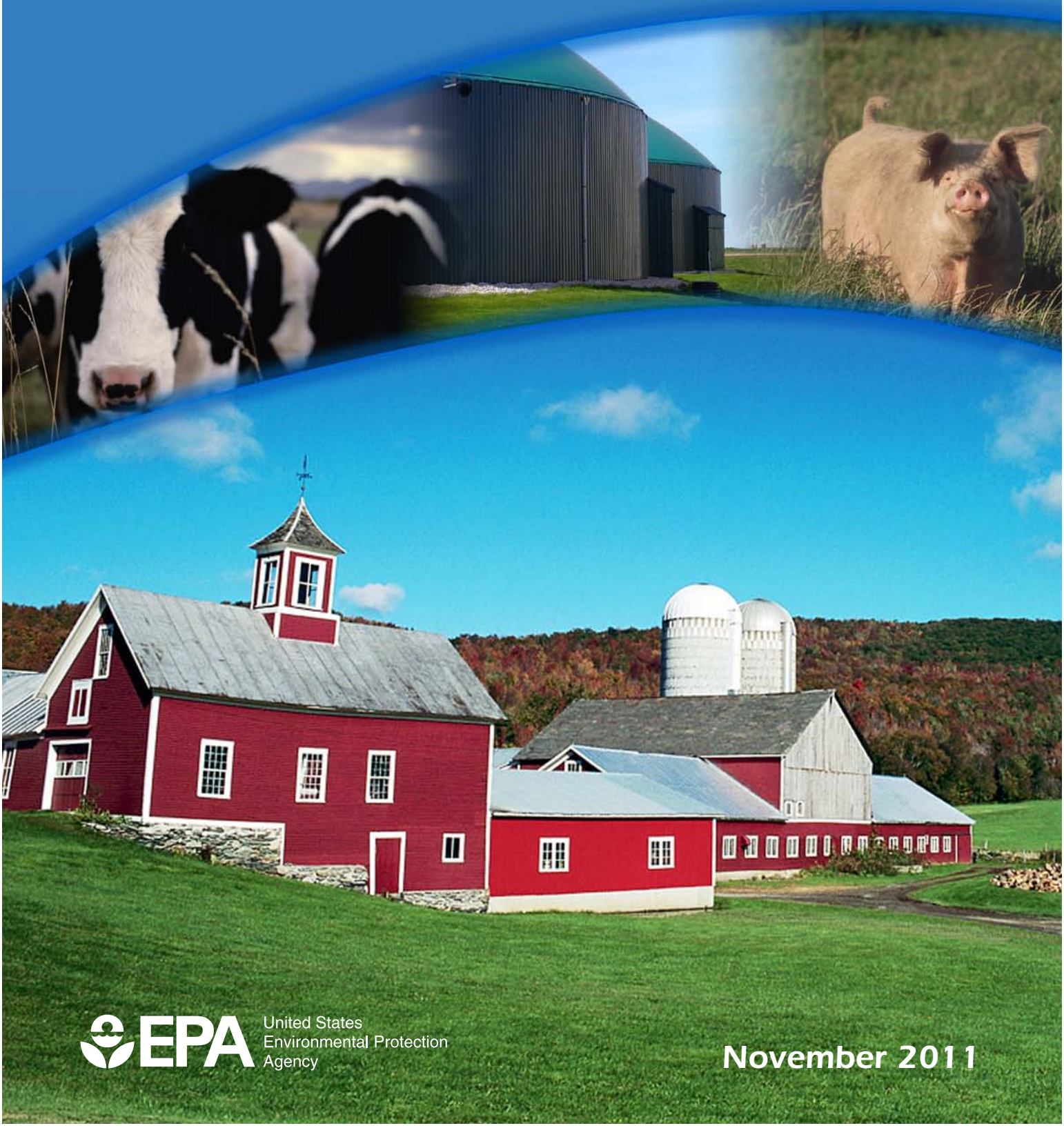
EARTH ENGINEERING CENTER, COLUMBIA UNIVERSITY

FOR FULL REPORT, SEE (1) COURTESY COPIES OF DOCUMENTS SUBMITTED VIA FTP LINK, OR (2) HARDCOPY SUBMITTED TO CEC DOCKET UNIT

ATTACHMENT

Market Opportunities for Biogas Recovery Systems at U.S. Livestock Facilities

AgSTAR



EPA United States Environmental Protection Agency

November 2011

ATTACHMENT

1-1-2010

The Role of energy storage with renewable electricity generation

P. Denholm

E. Ela

B. Kirby

M. Milligan

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Environmental Science & Technology

POLICY ANALYSIS

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Contribution of Anaerobic Digesters to Emissions Mitigation and Electricity Generation Under U.S. Climate Policy

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Supporting Information

ABSTRACT: Livestock husbandry in the U.S. significantly contributes to many environmental problems, including the release of methane, a potent greenhouse gas (GHG). Anaerobic digesters (ADs) break down organic wastes using bacteria that produce methane, which can be collected and combusted to generate electricity. ADs also reduce odors and pathogens that are common with manure storage and the digested manure can be used as a fertilizer. There are relatively few ADs in the U.S., mainly due to their high capital costs. We use the MIT Emissions Prediction and Policy Analysis (EPPA) model to test the effects of a representative U.S. climate stabilization policy on the adoption of ADs which sell electricity and generate methane mitigation credits. Under such policy, ADs become competitive at producing electricity in 2025, when they receive methane reduction credits and electricity from fossil fuels becomes more expensive. We find that ADs have the potential to generate 5.5% of U.S. electricity.

INTRODUCTION

As demand for food and energy grows, innovative ways to meet demand while enhancing environmental quality will be needed. Anaerobic digesters (ADs) can produce renewable energy from livestock manure, prevent the release of methane, and reduce air and water pollution, and digested manure can be applied to crops as a fertilizer.[1] Most ADs in the U.S. sell electricity and digested manure, but the net present value of most systems is insufficient to promote widespread adoption.[2,3] Placing an economic value on the climate, energy, and environmental benefits that ADs provide can help to accelerate their deployment.

Deployment of renewable energy technologies grows under climate policy compared to business-as-usual.[4] Although support for ADs in the U.S. has been limited,[5] countries such as China,[6] India,[7] and Germany [8] have higher rates of AD adoption, mostly due to government support and financial incentives. The incentives currently available at the local, state, and federal levels in the U.S. have stimulated some AD projects. Comprehensive inclusion of the GHG mitigation benefits and low-carbon energy generation of AD projects within a federal climate and energy policy would further enhance prospects for new projects.

Although economic and environmental models have tested the integration of many renewable energy technologies,[4,9,10] a rigorous evaluation of ADs within a computable general equilibrium model has yet to be completed. We used an economic model to test the effects of a representative climate stabilization policy on the penetration of ADs as a GHG mitigation and low-carbon energy generation technology in the U.S. agriculture sector. Engineering and life-cycle data were used to calculate the cost of electricity from a typical AD system.[11,12] Spatially explicit livestock density maps[13] and state-level methane emissions data[14] were used to estimate potential electricity generation capacity and emissions reductions from livestock manure. The climate policy scenarios simulated in the economic model included a reference case and an emissions reduction of 50% below 2005 levels by 2050.[4] As carbon dioxide equivalent (CO_2e) emissions prices increased under more stringent caps, AD systems became competitive, in part, because of additional credits for methane mitigation. Unlike most other low-carbon energy sources, ADs deliver additional nonmarket environmental benefits.

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ANAEROBIC DIGESTERS

Over the last century, as farms have become more specialized, nutrient cycling between crops and livestock has been decoupled.[15] Crop nutrient needs are increasingly met with off-farm resources, while the storage and land application of manure from livestock operations continues to have negative environmental impacts.[16] Agriculture accounts for 6% of greenhouse gas emissions in the United States.[14] Manure stored in anaerobic pits or lagoons supports environmental conditions for methane-producing bacteria, and these emissions account for 0.8% of U.S. emissions (26% of agricultural methane emissions and 9% of CO_2e emissions from agriculture).[14] Diverting manure away from traditional management techniques to ADs can have multiple benefits.[17] First, biogas, which is a mixture of methane, carbon dioxide, and trace gases such as hydrogen sulfide, can be combusted on-site in a generator. The electricity produced may offset purchased power or be fed into the electricity grid. Alternatively, biogas can undergo an upgrading process that results in an almost pure stream of methane that can be injected into natural gas pipelines.[18] Energy generated by ADs can attract low-carbon energy subsidies if life-cycle emissions are taken into account.[19] Second, digested manure that remains after the AD process can be separated into solids that may be used as a soil amendment or replacement for livestock bedding, and liquid that can be used as fertilizer. The AD process mineralizes nutrients, leading to improved crop uptake and increased crop yields.[20]

Whereas the sale of energy has direct economic benefits, anaerobic digestion of manure also performs several functions that have little current market value. First, during the typical 21 days that manure travels through a mesophilic AD, microbial activity and a constant ∼38 °C temperature break down the volatile compounds which are responsible for the malodorous qualities of other manure management systems, and kill weed seeds and pathogens such as *Salmonella* spp. and *E. coli*.[17,21] Second, when manure is separated postdigestion, most of the phosphorus remains in the solid portion, which can be recycled as livestock bedding or added to phosphorus-deficient soils.[22] The liquid portion of manure contains most of the nitrogen, which is converted in the digestion process to ammonium and is more readily available for plant uptake.[23] Separation of nutrients provides the opportunity to divert digestate from areas where soils are already nutrient enriched and additional nutrient loading could harm water quality. Processes to remove phosphorus in solid form are currently under development, but not ready for widespread deployment.[24,25] Finally, both market and nonmarket benefits of ADs, when compared to traditional manure management techniques, can increase and diversify farm income and maintain farmland.[26] Although factors in the decision to install an AD are primarily economic, valuing environmental benefits that are currently outside of the traditional market system may increase the financial viability of projects and accelerate their deployment.

The EPA estimates that the number of ADs in operation on U.S. farms has grown from 30 to 150 between 2002 and 2010 and can be attributed to demonstrated production and reliability, reduction of environmental impacts, state and federal funding programs, energy utility interest, and revenue potential.[27] Even with the 5-fold growth of ADs in the past decade, many roadblocks need to be removed in order to realize the climate, air, water, and development benefits that would accompany a widespread adoption. These barriers include high initial capital costs, uncertain accounting for current nonmarket benefits (including methane emissions), low farmer acceptance, difficult utility connections, and state and federal government regulations.[28,29]

METHODS

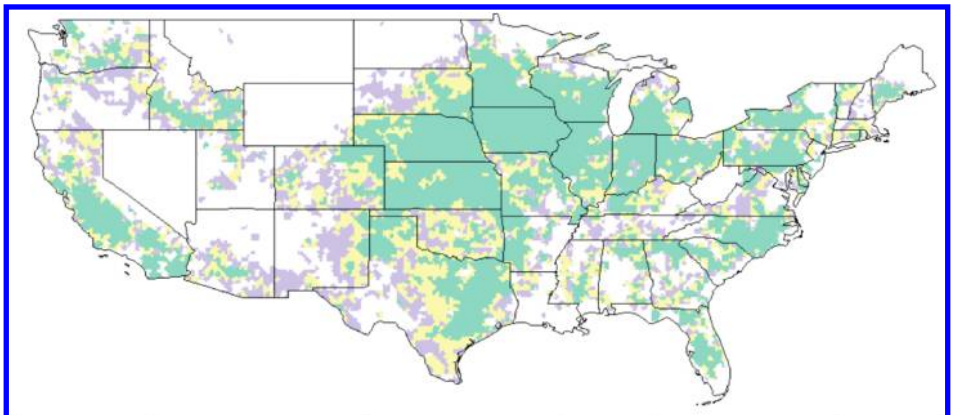
The MIT Emissions Prediction and Policy Analysis (EPPA) model was used to test a range of scenarios to quantify the economic and environmental responses to the introduction of ADs. EPPA is a recursive dynamic, multiregional, multisector computable general equilibrium model that simulates the world economy.[30] The model has been applied to a range of policy-relevant topics including energy legislation,[4,31] health,[32] biofuels,[9] agriculture,[33] and alternative energy technologies.[34] In this study, we compared the impacts of three scenarios on the use of electricity from ADs as a substitute for more carbon-intensive sources.

Anaerobic digesters are introduced into the model as a low-carbon alternative technology, in which the electricity produced competes with traditional electricity sources based on the levelized cost of electricity (LCOE) across sources with additional consideration of intermittency and experience with technology.[35] The LCOE takes into consideration the capital, operations, and fuel costs of electricity produced over the lifetime of the plant.[12] With no climate policy in place, alternative electricity generation technologies such as solar and wind power are one to four times more expensive than fossil-fuel-based generation.[12]

We compare three scenarios in EPPA to gauge the impact of ADs under climate legislation. The first, or reference scenario, assumed no climate policy. The policy scenarios described in refs 4 and 31 cover the range of recent Congressional proposals and are referred to by the cumulative number of GHG emission allowances each policy issues between 2012 and 2050. Our remaining scenarios implemented a representative U.S. climate policy, one with ADs available and one without. The policy specified an economy-wide emissions cap on all GHGs beginning in 2010. The 2010 cap was 95% of 2005 emissions in 2010 and was progressively lowered to 50% of 2005 emissions by 2050.

Version 5 of EPPA disaggregates the agricultural sector into separate crop, livestock, forestry, and biofuels production structures as described by ref 36. We modified the model to include livestock manure output and separate livestock production into traditional livestock, for which manure is treated as a byproduct, and livestock for which manure can potentially be used in ADs. Detailed changes to the model are described in the Supporting Information (SI) Methods and Figure S1. Livestock within the new production function is eligible for offsets from reduced emissions of methane, and income from the sale of electricity. The AD production structure employs capital, labor, and intermediate inputs from other industries to produce electricity (Figure S1).

ADs enter endogenously in EPPA when they become economically competitive with other forms of generation. Similar to other technologies within EPPA, ADs are parameterized using bottom-up engineering, life cycle and fuel cost data.[11] There are several types of ADs currently in use that range in size from 50 to 2800 kW (n = 55, mean = 573).[37] Acknowledging that there are several digester designs that operate best with certain feedstocks or in certain geographies, we based our analysis on capital cost data from horizontal plug flow ADs, as the most data were available from this technology.[37] The LCOE from ADs is



Digester Size	Available MW				Transport cost ($/kwh)				Capital Costs ($/kWh)	Total Electricity Cost ($/kWh)				Average Markup over Conventional Electricity
Cluster area (km²)	225	400	625	900	225	400	625	900		225	400	625	900	
1000kW	5755	1666	1287	882	0.06	0.07	0.08	0.10	0.09	0.15	0.16	0.17	0.18	1.6
500kW	82	179	462	429	0.06	0.07	0.08	0.10	0.11	0.17	0.18	0.19	0.20	2.0
250kW	46	85	213	180	0.06	0.07	0.08	0.10	0.14	0.20	0.21	0.22	0.23	2.3

Figure 1. Readily available manure resources can contribute over 11 000 MW of electricity generation potential. Each colored grid cell is included in a cluster less than 900 km^2 that can support an AD of a given capacity. Electricity cost for each cluster is based on AD capital costs and manure transportation costs. AD electricity generation is initially uncompetitive with conventional electricity but enters as the cost of conventional electricity rises.

determined by two factors: capital costs and transportation costs. ADs exhibit capital cost trends similar to other energy generation technologies: larger, centralized units are less expensive to operate per unit of energy produced.[38] Data collected by EPA AgSTAR on generator capacity and capital costs exhibit a power law relationship ($r^2 = 0.911$).[39] We assumed that each system had a postdigestion solids separation system and hydrogen sulfide (H_2S) treatment at an added cost of 9.5% of capital costs.[39] Although centralized ADs might be less expensive to operate, there are additional logistical and coordination factors that need to be considered for optimal day-to-day management. There are currently more centralized ADs outside the U.S.[8,40,41]

As AD size increases, the amount of manure needed to supply the generator increases proportionally. Large AD systems often require manure inputs from several farms in order to take advantage of lower capital costs per kWh for larger generator systems. We assumed that the manure input from multiple sources was optimized for total solid content, pH, and other physical characteristics important to the digestion process. The cost of hauling large amounts of manure can be a significant portion of the final LCOE. In this study, we represent the trade-off between low capital cost with high transportation cost of larger systems, and high capital cost with low transportation cost of smaller systems, by including 1000, 500, and 250 kW ADs and spatially grouping manure resources according to system size. For each system, we assumed that 50% of the manure was available on-site, while the other half was transported via truck.[42] We further assumed that biogas was combusted on-site at 40% thermodynamic efficiency, and the electricity generated was sold to a utility at market prices averaged across users and states.[43,44] Waste heat collected from the generator was used to maintain the digester within the mesophilic temperature range (~38 °C). We assumed that digested manure was used as a fertilizer substitute, but not given an economic value. LCOE values for each digester size were computed using the methods described in ref 12 with operations and maintenance assumed to be 3% of capital costs[45,46] (Table S2).

Manure availability was estimated using spatially explicit maps of livestock density, manure production and management parameters, and identification of areas with high manure densities. Gridded densities of cattle, pigs, and poultry available at 0.05° spatial resolution (~5 km) adjusted to match FAOSTAT 2005 national totals for the U.S. were used to estimate livestock populations.[13] Reference 14 provided state-level parameters on the excretion rate of volatile solids, maximum methane producing capacity, and typical animal mass needed to calculate methane production for dairy cattle, beef cattle, swine, and poultry in each state. The U.S. Department of Agriculture National Agricultural Statistics Service QuickStats database[47] provided a breakdown of state swine and poultry data by animal type, while the Cattle Enteric Fermentation Model[48] provided the distribution of cattle types. It was assumed that all manure was available for digestion, except manure from animals managed in pastured systems, as manure collection would be uneconomical under current conditions. Given these data, statewide coefficients for methane production potential were computed for each livestock group over the contiguous U.S. To determine the manure input for a typical AD, the proportion of potential methane for each livestock type was used to compute the percentage of manure input into a typical digester. Using ref 14 manure management data, average methane emissions from livestock manure not diverted to an AD were calculated as the potential project offset value.

To assess the full LCOE of ADs, costs for digesters that transport manure from off-site were estimated. Given the gridded methane production potential, clusters were identified that met the minimum amount of methane needed for a given digester size and were contained in the smallest number of contiguous grid

cells. The ArcGIS Spatial Order tool constructed a Peano curve over the input data set to quantify the proximity of a given cell to its neighbors. Next, the ArcGIS Collocate tool grouped points based on the Spatial Order value until a specified threshold of methane production potential was met. Clusters of grid cells less than 900 km^2 in area were identified as areas compact enough to support an AD without excessive manure hauling costs. Remaining clusters were separated into groupings less than 225, 400, 625, and 900 km^2, and it was assumed that each cluster was square and manure densities were higher in cells closer to the central cell (where the AD would be located). Transport distances were calculated by summing the distance of every cell to the central cell. Transport costs for each cluster size were computed with distance-cost hauling relationships from refs 40 and 49.

We identified three potential AD sizes based on clusters of available manure. We first identified clusters of grid cells that met the biogas requirements of a 1000 kW AD and were within a reasonable transportation distance (900 km^2), and the remaining cells were recursively analyzed to identify clusters that met the biogas production potential threshold for 500 and 250 kw ADs. For ADs of each size, we determined the LCOE by calculating the weighted average of AD clusters from each of the four transportation distance categories. ADs were represented in EPPA as alternative electricity generation technologies. We assumed that manure located near an AD of a particular size could not be used in an AD of a different size. This approach is suitable for determining the potential methane production potential across a region, but has limitations for siting a specific AD.

RESULTS

Manure Resource Availability. Over two billion cattle, swine and poultry in the U.S. produce manure that can be diverted to ADs to produce energy and then used as fertilizer. Our estimates show that manure collected and deposited in lagoons or pits currently has the potential to produce 11 000 megawatts (MW) of electricity, while manure from pastured animals could produce an additional 7000MW with modified collection practices. In our core scenarios, only manure collected and stored in lagoons or pits, and not pasture manure, is available for use in ADs. The greatest density of manure available for ADs is located in the Southeast, Midwest, and Western regions, and 14% of electricity demand in Iowa and Nebraska could potentially be met by ADs. (Figure 1, Table S1).

Economies of scale for ADs, and variable distances between manure sources and ADs, result in a range of generation costs for electricity from manure. We first identified three potential AD sizes based on manure density: 1000, 500, and 250 kW. We estimate that, ignoring transport costs, a 1000 kW AD is able to produce electricity at $0.086/kWh, while a 250 kW AD is 58% more expensive at $0.136/kWh. Electricity from a 500 kW AD is $0.107/kWh (Table S2). The cost to transport manure ranges from 30 to 53% of total electricity cost (capital + transportation cost), based on digester size and transportation distance. Transportation costs are $0.060/kWh for the smallest (225 km^2) and $0.096 for the largest (900km^2) clusters. Total electricity costs range from $0.128/kWh to $0.204/kWh, which is 1.52 to 2.44 times the cost of conventional electricity in the base year (2004) of our modeling framework.

Carbon Prices, Anaerobic Digesters, and Economic Welfare. Electricity from ADs competes with electricity from traditional sources based on generation costs. Under a climate policy that includes emissions from all sectors, electricity from fossil fuels becomes more expensive, and renewable and low-carbon electricity sources become more competitive. We consider a policy where between 2010 and 2050 the emissions cap is progressively reduced. Under the cap, the price per tonne of emissions increases to $316/t$CO_2$e (Figure 3a, Table S3) by 2050. This CO_2e price is much higher than prices currently observed in the E.U., but is consistent with other studies that consider emission limits that decrease over time.[50] CO_2e prices increase faster in the later years of the scenario, as more costly emission reductions are put into place. There is a sharp increase in the CO_2e price after 2045, as prior to this date the cap is largely met by switching electricity generation from coal to gas, but more radical measures are required to meet the cap after this date. The availability of ADs reduces CO_2e prices by $42 in 2050 relative to when ADs are not available, since ADs are able to produce energy less expensively than other low-carbon energy technologies and reduce agricultural methane emissions. By 2050, relative to a scenario with climate policy without ADs, ADs displace electricity from natural gas combined cycle (0.1 petawatt-hours, PWh) and wind (0.03 PWh) in 2050.

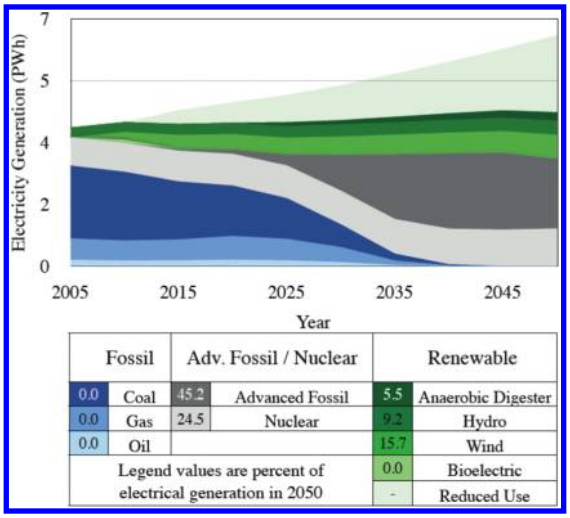


Figure 2. Simulated U.S. electricity generation 2005−2050 under a climate policy. Electricity generation under reference and climate policy without digesters are shown in Figure S2. Note: Advanced fossil includes natural gas combined cycle (NGCC), NGCC with sequestration, integrated gasification with combined cycle and sequestration, and wind with gas backup.

Under the climate policy, ADs are first introduced in 2025 when the price of CO_2e is $76/tonne and electricity is $0.15/kWh. In the first year ADs are economically available, assuming that potential AD electricity generation is maximized, they produce 0.1 PWh of electricity, which is 2.6% of national electricity generation. In 2050, ADs contribute 0.24 PWh of electricity, or 5.5% of national generation (Figure 2, Figure S2). This increase is mainly driven by the expansion of the livestock sector, but the introduction of more costly AD electricity generation as the price of electricity increases also plays a role. Compared to the climate policy scenario without ADs, the livestock sector grows faster when ADs are available, as increased profits from electricity sales and methane mitigation credits are realized.

As carbon prices rise, the cost to produce electricity from ADs becomes competitive with other electricity generating technologies

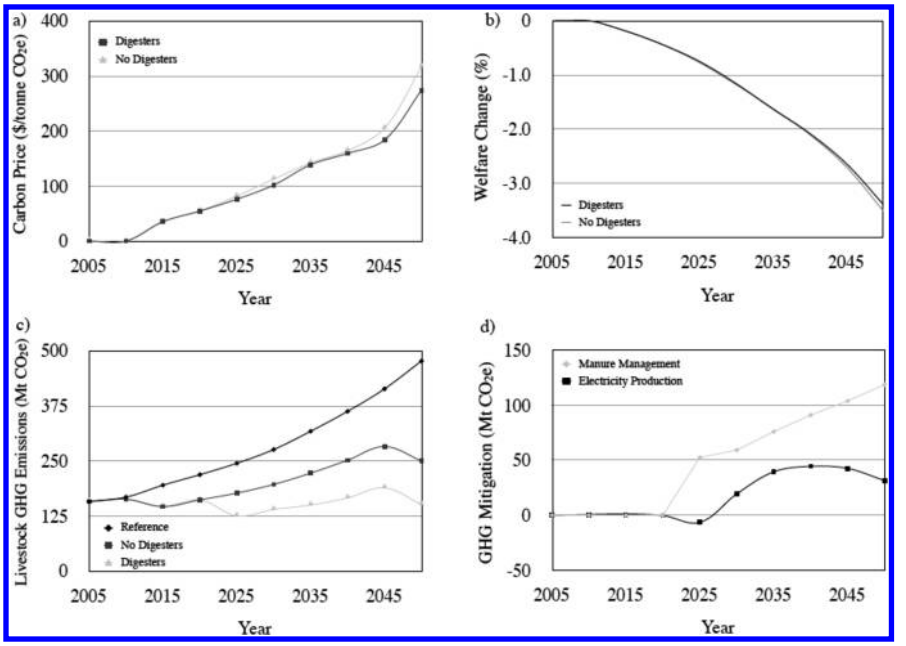


Figure 3. Changes in reference and policy scenarios until 2050 for (a) carbon prices, (b) economic welfare, (c) livestock greenhouse gas emissions, and (d) greenhouse gas mitigation (there is a net increase in GHGs from electricity production between 2020 and 2025 when ADs displace expensive, low-carbon).

and AD market penetration increases. The least expensive electricity is available from 1000 kW ADs, which enter in 2025. Further increases in the CO_2e price are required before smaller digesters become competitive. Electricity production from 500 kW and 250 kW begins in, respectively, 2035 and 2040.

Changes in consumer welfare, measured as equivalent variation changes in annual income, are often used as an indicator to measure the economic effects of a policy.[51] Not accounting for climate benefits, welfare under climate policy (without ADs) decreased by 3.5% relative to the reference scenario in 2050 (Figure 3b). When ADs were included, welfare increased by 0.2% ($33 billion), as they provided an additional mitigation option. This indicator of consumer welfare measures only changes due to the cost of GHG mitigation, and does not take into account potential social and environmental benefits of implementing this technology. Although important, analysis of these benefits is beyond the scope of this study.

Greenhouse Gas Emissions. Manure collected and managed under anaerobic conditions releases methane, a potent GHG. By diverting the manure to ADs, an opportunity to capture and combust the methane is created. Mitigating these emissions enables livestock operations to sell emissions permits, thereby increasing the economic viability of the projects. By 2050, ADs are able to mitigate 151 million metric tons (Mt) of CO_2e, mostly from methane abatement (Figure 3c, Table S3). In the reference scenario, the livestock sector emits 477 Mt CO_2e of methane in 2050, which is reduced to 250 Mt CO_2e under a climate policy without ADs as technologies are used to mitigate livestock emissions. Introducing ADs decreased livestock methane emission to 151 Mt CO_2e by 2050.

As electricity from ADs was introduced, electricity from other sources decreased. If electricity from ADs displaces an electricity generation technology with higher emissions intensity per unit of electricity, then additional GHGs are mitigated. In 2050, 31 Mt CO_2e of electricity emissions are displaced by digesters (Figure 3d). This was mainly due to a decrease in electricity generation from natural gas-combined cycle (NGCC) and under the emissions cap, economy-wide emissions remained constant.

Interestingly, ADs do not necessarily displace high-carbon electricity production, such as coal. In our framework electricity generation sources compete with each other. The electricity mix is determined endogenously so as to minimize the cost of meeting the emissions cap. When ADs are available (and are profitable), ADs reduce the CO_2 price, which reduces the costs of electricity from high-carbon sources, relative to when ADs are not available.

DISCUSSION

Our results demonstrate the potential for climate policy to hasten the use of ADs, both to reduce GHG emissions from livestock and to produce renewable energy. By including ADs within an economic modeling framework, we illustrated the opportunity for a win−win scenario where, by providing incentives for the GHG benefits of digester operation, there are additional nonmarket benefits, even though they were not explicitly incentivized. This bundle of market and nonmarket benefits may increase the adoption rates of ADs.

Although capital costs are a major barrier to further introduction of ADs, there are opportunities to improve the efficiency of manure collection, processing, and subsequent biogas combustion that would increase the economic competitiveness of the technology. Most AD systems are currently installed at livestock operations with existing manure management strategies that may not be optimal for biogas extraction. Further research, development, and innovation is needed to design manure collection systems that simultaneously maximize biogas production and animal well-being, while minimizing the release of nutrients and GHGs. Siting ADs near energy-intensive industries would allow for better utilization of the waste heat from the combustion process.

Although livestock that spend a majority of their time on pasture were excluded from our core scenarios, financial incentives to produce biogas may spur development of pasture-based manure collection systems that allow for both grazing and manure collection. These systems would realize both the environmental and animal welfare benefits of pasturing animals, and the economic benefits of biogas production.

The assumptions and core data that are the backbone of EPPA are routinely updated to the latest state of the science (SI and refs 4 and 31. While we parameterized the model with values from the literature, and conducted sensitivity analyses, many social, economic, and environmental trends cannot be modeled with certainty far into the future. We assumed that there were no major changes in consumer preferences, but as we move into an increasingly energy and resource constrained future, these assumptions may be optimistic. Therefore, less manure may be available for ADs in the future than in our estimates. Additionally, concern over environmental and health impacts of meat consumption may also reduce future livestock production.[52,53]

Although we only considered livestock manure as an input to ADs, they can also break down many other forms of organic wastes to produce biogas, often at higher rates of biogas production per unit input than manure, as manure has already been digested by the animal.[54] Co-digesting other organic materials with manure can relieve pressure on other waste processing facilities and increase biogas production without greatly increasing the size and capital costs of the digester.[55] Several municipalities already collect household food scraps and waste grease, and digestion of these materials could increase AD profitability and further reduce the environmental impact of waste disposal.[56]

We derived model parameters for AD GHG mitigation and electricity generation from published sources, but we acknowledge that there remains uncertainty about methane emission rates from livestock under different management practices.[57] Even if methane credits increased by 30%, which we considered in a sensitivity analysis, electricity generated by ADs only increased by 0.003 PWh in this scenario, and 500 kW ADs became economical five years earlier (Table S6). Improved methods to measure GHG emissions from livestock, e.g. ref 58, will be needed to improve upon currently used generalized emissions models. Life cycle assessment is one tool that can be used to assess the release of GHGs and nutrients from a farm that can lead to implementing the most effective mitigation options.[58]

Even in the absence of a broad climate policy that prices carbon, there are other mechanisms to encourage installation of additional AD capacity. Several states have implemented renewable portfolio standards that have driven the adoption of alternative energy sources.[59] Germany uses a feed-in-tariff to guarantee competitive prices for energy produced from ADs, and is a global leader in biogas production.[54] California's low carbon fuel standard (LCFS) ranks transportation fuels by their life-cycle carbon intensity. For illustration, biogas from dairy ADs can be used as a transportation fuel if it undergoes upgrading and compression. It is then comparable to traditional compressed natural gas with one-fifth the carbon intensity because a credit is applied to the biogas owing to decreased methane emissions compared to traditional manure management techniques.[60] Some AD projects are intended to reduce other environmental impacts such as nutrient runoff, and GHG emissions may be a secondary concern.

ADs can provide energy for a single household, as seen in India and China,[6,7] or up to several thousand households such as in Toronto, Canada.[61] While the technology is scalable, decisions regarding sites, operations, and sources of digestable material are outside the context of this study. Our approach matched digester sizes (1000, 500, 250 kW) to resource density in order to minimize the capital investment and transportation costs per unit of energy generation. While this approximation is useful at a national level, each potential AD project will need to survey the availability and cost of manure and organic materials for codigestion to maximize the environmental and economic efficiency of the project.

Using a computable general equilibrium model in this context allows us to investigate the interactions among sectors, illustrated here in the novel linkages between agriculture and energy production. While economic welfare decreased across all scenarios relative to the reference, the climatic benefits were excluded from these values, mostly because such calculation will suffer from much greater uncertainty and lack of information than on the cost side. Additionally, there are few metrics to quantify nonclimatic environmental benefits from ADs and thus these were excluded from the analysis.[62] Caution should be used when applying the results of this study to a specific project, since they are estimated across the entire economy and the projected changes in welfare do not include all costs and benefits to society.

Many of the fuel sources used today have social and environmental impacts that are not accounted for in standard economic transactions. Similar externalities exist within the agricultural sector, which will increase as livestock operations expand. Implementing a climate policy that places a value on carbon will ease the transition from diverting livestock manure to ADs to provide energy. As the external costs of fossil fuel energy are realized throughout the economy, the environmental cobenefits of AD further increase the societal value of avoiding traditional manure management.

■ ASSOCIATED CONTENT

Supporting Information. Expanded explanation of the economic modeling framework with a focus on the modifications made to the Emissions Prediction and Policy Analysis (EPPA) model, documentation of the methods used to integrate anaerobic digesters into an economic modeling framework, and an explanation of the alternative scenarios. Supporting tables and figures include model inputs and results from the modeling scenarios. This material is available free of charge via the Internet at http://pubs.acs.org.

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ATTACHMENT

CALIFORNIA
ENERGY
COMMISSION

2009 PROGRESS TO PLAN BIOENERGY ACTION PLAN FOR CALIFORNIA

Prepared for the Bioenergy Interagency Working Group:

Air Resources Board
California Energy Commission
California Environmental Protection Agency
California Resources Agency
California Department of Food and Agriculture
Department of Forestry and Fire Protection
Department of General Services
Integrated Waste Management Board
Public Utilities Commission
Water Resources Control Board

STAFF REPORT

April 2010
CEC-500-2010-007

Arnold Schwarzenegger, *Governor*

CALIFORNIA ENERGY COMMISSION

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Abstract

In 2005, Governor Schwarzenegger expressed support for the public-private California Biomass Collaborative and directed the Interagency Bioenergy Working Group to develop an integrated and comprehensive state policy on the use of biomass for electricity generation and natural gas and petroleum consumption. In 2006, the Governor issued Executive Order S-06-06, establishing targets for the use and production of biofuels and biopower and directing state agencies to work together to advance biomass programs in California. The Interagency Bioenergy Working Group assembled a plan that provides specific actions and timelines that agencies agreed to take to implement the Executive Order. This report serves as the second Progress to Plan.

Keywords: Interagency Bioenergy Working Group, California Energy Commission, Bioenergy Action Plan, Progress to Plan, biofuel, biopower

Executive Summary

The 2009 Bioenergy Action Progress to Plan addresses the State of California's progress in developing a coordinated state government approach to bioenergy issues and responds to Executive Order S-06-06 that established biomass productions and use targets for California.

The 2006 Action Plan identified 63 action items for various state agencies (Attachment 1). Despite better coordination within state agencies, progress towards meeting California's ambitious bioenergy goals has been slow, and in some cases, the state is losing ground.

Without major initiatives to make legislative and regulatory changes, and state and federal financial incentives and policies that recognize the benefits of using "waste" material for energy, California will fall far short of the goals outlined when Governor Schwarzenegger signed Executive Order S-06-06 which stated:

- For biomass used for electricity, the state shall meet a 20 percent target within the established state goals for renewable generation for 2010 and 2020.
- For biofuels, the state shall produce a minimum of 20 percent of its biofuels within California by 2010, 40 percent by 2020, and 75 percent by 2050.

The action items of the 2006 *Bioenergy Action Plan* remain important and California state government continues to:

- Coordinate research, development, demonstration, and commercialization efforts with federal and state agencies.
- Align existing state regulatory requirements to encourage production and use of California's biomass resources.
- Promote California as a market leader in technology innovation and market development.
- Encourage market entry for new applications of bioenergy, including electricity, biogas, and biofuels.
- Maximize the contributions of bioenergy toward achieving multiple state policy goals of petroleum reduction, addressing climate change, renewable energy, and environmental protection.

This is the Second Progress to Plan update of the 2006 Bioenergy Action Plan

CHAPTER 1: Introduction

The Interagency Bioenergy Working Group assembled a plan that provides specific actions and timelines that agencies agreed are necessary to implement the Executive Order. This Second Progress to Plan developed by the California Energy Commission presents the status, barriers, and recommendations of biopower and biofuel development using biomass in California. The status of biopower and biofuel are summarized in Chapters 2 and 4, respectively, and the barriers and recommendations to the development of each are summarized in Chapters 3 and 5. Chapter 6 includes conclusions drawn from Chapters 2 to 5.

CHAPTER 2: Status of California's Biopower Development

California consumed 306,577 gigawatt hours (GWh) of electricity in 2008 with about 64 percent generated from fossil fuel including natural gas and coal, 14 percent from nuclear, 11 percent from large hydroelectric, and 11 percent from renewable resources (Table 1).

Table 1: 2008 Total System Power (GWh)

Fuel Type	In-State	Northwest Imports	Southwest Imports	Total System Power
Coal	**3,977**	**8,581**	**43,271**	**55,829**
Large Hydro	**21,040**	**9,334**	**3,359**	**33,733**
Natural Gas	**122,216**	**2,939**	**15,060**	**140,215**
Nuclear	**32,482**	**747**	**11,039**	**44,268**
Renewables	**28,804**	**2,344**	**1,384**	**32,532**
Biomass	5,720	654	3	6,377
Geothermal	12,907	0	755	13,662
Small Hydro	3,729	674	13	4,416
Solar	724	0	22	746
Wind	5,724	1,016	591	7,331
Total	**208,519**	**23,945**	**74,113**	**306,577**

Source: California Energy Commission

The 2006 *Bioenergy Action Plan* follows the Governor's Executive Order for in-state electricity production using biomass resources, and has a target of producing 20 percent of the state Renewables Portfolio Standard (RPS) goals for renewable generation by 2010 and 2020. The RPS obligates investor-owned utilities (IOUs), energy service providers (ESPs) and community choice aggregators (CCAs) to procure an additional 1 percent of retail sales per year from eligible renewable sources until 20 percent is reached, no later than 2010. For 2020, an accelerated RPS goal of 33 percent has been established.

California generates over 80 million bone dry tons (BDT) of biomass annually. [1] Of the total biomass generated each year, 28.5 million BDT come from solid fuel biomass including forest thinnings, slash, shrub, and mill residues, agricultural crop residues, and recovered municipal solid waste (MSW); 19.2 million BDT come from MSW that is currently disposed of in landfills; and 4.5 million BDT come from livestock manures, sewage sludge, and food processing wastes.

1 Bone dry means completely dry and without any trace of moisture.

The remaining 27.8 million BDT are not technically feasible to collect and use in producing renewable electricity, fuels, or biobased products.[2]

In 2008, California generated approximately 20 percent of its renewable electricity from biomass fuels, including:

- Solid fuel biomass (including mill and agricultural residues, forest slash and thinnings, urban wood wastes, and recovered MSW[3]).
- Unrecovered MSW. [4]
- Landfill gas from the existing wastes in place.
- Digester gas generated from anaerobic digestion of
    - Sewage sludge
    - Livestock manure
    - Agricultural and industry wastes or wastewaters.

Since 2002, electricity generated from biomass fuels decreased from 6,192 GWh to 5,724 GWh in 2008 while the state's total electricity generation and demand has increased.[5] Meeting California's 20 percent RPS goal and the 2010 biopower targets would require an additional 6,562 GWh biopower generation annually assuming that total electricity consumption in 2010 will remain the same as in 2008 at 307,141 GWh.

California's biopower generation was about 943 megawatts (MW) in 2008; 60 percent of existing biopower generation comes from solid fuel biomass, 28 percent from landfill gas, 7 percent from digester gas, and 4 percent from unrecovered MSW (Figure 1).

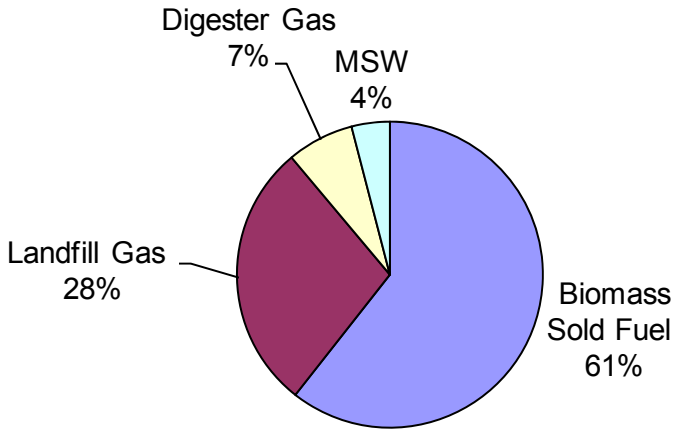
2 California Biomass Collaborative. 2005. *Biomass in California: Challenge, Opportunities, and Potential for Sustainable Management and Development. Prepared for the California Energy Commission*. http://biomass.ucdavis.edu/materials/reports%20and%20publications/2005/2005_Biomass_in_California.pdf.

3 Recovered MSW includes the portion of the MSW that is currently recycled, composted, or transformed into energy.

4 Unrecovered MSW includes the portion of the MSW that is currently landfilled.

5 Daryl Metz presentation at the 2009 Integrated Energy Policy Report staff workshop on Research Development and Demonstration of Advanced Generation Technologies, "California Generation Portfolio," California Energy Commission, August 10, 2009.

Figure 1. California Biopower Mix (943 MW), 2008



Data Source: California Biomass Collaborative

Table 2 shows the total number of biomass solid fuel facilities constructed during the 1980s, 1990s, and 2000s; number of currently operating facilities built during the 1980s or before, 1990s, and 2000s; and electric power capacity for the facilities constructed to date and currently operating. Although 60 percent of California's biopower generation comes from solid-fuel biomass, over half of the total biomass solid fuel biopower plants constructed to date are idle, dismantled, or converted to natural gas power plants. Only one new facility has been constructed since 2000. The total generating capacity from solid fuel biomass has decreased from 958 MW in the 1990s to 667 MW today. Assuming that 19.6 million BDT solid fuel biomass (not including 8.9 million BDT/yr recovered MSW) is available to be converted into electricity, a potential of 2,754 MW could be added based on existing biomass solid fuel resources.[6]

While only one new facility has been constructed since 2001, three idled biomass plants have restarted commercial operations and received financial assistance from the Energy Commission's Existing Renewable Facilities Program. Also, an idled coal facility and two operational coal facilities are undergoing full and partial fuel switches to biomass, respectively. The idled coal facility will restart commercial operations as a biomass generator in the third quarter of 2010, and the operational facilities are firing with at least 10 percent biomass, with plans for higher biomass fuel usage in 2010 and 2011.

6 With an average of 8000 Btu/lb heating value and a 13,000 Btu/kWh of conversion efficiency.

Table 2: California Biomass Solid Fuel Biopower Plants Developed

Year of Construction	# of Total Facilities Constructed	# of Facilities Currently Operating	MW Capacity of Total Facilities Constructed	MW Capacity of Facilities Currently Operating
1980s or before	53	22	759	474
1990s	13	7	199	179
2000s	1	1	36	14
Total	67	30	994	667

Data source: Dr. Gregory Morris, Future Resources Associates, Berkeley, CA

Table 3 shows the development of biopower plants using MSW in California during the last 30 years. Three MSW incineration plants were constructed in the 1980s with a total power generation capacity of 70 MW. No new MSW power plants have been constructed since 1990. Assuming that 19.2 million BDT MSW that is currently disposed of in landfills will be used for electricity production, a potential of 2,192 MW power could be generated.[7] All three MSW incineration power plants constructed during the 1980s remain operating to date and are profitable, even though only one can claim renewable energy credit under the existing renewable energy definition.

Table 3: California MSW Incineration Power Plants

Year of Construction	# of Total Facilities Constructed	# of Facilities Currently Operating	MW Capacity of Total Facilities Constructed	MW Capacity of Facilities Currently Operating
1980s or before	3	3	70	70
1990s	0	0	0	0
2000s	0	0	0	0
Total	3	3	70	70

Data Source: California Energy Commission

Table 4 shows the landfill gas to electricity biopower plants development in California during the last 30 years. There were 118 landfill gas to electricity (LFGTE) facilities constructed with 90 operating today. The total power generation capacity of the 90 facilities is about 309 MW.

7 With an average of 6500 Btu/lb heating value and a 13,000 Btu/kWh of conversion efficiency.

Table 4: California Landfill Gas to Electricity Biopower Plants [8]

Year of Construction	# of Total Facilities Constructed	# of Facilities Currently Operating	MW Capacity of Total Facilities Constructed	MW Capacity of Facilities Currently Operating
1980s or before	43	24	170	127
1990s	24	19	84	72
2000s	51	47	126	110
Total	118	90	380	309

Data Source: US EPA Landfill Methane Outreach Program

During the 2000s, only one new facility was constructed using solid fuel biomass and no new facilities constructed using MSW; however, 47 new LFGTE facilities were added during that time. The total power generation capacity from the 47 LFGTE facilities is about 110 MW. Technologies used to convert landfill gas to electricity include internal combustion (IC) engine, gas turbine, microturbine, and others (Table 5). Locations of the 47 LFGTE facilities developed during the 2000s are shown in Figure 2.

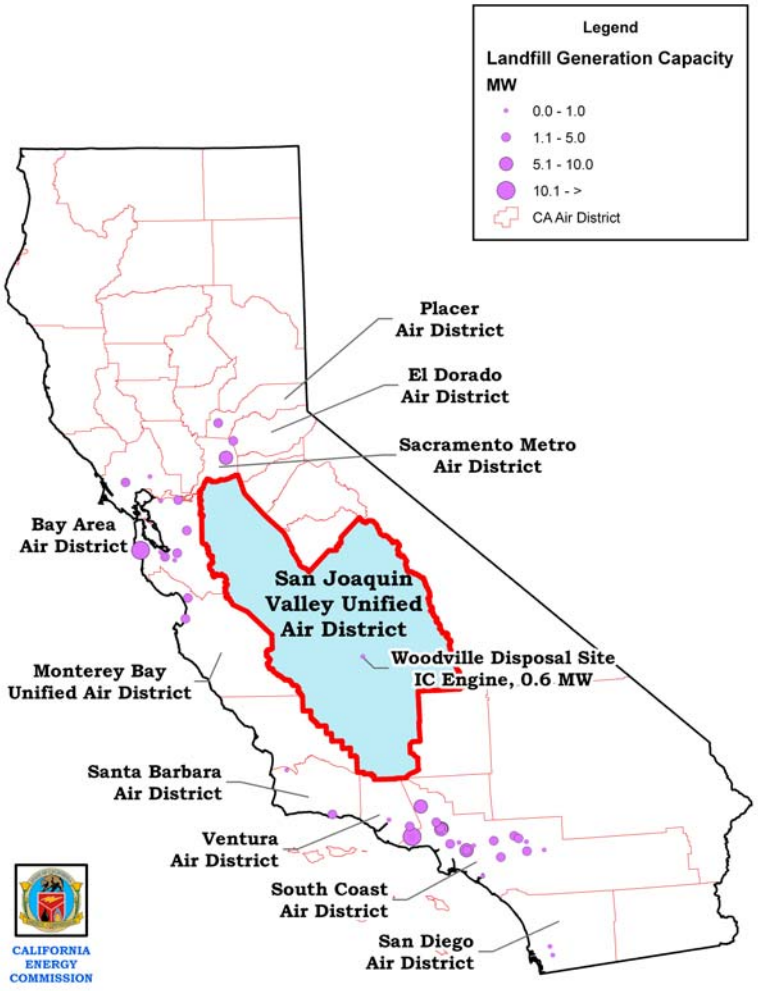
Table 5. California Technologies Used for Landfill Gas to Electricity Since 2000

Technologies	# of Facilities	MW Power Generation
IC Engine	25	78
Gas Turbine	3	20
Microturbine	12	6
Co-generation	4	6
Alternative fuel or direct thermal	3	NA
Total	47	110

Data Source: US EPA Landfill Methane Outreach Program.

8 US EPA Landfill Methane Outreach Program. http://www.epa.gov/lmop/proj/index.htm

Figure 2: California Landfill Gas to Electricity Facilities Developed During 2000s



Digester gas generated from anaerobic digestion of sewage sludge, livestock manure, and agricultural and industry wastes contributed about 7 percent of California's total biopower generation in 2008. Almost all of the biopower generated from digester gas is produced from anaerobic digestion of sewage sludge at domestic wastewater treatment plants. California has 242 sewage wastewater treatment plants, 74 of which have installed anaerobic digesters. The total biopower generation from the 74 plants is about 66 MW.[9]

Table 6 shows the development of biopower plants using livestock manure in California during the last 30 years.

9 Database provided by Lauren Fondahl, US EPA Region 9.

Table 6: California Livestock Manure Biogas Power Plants

Year of Construction	# of Total Facilities Constructed	# of Facilities Currently Operating	MW Capacity of Total Facilities Constructed	MW Capacity of Facilities Currently Operating
1980s or before	18	1	NA	0.03
1990s	0	0	0	0.00
2000s	18	4/5	3.8	0.90
Total	36	10	3.8	0.93

Data Source: California Energy Commission

The tax incentives of the late 1970s and early 1980s encouraged the construction of 18 livestock manure digester systems. To date, only one of the 18 digester facilities built during the 1980s or before remains in operation. Poor engineering design, lack of understanding by the system developers, excessive initial investment, and poor equipment selection with resulting high maintenance cost are the primary reasons for the closure of the 17 livestock manure digester systems developed during the 1980s and earlier.[10]

Senate Bill 5X (Sher, Chapter 7, Statutes of 2001) earmarked $10 million of the approximately $709 million available under the legislation for grants that "encourage the development of manure methane power production projects and reduce air and water pollutions on California dairies." About $3.4 million was awarded to 10 dairy digesters in 2001, and $2.6 million dollars was awarded to an additional eight dairy biogas projects (including one refurbished digester built during the 1980s) in 2006. Nine of the 10 digesters awarded in 2001 became operational by 2005 with a generating capacity of 2.5 MW. However, by the end of 2008, seven of these nine operational projects were shut down. Temporary air permits were issued to the projects awarded in 2006—three of them are operating, and the remaining five are under construction. The locations of the 18 dairy digesters developed during the 2000s are shown in Figure 3.

The Self-Generation Incentive Program (SGIP), initiated in 2001, is also part of the actions taken by the Legislature to address peak electricity demand problems. Assembly Bill 970 (Ducheny, Chapter 329, Statutes of 2000) directed the California Public Utilities Commission (CPUC), in consultation with the California Independent System Operator (California ISO) and the Energy Commission, to reduce demand for electricity and reduce load during peak periods. The same legislation required the CPUC to consider incentives for load control and distributed generation to enhance reliability with "differential incentives for renewable or super-clean distributed generation resources." The CPUC issued Decision 01-03-073 on March 27, 2001, outlining the provisions of a distribution generation incentive program known as the SGIP.[11] The results of electricity delivered by the SGIP for biopower facilities are shown in Table 7. As of December

10 Mark A. Moser. 1997. *Resource Potential and Barriers Facing the Development of Anaerobic Digestion of Animal Waste in California*. CEC P500-97-B100.

11 *CPUC Self-Generation Incentive Program – Eight-Year Impact Evaluation Revised Final Report*. July 2009. Prepared by Itron, Inc.

31, 2008, $601 million in incentives has been paid to 1,268 complete projects, which delivered 718,000 MWh in 2008. Electricity delivered from biopower facilities funded under the SGIP represents about 9 percent of the total.

Figure 3: California Dairy Biogas Digesters Developed During 2000s

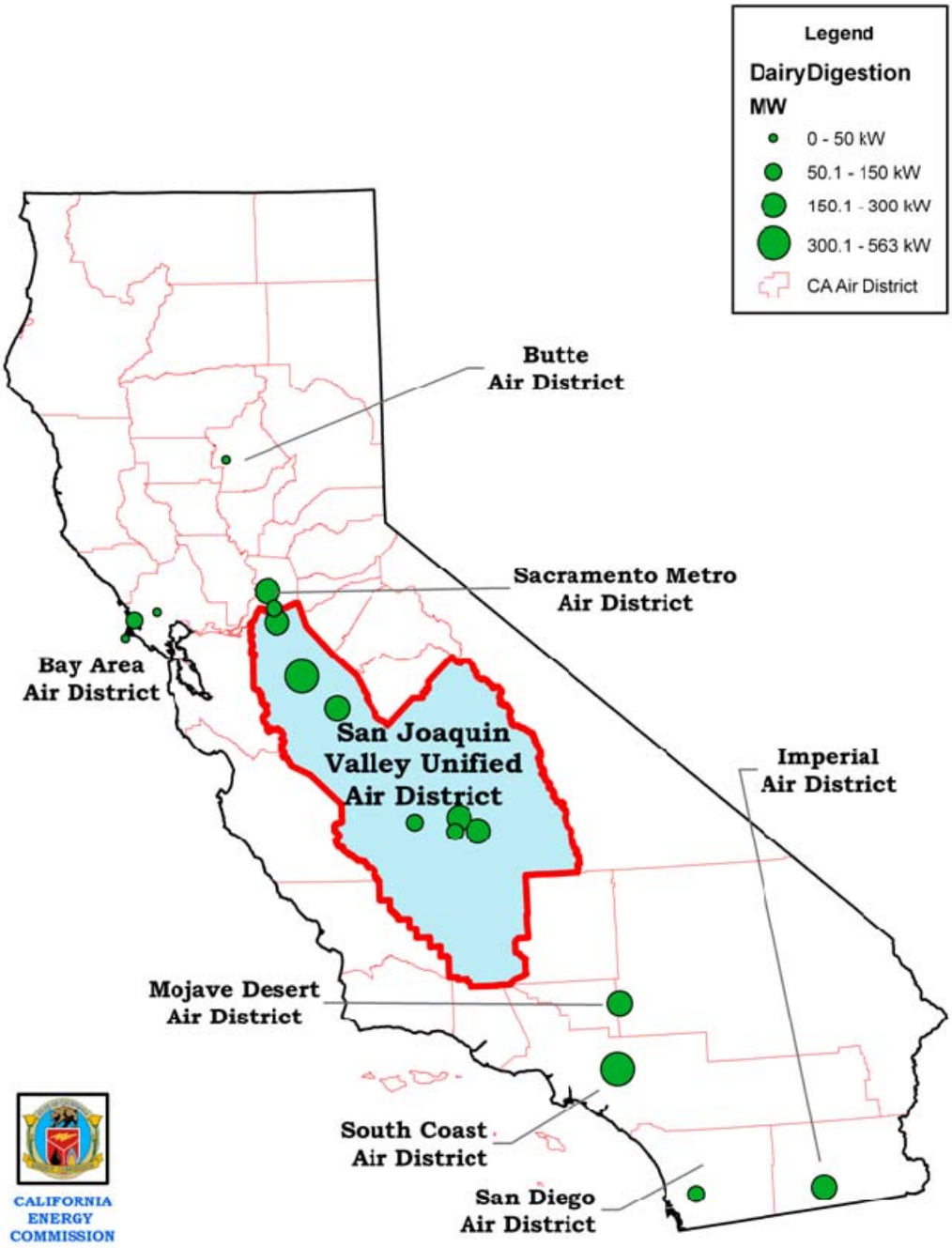


Table 7: Summary of SGIP Electricity Delivered by Biopower Facilities in 2008

Biopower Technologies	MWh	Annual Capacity Factor
Fuel Cell	12,572	0.612*
IC Engine	47,848	0.211*
Microturbine	6,863	0.487*
Total	67,283	

* Indicated confidence lever is better than 70 percent.
Data Source: *CPUC Self-Generation Incentive Program – Eight-Year Impact Evaluation Revised Final Report*. July, 2009. Prepared by Itron, Inc.

CHAPTER 3: Barriers and Recommendations to California's Biopower Development

On April 21, 2009, the Energy Commission held a workshop on biopower in California as part of the 2009 Integrated Energy Policy Report proceeding. Several speakers identified major issues currently facing biopower, including air quality permitting, financial constraints, project financing difficulties, challenges with injecting landfill gas into nature gas pipelines, and barriers to the development of municipal solid waste gasification facilities.

Air Quality Permitting

The main obstacle to developing new biopower facilities in California is obtaining local air permits. In the San Joaquin air basin, the Energy Commission sponsored five new dairy digester projects using internal combustion (IC) engines at rated capacities of 500 kW or less to meet the dairies' electricity needs and, with approved power purchase agreements, to sell excess electricity to the local utilities. Because the air basin is an extreme non-attainment area, the San Joaquin Air Quality Management District imposed strict nitrogen oxide (NOx) requirements on these generators, requiring the most advanced emission control systems. The dairies, facing severe distress from low milk prices, balked at these substantially increased costs and could not agree to the conditions of the permit. Several meetings with the district, the dairymen, the California Environmental Protection Agency, the California Air Resources Board, the local air districts, and other stakeholders resulted in conditional agreement on permits.[12]

Regulating air quality pollutants by annual emissions (tons pollutant /yr) rather than by unit emissions (tons pollutant/kWh) can lead to missed opportunities and prohibit large facility development for biopower. For example, the Lopez Canyon Landfill in Los Angeles had 25 MW of available landfill gas resource; however, that facility could only obtain an air permit for 6 MW. The remaining gas must be flared.

In addition to NOx permitting issues, new solid-fuel biomass projects located in the South Coast Air Quality Management District face the added challenge of obtaining permits to emit particulate matter. A 25 MW solid-fuel biomass project required permits for about 90 pounds per day[13] of PM-10 emission offsets or emission reduction credits.[14] At a cost of about $350,000

12 April 10, 2009, letter from the Western United Dairymen to Governor Arnold Schwarzenegger. This can be downloaded from the Energy Commission's website at http://www.energy.ca.gov/2009_energypolicy/documents/2009-04-21_workshop/comments/Letter_from_Western_United_Dairymen_to_the_Governor_04-10-09_TN-51189.pdf.

13 California Air Resources Board, facility details for Burney Mountain Power, available at http://www.arb.ca.gov/app/emsinv/facinfo/facdet.php?co_=45&ab_=SV&facid_=42&dis_=SHA&dbyr=2007&dd=

per pound per day[15] or $31.5 million for the PM-10 permit, this requirement could make new biomass projects in this part of the state financially unviable.

Financial Situation for Biomass Facilities

About 60 percent of California's biopower generation comes from solid-fuel biomass facilities that were operational before 1996. Since 1998, the Energy Commission has provided production incentives for these facilities; however, these production incentives will expire in 2011. Representatives of the biomass facilities receiving incentives have informed staff that they face difficulties keeping their facilities on-line. For example, many of the existing biomass facilities are nearly 30 years old and face financially challenging maintenance issues. Also, facilities managers report that while plenty of biomass feedstocks are available, they are having difficulty procuring affordable biomass sources.[16] Most of these facilities sell their power under fixed price qualified facility (QF) contracts with an average annual energy price under $66 per MWh. The facilities report that their fuel costs alone can range between $20 and $60 per MWh, with transportation contributing most of the cost.

Project Financing

In recent years, the Energy Commission and other agencies have funded several bioenergy projects with research and demonstration grants to take advantage of the state's diversity of biomass resources through research and demonstration programs. While these projects demonstrate that biomass to electricity could have widespread applications, the costs are still high compared with conventional sources of electricity. Using biopower for distributed generation could offset some of the costs, but reliable, durable, and consistent performance of these generators are necessary to give investors confidence that this system will have adequate payback.

Using biogas to generate electricity faces challenging financial hurdles related to the need to acquire expensive pollution control equipment unless less reliable microturbines are used. The

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14 PM-10 refers to particles with a diameter of 10 micrometers or less; definition found at: http://epa.gov/airtrends/aqtrnd95/pm10.html

15 South Coast Air Quality Management District, September 24, 2009, "PM-10 Market Conditions and Offset Availability in SCAQMD," presentation by Mohsen Nazemi, available at http://www.energy.ca.gov/2009_energypolicy/documents/2009-09-24_workshop/presentations/06_SCAQMD-Nazemi_Market_Conditions_and_Offset_Availability-092409_Final.pdf

16 According to research by the U.S. Forest Service aimed at studying forest management scenarios and at estimating the cost of extracting biomass fuels from the forest, which was presented by Mark Nechodom, Ph.D. of the U.S. Forest Service, treatment and transportation of biomass fuels costs $68 per bone dry ton while plant operators could only afford to pay $8.20 per bone dry ton to get an acceptable return.

alternative to using biogas for electricity generation is to inject the gas directly into the natural gas pipeline. Pipeline injection of biogas such as that produced by dairy cows or wastewater sewage sludge in anaerobic digesters is eligible for the Renewables Portfolio Standard. However, it is very costly to clean the biogas to the level needed to meet rigorous fuel standards set by the gas utilities. In addition, the location of injection points for the gas into the pipeline may require costly extensions to the digesters and gas clean up facility.[17] Also, these biogas injection projects cannot claim federal production tax credits because the credits apply only to the generating facility that uses the gas.[18]

Additionally, other project developers have reported that interconnection and metering fees are costly and that feed-in tariffs cannot help with these costs because they only apply once the project is generating.[19] Developers of solid-fuel biomass facilities have also had difficulty obtaining affordable supplies of biomass fuels.[20]

Injection of Landfill Gas Into the Natural Gas Pipelines

Assembly Bill 4037 (Hayden, Chapter 932, Statutes of 1988), effectively precludes using California landfill gas in gas pipelines, although utilities can purchase out-of-state landfill gas without restrictions. The statute added Section 25421(a) to the California Health and Safety Code, which states that "no gas producer shall knowingly sell, supply, or transport landfill gas to a gas corporation, and no gas corporation shall knowingly purchase landfill gas, if that gas contains vinyl chloride in a concentration that exceeds the operative no significant risk level set forth in Article 7 (commencing with Section 12701) of Chapter 3 of Division 2 of Title 22 of the California Code of Regulations." If a pipeline operator allows the injection of landfill gas into the pipeline, there is a twice monthly measuring requirement. If vinyl chloride is present, both the landfill gas developer and the pipeline operator face a $2,500 penalty per day for each violation. This requirement has resulted in the refusal by in-state pipeline operators to accept purchases of landfill gas produced in-state for injection into the pipeline. Landfill gas injected into the pipeline from out-of-state sources is not restricted under the code. Sacramento Municipal Utility District (SMUD) recently published a press release stating that it has a 15-year contract to purchase landfill gas produced in Texas.[21]

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17 Pg. 138, *Transcript for Tuesday, April 21, 2009 Workshop on Biopower in California*. Allen Dusault, Sustainable Conservation.

18 Pg. 163, *Transcript for Tuesday, April 21, 2009 Workshop on Biopower in California*. Bill Nelson, Sempra Generation.

19 Pg. 2-3 Comments filed by Paul Fukumoto of FlexEnergy, LLC.

20 Pg. 4. Comments filed by Jesus Arredondo of Buena Vista Biomass Power.

21 *SMUD to Purchase Green Gas from Texas*. SMUD press release. http://www.smud.org/en/news/Documents/09archive/texas-gas-4-15-09.pdf

Municipal Solid Waste Gasification Conversion

Although MSW gasification conversion is RPS eligible, the stringent definition of "gasification conversion"[22] effectively prohibits the use of these technologies for RPS compliance. To date, no MSW gasification facility has met this definition, particularly the requirement that the MSW gasification conversion occur without using air or oxygen except ambient air to maintain temperature control.[23]

Most Western Electricity Coordinating Council (WECC) states do not explicitly allow MSW to be used for RPS compliance. California's RPS allows MSW that has undergone gasification or been converted to biodiesel to be used for RPS compliance, but combustion of solid unconverted MSW is not eligible (with the limited exception of facilities located in Stanislaus County and operational before Sept. 26, 1996). Similarly, Arizona allows only gasified MSW to be used for RPS compliance but does not specifically permit combustion of solid MSW. Nevada is the only WECC state to specifically allow unlimited or unrestricted combustion of solid MSW and gasified MSW to be used for RPS compliance. All other WECC states do not identify any form of MSW as eligible for RPS compliance.

As the space available for landfills becomes more limited in California, renewable energy developers have expressed interest in MSW gasification and are seeking clarification of rules for RPS eligibility of MSW conversion.

Recommendations to Support California's Biopower Development

- The 2006 *Bioenergy Action Plan* should be updated to address existing barriers described in this report and identify potential solutions to solve the barriers to meeting the Governor's goal to meet 20 percent of renewable energy goals with electricity generated from biomass. While the *Bioenergy Action Plan* successfully addressed a number of important tasks, further action is needed to meet the goals of the Governor's Executive Order for biopower and biofuels.
- Given the state's aggressive renewable energy targets and the need for additional renewable energy to meet those targets, the 2009 IEPR recommended that the Energy Commission and the California Integrated Waste Management Board should review

22 Public Resources Code Section 25741.

23 April 21, 2009, IEPR workshop comments by Phoenix Energy: "There is no way you can do this without the presence of oxygen. Limited oxygen, yes, but if you follow the definition to the letter of the law, it can't be done.", transcript p. 74, see [http://www.energy.ca.gov/2009_energypolicy/documents/2009-04-21_workshop/2009-04-21_TRANSCRIPT.PDF].

emerging technologies to gasify MSW that most closely meet the intent of current RPS eligibility requirements as well as environmental considerations and, if appropriate, suggest modifications to applicable state statutes to allow such technologies to be RPS-eligible.

- The Energy Commission should explore options to ensure that existing biomass facilities continue to operate, including continuation of the Existing Renewable Facilities Program, subsidizing biomass feedstocks, or developing a feed-in tariff for existing biomass facilities.
- The state should expend the efforts to encourage biomass co-digestion, biopower and biofuel co-generation technologies to maximize the use of California's abundant biomass, solve waste disposal problems, and reduce catastrophic wildfires.
- Local air pollution districts should be encouraged to become involved in the Interagency Biomass Working Group since they have key regulatory authority over biomass projects. Furthering the dialogue between air districts, the state's energy agencies, the Governor, and the Legislature can result in innovative solutions to reduce air pollution while enabling California to meet its air quality and biomass energy goals.
- A long-term program should be established to validate and track critical research results and data achieved to date for bioenergy technologies, fund research on integrated bioenergy system design and operation, and support bioenergy education, research, and training programs established under colleges, universities, and other institutions to ensure that well-trained and qualified human resources are available for the bioenergy industry development

CHAPTER 4: Status of California's Biofuel Development

The *Bioenergy Action Plan* calls for in-state transportation fuel production using biomass resources and has a target of producing a minimum of 20 percent of its biofuels within California by 2010, 40 percent by 2020, and 75 percent by 2050.

Near term biofuel production for California will most likely be ethanol, biodiesel, and biomethane either as compressed natural gas (CNG) or liquefied natural gas (LNG). Currently, about 1 billion gallons of ethanol is consumed in California each year as a transportation fuel. Nearly all of this is used as a blendstock for California Reformulated Gasoline, which is blended at the E-6 (six percent) level. About one million gallons is used annually at the E-85 blend level.

California has seven biorefineries. Five convert corn grain to ethanol, and two convert cheese and beverage wastes to ethanol. The total production capacity of the seven biorefineries is about 250 million gallons per year (MGPY). As of December 2009, four of the five modern corn grain ethanol biorefineries are off-line due to adverse market conditions.[24] As a result, nearly all of the 1 billion gallons of ethanol used each year in California is imported from large Midwest ethanol producers. The ratio of existing ethanol generation to consumption in California is 55 million gallons/960 million gallons or 5.7 percent.

Biodiesel is the second most widely used biofuel in California. About 50 million gallons were consumed in California in 2009, primarily at the B5 blend level. California has 11 biodiesel plants with a combined production capacity of 87 MGPY. Due to biodiesel's inability to compete with petroleum-based diesel prices, however, six of these plants are idle and the remainder will likely produce less than 25 MGPY. California's biodiesel plants currently use yellow grease as their lowest-cost feedstock but also use more expensive and abundant soybean, palm, and a variety of plant and animal byproducts for biodiesel production.[25] As of September 2009, the ratio of biodiesel generation/consumption was 6 million gallons/50 million gallons or 12 percent.

In addition to ethanol and biodiesel used for transportation, in 2008, California used about 150 million therms of natural gas for CNG or LNG vehicles, and 828 GWh of electricity for plug-in hybrid electric vehicles (PHEVs) in California in 2008. There are also 190 hydrogen-powered vehicles on the road in California.[26] However, it is unclear how much of these alternative

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24 All five of the large biorefineries were idle for most of 2009. Calgren recently restarted production at its 52.5 MGPY facility at Pixley, California. Staff presentation by Jim McKinney at the AB 118 Investment Plan Biofuels Workshop, September 14 and 15, Sacramento, California.

25 Jim McKinney's presentation at the AB 118 Investment Plan Biofuels Workshop, "Status of Biofuel Production Facilities in California," California Energy Commission, September 14 and 15, 2009.

26 *2009 Integrated Energy Policy Report*, California Energy Commission, CEC-100-2009-003-CTD.

transportation fuels are derived from renewable resources. If these fuels become major alternative transportation fuels and are largely imported from out of state using imported renewables, there will be additional instate biofuel production requirements needed to meet the biofuel target.

California developed two ethanol plants during the 1980s that converted beverage and cheese wastes or wastewater to ethanol with annual production capacity of 8.5 million gallons (Table 8). No new ethanol facilities were built during the 1990s. When Methyl Tertiary Butyl Ether was phased out to meet the US EPA's Clean Air Act, five new ethanol plants were developed during the 2000s to replace 5.7 volume percent of the total gasoline consumed in the state. All five ethanol plants built during the 2000s used corn brought in by rail from the Midwest as the predominant feedstock; however, as of December 2009, only one of the five corn grain-to-ethanol biorefineries continues in operation. In addition to the corn ethanol plants sitting idle, the Golden Cheese Plant, built in 1985, was permanently closed after more than two decades in operation.

According to a recent study, the five modern California corn ethanol biorefineries produced ethanol with a carbon intensity value of 80.7 grams of CO_2–equivalent per megajoule (gCO_2-eq/MJ), which is about 20 percent lower than imported Midwest corn ethanol at 99.4 gCO_2-eq/MJ).[27] This lower carbon intensity is due to using natural gas for process energy (rather than a Midwestern mix of coal and natural gas), a higher process efficiency, and the distribution of "wet grains" for dairies and cattle feedlots, rather than drying the distiller grains.

Table 8: California Ethanol Plants

Year of Construction	# of Total Facilities Constructed	# of Facilities Currently Operating	Million gal/yr Capacity of Total Facilities Constructed	Million gal/yr Capacity of Facilities Currently Operating	Feedstock Used
1980s	2	1	8.5	5	Beverage and cheese wastes
1990s	0	0	0	0	
2000s	5	0	239	0	Corn
Total	7	1	247.5	5	

Data source: California Energy Commission[28]

Several advanced sugar ethanol projects in California are in the planning and early development phase. These facilities would use sugar cane, sweet sorghum, or sugar beets as feedstocks and produce very low carbon intensity fuels (80 to 90 percent reduction) using

27 "Detailed Modified California GREET Pathway for Corn Ethanol," ARB Staff Draft Report, February 22, 2009.

28 Presentation by Jim McKinney at the AB 118 Investment Plan Biofuels Workshop, "Status of Biofuel Production Facilities in California," California Energy Commission, September 14 and 15, 2009.

conventional fermentation and distillation process technologies. These projects would use fully integrated, complimentary technologies to produce ethanol, electricity, building materials, beverages, fertilizer, or soil amendment and other value-added products.

The Energy Commission has also funded several pilot or full-scale demonstration projects for coproduction of ethanol and electricity that uses ligno-cellulosic biomass including forest residues, rice straw, and recovered MSW and yard wastes. These projects are the Sacramento Ethanol Partners Arkenol Ethanol, Collins Pine/BC International/Ogden, Gridley, and Bluefire Ethanol. To date, technologies converting ligno-cellulosic biomass to ethanol have not passed the most important test—demonstration in a commercially viable facility; however, biomass-to-biofuel conversion technology commercialization continues to progress.

Biomethane, a renewable form of natural gas, is not currently used in large quantities in transportation but has shown potential as a transportation biofuel in California. The most likely sources of biomethane will be dairies, landfills, wastewater treatment facilities, and agricultural food processing facilities. While technologies upgrading biogas to biomethane exist, they still must demonstrate financial and economical feasibility. Renewable hydrogen has also been cited as a source of renewable fuel but is currently produced in very small amounts in California using solar energy as its energy source. Hydrogen production is a very energy-intensive process, and it is difficult to harness enough renewable energy to produce in large quantities; however, if the technology becomes commercialized, renewable hydrogen could potentially provide numerous environmental benefits coupled with a stable fuel source that can be derived from many feedstocks.

For ethanol to meet the *Bioenergy Action Plan*'s instate biofuel production goal for 2010, the state should consider restarting its largely idle in-state production capacity to add 145 MGPY. To meet the 2020 target, the state will need to add an additional 500 MGPY of new ethanol production capacity. Furthermore, several state and federal policy drivers will lead to increased use of biofuels in California. Policies that have become key influential factors in the use of biofuels in California include revisions to the Energy Independence and Security Act (EISA), the Federal Renewable Fuel Standard (RFS2), California's Low-Carbon Fuel Standard[29] (LCFS), and California's shift from E-6 ethanol blend level to E-10 in 2010. The shift to E-10 alone will increase consumption of ethanol to about 1.5 billion gallons per year, while California's "fair share" of the 36 billion gallons of advanced biofuels specified nationally in the RFS2 will be 3 billion gallons per year in 2022. These policies will work together to increase the amount of biofuel consumption in California, and the increases will have to be accounted for when calculating in-state biofuel production requirements.

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29 Air Resources Board staff estimates that up to 30 new biorefineries will be needed in California to help achieve the 10 percent carbon intensity reduction targets in the Low-Carbon Fuel Standard. Advanced biofuels are projected to account from 60 to 89 percent of the total carbon reductions from transportation fuels by 2020. California Air Resources Board, *Proposed Regulation to Implement the Low-Carbon Fuel Standard: Initial Statement of Reasons*, March 5, 2009.

For biodiesel to meet the *Bioenergy Action Plan*'s in-state biofuel production goal for 2010, the state may need to consider restarting its largely idle in-state biodiesel production capacity to add 4 MGPY. The state will need to add an additional 44 MGPY of new biodiesel capacity to meet the 2020 biofuel production goal. It is assumed that the biodiesel consumption in 2020 will remain the same as it is in 2009 at 50 MGPY.

CHAPTER 5: Barriers and Recommendations to California's Biofuel Development

Factors inhibiting biofuel development include feedstock supply versus viable technology, fundamental mass and energy balance data using fully integrated process, fossil fuel competition, cost of biomass collection and processing and unrealized net social, economical, and environmental benefit, current credit crisis, and adequate government policy.

Feedstock Supply versus Viable Technology

Ethanol can be produced from either ligno-cellulosic or starch/sugar type of biomass feedstocks. California has substantial biomass resources of waste streams from the agricultural, municipal, and forest sectors that are available for use as feedstocks for advanced biofuels with low carbon intensity values. California's agricultural and municipal waste streams provide a technical potential of 17 million bone dry tons per year (MBDT/yr), with an additional 14.2 MBDT/yr available through forest residues. However, over 95 percent of the biomass produced in California is the ligno-cellulosic type of feedstock. To date, technologies converting ligno-cellulosic biomass to ethanol have not yet passed the most important test—demonstration in a commercially viable facility. However, as evidenced by information presented by energy developers, and at the AB 118 Investment Plan workshops, as well as recent American Recovery and Reinvestment Act awards, commercial viability may be fast approaching. Should the ligno-cellulosic ethanol technology become developed to commercialization, about 1.9 billion gasoline gallon equivalent ethanol could potentially be produced using the existing available biomass feedstocks in California.

Technologies available for ligno-cellulosic ethanol include separate hydrolysis/fermentation (SHF), simultaneous saccharification/fermentation (SSF), simultaneous saccharification/co-fermentation (SSCF), consolidated bioprocessing (CBP), and gasification and fermentation or catalytic synthesis (GF/CS). Significant challenges remain and need to be overcome. The challenges for SSF, SSCF, and CBP, and GF/CS technologies are listed below.

- Dilute and Strong Acid Hydrolysis (SHF)
  - The need to regenerate acids.
  - Formation of inorganic waste streams.
  - High operational temperatures and pressures.
  - The corrosiveness of the pretreatment.
  - High water consumption: 28-54 gallon water/ gallon ligno-cellulose ethanol produced versus 15 gallon water/gallon corn ethanol produced.
- SSF, SSCF, and CBP
  - Effective enzymes to separate lignin from cellulose and hemi-cellulose.
  - Effective enzymes to simultaneously hydrolyze cellulose and hemi-cellulose into simple C5 and C6 sugars.

- GF/CS
  - Feedstock homogeneity (moisture and composition).
  - Capital cost.
  - Tar formation.
  - Syngas cleanup.

Fundamental Mass and Energy Balance Data Using Fully Integrated Systems

Mass and energy balance data for an integrated system at both laboratory and pilot scales are critical to determine system net energy requirement, conversion efficiency, and technical and economical feasibilities before it is commercialized. To date, complete mass and energy balance data using lingo-cellulosic biomass to produce ethanol with a fully integrated system are lacking at all scales including laboratory. Existing partial process data are based on plant capacity at 1 ton/day or less.[30] These have posed serious risk when investing large scale or so called commercialized facilities in the past.

Fossil Fuel Competition

Organization of the Petroleum Exporting Countries (OPEC) and oil industry actions are not predictable. While oil prices are expected to increase over time, increase or decrease of flow from existing reserves can always decrease or increase oil market prices at any time. [31]

Cost of Feedstock Collection and Processing, and Unrealized Net Social, Economical, and Environmental Benefits

California's existing available biomass, in general, is generated from waste streams. The cost per unit of fuel in terms of $/million BTU for biomass is often higher than it is for fossil fuel due to the cost needed to collect and process biomass before it is ready as a feedstock for energy production. However, using in-state biomass resources for renewable energy generation will help solve waste disposal problems, reduce potential wildfires, reduce dependency on fossil fuels, and protect the environment and public health by reducing air, water, and soil pollution. Such net benefits have not been fully quantified and realized when biomass feedstock is competing with fossil fuel for energy production.

30 J.R. Hettenhaus, R. Wooley and A. Wiselogel. 2000. *Biomass Commerzialization Prospects in the Next 2-5 Years*. National Renewable Energy Laboratory.

31 J.R. Hettenhaus, R. Wooley and A. Wiselogel. 2000. *Biomass Commerzialization Prospects in the Next 2-5 Years*. National Renewable Energy Laboratory.

Current Credit Crisis

The biofuels industry has taken a hit due to the severe downturn of the economy. Construction on a number of biofuel projects has ceased due to companies' inability to secure financing. In today's economically risk-adverse climate, financial institutions are not funding unique bioufuel infrastructure projects, which all pose uncertain risks. Lack of capital and debt financing is impeding biofuel plant development and upgrades at existing plants. If capital and debt financing were readily available, California's existing and planned biofuel plants could move forward to use instate biomass wastes and other alternative feedstock.

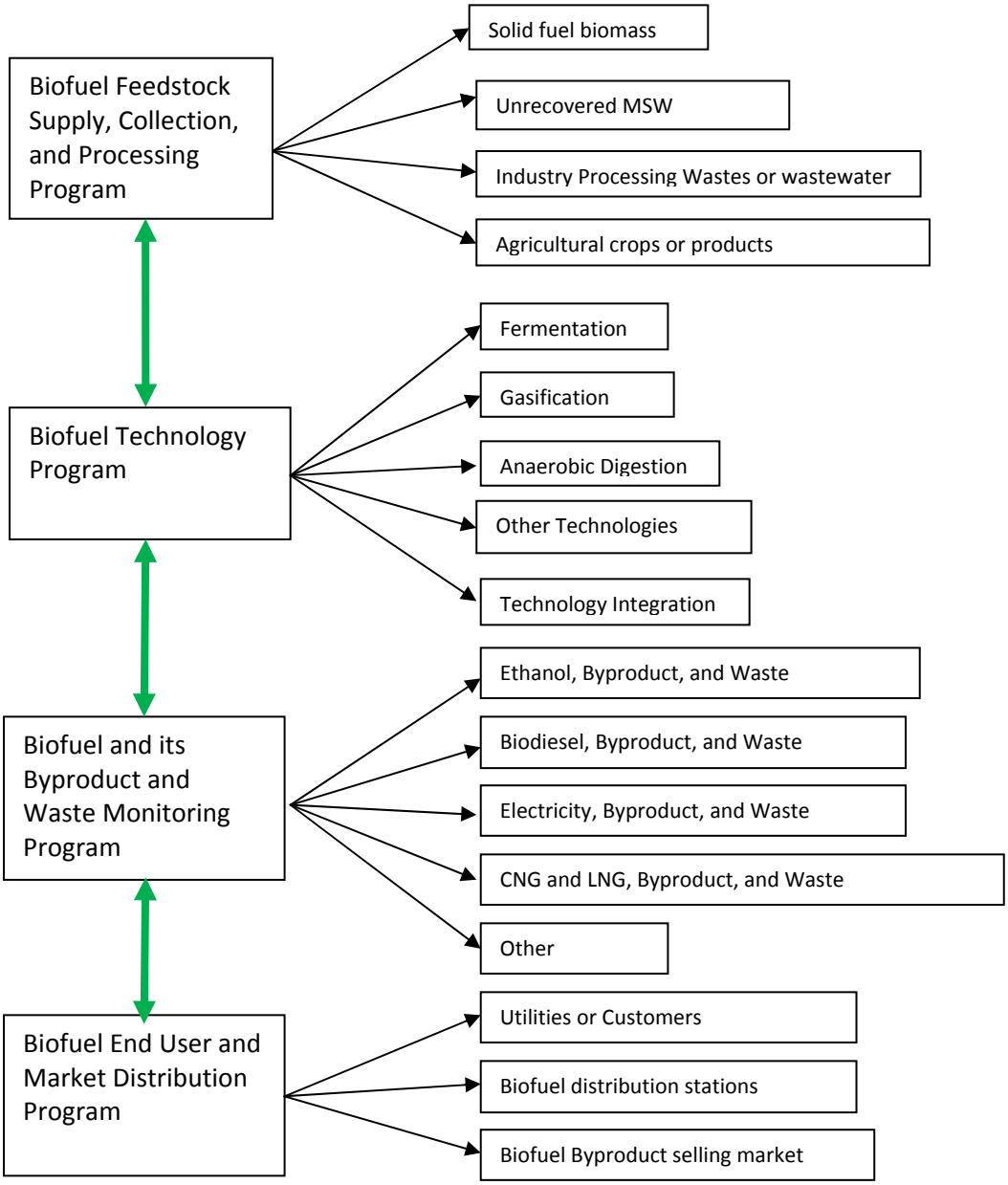
Adequate Government Policy

The federal and state environmental policies are fragmented and sometimes conflicting. Adequate and validated environmental data often do not yet exist when pollutant emission standards are established even for existing industry operation. For example, as of October 1, 2007, California's agricultural operations are required to meet the U.S. Environmental Protection Agency's Clean Air Act (CAA) Title V regulations although it is still unclear if the regulations are based on sufficient research data to adequately identify and quantify agricultural source emissions. To meet the new CAA requirements, many agricultural operations will face challenges to obtain sufficient funds to add waste treatment facilities.

Recommendations to Support California's Biofuel Development

- Establish multiple but well connected chain programs to use in state biomass resources for biofuel development in California. These multiple and chain programs include Biofuel Feedstock Supply, Collection, and Processing, Biofuel Technology, Biofuel and its Byproduct and Waste Monitoring, and Biofuel End-User and Market Distribution as shown in Figure 4.

Figure 4: Biofuel Multiple Program Connection



Source: California Energy Commission

- Establish comprehensive policies and incentives targeting usage of in-state biomass resources with consideration of the multiple program connections and barriers presented.
- Establish multiple but well-connected performance and environmental standards based on best available technology using in-state biomass resources.
- Create short-term grants to help all cities in California establish a long-term business plan on bioenergy development using existing available feedstock and viable technologies and at the same time solve urgent problems such as waste disposal.
- Create long-term, zero-interest loans and grants to help the biofuel industry invest capital equipment and ease the financing process based on the business plan developed.
- Work with utilities and stakeholders to create a fair bioenergy market price that reflects the cost of biomass feedstock collection and processing and unrealized net social, economical, and environmental benefits.
- Establish long-term monitoring programs for biofuel/bioenergy and its byproducts produced and distributed into the market.
- Establish long-term grants to support bioenergy education, research, and training programs established under colleges, universities, and other institutions to ensure that well-trained and qualified human resources are available for the bioenergy industry development.
- Validate and track critical research results and data achieved to date for bioenergy technologies.
- Encourage research on integrated system design and operation from feedstock collection to energy production and waste handling at both laboratory and pilot scales prior to full-scale or so-called commercialized facilities being demonstrated.
- Provide incentives to successful technology demonstrations using integrated systems to attract real private investment to make the projects both economically and financially feasible.

CHAPTER 6: Conclusions

- The development of both biopower and biofuel production using biomass has been slow and is unlikely to meet the Governor's Executive Order bioenergy targets in 2010. Meeting both California's 20 percent RPS goal and the 2010 biopower targets would require an annual addition of 6,562 GWh electricity with the assumption that total electricity consumption in 2010 will remain the same as it is in 2008 at 307,141 GWh. Meeting California's 20 percent biofuel target by 2010 would require an annual addition of 141 million gallons per year (MGPY) of combined ethanol and biodiesel production.
- California generates about 80 million bone dry tons (BDT) biomass annually. Managing this amount of biomass presents clear opportunities and challenges when increasing attention on biomass use is driven by renewable energy, economic, environmental, social, and market considerations. These considerations include meeting RPS and Renewable Fuel Standard (RFS)2 goals, low carbon fuel standards, and bioenergy targets; reducing severity and risk of wildfire; improving forest health and watershed protection and air and water quality; reclaiming greenhouse gas emissions; developing municipal resources; reducing dependency on imported energy sources; developing new economic opportunities for agriculture and other industries; improving electric power quality and support to the power grid from distributed electricity generation; creating jobs; and revitalizing the economies of many agricultural and rural communities.[32]
- Of the total biomass generated in California, about 43 million BDT/yr, including 19.6 million BDT/yr solid fuel biomass, 19.2 million BDT/yr municipal solid waste (MSW) landfills, and 4.5 million BDT/yr livestock manure, sewage sludge, and food processing wastes, can be used for energy production. If all 43 million BDT/yr biomass sources were used for energy production using existing viable technologies, a total of 5,000 MW biopower and 200 million gallons of biofuel could be added to California's energy system. It is assumed that 41 million BDT/yr biomass generated from solid fuel biomass, MSW landfills, sewage sludge, and livestock manure will be used for electricity generation, and 2 million BDT/yr of biomass generated from existing agricultural food processing facilities will be used for ethanol production.
- Policies have been the key driver for bioenergy development in California. Massive development of biopower plants using biomass solids fuel was driven by the federal Public Utilities Regulatory Policy Act, established in 1978, which allowed utilities to create standard-offer contracts for power purchases from independent generators during 1980s. These contracts enabled the development of approximately 1,000 MW of biopower

32 California Biomass Collaborative. 2005. *Biomass in California: Challenge, Opportunities, and Potential for Sustainable Management and Development*. Prepared for the California Energy Commission. Http://biomass.ucdavis.edu/materials/reports%20and%20publications/2005/2005_Biomass_in_California.pdf

capacities using solid fuel biomass in California by 2000. However, policies have changed. When state and federal incentives expire, it is questionable whether these systems can afford to operate due to high operational costs when incentives are no longer available. Also, the limitation on maximum incentive size discourages large biomass facility development in California.

- The Energy Commission should collaborate with partner agencies and stakeholders to develop policy changes and support legislation that address regulatory hurdles and price uncertainty for biopower and biofuel in California.
- The state should continue to coordinate the efforts to maximize the use of California's abundant waste stream, including agricultural waste, municipal solid waste, and forest waste to produce energy, solve waste disposal problems, and reduce catastrophic wildfires.
- State agencies, utilities, and stakeholders should work together to create long-term programs to help finance biopower and biofuel projects that can provide immediate greenhouse gas (GHG) emission reduction benefits and a bridge to the introduction of sustainable fuels that will reduce fossil fuel dependency and result in deeper GHG emission reductions in the future.
- A long-term grant program should be established to validate and track critical research results and data achieved to date for bioenergy technologies, fund research on integrated bioenergy system design and operation, and support bioenergy education, research, and training programs established under colleges, universities, and other institutions to ensure that well-trained and qualified human resources are available for the bioenergy industry development.

ATTACHMENT1: Action Items From the *2006 Bioenergy Action Plan* California Energy Commission, December 22, 2009

Bioenergy Action Items	Actions Taken
Multi-Agency Collaboration Responsibilities	
1. *The Governor has entrusted the Working Group with the responsibility for carrying out his bioenergy policy objectives and meeting the state's targets. The Working Group, chaired by the Energy Commission, will continue to meet as its member agencies carry out their individual and joint responsibilities. These meetings will provide consistent public forum for the interested stakeholders and members of the public to keep track of the progress being made throughout state government.*	Chair of the Working Group, California Energy Commission Commissioner Jim Boyd leads the Working Group to accomplish the sustainable development of biomass in California. Working Group meeting was held on December 21, 2009. Established a Bioenergy Coordination Group at the Energy Commission. Energy Commission Coordinator: Mike LeaonWorking Group Liaison: Sarah Michael
2. *As directed by the Governor, the Energy Commission will coordinate with the Working Group on the use of state funds and on securing federal funding that support strategic research, development, and demonstration (RD&D) projects including efforts to:*	

Bioenergy Action Items	Actions Taken
a. *Prove the commercial readiness of biofuels production and advanced biomass conversion technologies including cellulosic feed stocks derived from forestry, agriculture, and urban wastes; gasification; pyrolysis; biomass-to-liquids; and landfill gas to energy systems;*	Through the PIER Program – 2 biofuels projects are being funded; 1) SFPUC is conduction a project to convert fats, oil, and grease (FOG) to biodiesel, 2) REII is conducting an integration of biofuel and biopower project using rice straw, rice hulls and wood. In addition, six biopower projects are also being funded. On December 15, 2009, California Energy Cmmission conducted a workshop to discuss three grant solicitations to be funded by the Alternative and Renewable Fuel and Vehicle Program. The three solicitations include: **1. Biomethane Production (available funding is $21.5 million):** The Energy Commission is seeking to fund projects that involve the design, construction and operation of biomethane production facilities. The intent of this solicitation is to encourage the development of a new industry in California to produce a transportation fuel that is one of the most effective greenhouse gas reduction strategies, and that can significantly reduce petroleum fuel demand, stimulate economic development, and reduce environmental impacts associated with the state's major waste sources. The Energy Commission reserves the right to increase this total amount to $26 million without issuing a new solicitation. **2. Alternative and Renewable Fuel Infrastructure (available funding is $13.8 million):** The Energy Commission is seeking to fund projects that develop infrastructure necessary to store, distribute and dispense the following transportation fuels:

Bioenergy Action Items	Actions Taken
	• Electricity • E-85 • Biomass-based diesel • Natural gas The intent of this solicitation is to upgrade public and private infrastructure investments, expand the network of public-access and fleet fueling stations and charging sites based on the population of existing and anticipated vehicles, and put in place infrastructure that will ultimately be needed to accommodate transportation fuels with very low greenhouse gas emissions. The Energy Commission reserves the right to increase this total amount to $17 million without issuing a new solicitation. **3. Medium- and Heavy-Duty Advanced Vehicle Technology (available funding is $9.5 million):** The Energy Commission is seeking to fund projects that develop the commercialization of advanced medium- and heavy-duty vehicle technologies. The intent of this solicitation is to provide funding to advance the state-of-the-art in medium- and heavy-duty vehicles to significantly reduce the demand for petroleum fuels and greenhouse gas emissions in this critical market sector. The Energy Commission reserves the right to increase this total amount to $12 million without issuing a new solicitation.
b. Develop up to four afforestation (replanting trees) and	No action yet.

Bioenergy Action Items	Actions Taken
carbon sequestration pilot and demonstration projects in California of sufficient size to supply 3 to 5 megawatts of biomass-fueled electricity to an electricity gasification plant or bio-refinery;	
c. *Identify the highest value use and market potential for forest fuel, harvest residues, and other small wood forest products as a potential source of energy, fuel, chemicals;*	No action yet.
d. *Demonstrate new cropping systems and biomass handling, storage, and distribution; and*	No action yet.
e. *Implement at least three field demonstrations of the most efficient biomass harvesting systems for small forest material.*	CDFFP is doing something with UCD and John Deere.
3. *The Working Group and its member agencies will also collaborate at the state, regional, and national levels through various interagency and coalition venues to develop strategic alliances to accelerate deployment of bioenergy production and use technologies in California. Examples include:*	
a. *The 25/25 coalition is a broad-based, non-partisan group of stakeholders advocating increased use of renewable energy, supporting a national goal of meeting 25 percent of our domestic energy needs with renewable resources by 2025; and*	CDFA is actively involved in the 25/25 coalition being led by Secretary of CDFA.
b. *The "Wildland Biomass for Electric Power" project that is addressing life-cycle costing for forestry projects, which is currently underway through the Public Interest Energy Research (PIER) Program in collaboration with the U. S. Forest Service.*	LCA Report for forestry has been drafted.

Bioenergy Action Items	Actions Taken
4. *The Working Group will create and implement a communications plan to disseminate information about the benefits of bioenergy to the general public and to policy makers.*	No specific action taken yet.
5. *The Working Group will explore new avenues for financing new project development, including investigation of existing state bonding authority such as the California Consumer Power and Finance Authority, which may be applicable to bioenergy projects.*	No action yet.

Bioenergy Action Items	Actions Taken
The Energy Commission Responsibilities	
a. *Report on progress in implementing the state policy objectives, biomass production and use targets, and actions detailed in this plan in the biennial Integrated Energy Policy Report and Joint Energy Action Plan.*	Reported the Progress to Plan of the *Bioenergy Action Plan* at *2007 IEPR*. Updates have been included in the *2008 and 2009 IEPR*.
b. *Complete a comprehensive "road map" to guide future research, development, and demonstration activities through the California Biomass Collaborative by June 2006.*	Revision is underway by CBC staff to include priority ranking for actions in the roadmap. Conducted public workshops about this roadmap in 2007.
c. *Prepare the State Alternative Fuels Plan, as required by AB 1007, by the end of 2006 that, among other things, will identify actions and incentives to increase the production and use of biofuels and to develop an extensive and convenient E-85 network in new and retrofitted service stations in California.*	Completed the State Alternative Fuels Plan http://www.energy.ca.gov/2007publications/CEC-600-2007-011/CEC-600-2007-011-CMF.PDF Now implementing AB 118 that directs the California Energy Commission to develop the **Alternative and Renewable Fuel and Vehicle Technology Program** http://www.energy.ca.gov/proceedings/2008-ALT-1/index.html

Bioenergy Action Items	Actions Taken
Legislative Options	
The Working Group has identified the following two topics for possible legislative action during the 2006 session: 1. *Amend existing law to revise existing technology definitions and establish new ones, where needed. In particular, review the definitions of gasification, transformation, fermentation, pyrolysis, and manufacturing. Such statutory clarification would enable the use of biomass residues through combustion or non-combustion technology.* 2. *Amend existing law to provide incentives to local jurisdictions for energy production activities.*	The Energy Commission and CalRecyle are overseeing the bills to revise the definitions. No action taken by the Legislature in 2006. AB 222 (2009) is pending before the Senate Environmental Quality Committee and is supported by the Schwarzenegger Administration. Among other things, AB 222 would allow new non-incineration technologies to be used in the production of renewable biofuels and electricity from biogenic material diverted from California's landfills. No action yet.
The Working Group also has identified the following that may be potential topics for legislation in the future, but for which additional evaluation is needed before determining the suitability of a legislative remedy: 1. *Establish a California renewable fuels standard based on fuel content that could include a minimum average of 10 percent renewable content in gasoline and a 5 percent non-petroleum diesel fuel standard.*	On April 23, 2009, the Air Resources Board adopted a regulation that will implement Governor Schwarzenegger's Low-Carbon Fuel Standard calling for the reduction of greenhouse gas emissions from California's transportation fuels by 10 percent by 2020. http://www.arb.ca.gov/newsrel/nr042309b.htm

Bioenergy Action Items	Actions Taken
2. *Recommend a package of tax incentives to encourage use of biomass, biofuels and other bio-based products. (e.g., production tax credits, fuel excise taxes based on energy content, gas tax exemptions.*	Federal tax incentives for new plants were included in the federal stimulus legislation; Congress passed a one-year extension of the Production Tax Credit for existing biomass facilities.
3. *Establish broad-based funding mechanisms that recognize the unique benefits of bioenergy, including but not limited to, use of existing state bonding authority, state investment tax credits for new and emerging technologies.*	No action yet.
4. *Evaluate alternative sources of revenue, including but not limited to surcharges on trash collection, landfill tipping fees and other sources, to provide stable funding for grant and incentive programs research activities for biomass-to-energy production from landfill-bound residuals.*	No action yet.
5. *Establish a system of carbon credits, consistent with broader state policy on greenhouse gas reduction.*	No action yet.
6. *Encourage coordinated permitting and mediation of environmental impacts and mitigation at the project level.*	A coordinated permitting guidance manual has been drafted and is awaiting approval by CalEPA.

California Air Resources Board ACTION ITEMS

December 22, 2009

Bioenergy Action Items	Actions Taken
a. *As the Governor urged in the Executive Order, enable the most flexible possible use of biofuels, through its Rulemaking to Update the Predictive Model and Specifications for Reformulated Gasoline, while preserving the full environmental benefits of California's Reformulated Gasoline Programs, as required by Health and Safety Code section 43013.1 by January 31, 2007.*	RFG3 amendments approved by the Board June 14, 2007, allowing the blend wall to be as high as E10.
b. *Complete the Rulemaking for presentation to the Board by January 31, 2007. As part of the rulemaking, reflect the emissions performance of current and future vehicle fleets and incorporate available data on the emissions impact of fuel properties.*	RFG3 amendments approved by the Board June 14, 2007. Amendments incorporated vehicle fleet updates.
c. *As data becomes available on the impacts of fuel specifications on the current and future vehicle fleets, review and update motor vehicle fuel specifications as appropriate. In reviewing the specifications, consider the emissions performance, fuel supply consequences, potential greenhouse gas reduction benefits, and cost issues surrounding ethanol blends, particularly E6, E10, and E8, for gasoline by January 31, 2007, and for diesel by December 31, 2008.*	RFG3 amendments approved by the Board June 14, 2007 updated the motor vehicle fuel specifications for ethanol blends from E0 through E10. The Low-Carbon Fuel Standard (LCFS) requires reductions of greenhouse gas emissions from gasoline and diesel used as a transportation fuel. See below for diesel plans.
d. *Consider adoption of fuel specifications for motor vehicle fuels, such as B2, B5, B20, and B100 by January 31, 2007.*	Currently, B1-B5, B6-B20 and B100 are subject to regulation by the Division of Measurement Standards under ASTM specifications approved in 2008. ARB staff is midway through a multimedia evaluation of motor-vehicle biodiesel and renewable diesel fuel pursuant to Health & Safety Code Section

Bioenergy Action Items	Actions Taken
	43830.8, which is scheduled to be completed by end of October 2009. This multimedia evaluation is being conducted in anticipation of a proposed rulemaking to establish new motor vehicle fuel specifications for biodiesel/renewable diesel by early 2010.
e. Evaluate the greenhouse gas reductions benefits of biofuels and biomass production and use, and report back to the Working Group on recommended options to encourage their use, in close cooperation with the other members of the Working Group, by June 30, 2007.	Done as part of the Low-Carbon Fuel Standard which was approved by the Board in April 2009. Results of the evaluation can be found in the LCFS staff report.
f. Evaluate the suitability of using available regulatory levers to encourage the establishment of E-85 stations in California by June 30, 2007.	There are several sources of funding available for E85 infrastructure and several regulations that will increase the need for the infrastructure: AFIP funding of $5 million for E85 stations and AB118 monies to build infrastructure. Federal RFS mandates large volumes of biofuels, which in turn will increase the use of E85. LCFS that in coming scenarios, will require a larger E85 fuel pool.
g. Complete a peer-reviewed study of the emissions performance, costs, and benefits of using biofuels and biofuel blends, using a multi-media approach by July 31, 2008.	The LCFS estimated the emissions performance, costs, and benefits of biofuel and biofuel blends. The staff report was peer reviewed by four independent researchers.
h. Consider adoption of regulations by June 30, 2008 that require all gasoline-powered vehicles sold in the state to meet the state's	RFG 3 amendments relating to E85 vehicles and their requirements to meet all of the state's emission standards for

Bioenergy Action Items	Actions Taken
emission standards using gasoline blended with up to 10 percent ethanol and consider a requirement increasing the percentage of E85-compatible vehicle sold in the state	gasoline vehicles was approved by the Board in June 2007. The California Energy Commission recently projected a population of 4.2 million FFVs in California in 2020. Many of the new cars/light trucks offered by U.S. manufacturers are expected to be FFVs after 2012.
i. *Consider adoption of regulations by June 30, 2008, requiring heavy-duty diesel engine manufacturers to warrantee heavy-duty diesel engines using California diesel and B2, B5 and B 20 meeting the California specifications indicated in "d" above.*	Consideration of whether to require engine manufacturers to warranty their heavy-duty engines for use with biodiesel is expected to be part of the proposed rulemaking noted in response to Question d. Because that process is still in the multimedia evaluation stage, no decision has been made yet with regard to warranties for in-use engines and fleets.
j. *Examine the air pollutant emissions performance of biofuels and biomass in stationary sources and recommend appropriate emissions performance standards and mitigation for emissions remaining after the application of controls.*	As part of the LCFS, ARB staff committed to prepare a "best practices" document to guide districts that have regulatory authority over stationary sources.

California Integrated Waste Management Board ACTION ITEMS

December 22, 2009

Bioenergy Action Items	Actions Taken
a. *Identify and quantify the amount of material currently being landfilled and assess the potential for its conversion to biofuels and other bio-based products by December 31, 2006.*	Completed; Needs update.
b. *Establish goals for 2010 and beyond for the use of landfill-bound residuals to be used for bioenergy production by December 31, 2006.*	Completed.
c. *Identify state and private revenue sources of grant and incentive program research activities related to bioenergy production from landfill-bound residuals by December 31, 2006.*	Completed.
d. *Identify and quantify the potential of using landfill gas as a biofuel by December 31, 2006.*	Completed.

STATE WATER BOARD ACTION ITEMS

December 22, 2009

Bioenergy Action Items	Actions Taken
a. *Identify clear and consistent procedures that are used to protect water quality from the harvesting of biomass and the operation of biomass facilities.*	In November 2009, the Central Valley Regional Water Board (RWB) obtained a $742,000 contract to develop a Programmatic Environmental Impact Report (PEIR) for anaerobic manure digestion and co-digestion facilities located at dairies and other sites. The RWB plans to use the PEIR to support adoption of a General Waste Discharge Requirements (WDR) Order for such digesters. Having a General WDR Order should significantly reduce permitting time for such facilities in the Central Valley.
b. *Conduct prompt reviews of planning documents, environmental documents prepared under the California Environmental Quality Act (CEQA), and monitoring proposals for biomass harvesting and biomass facilities.*	This is an ongoing activity. The SWB's Executive Director has requested all RWBs to provide SWB staff with information on all new permitting of biomass/bioenergy facilities so that progress in issuing permits can be tracked.
c. *Work in cooperation with the Department of Forestry and Department of Food and Agriculture to ensure that adequate criteria for water protection and water quality are put in place on agriculture and forest lands in California.*	This is an ongoing activity. In cooperation with DoF and CDFA, the SWB and RWB have developed regulatory water quality programs for irrigated agriculture and forest practices. Staff is working with DoF and CDFA to clarify and simplify the program.

SWB representatives on the Bioenergy Interagency Working Group (BIAWG) have noted that certain BIAWG participants can take proactive steps to promote an increase in the number of energy production facilities that use biomass as a feedstock. Regulatory agencies such as the Water Boards can support those efforts by expediently reviewing environmental documents and processing permits. Planning and tracking efforts are needed to ensure that objectives in the work plan are achieved.

The SWB representatives have also noted the need for a website that identifies proposed biomass / bioenergy facilities and tracks their progress to operational status. The website should be linked to sites that provide information on biomass / bioenergy including available grants and ongoing studies. Hopefully, resources can be found to develop the website.

STATE FOOD AND AGRICULTURE ACTION ITEMS

December 22, 2009

Bioenergy Action Items	Actions Taken
a. Report on the existing market potential for the sustainable production and use of agricultural crops and residues as a source of electricity, fuel, chemicals, and other valuable co-products by June 30, 2007.	Nothing specific to report, but the California State Food and Agriculture (CDFA) has worked with the Biomass Collaborative and 25x25.
b. Develop a plan to determine how to gain better access to agricultural and forestry biomass resources, including regulatory and technology development needs, in cooperation with the Department of Forestry and Fire Protection by December 31, 2006.	
c. Identify "biomass management zones" in key agricultural areas of California, in coordination with the Department of Forestry and the California Biomass Collaborative by June 30, 2007.	CDFA has made progress in concept, but have not quantified. CDFA is working on a Western Governor's Association study on the use of sugar cane in Imperial County to generate energy for desal and will add information when completed by month's end.
d. Evaluate the potential for regional manure management centers as potential sites for dairy bio-digesters in the San Joaquin Valley and at other suitable locations, in cooperation with the Energy Commission by June 30, 2007.	Defer to the Energy Commission. CDFA has a report from CalPoly-SLO, but it is now dated and does not meet CDFA's needs. CDFA has a staff person working on fuel cells to address the NOx issue.
e. Evaluate the potential for biomass technologies to address animal disposal and animal health concerns associated with emerging animal diseases by June 30, 2007.	CDFA can report on meeting with BioRefinex on their technology.

Bioenergy Action Items	Actions Taken
f. Work with the Public Utilities Commission to facilitate the sales and distribution of on-farm produced power.	
g. Develop and implement a strategy by December 31, 2006, to support bioenergy production and use under provisions of the existing federal Farm Bill and to improve those opportunities as the Farm Bill is rewritten for 2007.	Title IX of the farm bill was much enhanced due to Secretary Kawamura's leadership on behalf the Governor to represent the state's interest in the Farm Bill's formulation. 25X25 and others were also instrumental. The purpose of this action was accomplished; now need to work to develop projects for CA.

DEPARTMENT OF FORESTRY AND FIRE PROTECTION ACTION ITEMS

December 22, 2009

Bioenergy Action Items	Actions Taken
a. Identify "biomass management zones" in key forest and range areas of California, based on known resource, contribution to the maintenance of forest health, and reduction in large high-intensity wildfires by December 31, 2007.	Task has been delegated to the Biomass Collaborative. This is due in December 2009.
b. Determine and update geographic areas in the Urban Interface most in need of fuel reduction by December 31, 2007.	Nearing Completion – Final refinements will be completed by December 31, 2008.
c. Work with ARB and local air districts to evaluate the air quality impacts of wildfire emissions before and after fuel hazard reduction and provide intial findings by December 31, 2008.	Ongoing meetings with ARB.
d. Build upon the existing California Climate Action Registry protocols and continue development of additional protocols for the forest management and resource conservation and production and use of long-lived wood products by December 31, 2008.	Contracted to CCAR. Protocols to be completed in November.
e. Identify actions that can be taken by the Board of Forestry to encourage biomass production and use by December 31, 2006.	Continuing to work on this.
f. Work with the Department of General Services to install at least three combined heat and power units, using new technologies, at Forestry Conservation Camps at sites located along the California coast, in the Sierra Nevada range, and in the southern area of California by December 31, 2010.	Feasibility study ongoing.

Bioenergy Action Items	Actions Taken
g. Along with Board of Forestry and Fire Protection, collaborate in further development of long-term harvest contracts or agreements with the Federal Land Management Agencies with California land holdings, in close coordination with the U.S. Forest Service, Bureau of Land Management, and the Bureau of Indian Affairs. This effort would begin by July 31, 2006.	Ongoing with progress in Tahoe and El Dorado Forests.

The State Department of General Services ACTION ITEMS

December 22, 2009

Bioenergy Action Items	Actions Taken
a. Develop an annual statewide vehicle asset plan by December 31, 2006, that, through the Statewide Equipment Council: *a. Includes flexible fuel vehicles in the state's vehicle procurement program.* *b. Requires state vehicle contracts to be based on a Life Cycle Cost Analysis method.* *c. Requires state agencies (for light-duty, non-public safety applications, and other applications as practical) to purchase flexible-fuel vehicles capable of operating on renewable and alternative fuels, increasing to 50 percent of total new vehicles purchased by 2010.*	
b. Develop criteria, establish funding priorities, and identify potential revenue sources by December 31, 2006, to facilitate the incorporation of renewable energy into new state buildings and major renovations where feasible. Where feasible means capable of being accomplished in a successful manner within a reasonable period of time, taking into account life-cycle costing analysis, and the environmental, social, and technological factors. Feasibility shall not be based solely on cost considerations (excerpted from Government Code 14710(c).	
c. Recommend criteria by December 31, 2006 for use by the Department of Finance for the review and approval of funding for renewable and alternative energy projects. These criteria shall include a Life Cycle Cost Analysis methodology. Where projects cannot be justified solely on the basis of a Life Cycle Cost Analysis, policy justifications shall be articulated by the Governor.	

Bioenergy Action Items	Actions Taken
d. *Work with the Department of Forestry and Fire Protection to install at least three combined heat and power units, using new technologies, at Forestry Conservation Camps at sites located along the California coast, in the Sierra Nevada range, and in the Southern California by 2010.*	

California Public Utilities Commission ACTION ITEMS

December 22, 2009

Bioenergy Action Items	Actions Taken
As requested by the Governor, the California Public Utilities Commission will develop policies and establish mechanisms that would encourage increased future development and sustainable use of biomass and other renewable resources by the state's investor-owned utilities. Specific actions in 2006-2007 may include:	
a. Jointly investigating with the Energy Commission ways to simplify and streamline the RPS process to ensure that biomass and other renewable generation meets RPS goals.	
b. Reviewing and streamlining interconnection requirements to remove potential barriers to biopower development.	Aspects of both biogas and electric interconnection rules have undergone review at the CPUC. Recent activities include: 1) Gas Interconnection; resolution G-3420, approved on 9/18/08, dismissed SDG&E's and SoCalGas' interconnection subsidy because it was filed by advice letter. The resolution states the utilities should file their proposal via a formal application. There may be additional action taken to address potential barriers to interconnection through a more thorough examination of the issues at the Commission potentially triggered by a future application. 2) Electric Interconnection; Biogenerators may choose Rule 21 interconnection by net metering or by selling to the utility as a qualifying facility (QF) at avoided cost. Rule 21 Working Group may consider whether QFs that sell their entire output at other than avoided cost rates (i.e. feed-in tariff rates) may also use a Rule 21 interconnection. Currently, FERC interconnection applies.

Bioenergy Action Items	Actions Taken
c. *Allowing investor-owned utilities to continue offering net metering for biopower facilities and support legislation to increase net metering caps.*	Net metering for biogas digesters is codified in PUCode Section 2827.9. There has not been legislation in this session to increase the statewide net metering cap.
d. *Assessing the costs and benefits of providing specific exemptions to allow biomass facilities to wheel power directly to a farm and to consolidate net metering accounts on a farm.*	Net metered biogas customer generators can aggregate load on adjacent property attributable to milking and water pumping (PUCode Section 2827.9.c.1). PUCode does not permit aggregation, wheeling or self-wheeling by other biogas or biomass generation.
e. *Implementing mechanisms, including establishing appropriate avoided costs and long-term contracts, to preserve existing biopower facilities.*	650 MW of biomass QFs with bilaterally negotiated contracts have access to Standard Offer contracts. PUC approval of investor owned utility (IOU) (SCE) standard offer bioenergy contracts eliminated the complex negotiation process that is needed for larger projects and give bioenergy contracts for facilities up to 20 MW the opportunity to execute contracts with the IOU and contribute to California's RPS goals.
f. *Evaluating unique benefits that biopower may provide in meeting resources adequacy and RPS requirements and global climate change reduction targets.*	Revisions to the Market Price Referent in the RPS Proceeding put forth in the Proposed Decision in R.06-02-012 issued on September 16, 2008, provide more value for the reductions in GHG emissions. http://docs.cpuc.ca.gov/efile/PD/90863.pdf Under the Climate Smart Tariff, methane capture projects are now deemed eligible GHG offsets following the protocol developed by the California Climate Registry.

ATTACHMENT

CEC workshop: Use of biomethane delivered via the natural gas pipeline system for California's RPS

Comments by:
Southern California Public Power Authority
September 20, 2011

Introduction to SCPPA

12 SCPPA members

Anaheim, Azusa, Banning, Burbank, Cerritos, Colton, Glendale, Los Angeles, Pasadena, Riverside, Vernon and the Imperial Irrigation District

SCPPA members' planning objectives:

- Reliable Power
  - Fuel and geographic diversity to increase the efficiency of existing assets such as transmission
- Competitive and Stable Power Rates
  - Our ratepayers are our "shareholders"
- Environmentally Responsible

2

RPS Challenges

Need compliance flexibility in order to maintain electrical system reliability

- SCPPA members are fully resourced with a nominal load growth forecast ⟹ few if any "unmet needs"
  - Likely **to displace existing owned generation or long term purchase contracts to accommodate RPS**
- From start of negotiation to a signed contract may take 1-2 years; Commercial Operation Date of projects is usually 2-4 years after contracts are signed; projects are often delayed
- In-State "Bucket 1" renewable energy resources are very limited for the short term due to typical project development issues (including siting difficulties) and ongoing transmission constraints
- **Legislative and regulatory uncertainty creates contract (financial) risk and supply risk**

3

Benefits of Biomethane

As a part of mix with other renewable and conventional resources

- Least-cost, best-fit and viable resource [PUC 399.13 (a) (4) (A) & 399.16(b)]
- Viable alternative to reduce coal use
- Can be reliably used in generation facilities which can be dispatched to meet local load profiles and accommodate variable renewable sources (solar, wind, etc.)
- Provides fuel diversity…a must for electrical system reliability
- No additional power transmission infrastructure is needed
- Can be stored to match utility's energy needs, with no adverse impact on natural gas pipeline system
- Easily auditable from source to sink

4

Certification Issues

- CEC should continue to process applications for certification under the regulations and guidelines as of the date the application was submitted (or the date biomethane started flowing), not the date the application was processed
- Certification process should provide for multiple biomethane sources to be added sequentially without affecting eligibility, content category, or other criteria for previously approved biomethane sources
- CEC should consider certifying biomethane sources as RPS eligible so that electric generators using certified biomethane can be expeditiously certified, reducing the regulatory risk
- Certified generators that are repowered or replaced should maintain certification under original conditions

5

Certification and Content Category Issues

- Certification of the generation should align with the existing WREGIS practice of itemizing each "unit" of a facility
  - The operator of a generating facility with multiple generating units should be able to specify the units at which the biomethane is combusted
- Under SBX 12, the RPS Portfolio Content Category is determined by the location of the generator, not the source of the fuel
  - If the electricity generated from combustion of biomethane is scheduled into CA Balancing Authority Area, the electricity corresponds to PUC §399.16(b)(1)(A) and should be considered "Bucket 1"

6

1) Delivery of Biomethane

- **Existing CEC requirements for delivery should be retained**
- **Both options (a) and (b) impose unnecessary restrictions that will raise the costs of procuring biomethane and complying with the RPS**
- **In California, delivery of biomethane should be treated in the same way as natural gas – in accordance with established rules set out in CPUC-approved gas tariffs**
  - **Existing delivery requirements are well vetted, comply with the regulatory structure of the natural gas utilities and should be retained**
  - **Once biomethane is nominated to California, its path should not be relevant to the CEC for RPS purposes**

7

2) Location Requirements

- **The CEC should not add location requirements**
- **Neither existing regulations nor SBX1 2 provide any basis for imposing location requirements on biomethane production**
- **Total potential supply of biomethane from the whole of the USA is very limited and will not prevent uptake of other types of renewable energy**
- **Use of biomethane from a range of sources should be encouraged as it diversifies energy supply, reduces reliance on natural gas imports, and supports best possible operational integration of variable renewable resources**

8

3) Transportation Agreements

- **The CEC should retain the current requirements (option a)**
- **If restrictions are imposed on transportation, costs will increase without any corresponding environmental benefit**
- **Delivery of biomethane should be treated in the same way as natural gas – in accordance with established rules set out in CPUC-approved gas tariffs**
  - **Greater transport flexibility and reduced delivery risk**

9

4) Delay in Combustion

- **Delays in combustion of biomethane should be allowed**
- **Delays may occur for many reasons outside the control of the generating facility operator, even after the biomethane has reached California**
  - **For example, a pipeline may be out of service or there may be an unplanned shutdown at the generating facility**
- **In addition, there may be good operational reasons why a facility chooses to store biomethane for use when production drops or to help stabilize gas flow**
- **The CEC should only require record keeping to enable audits of biomethane purchases, delivery, potential storage, and ultimate combustion of the fuel**

10

5) Biomethane Imbalances

- Biomethane imbalances should be treated in the same way as natural gas imbalances – in accordance with established rules set out in CPUC-approved gas tariffs
  - Tariffs provide +/- 10% monthly imbalance tolerance for all pipeline gas, including biomethane (with seasonal adjustments)
- The CEC should not impose imbalance limitations that are stricter than existing tariffs – this would conflict with settlement agreements imposed by the CPUC, and would not add value

11

6) Biomethane Records

- Electricity generating facilities retain extensive records to support the auditing of biomethane, including:
  - Chain of title from the source of the biomethane to the meter, including storage and parking transactions
  - Pipeline scheduling and balancing records
  - Schedules of nominations and confirmations
- Such records provide a complete picture of the delivery and use of biomethane and will prevent double-counting
- The ARB proposes to accept such records for the purposes of the cap-and-trade program

12

Thank you

Gurcharan Bawa
Pasadena Water & Power
(626) 744-7598
gbawa@cityofpasadena.net

ATTACHMENT

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Assembly
California Legislature

MIKE GATTO
ASSEMBLYMEMBER, FORTY-THIRD DISTRICT

COMMITTEES
APPROPRIATIONS
ARTS, ENTERTAINMENT, SPORTS, TOURISM AND INTERNET MEDIA
BANKING AND FINANCE
GOVERNMENTAL ORGANIZATION
WATER, PARKS AND WILDLIFE

March 8, 2012

Dr. Robert Weisenmiller, Chair
California Energy Commission
1516 Ninth Street
Sacramento, CA 95814

RE: Pipeline Biomethane and 33% Renewable Portfolio Standard (RPS)

Dear Chair Weisenmiller and Commissioners,

We applaud the Commission's thoughtful efforts to engage stakeholders in a robust discussion about what changes are needed in the RPS compliance guidelines concerning biomethane. While we understand that the Commission is under pressure to make immediate changes, including a moratorium on contracts, we believe the only responsible path is to wait for the Legislature to act before making changes that may have to be reconfigured after the conclusion of this year's legislative session. We are primarily motivated by the interests of our constituents, who are the true beneficiaries of our State's RPS policy, but are also the ratepayers affected by this ongoing discussion and will bear the burden of any negative impact to their energy providers.

We share the concerns of our colleagues on how the enactment of SB 2-1X may or may not impact the eligibility of pipeline biomethane under the RPS and its broader implications for the state's renewable energy goals. We are ready to engage with all of our colleagues to find a responsible course forward. That's why we are working with ratepayer and environmental advocates, scientists and stakeholders from the energy industry, public and private utilities to craft legislation that will answer important questions about the future of biomethane use under the RPS. There are currently several bills pending in the Legislature on this subject.

At workshops hosted by the CEC, legitimate concerns were expressed by stakeholders regarding environmental benefits, "additionality" in the greenhouse gas (GHG) context, and the need for a tracking system to prevent double counting of these transactions. We believe these concerns can be addressed and believe a concerted effort to discuss productive solutions should predate changes in law or the guidelines.

A moratorium would constitute a change in the existing rules of the CEC that have been in place for over three years. These rules have served as the basis for investment decisions by California's municipal utilities and private sector renewable energy producers acting in good faith to meet California's demand for renewable fuel. Such a moratorium ignores efforts at the CEC and in the Legislature to engage stakeholders from all sides in efforts to outline a way forward which protects California rate-payers, meets the state's renewable energy goals and respects the health of the biomethane industry, including preserving the ability of producers to assist in development of California's biomethane resources.

To that end, we request that the Commission allow time for the Legislature to act to carefully consider all of the ramifications of future rules for biomethane eligibililty in RPS for our constituents and the utilities which supply their energy prior to changing rules that will most likely change again in a matter of a few short months.

Thank you in advance for your consideration.

Sincerely,

Assemblyman Mike Gatto
AD-43

Assemblyman Roger Hernández
AD-57

ATTACHMENT

CALIFORNIA LEGISLATURE

STATE CAPITOL
SACRAMENTO, CALIFORNIA
95814

March 14, 2012

Chair Robert Weisenmiller, Ph.D.
California Energy Commission
1516 Ninth Street
Sacramento, CA 95814

RE: Pipeline Biomethane and 33% Renewable Portfolio Standard (RPS)

Dear Chair Weisenmiller and Commissioners,

We applaud the Commission's thoughtful efforts to engage stakeholders in a robust discussion about what, if any, changes are needed in the RPS compliance guidelines concerning biomethane. While we understand that the Commission is being pushed to make immediate changes to the RPS guidelines, including a moratorium on additional pipeline biomethane transactions that are credited toward RPS compliance obligations, we write to respectfully urge the Commission to make no changes in the guidelines to allow time for the Legislature to clarify eligibility conditions for pipeline biomethane use during the legislative session.

We the undersigned share the concerns of our colleagues on how the enactment of SB 2-1X may or may not impact the eligibility of pipeline biomethane under the RPS and its broader implications for the state's renewable energy goals. That's why many of us are working with stakeholders from the energy industry, utilities and environmental advocates to craft legislation that will answer important questions about the future of biomethane use under the RPS. There are currently two bills pending in the Legislature on this subject.

At workshops hosted by the CEC, concerns were expressed by stakeholders over whether there are demonstrable environmental benefits to California from biomethane as required by law, whether "additionality" is achieved in the greenhouse gas (GHG) context, and over the apparent lack of any national tracking system to prevent double counting of these transactions, a larger group of stakeholders at the Commission workshop countered such opinions by demonstrating an ability to meet each of these criteria.

Further, additional concerns have been expressed by clean energy companies and utilities representing California consumers that the Biomethane Industry, which produces "ultra low carbon fuel" with great potential to advance the state's AB 32 goals, will be significantly harmed by any "moratorium" imposed outside of the legislative process. Not only would such a moratorium negatively impact renewable energy projects in which California investors and entrepreneurs have invested hundreds of millions of dollars, a moratorium would constitute a change in the existing rules of the CEC that have been in place for over three years. These rules have served as the basis for investment decisions made by renewable energy producers acting in good faith to meet California's demand for renewable fuel.

Such a moratorium would also impact utilities and could well result in skyrocketing electricity costs for California consumers as it would eliminate utilities access to one of the most cost-effective baseload renewable energy resources currently available. Finally, we are of the understanding that the stakeholders

Finally, we are of the understanding that the stakeholders from both sides of the issue have been routinely meeting with the intent to resolve their differences and outline a way forward that preserves the health of the Biomethane Industry, protects California rate-payers and meets the state's renewable energy goals.

For these reasons, we agree that the eligibility of pipeline biomethane deserves additional consideration by the Legislature. However, we feel that any administrative attempt to impose a "moratorium" on biomethane transactions under the CEC's existing rules (pending legislative action) could have significant negative impact on our constituents and the utilities that serve them. The suggested "moratorium" in effect decides the issue through agency action and imposes consequences before the California legislature has even had an opportunity to craft careful legislation that could protect California ratepayers and preserve much of the California Biomethane Industry.

To that end, we request that the Commission reject the request to arbitrarily place a moratorium on permitting any additional pipeline biomethane transactions to be credited toward RPS compliance obligations and allow the Legislature to act to clarify rules and conditions for use of pipeline biomethane in RPS compliance in the present legislative session.

Thank you in advance for your consideration.

Sincerely,

CONNIE CONWAY
34th Assembly District

TED LIEU
28th Senate District

ROGER HERNANDEZ
57th Assembly District

CAROL LIU
21st Senate District

KATCHO ACHADJIAN
33rd Assembly District

TOM BERRYHILL
14th Senate District

STEPHEN T. KNIGHT
36th Assembly District

JEFF MILLER
71st Assembly District

CAMERON SMYTH
38th Assembly District

Cc: Carla Peterman, Commissioner
Karen Douglas, Commissioner
Darrell Steinberg, Senate President Pro Tempore
John A. Perez, Speaker of the Assembly
Gareth Elliott, Legislative Affairs Secretary, Office of the Governor

ATTACHMENT

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California State Senate

SENATOR
KEVIN DE LEÓN
DEMOCRATIC CAUCUS CHAIR
TWENTY-SECOND SENATE DISTRICT

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LEGISLATIVE AUDIT
RULES

March 9, 2012

Robert Weisenmiller, Chair
California Energy Commission
1516 Ninth Street
Sacramento, CA 95814

RE: Pipeline Biomethane and 33% Renewable Portfolio Standard (RPS)

Dear Chair Weisenmiller:

The Commission has engaged in a thoughtful process involving stakeholders in a robust discussion about what, if any, changes are needed in the RPS compliance guidelines concerning biomethane. But I must respectfully urge the Commission to make no changes in the guidelines and to allow time for the Legislature to clarify eligibility conditions for pipeline biomethane use during the Legislative session.

I understand that the Commission is being pressured to make immediate changes to the RPS guidelines, including consideration of a moratorium on additional pipeline biomethane transactions that are credited toward RPS compliance obligations, but it must demonstrate prudency before it takes action that will harm responsible parties and environmental progress.

I am particularly concerned about how the enactment of SB 2-1X may or may not impact the eligibility of pipeline biomethane under the RPS and its broader implications for the state's renewable energy goals. That is why many Legislators are working with stakeholders from the energy industry, utilities and environmental advocates to craft legislation that will answer important questions about the future of biomethane use under the RPS. There are currently two bills pending in the Legislature on this subject.

At workshops hosted by the CEC, concerns were expressed by stakeholders over whether there are demonstrable environmental benefits to California from biomethane as required by law, whether "additionality" is achieved in the greenhouse gas (GHG) context, and over the apparent lack of any national tracking system to prevent double counting of these transactions. A larger group of

stakeholders at the Commission workshop countered such opinions by demonstrating an ability to meet each of these criteria.

Further, additional concerns have been expressed by clean energy companies and utilities representing California consumers that the Biomethane Industry, which produces "ultra low carbon fuel" with great potential to advance the state's AB 32 goals, will be significantly harmed by any "moratorium" imposed outside of the legislative process. Not only would such a moratorium negatively impact renewable energy projects in which California investors and entrepreneurs have invested hundreds of millions of dollars, a moratorium would constitute a change in the existing rules of the CEC that have been in place for over three years. These rules have served as the basis for investment decisions made by renewable energy producers acting in good faith to meet California's demand for renewable fuel. Such a moratorium would also impact utilities and could well result in skyrocketing electricity costs for California consumers as it would eliminate utilities access to one of the most cost-effective baseload renewable energy resources currently available.

For these reasons, I believe that the eligibility of pipeline biomethane deserves additional consideration by the Legislature. On the other hand, any administrative attempt to impose a "moratorium" on biomethane transactions under the CEC's existing rules (pending legislative action) could have significant negative impact on our constituents and the utilities that serve them. The suggested "moratorium" in effect decides the issue through agency action and imposes consequences before the California legislature has even had an opportunity to craft careful legislation that could protect California ratepayers and preserve much of the California Biomethane Industry.

To that end, I respectfully request that the Commission reject the request to arbitrarily place a moratorium on permitting any additional pipeline biomethane transactions to be credited toward RPS compliance obligations and allow the Legislature to act to clarify rules and conditions for use of pipeline biomethane in RPS compliance in the present legislative session.

Thank you for your prompt attention to this matter. If you have any questions please do not hesitate to contact me directly at (916) 651-4022.

Sincerely,

Kevin de León

KEVIN DE LEÓN
Senator, Twenty-second District

Cc: Gareth Elliot, Legislative Affairs Secretary, Office of the Governor

ATTACHMENT

California Public Utilities Commission

33% RENEWABLES PORTFOLIO STANDARD
Implementation Analysis Preliminary Results

June 2009

FOR FULL REPORT, SEE (1) COURTESY COPIES OF DOCUMENTS SUBMITTED VIA FTP LINK, OR (2) HARDCOPY SUBMITTED TO CEC DOCKET UNIT

ATTACHMENT







Climate Change Scoping Plan

a framework for change

DECEMBER 2008

Pursuant to AB 32
The California Global Warming Solutions Act of 2006

Prepared by
the California Air Resources Board
for the State of California

Arnold Schwarzenegger
Governor

Linda S. Adams
Secretary, California Environmental Protection Agency

Mary D. Nichols
Chairman, Air Resources Board

James N. Goldstene
Executive Officer, Air Resources Board

FOR FULL REPORT, SEE (1) COURTESY COPIES OF DOCUMENTS SUBMITTED VIA FTP LINK, OR (2) HARDCOPY SUBMITTED TO CEC DOCKET UNIT

STATE OF CALIFORNIA
ENERGY RESOURCES
CONSERVATION AND DEVELOPMENT COMMISSION

In the Matter of:	)	Docket No. 11-RPS-01
	)	Docket No. 02-REN-1038
Developing Regulations and Guidelines for the 33 Percent Renewables Portfolio Standard	)	
	)	**PROOF OF SERVICE**
and	)	
	)	(March 23, 2012)
Implementation of Renewables Investment Plan Legislation	)	
	)	

ENERGY COMMISSION

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Developing Regulations and Guidelines for the 33 Percent Renewables Portfolio Standard
And Implementation of Renewables Investment Plan Legislation
CEC Docket No. 11-RPS-01
CEC Docket No. 02-REN-1038

DECLARATION OF SERVICE

I, Paul Kihm, declare that on March 23, 2012, I served and filed copies of the attached:

Comments on the CEC's Proposed Suspension of RPS Eligibility Guidelines related to Biomethane

to all parties identified on the Proof of Service List above in the following manner:

California Energy Commission Docket Unit

☒ Transmission via electronic mail and by depositing an original copy with FedEx overnight mail delivery service at Costa Mesa, California, with delivery fees thereon fully prepaid and addressed to the following:

CALIFORNIA ENERGY COMMISSION
Attn: DOCKET NOS. 11-RPS-01 and 02-REN-1038, RPS Proceedings
1516 Ninth Street, MS-4
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docket@energy.state.ca.us

For Service to All Other Parties

☒ Transmission via electronic mail to all email addresses on the Proof of Service list.

I declare under penalty of perjury that the foregoing is true and correct. Executed on March 23, 2012, at Costa Mesa, California.

Paul Kihm